Western Planning Regions (WPR) Interregional Coordination Meeting

Portland, Oregon

February 23, 2017

Introductions & Meeting Logistics

Patrick Damiano
Paul Didsayabutra

ColumbiaGrid

Agenda for Today

- Meeting objectives & finalize agenda
- WPR Annual Interregional Information & Interregional Transmission Project (ITP) proposals evaluation update
  - ColumbiaGrid
  - Northern Tier Transmission Group ("NTTG")
  - WestConnect
  - California ISO
- WPR engagement with the development of Anchor Data Set (ADS)
- Open discussion
- Review of key points, action items, assignments
- Closing remarks & next meeting

Meeting Objectives

- Describe interregional coordination activities
- Briefly summarize each Planning Region's Annual Interregional Information
- Provide update regarding ITP proposals evaluation, if any
- Discuss interregional solutions that may meet regional transmission needs
- Open Discussion

WPR Annual Interregional Information & ITP Evaluation

ColumbiaGrid

NTTG

WestConnect

California ISO

ColumbiaGrid Regional Planning Process

Annual Interregional Coordination Meeting

February 23, 2017

In This Presentation

- Introduction
- Overview of ColumbiaGrid Planning Process
- 2016 Planning activities, results (Needs Assessment), and conclusions
- 2017 Planning activities
- Information and Notifications

Introduction

Members and Planning Participants

- Avista Corporation**
- Bonneville Power Administration
- Chelan County PUD
- Cowlitz County PUD*
- Douglas County PUD*
- Grant County PUD
- Puget Sound Energy**
- Seattle City Light
- Snohomish County PUD
- Tacoma Power

* Non-Member PEFA Planning Participants
** Order 1000 Functional Agreement Party

ColumbiaGrid

ColumbiaGrid

- Independent staff
- Conducts a wide range of technical studies
  - Reliability (power flow, stability)
  - Economic planning studies (Production Cost Simulation)
  - Sensitivity studies that focus on specific issues
  - Other studies (scope TBD)
- Focuses on transmission grid planning
- Two Functional Agreements (FA) define Grid Planning
  - Planning and Expansion Functional Agreement (PEFA)
  - Order 1000 (O1K) Functional Agreement

Overview of ColumbiaGrid

Grid Planning Process

ColumbiaGrid Planning Process

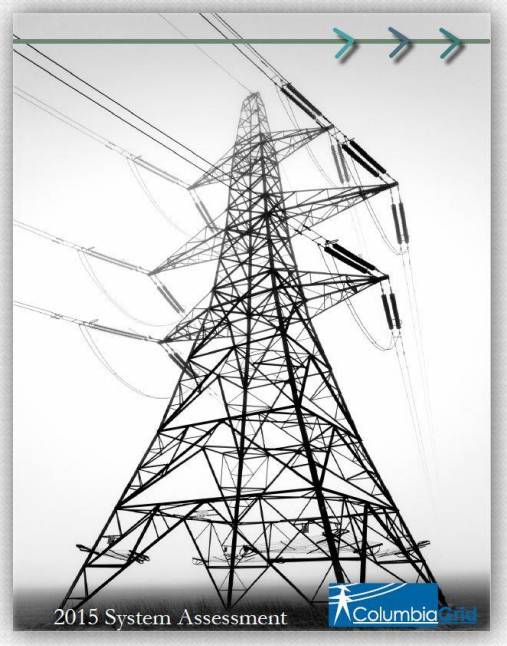
- Single process complies with both PEFA and Order 1000 FA
- Single planning cycle covers 2 years. However, most technical studies are conducted annually
  - System Assessment*
  - Sensitivity Studies*
  - Transient Stability*
  - Economic Planning Study*
  - Special studies**
  - Specific Study Team analysis**
- Planning meetings (6 meetings/year) are opened to public

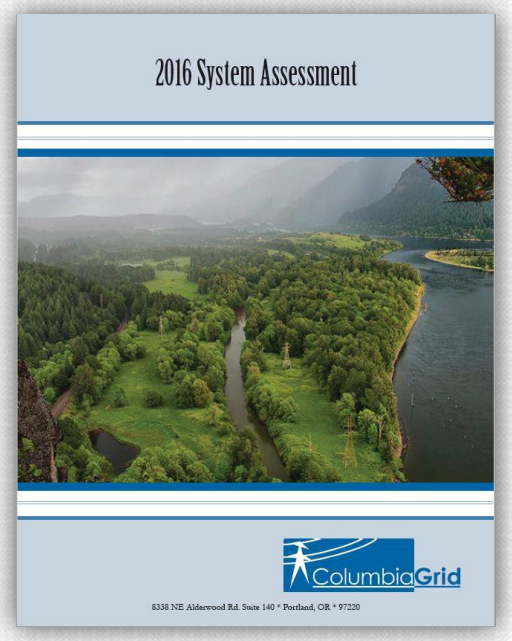
* Annual studies

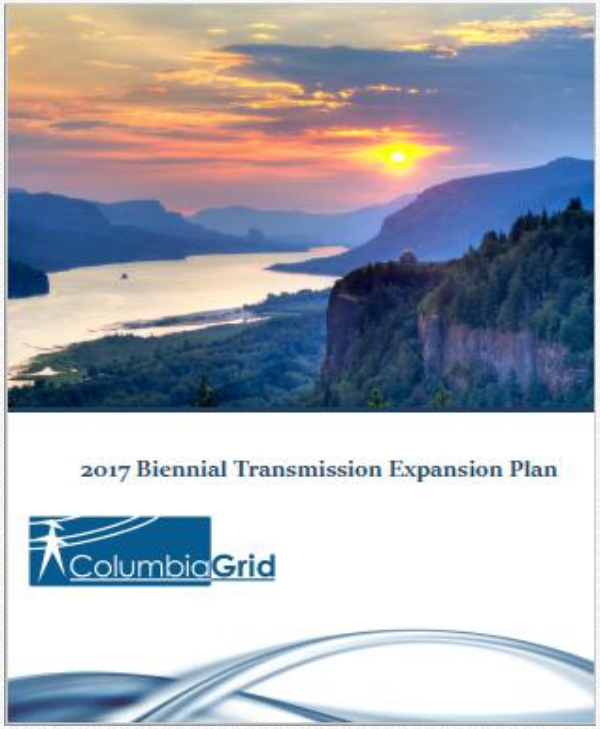
** Flexible timeline, may take longer time to complete the studies

ColumbiaGrid Planning Process

- Two documents summarize planning activities/results
  - System Assessment Report (Needs Statement) – issued annually
  - Biennial Transmission Expansion Plan (BTEP) – issued every 2 years*





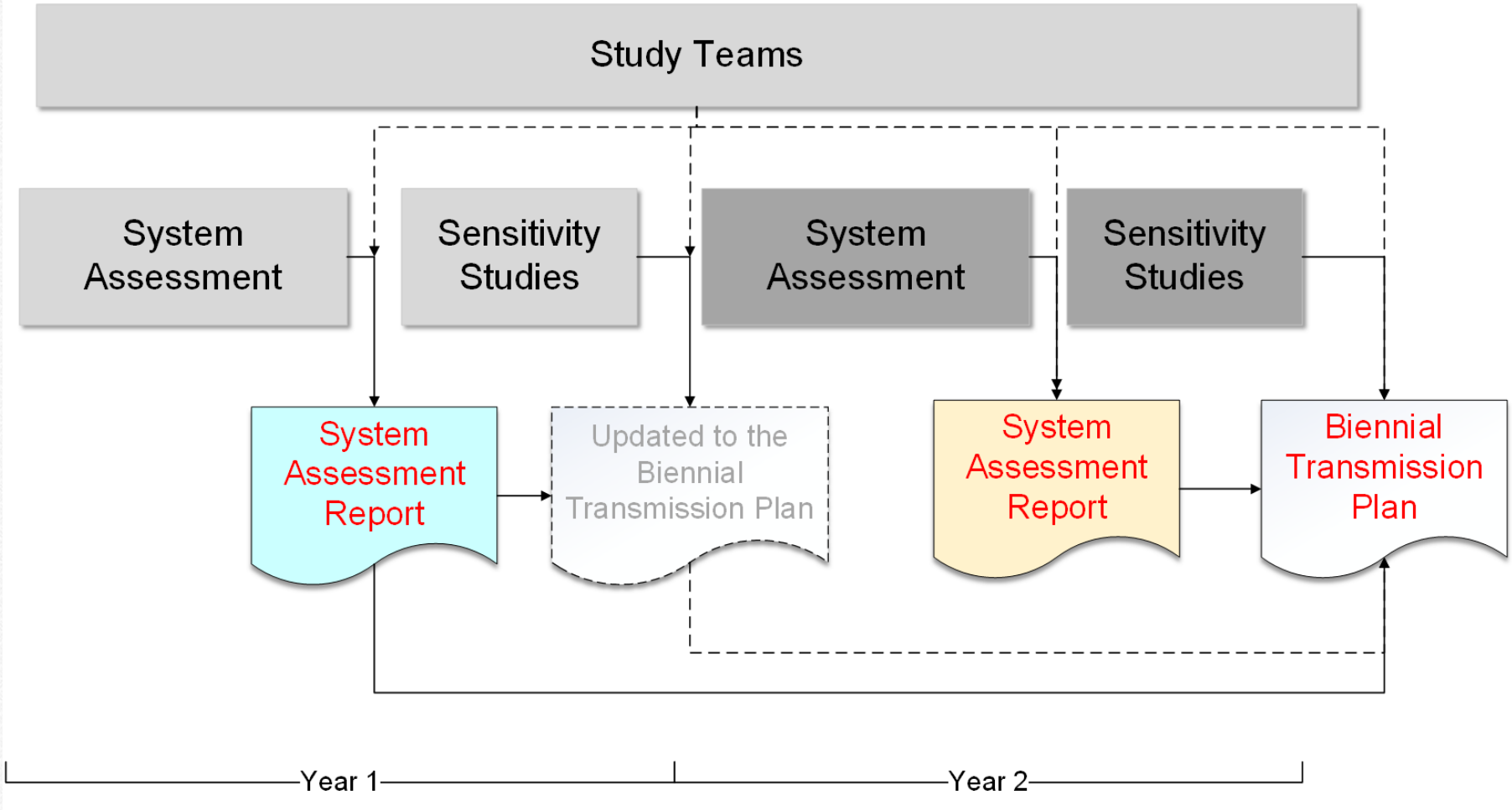


* If significant issues are identified, an update to the previous BTEP may be issued for the interim year

ColumbiaGrid Planning Process

- Additional reports/documents may be issued, for example:
  - An update to the BTEP may be issued for the interim year
  - Study team reports
  - Special study reports
- Opportunities for stakeholder participation
  - Submit data & suggestions e.g. for Order 1000 Potential Needs
  - Participate in the meetings (in person, phone, Web)
  - Receive information & notifications (emails, web postings)

ColumbiaGrid Planning Process



2016 Planning Activities, Needs Assessment Results & Conclusions

Regional/Interregional Activities in 2016

- January – March 2016
  - ColumbiaGrid Order 1000 Needs Suggestions window
  - Interregional Transmission Project (ITP) submittal window
  - Developed System Assessment Study plan and base cases
- April – August 2016
  - Evaluated O1K Needs suggestions that were received
  - Conducted System Assessment studies
  - Developed 2016 System Assessment (Needs Statement) report
  - Conducted Transient Stability & Economic Planning Studies
  - Participated in ITP evaluation efforts
- September – December 2016
  - Conducted Sensitivity Studies
  - Drafted 2017 BTEP

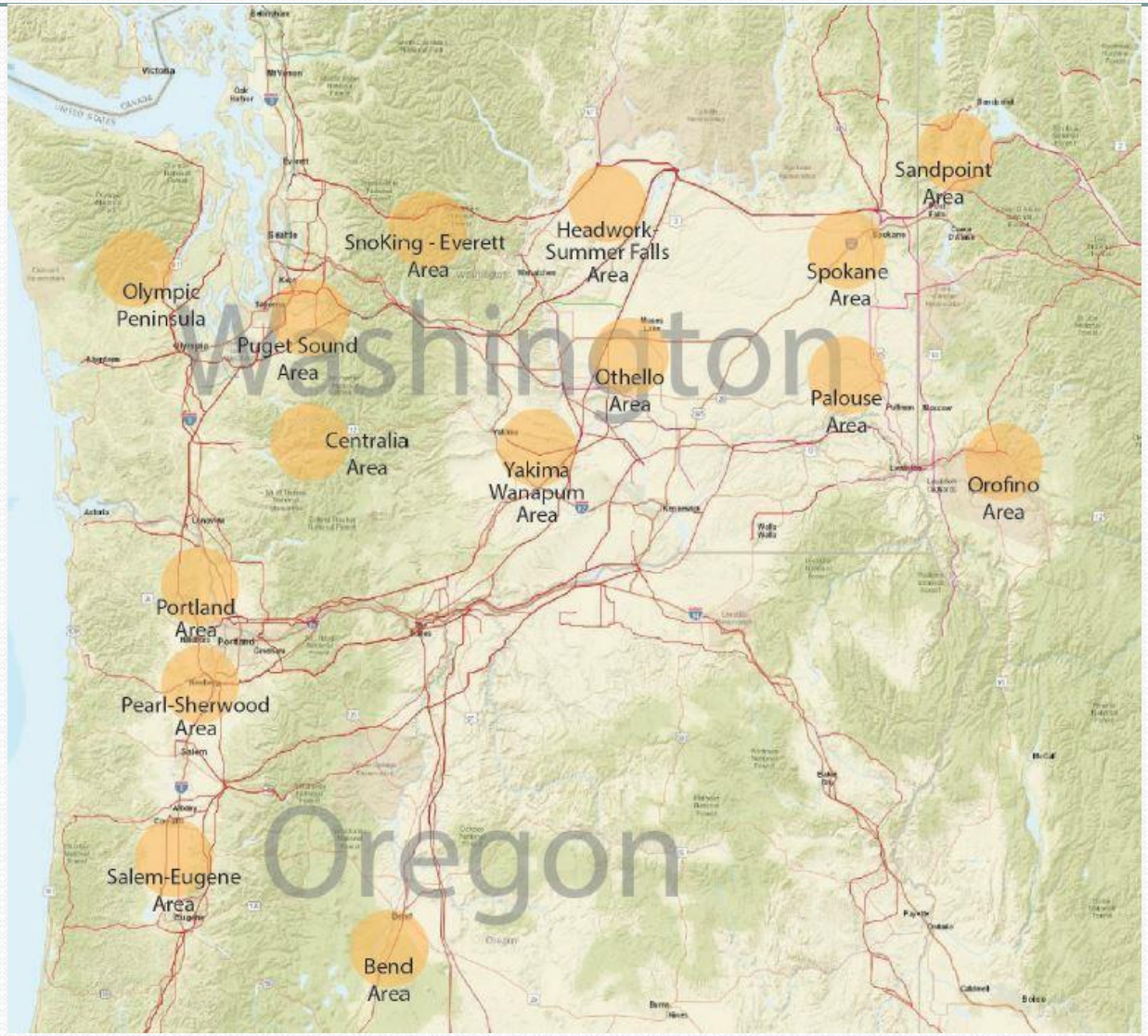
Summary of 2016 Planning Cycle

- Two suggestions of Order 1000 Potential Needs were received but they did not conform with the criteria to be considered as Order 1000 Potential Needs
  - Reliability
  - Economic
  - Public Policy
- Four projects were submitted to be considered as ITPs. However, ColumbiaGrid's region was not interconnected to any of the four proposed ITPs
- System Assessment was conducted based on assumptions / scenarios identified by planning participants
  - Seven base scenarios were studied

Summary of 2016 Studies

- System Assessment report identified 15 Areas of Concern
  - No major issues related to the NW were identified
  - Various local concerns
  - Similar to issues found to those in 2015 System Assessment
  - Load reduction in some areas resulted in less loading/less severity of previous concerns
  - Mitigation plans have been evaluated
- Economic Planning Study evaluated system conditions in 2026
  - The results showed similar system behavior compared to previous year studies

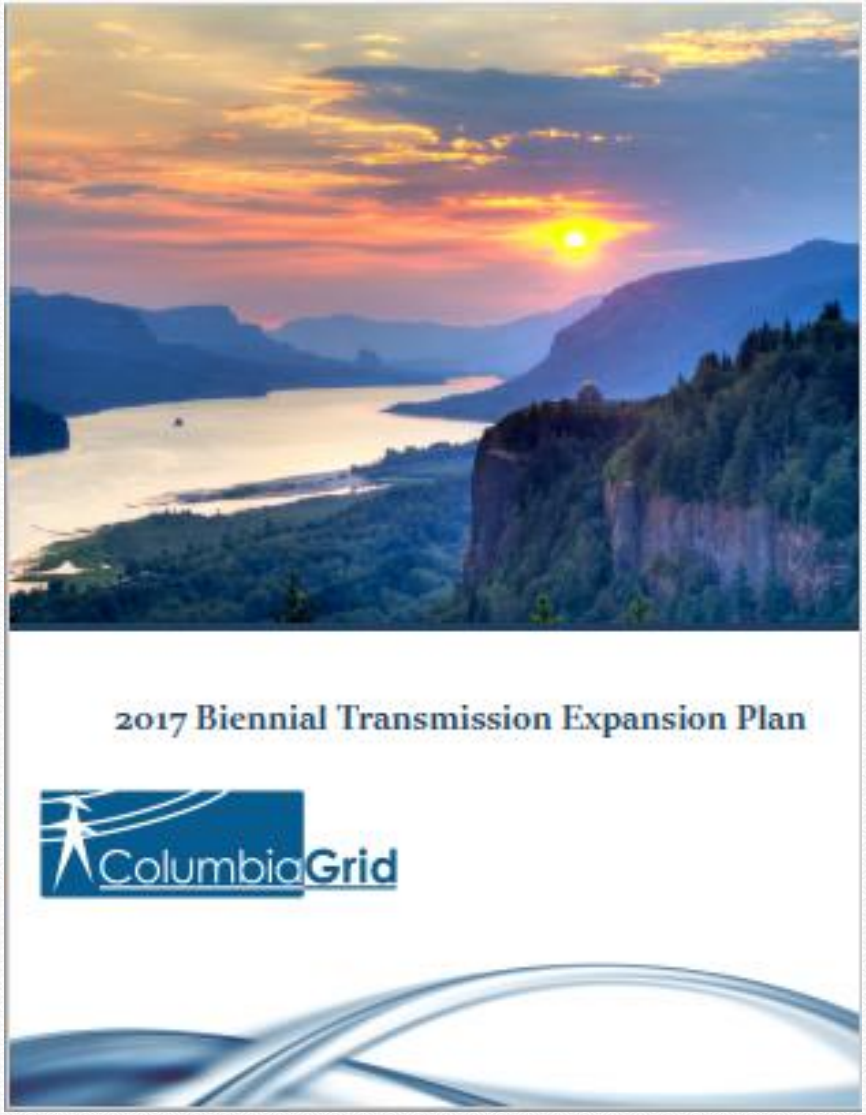
System Assessment Results



Summary of 2016 Studies

- Transient Stability studies simulated more than 6,000 contingencies. No significant issues were identified
  - After each issue was closely analyzed
- Three sensitivity studies (N-1-1, Extra Heavy Winter, High Renewables) identified potential issues that may need additional studies
- All study activities are documented in the 2017 BTEP
- The 2017 BTEP has been approved by CG's Board of Directors and is now available on CG's website at: http://www.columbiagrid.org/planning-expansion-overview.cfm

Current Status: 2017 BTEP

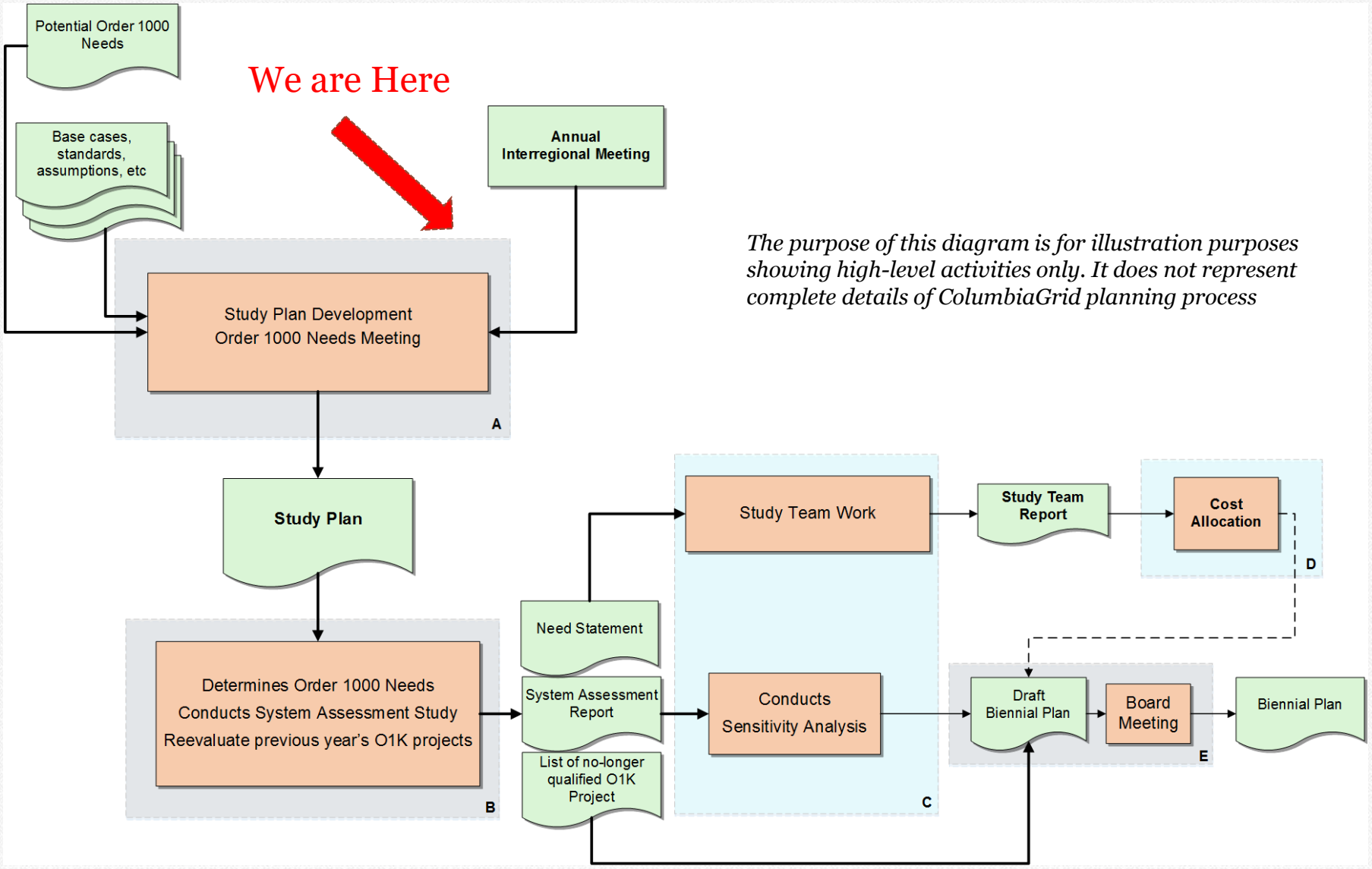


Major contents

- 2016 System Assessment: 15 joint areas of concern identified; No new issues.
- List of transmission expansion projects in the ColumbiaGrid Ten Year Plan. Total costs ~ $2.4B
- Study Team updates: Puget Sound, Northern Mid-Columbia
- 2016 Sensitivity Studies: Extra Heavy Winter, N-1-1, and High Renewable Contingency Study results
- Transient Stability Study Results
- Economic Planning Study Results
- Summary of Order 1000 activities
- Special studies summary/other updates

2017 Planning Activities

2017 Planning Activities: Current Status



The purpose of this diagram is for illustration purposes showing high-level activities only. It does not represent complete details of ColumbiaGrid planning process

2017 Planning Activities: Current Status

- Order 1000 Needs Suggestion Window
  - Interested persons may submit suggestions for "Order 1000 Potential Needs"
  - Potential drivers for Order 1000 project(s)
  - For more info: Please refer to the 1/13/17 notification
  - An Order 1000 Potential Needs submission form can be downloaded at the following link:

    https://www.columbiagrid.org/1000-overview.cfm

Annual Interregional Information

- Posted under ColumbiaGrid's "Order 1000 Inter-regional page" at: Order 1000 Interregional Overview
  - ColumbiaGrid information package
  - 2017 Draft Study Plan
  - 2017 Biennial Transmission Expansion Plan
  - 2016 System Assessment Report
- More information, once available, will be posted at this location
  - Notifications will be sent to inform interested persons

2017 Planning Activities: Studies/Tasks

- 2017 System Assessment (2017 SA)
  - Study Plan is being finalized
  - Focus on reliability compliance for joint areas of concern (involve multiple entities/systems)
  - 10-year planning horizon
  - NERC TPL Reliability Standards used as reference for system performance
  - Evaluate applicable Order 1000 Potential Needs
- Sensitivity & Special studies
  - Study scope for each year determined by Planning participants
  - Start the study after the completion of the 2017 SA

2017 Planning Activities: Studies/Tasks

- Additional Studies
  - Transient stability assessment
  - Economic Planning Study (Production cost)
  - System model validation (MOD-033)
  - Geomagnetic Induced Currents (TPL-007-1)
- Study Teams: Dedicated study groups
  - For studies that need more time and resources
  - Examples: Puget Sound, Mid Columbia areas, Order 1000 Needs and project reevaluation
- Regional coordination & base case development

2017 Planning Activities: Major Milestones

- March 2017
  - Finalize Study Plan, Order 1000 Potential Needs, Base Cases
- April - August 2017
  - Conduct 2017 System Assessment and other studies
  - Finalize the scope of Sensitivity & special studies (MOD-033, GMD)
  - Start conducting Transient, Economic Planning, and special studies
- September 2017
  - Issue 2017 System Assessment Report (Needs Statement)
  - Start conducting Sensitivity Studies
- November 2017
  - Finalize Sensitivity Studies
- December 2017
  - Announce the 2018 O1K Needs Suggestions & ITP submission windows

2017 Planning Activities: Planning Meetings

Please refer to ColumbiaGrid's website for more details

No	Date	Location	Focus
1	February 9, 2017	Portland, OR	Order 1000 Needs suggestions, 2017 System Assessment assumptions, other updates
2	April 2017	Portland, OR	Order 1000 Potential Needs, finalize 2017 study plan, updates on system assessment
3	June 2017	Portland, OR	Order 1000 Needs, Draft System Assessment study results, Updates
4	August 2017	Seattle, WA	Updates & Technical discussion
5	October 2017	Portland, OR	Order 1000 updates, Draft Sensitivity Study results, Other updates
6	December 2017	Portland, OR	Draft Update to 2017 BTEP*, Updates

* Optional for this year

Information and Notifications

Information, Events and Announcements

Recent Announcements

Planning and Expansion: General postings & PEFA related information

Order 1000 Regional

Order 1000 Inter-regional

Stay Informed About Future Activities

- Public notifications
  - ColumbiaGrid will notify interested persons regarding future activities through email
  - Self-register system
  - Refer to “Join Interest List” on ColumbiaGrid’s main page

Stay Informed About Future Activities

Question:

Larry Furumasu, furumasu@columbiagrid.org
Paul Didsayabutra, paul@columbiagrid.org

WestConnect
Regional Planning Update

Western Planning Regions

Annual Interregional Coordination Meeting

Portland, OR

February 23, 2017

Overview

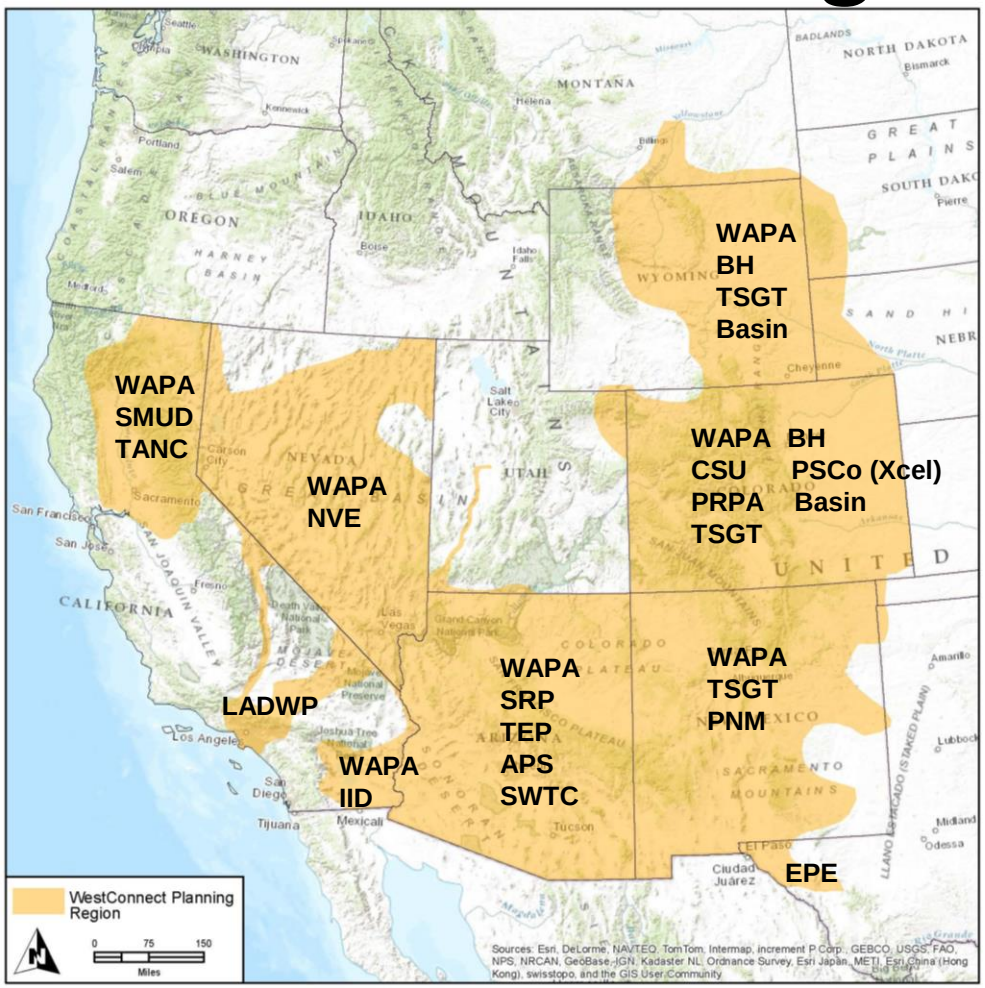
- WestConnect Overview
- Interregional Transmission Project Submittals
- Annual Interregional Information and 2016/2017 Planning Cycle Update
- Upcoming Meetings and Opportunities for Stakeholder Input

WestConnect Overview

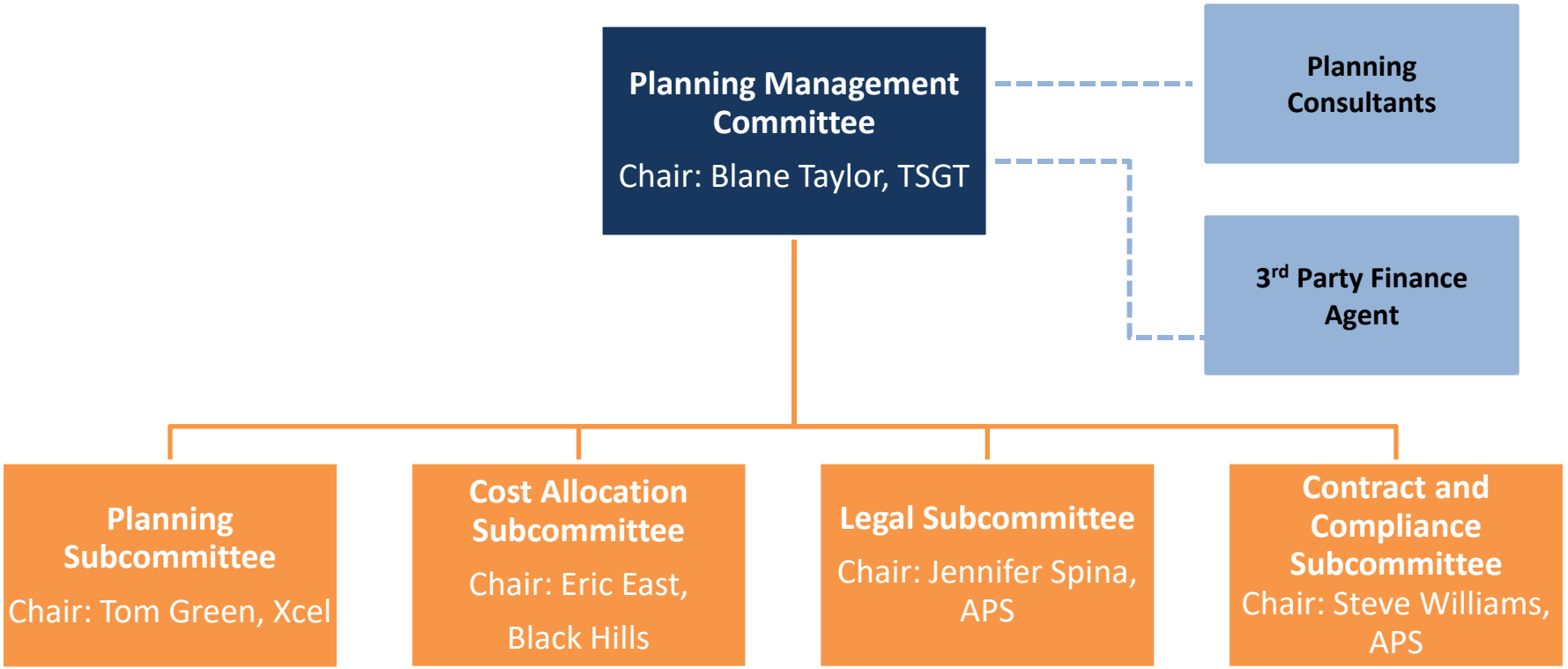
Regulatory Update

- Regional Compliance Filings
  - All tariff revisions related to the regional planning requirements of Order 1000 were fully accepted by FERC on January 21, 2016
  - On August 8, 2016 the 5th Circuit Court of Appeals vacated FERC's compliance orders related to mandates regarding the role of the non-jurisdictional utilities in cost allocation
    - WestConnect public TOs are awaiting a FERC response

WestConnect Planning Region



PMC Organization



PMC Membership as of 12/21/2016

Transmission Owner w/Load Serving Obligation (18)

Enrolled TO

- Arizona Public Service
- Black Hills
- El Paso Electric
- NV Energy
- Public Service of New Mexico
- Tucson Electric
- Xcel - PSCo

Coordinating TO

- Arizona Electric Power Cooperative (formerly SWTC)
- Basin Electric
- Colorado Springs Utilities
- Imperial Irrigation District
- Los Angeles Department of Water and Power
- Platte River
- Sacramento Municipal Utility District
- Salt River Project
- Transmission Agency of Northern California
- Tri-State G&T
- Western Area Power Administration

Transmission Customer

- Vacant

Independent Transmission Developer (8)

- American Transmission Company
- Blackforest Partners
- Exelon Transmission
- ITC Grid Development, LLC
- Southwestern Power Group
- TransCanyon
- Western Energy Connection
- Xcel – Western Transmission Company

State Regulatory Commission

- Vacant

Key Interest Group (1)

- Natural Resources Defense Council

Updated 12/21/16

PMC Activities

- Monthly in-person meetings (3rd Wednesday) held at rotating member facilities
  - Meeting information can be accessed via the WestConnect calendar
- Manages the Regional Transmission Planning Process
- Continues to develop procedures to implement the Planning Process
  - Project Selection Task Force
  - Transmission Developer Selection Process Task Force

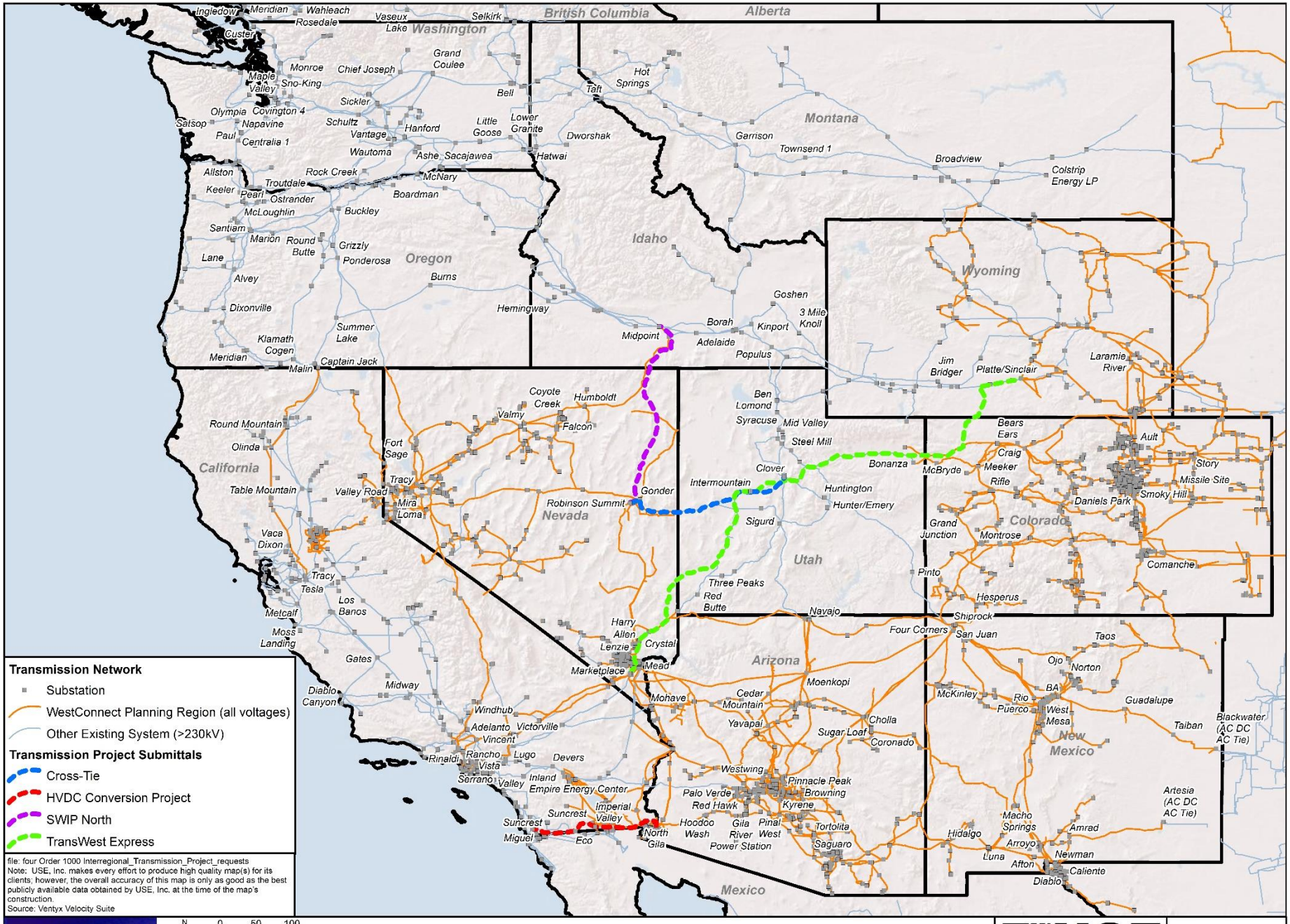
Interregional Transmission Project Submittals

Interregional Transmission Project Submittals

Project Name	Company	Project Submitted To	Relevant Planning Regions	Seeking Cost Allocation from WestConnect
SWIP North	Western Energy Connection, LLC	WestConnect CAISO NTTG	WestConnect NTTG*	Yes
Cross-Tie Project	TransCanyon, LLC	WestConnect CAISO NTTG	WestConnect* NTTG	Yes
TransWest Express	TransWest Express, LLC	WestConnect CAISO NTTG	WestConnect CAISO* NTTG	Yes
HVDC Conversion Project	San Diego Gas & Electric	WestConnect CAISO	WestConnect CAISO*	No

* = Indicates lead planning region

- The lead planning region will organize and facilitate interregional coordination meetings and track action items and outcomes of those meetings.
- Project submittal summaries are available here
- An "ITP Evaluation Process Plan" is also posted for each ITP



WestConnect Order 1000 2016-17
Interregional Transmission Project (ITP) Submittals

Figure 1
Drawn By: M. Wood
5/3/2016

2016/2017 Planning Cycle Update

Keegan Moyer, WestConnect Planning Consultant, ES
Tom Green, Planning Subcommittee Chair, Xcel Energy

WestConnect Annual Interregional Information to be Shared with WPRs

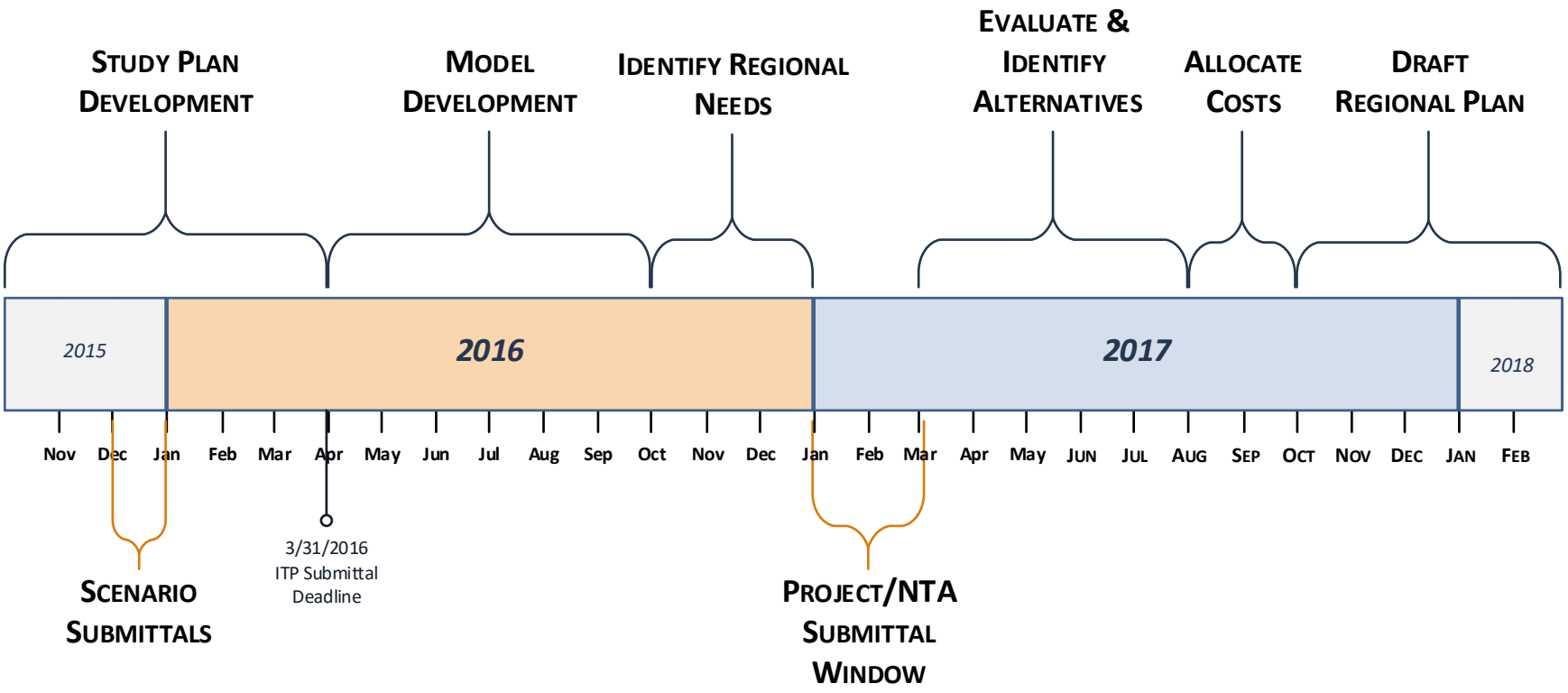
Year 1 (2016)	Year 2 (2017)
✓ Current cycle Study Plan ✓ Current cycle Base Transmission Plan ✓ Previous cycle Regional Transmission Plan	❑ Current cycle Regional Transmission Needs Assessment Report ❑ List of any ITPs submitted during regional project submittal window

- WestConnect makes the WPRs aware of this information through this annual Interregional Coordination meeting
- WestConnect also coordinates on an ongoing basis more informally through data exchanges and planning assumption development at relevant points in the planning process
- Any ITP evaluation would require extensive coordination between WestConnect and the relevant planning region

WestConnect ITP Proposals: Status Update

- WestConnect did not identify any regional transmission needs as a part of its 2016-17 regional planning process
- Commensurately, there will not be any ITP evaluations
  - Had there been regional needs, ITPs would have had the option to be resubmitted in Q1 2017 for evaluation alongside other regional alternatives (indicating which specific need they would meet)
  - WestConnect did coordinate ITP transmission and resource assumptions whenever timing and processes allowed (despite not having any established regional needs and no evaluation path for the projects)

2016-17 Planning Cycle Schedule



Model Development Schedule and Status

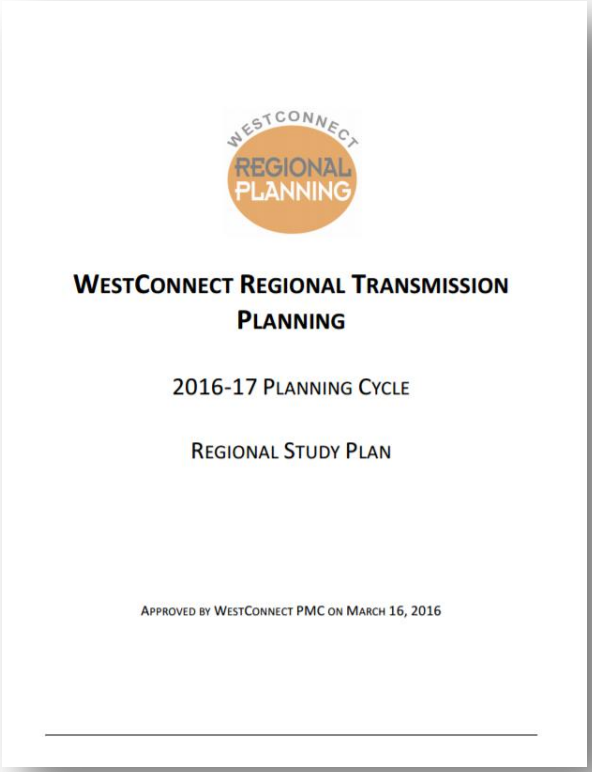
Reliability Model Case Summary				
	Case Name	**Case ID**	**Case Description and Scope**	**Status**
Base Cases	**2026 Heavy Summer Base Case**	WC26-HS	Summer peak load conditions during 1500 to 1700 MDT, with typical flows throughout the Western Interconnection	***Complete*** *– Case & Assessment Done; no Regional Needs identified*
	2026 Light Spring Base Case	WC26-LSP	Light load conditions with high wind and solar generation	***Complete-*** *Case & Assessment Done; no Regional Needs identified*
Scenario Cases	**CPP – WestConnect Utility Plans Scenario**	WC26-CPP1	Reflect individual WestConnect member utility plans for Clean Power Plan (CPP) compliance – *export stressed hour from PCM*	***In progress****– PCM case is complete and stressed hour identified and exported to PF. PF is solved. Planning Subcommittee is reviewing draft case.*
	CPP – Heavy RE/EE Build Out Scenario	WC26-CPP3	Additional coal retirements, additional RE/EE, minimal new natural gas generation – *export stressed hour from PCM*	***In progress****– PCM case is complete and stressed hour identified and exported to PF. PF is solved. Planning Subcommittee is reviewing draft case.*

Model Development Schedule and Status (cont.)

Economic Model Case Summary				
	Case Name	**Case ID**	**Case Description and Scope**	**Status**
Base Case	**2026 Base Case**	WC26-PCM	Business-as-usual case based on WECC 2026 Common Case with additional regional updates from PMC members.	***Complete***– *Case & Assessment Done; no regional needs identified*
Scenario Cases	**High Renewables**	WC26-PCM-HR	California 50% RPS with regional resources (Wyoming wind and New Mexico wind) *and* increase WestConnect state RPS requirement beyond enacted with other resources	***Complete***– *Case & Assessment Done, considering potential for Regional Opportunities based on congestion*
	CPP – WestConnect Utility Plans	WC26-PCM-CPP1	Reflect individual WestConnect member utility plans for CPP compliance	***Complete***– *Case & Assessment Done, considering potential for Regional Opportunities based on congestion*
	CPP – Market-based Compliance	WC26-PCM-CPP2	Model CO_2 price in WestConnect to achieve mass-based regional CPP compliance	***Complete***– *Case & Assessment Done; considering potential for Regional Opportunities based on congestion*
	CPP – Heavy RE Build Out	WC26-PCM-CPP3	Additional coal retirements, additional RE/EE, minimal new natural gas generation	***Complete***– *Case & Assessment Done; considering potential for Regional Opportunities based on congestion*

2016-17 Study Plan

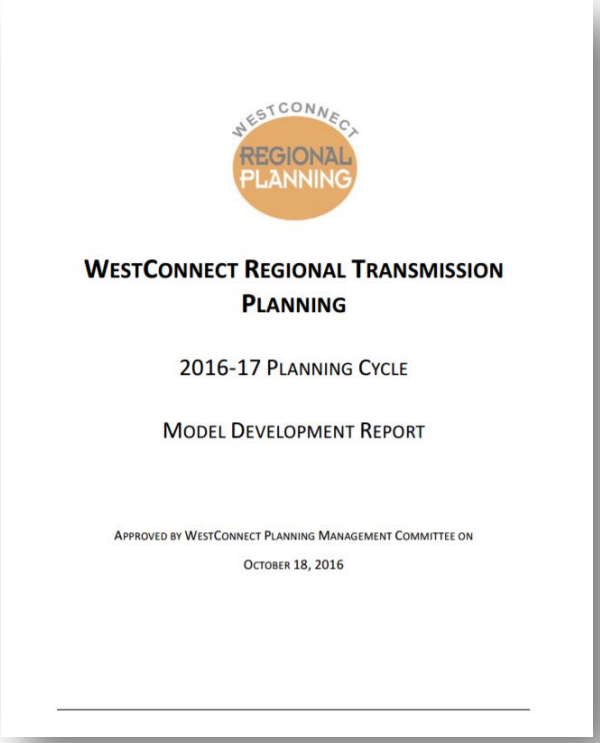
- Formal work plan document approved by PMC on March 16th
- Identified Base Cases, Scenarios, Base Transmission Plan, and regional transmission need assessment approach for:
  - Reliability needs
  - Economic needs
  - Public Policy needs
- Defines local versus regional transmission issues



Download 2016-17 Study Plan *HERE*.

2016-17 Model Development

- Document summarizing major model assumptions approved by PMC on October 18th
- Includes generation, load and other modeling assumptions for economic and reliability Base Case and Scenario assessments
  - Lists of Coal retirements for scenario studies
  - Summary of changes made to WECC cases, including 2026 Common Case



WESTCONNECT REGIONAL TRANSMISSION PLANNING

2016-17 PLANNING CYCLE

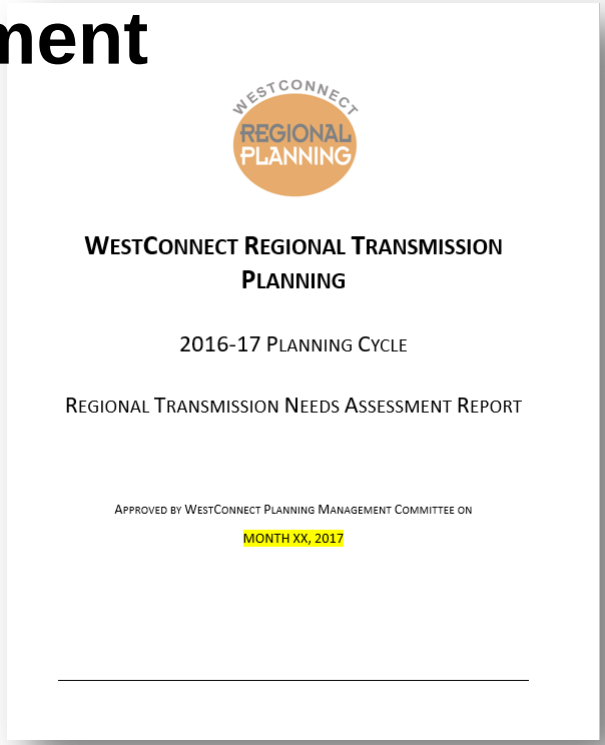
MODEL DEVELOPMENT REPORT

APPROVED BY WESTCONNECT PLANNING MANAGEMENT COMMITTEE ON OCTOBER 18, 2016

Download 2016-17 Model Development Report *HERE*.

2016-17 Regional Needs Assessment

- In December, the PMC approved that **no regional transmission needs** will be identified as a part of the 2016-17 WestConnect Regional Planning Process
  - Based on results from Base Case Assessments
- Regional Needs Assessment Report will be considered for approval by the PMC in March
  - Draft report is under review by Planning Subcommittee
  - Addresses Base Cases and the identification of regional transmission needs, updates assumptions on Base Economic Model
  - Scenario results to be summarized in future report/slides



WESTCONNECT REGIONAL PLANNING

WESTCONNECT REGIONAL TRANSMISSION PLANNING

2016-17 PLANNING CYCLE

REGIONAL TRANSMISSION NEEDS ASSESSMENT REPORT

APPROVED BY WESTCONNECT PLANNING MANAGEMENT COMMITTEE ON

MONTH XX, 2017

2016-17 Regional Needs Assessment Report is DRAFT

Regional Needs Assessment Outline

2016-17 Regional Needs Assessment (cont.)

- Regional Reliability Assessment
  - Violations of NERC TPL-001-4 Table 1 (P0 and P1) and TPL-001-WECC-CRT-3 reliability standards on or between more than one TOLSO Member system may constitute a regional need
  - Evaluated contingencies >200kV, unless specified by TO
  - Monitor elements >100kV for performance, unless specified by TO
  - **No regional reliability needs were identified based on the evaluation of the 2026 Heavy Summer and 2026 Light Spring cases**

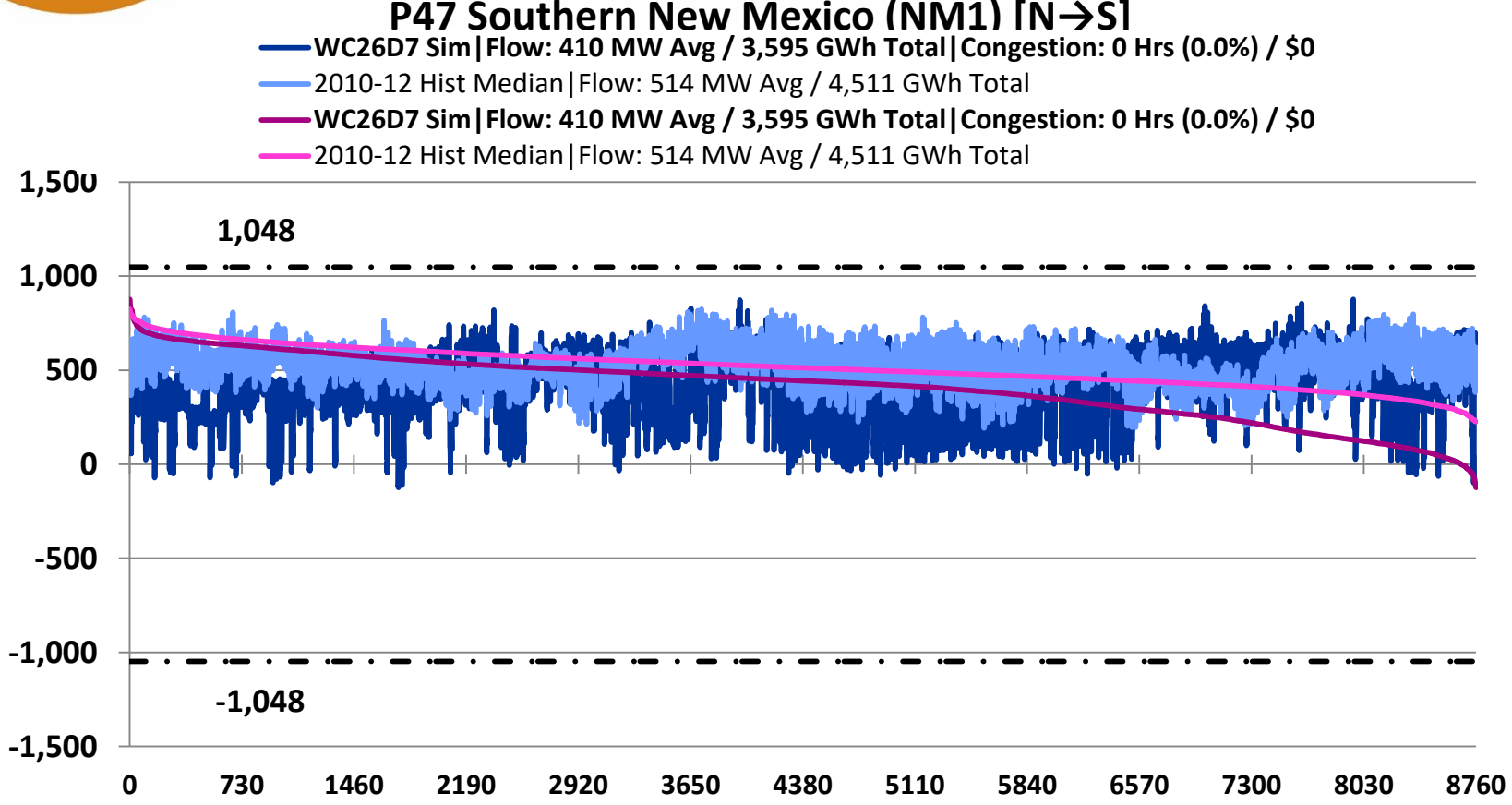
2016-17 Regional Needs Assessment (cont.)

- Regional Economic Assessment
  - Base & Sensitivity Analysis Performed for year 2026 using case developed from WECC Common Case supplemented by WestConnect updates
  - Objective of the economic need assessment was to identify congested elements that have economic potential for a regional project solution
  - **The analysis did not identify any regional economic needs based on the lack of congestion observed in the Base Case and accompanying sensitivity studies**
  - Sensitivities performed for EIM modeling, Phase Shifting Transformer modeling, contingency modeling, and gas price (2x)

Congestion Across All Cases (Branches* & Paths)		Congestion Across Cases Total Congestion Hours (% Hrs) / Cost ($) Green=Less Congestion, Red=More Congestion					
Owner(s)	**Branch/Path Name**	**WC 26PCM-D7_161214**	**D7-HighNG**	**D7-NoPST**	**D7-WithEIM**	**D7-WithOTG**	**D7-EPEBal200**
APS	WESTWNGE - WESTWG14	10 (0%) / $1,818K	11 (0%) / $2,000K	10 (0%) / $1,818K	10 (0%) / $1,818K	10 (0%) / $1,817K	10 (0%) / $1,818K
APS	WESTWNGE - WESTWG11	10 (0%) / $1,818K	11 (0%) / $2,000K	10 (0%) / $1,818K	10 (0%) / $1,818K	10 (0%) / $1,817K	10 (0%) / $1,818K
APS	CTRYCLUB_230.0 - LINCSTRT_230.0	143 (2%) / $1,689K	112 (1%) / $2,826K	150 (2%) / $1,657K	148 (2%) / $1,902K	127 (1%) / $1,599K	148 (2%) / $1,742K
NEVP/ CAISO	P24 PG&E-Sierra	552 (6%) / $1,422K	769 (9%) / $2,038K	624 (7%) / $4,508K	237 (3%) / $629K	577 (7%) / $1,412K	554 (6%) / $1,409K
LADWP	TARZANA_230.0 - OLYMPC_230.0	19 (0%) / $1,272K	21 (0%) / $1,414K	22 (0%) / $1,535K	16 (0%) / $955K	19 (0%) / $1,128K	17 (0%) / $1,342K
NEVP	HIL TOP - HIL TOP	161 (2%) / $519K	442 (5%) / $1,891K	-	2 (0%) / $5K	162 (2%) / $564K	145 (2%) / $511K
LADWP	RINALDI_230.0 - AIRWAY_230.0	4 (0%) / $105K	2 (0%) / $62K	3 (0%) / $155K	4 (0%) / $168K	4 (0%) / $156K	5 (0%) / $145K
	P66 COI	4 (0%) / $64K	12 (0%) / $233K	3 (0%) / $49K	8 (0%) / $137K	4 (0%) / $49K	4 (0%) / $54K
PSCO	LEETSDAL_230.0 - MONROEPS_230.0	2 (0%) / $18K	-	3 (0%) / $18K	3 (0%) / $20K	-	2 (0%) / $17K
PNM	P48 Northern New Mexico (NM2)	3 (0%) / $4K	4 (0%) / $42K	2 (0%) / $1K	2 (0%) / $2K	-	2 (0%) / $1K
PSCO	GREENWD_230.0 - MONACO12_230.0	1 (0%) / $1K	10 (0%) / $110K	2 (0%) / $2K	2 (0%) / $1K	4 (0%) / $13K	1 (0%) / $1K
NEVP	CLARK 6 - CLARK	1 (0%) / $1K	2 (0%) / $4K	4 (0%) / $17K	1 (0%) / $16K	3 (0%) / $9K	2 (0%) / $4K
	P41 Sylmar to SCE	1 (0%) / $0K	1 (0%) / $0K	-	2 (0%) / $1K	-	1 (0%) / $0K
APS	MEADOWBK_230.0 - SUNYSLOP_230.0	-	-	-	-	10 (0%) / $393K	-
NEVP	TRACY E_345.0 - VALMY_345.0	-	-	-	1 (0%) / $9K	-	-
PSCO	CABINCRK_230.0 - DILLON_230.0	-	13 (0%) / $70K	-	-	-	-
MULTI	P30 TOT 1A	-	-	-	2 (0%) / $3K	-	-
LADWP | NEVP| CAISO	P32 Pavant-Gonder InterMtn-Gonder 230 kV	-	1 (0%) / $1K	2 (0%) / $4K	7 (0%) / $36K	3 (0%) / $8K	2 (0%) / $4K
PSCO	P36 TOT 3	-	45 (1%) / $1,247K	-	-	-	-
PNM|EPE | TGST	P47 Southern New Mexico (NM1)	-	7 (0%) / $61K	-	-	-	-
NEVP|CAISO	P52 Silver Peak-Control 55 kV	-	64 (1%) / $9K	184 (2%) / $420K	2 (0%) / $0K	2 (0%) / $0K	-
LADWP |CAISO |Other	P61 Lugo-Victorville 500 kV Line	-	3 (0%) / $21K	-	-	-	-
Total Congestion Cost ($K)		**$8,731**	**$14,028**	**$12,002**	**$7,520**	**$8,964**	**$8,866**

Negligible amounts of regional congestion in Base Case study

Sensitivities had varying impacts on single-TO congestion. However, with few exceptions no new regional congestion was identified.



- **The Planning Subcommittee also reviewed duration curves for all regionally significant paths to evaluate seasonality of congestion and changes from historical path flows**

2016-17 Regional Needs Assessment (cont.)

- Regional Public Policy Assessment
  - Enacted public policies are represented in regional base models
  - Proposed public policies are considered as a part of scenario planning process
  - Identification of public policy needs driven by reliability and economic assessment and feedback on transmission plans provided by stakeholders
  - No public policy-driven transmission needs were identified

2016-17 Regional Needs Assessment (cont.)

- Based on the Base Case scenarios performed as a part of the WestConnect 2016-17 Regional Planning Process there were:
  - No regional reliability needs identified;
  - No regional economic needs identified; and
  - No regional public policy needs identified.
- Because there were no regional needs identified, in 2017 there will not be:
  1. Evaluation and selection of project solutions to meet regional needs (including interregional transmission projects);
  2. Cost allocation evaluation and identification; and
  3. Project developer selection.

2016-17 SCENARIO STUDIES

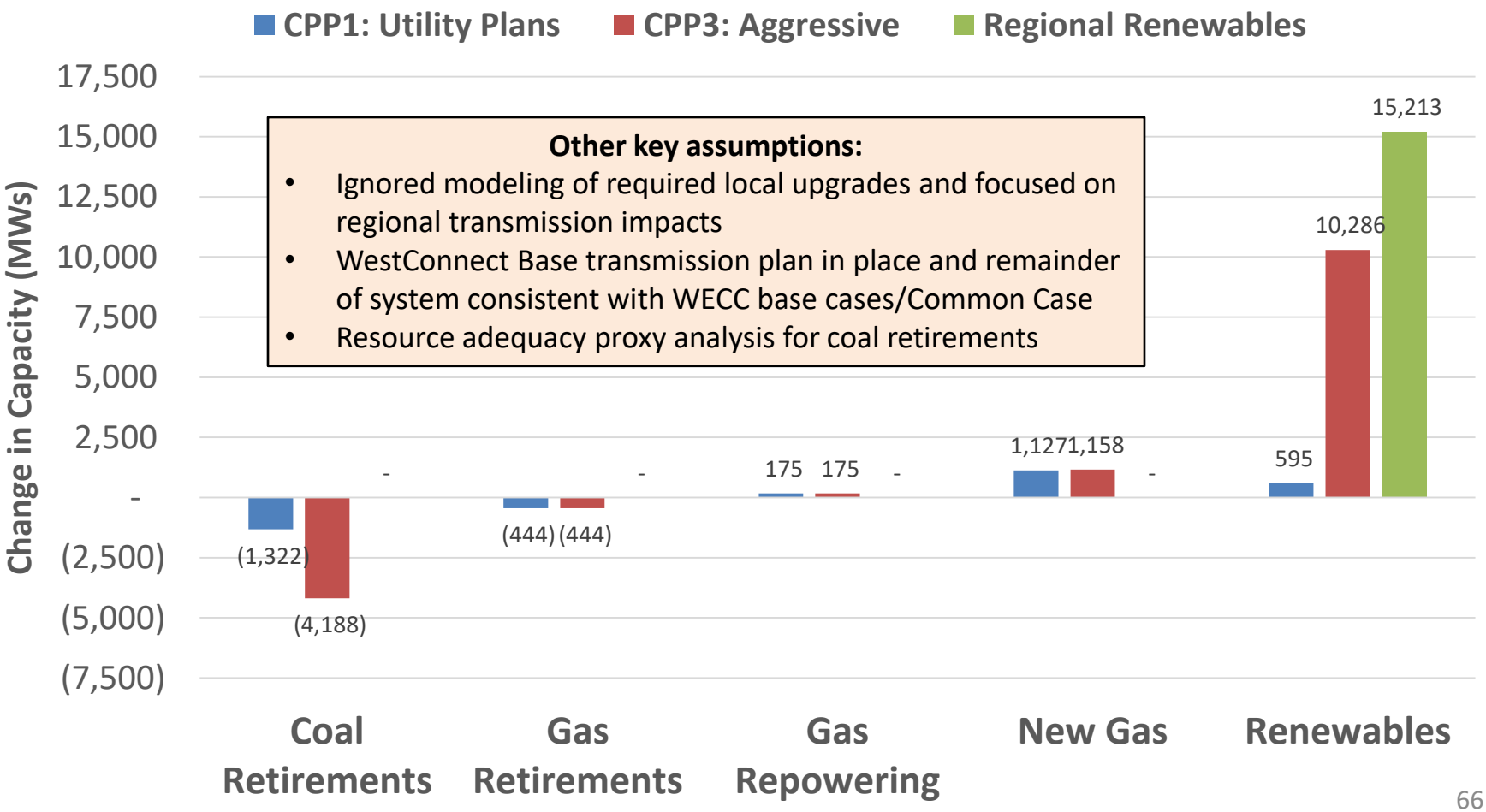
This section summarizes:

1) Key assumptions in modeling scenarios;
2) Draft results from assessment;
3) Remaining work and next steps

Summary of Scenarios Studied in 2016-17

Scenario Name	Description	*Key Assumptions (changes to Base)*	*Study Scope*
Regional Renewables (RR)	50% increase to enacted WestConnect-state RPS with required resources added locally to TOs. 4,000 MW of resources added in Wyoming and New Mexico for CA 50% RPS purposes ("sunk" in CA).	• 3,651 MW of wind in WestConnect • 7,166 MW of solar in WestConnect • 396 MW of geothermal in WestConnect • 4,000 MW of wind in WY/NM for CA	*Economic assessment only*
CPP – WestConnect Utility Plans (CPP1)	Reflect individual WestConnect member utility plans for CPP compliance, including retirements and replacement assumptions. Represents compiled set of assumptions developed independently by TOs from IRPs or other planning initiatives.	• 1,322 MW of coal retirements • 444 MW of gas retired (175 MW of repowering) • 1,127 MW of gas added • 595 MW of renewable energy	*Economic and reliability assessment*
CPP – Heavy RE Build Out (CPP3)	Reflects more aggressive coal retirements than in CPP3, with replacement capacity from additional RE minimizing new natural gas generation (while meeting resource adequacy).	• 4,188 MW of coal retirements • 444 MW of gas retired (175 MW of repowering) • 1,158 MW of gas added • 10,286 MW of additional renewable energy	*Economic and reliability assessment*

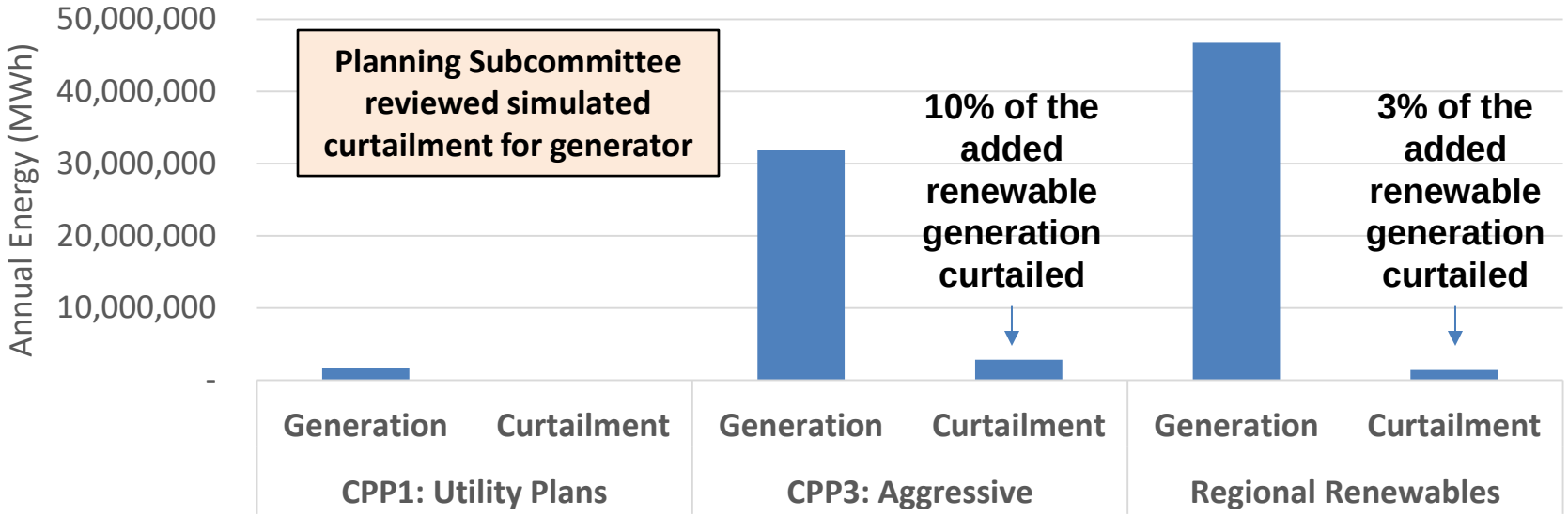
Comparison of Scenario Resource Changes (in MWs)



Other key assumptions:

- Ignored modeling of required local upgrades and focused on regional transmission impacts
- WestConnect Base transmission plan in place and remainder of system consistent with WECC base cases/Common Case
- Resource adequacy proxy analysis for coal retirements

WestConnect reviewed simulation results for renewable resource curtailment driven by transmission constraints



No curtailment; all added resources delivered to loads

Significant curtailment in select locations; Colorado up to 50% of energy, others around 1% of total output

Significant curtailment in select locations: Colorado, Arizona, Southern CA, New Mexico and Wyoming

Key findings from CPP1 Utility Plans Study:

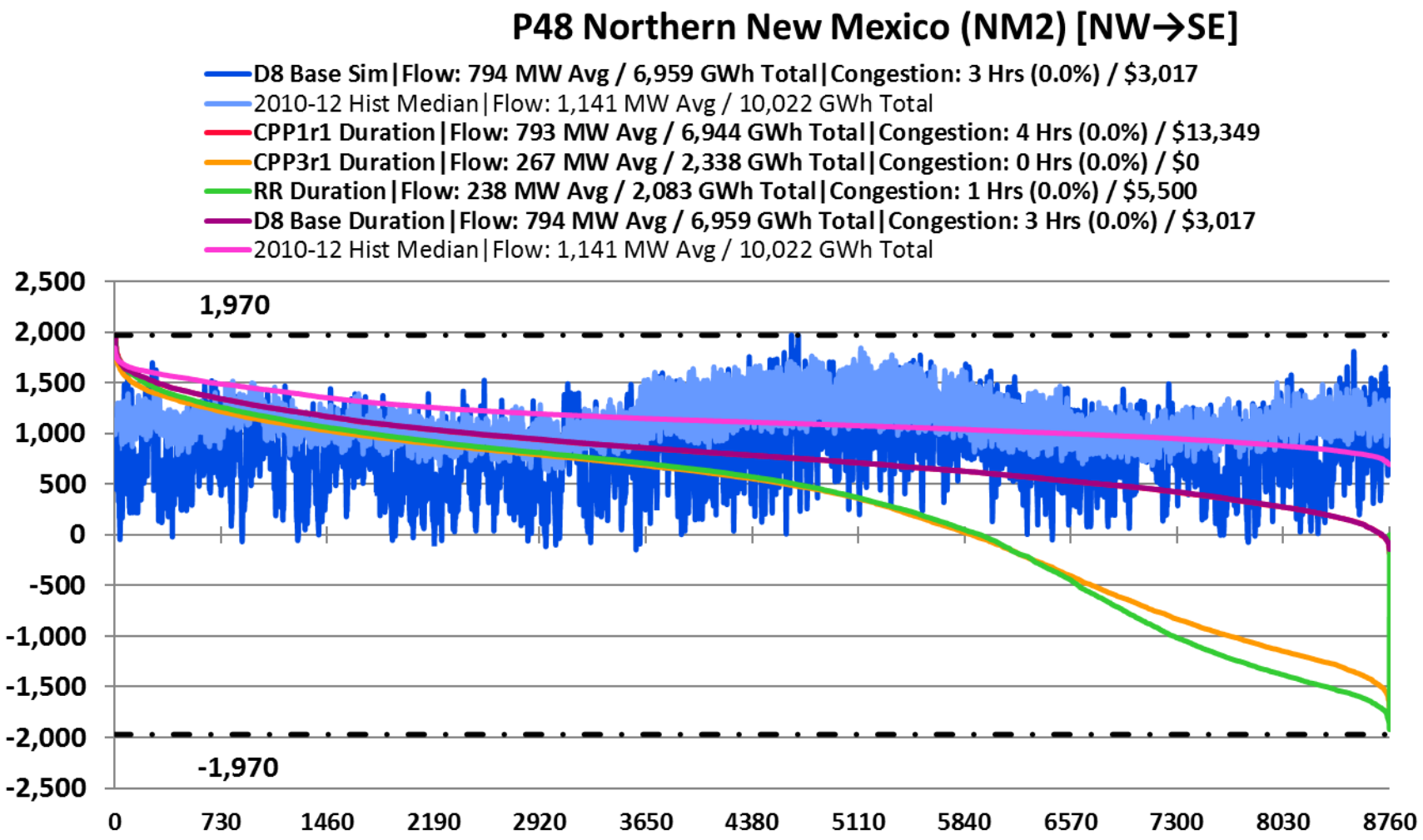
- All added renewable generation able to serve load (zero curtailment due to transmission constraints)
- Minimal impact on regional and single-TO congestion
- Reliability assessment is being finalized

Key findings from CPP3 Aggressive Study:

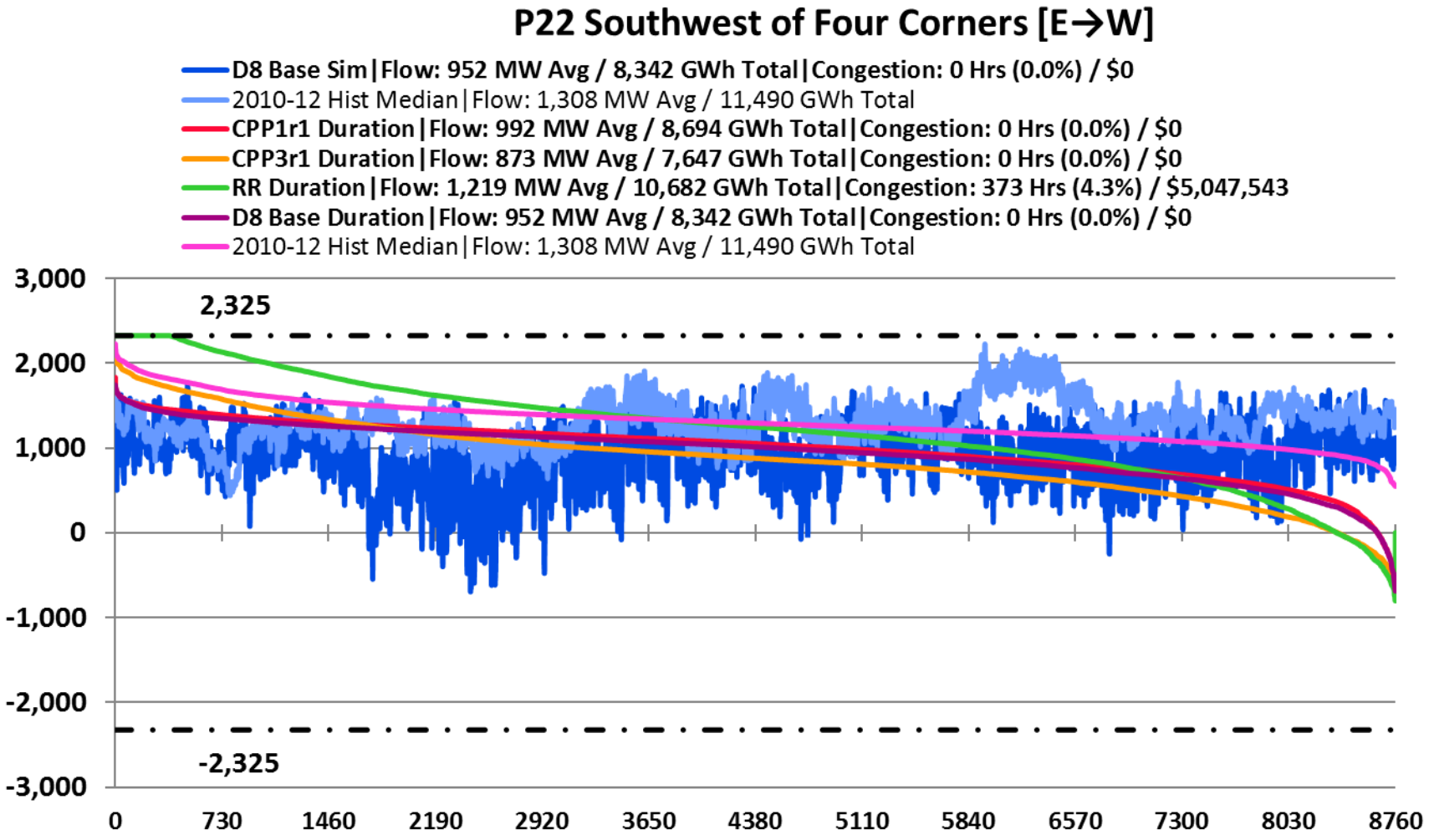
- Major impact on regional congestion and inter-regional paths
- 10% of the added renewable generation curtailed due to transmission constraints
  - Majority of curtailments in Colorado
  - In some instances more than 50% of the annual energy was curtailed
- Scenario showed multiple regional economic transmission issues and some Inter-regional impacts
- Significant reduction in coal generation in AZ, NM, CO, WY, and UT
- Reliability assessment is being finalized

Key findings from Regional Renewables Study:

- Major impact on regional congestion and inter-regional paths
- 3% of added renewable generation curtailed due to transmission constraints
  - Some in Colorado and the rest in NM, AZ, WY & CA.
  - Much higher values (50%) in certain locations
- CA 50% RPS resources were “sunk” into CA, with wind offsetting gas generation in-state
- This scenario appeared to cause multiple regional economic issues and had inter-regional impacts



- Base: 3 congested hours at a total cost of $4,000, flows decreased ~350 aMW from historical due to San Juan Four Corners retirements.
- CPP1: Similar congested hours to Base Case (4), but at 4x the cost ($12,000)
- CPP3 has more S→N flow, likely due to 2,000 MW RE additions in southern New Mexico
- RR: Similar to CPP3 with heavy flows S→N



- Base: Flow going SW out of Four Corners into Arizona system decreased 350 aMW from historical averages (driven by Four Corners retirements)
- CPP1: Similar to Base Case, Cholla retirement had little effect
- CPP3: More volatile flows (higher highs, lower lows) than Base & CPP1, likely due to the added variable resources
- RR: Significant congestion out of Four Corners (4%, $5M)

Congestion Across All Cases (Branches & Paths)			Total Congestion Hours (% Hrs) / Cost ($)			
Scope	**Owner(s)**	**Branch/Path Name**	**WC 26PCM-D8_170108**	**CPP1rev1**	**CPP3rev1**	**RR**
Multi-TO	PSCO|TSGT	BOONE_230.0 - LAMAR_CO_230.0	-	-	3,625 (41%) / $61,160K	2,290 (26%) / $29,193K
	PSCO|TSGT	SANLSVLY_230.0 - PONCHABR_230.0	-	-	2,311 (26%) / $20,127K	2,311 (26%) / $18,019K
	PSCO|TSGT	BOONE_230.0 - MIDWAYPS_230.0	-	-	-	131 (1%) / $1,522K
	PSCO|WAPA-RM	MIDWAYPS_230.0 - MIDWAYBR_230.0	-	-	-	19 (0%) / $123K
WECC Path	PG&E & Sierra	P24 PG&E-Sierra	493 (6%) / $1,286K	511 (6%) / $1,217K	896 (10%) / $2,170K	554 (6%) / $1,323K
	SMUD|NTTG-CG	P66 COI	4 (0%) / $58K	5 (0%) / $46K	9 (0%) / $89K	35 (0%) / $514K
	PNM	P48 Northern New Mexico (NM2)	3 (0%) / $3K	4 (0%) / $13K	-	1 (0%) / $5K
	MULTIPLE	P61 Lugo-Victorville 500 kV Line	1 (0%) / $1K	-	1 (0%) / $2K	99 (1%) / $747K
	NEVP|CAISO	P52 Silver Peak-Control 55 kV	2 (0%) / $0K	2 (0%) / $0K	34 (0%) / $5K	995 (11%) / $154K
	SCE,	P41 Sylmar to SCE	2 (0%) / $0K	1 (0%) / $1K	1 (0%) / $1K	-
	PACE	P32 Pavant-Gonder InterMtn-Gonder 230 kV	-	1 (0%) / $8K	127 (1%) / $793K	223 (3%) / $1,114K
	PNM,EPE	P47 Southern New Mexico (NM1)	-	1 (0%) / $0K	-	-
	WAPA, TSGT, PSC, BEPC	P36 TOT 3	-	-	4 (0%) / $23K	132 (2%) / $1,292K
	APS	P22 Southwest of Four Corners	-	-	-	373 (4%) / $5,048K
	WAPA, TS, PRPA, SRP, PACE	P30 TOT 1A	-	-	-	9 (0%) / $15K
Single TO	APS	CTRYCLUB_230.0 - LINCSTRT_230.0	145 (2%) / $1,705K	161 (2%) / $2,035K	227 (3%) / $2,638K	98 (1%) / $975K
	LADWP	TARZANA_230.0 - OLYMPC_230.0	18 (0%) / $1,327K	14 (0%) / $1,043K	19 (0%) / $1,864K	23 (0%) / $1,787K
	NEVP	HIL TOP - HIL TOP	144 (2%) / $492K	219 (3%) / $798K	115 (1%) / $423K	110 (1%) / $336K
	LADWP	RINALDI_230.0 - AIRWAY_230.0	2 (0%) / $118K	4 (0%) / $183K	3 (0%) / $74K	5 (0%) / $235K
	PSCO	LEETSDAL_230.0 - MONROEPS_230.0	2 (0%) / $16K	-	366 (4%) / $2,801K	600 (7%) / $4,942K
	NEVP	CLARK 6 - CLARK	1 (0%) / $2K	1 (0%) / $2K	20 (0%) / $109K	8 (0%) / $14K
	PSCO	GREENWD_230.0 - MONACO12_230.0	1 (0%) / $0K	3 (0%) / $29K	189 (2%) / $2,731K	482 (6%) / $6,545K
	APS	MEADOWBK_230.0 - SUNYSLOP_230.0	-	1 (0%) / $8K	2 (0%) / $16K	-
	WAPA-SN	TRCY PMP_230.0 - HURLEY S_230.0	-	-	10 (0%) / $1,479K	-
	NEVP	FRONTIER_230.0 - MACHACEK_230.0			17 (0%) / $74K	776 (9%) / $5,218K
	NEVP	FT CHUR - FT CH PS			18 (0%) / $61K	110 (1%) / $298K
	WAPA-RM	SANJN PS - WATRFLW	-		8 (0%) / $43K	-
	PSCO	STORY_230.0 - PAWNEE_230.0	-	-	5 (0%) / $22K	-
	NEVP	FAULKNER - FAULKNER	-	-	1 (0%) / $12K	-
	NEVP	GONDER_230.0 - MACHACEK_230.0	-	-	3 (0%) / $9K	197 (2%) / $717K
	WAPA-RM	ARCHER_230.0 - TERRY_RANCH_230.0	-	-	-	179 (2%) / $2,360K
	PSCO	BOONE - BOONE	-	-	-	140 (2%) / $1,065K
		Total Congestion Cost:	**$5,008K**	**$5,383K**	**$96,725K**	**$84,700K**

PRELIMINARY STUDY RESULTS

**Phase shifting transformers (PST) removed*

Negligible regional congestion in Base Case & CPP1 study

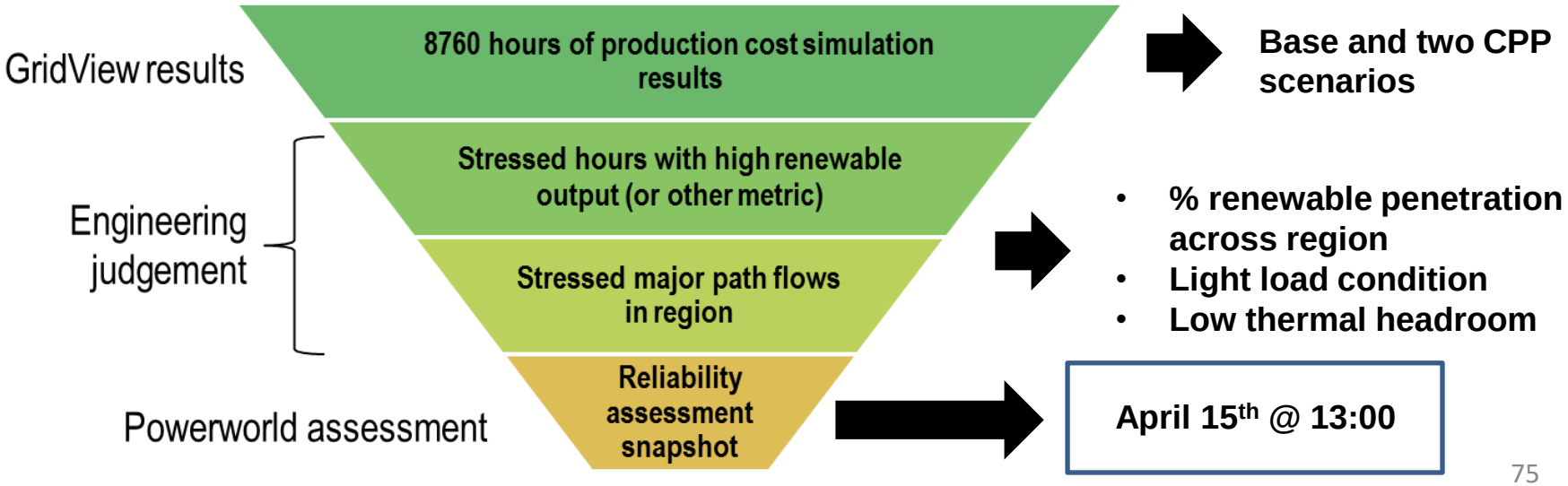
CPP3 & RR studies shows potential for regional congestion

Scenario Cases

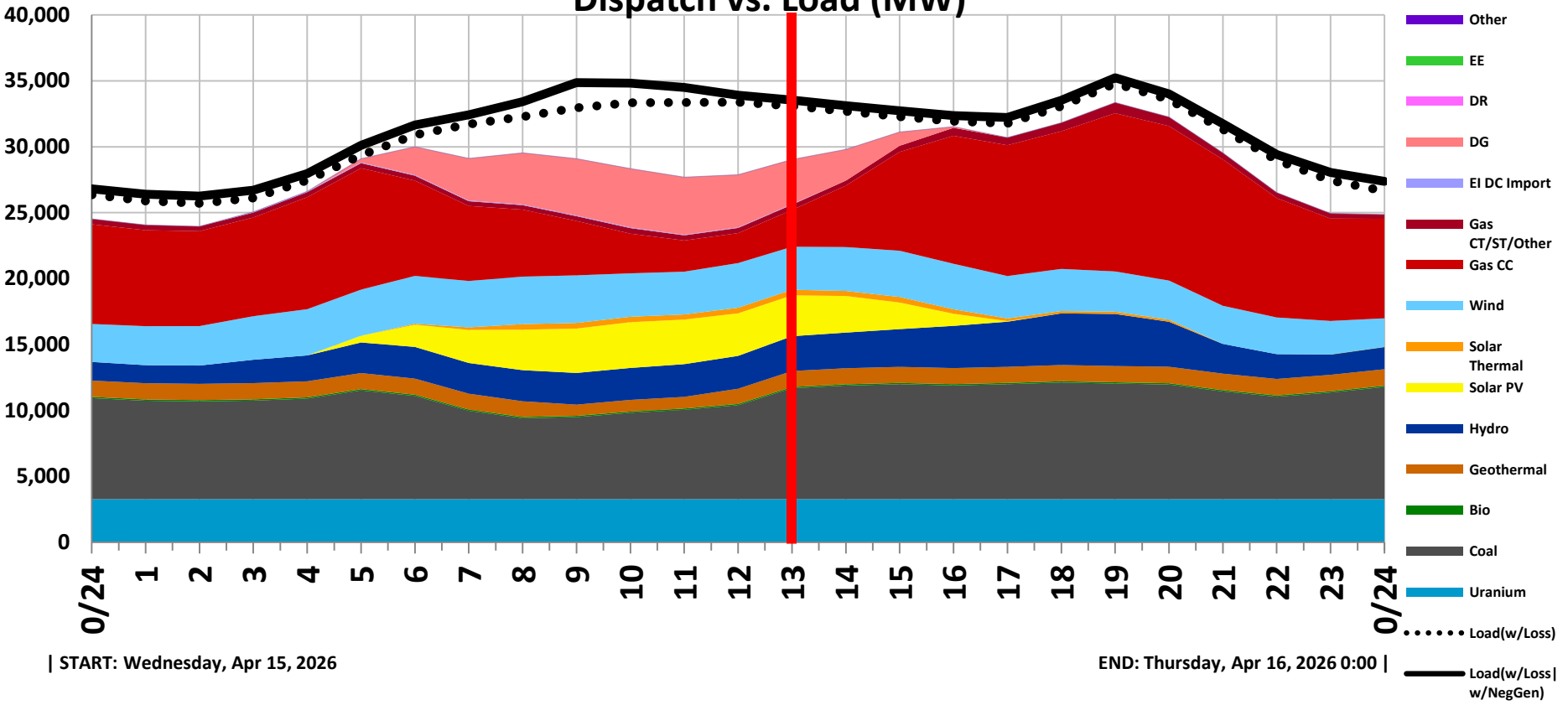
RELIABILITY ASSESSMENT

Study Purpose and Process

- WestConnect's Clean Power Plan reliability scenarios are intended to investigate a stressed condition under a future with varying levels of coal retirements and renewables
- Economic simulation results reviewed to identify stressed condition to export into power flow environment

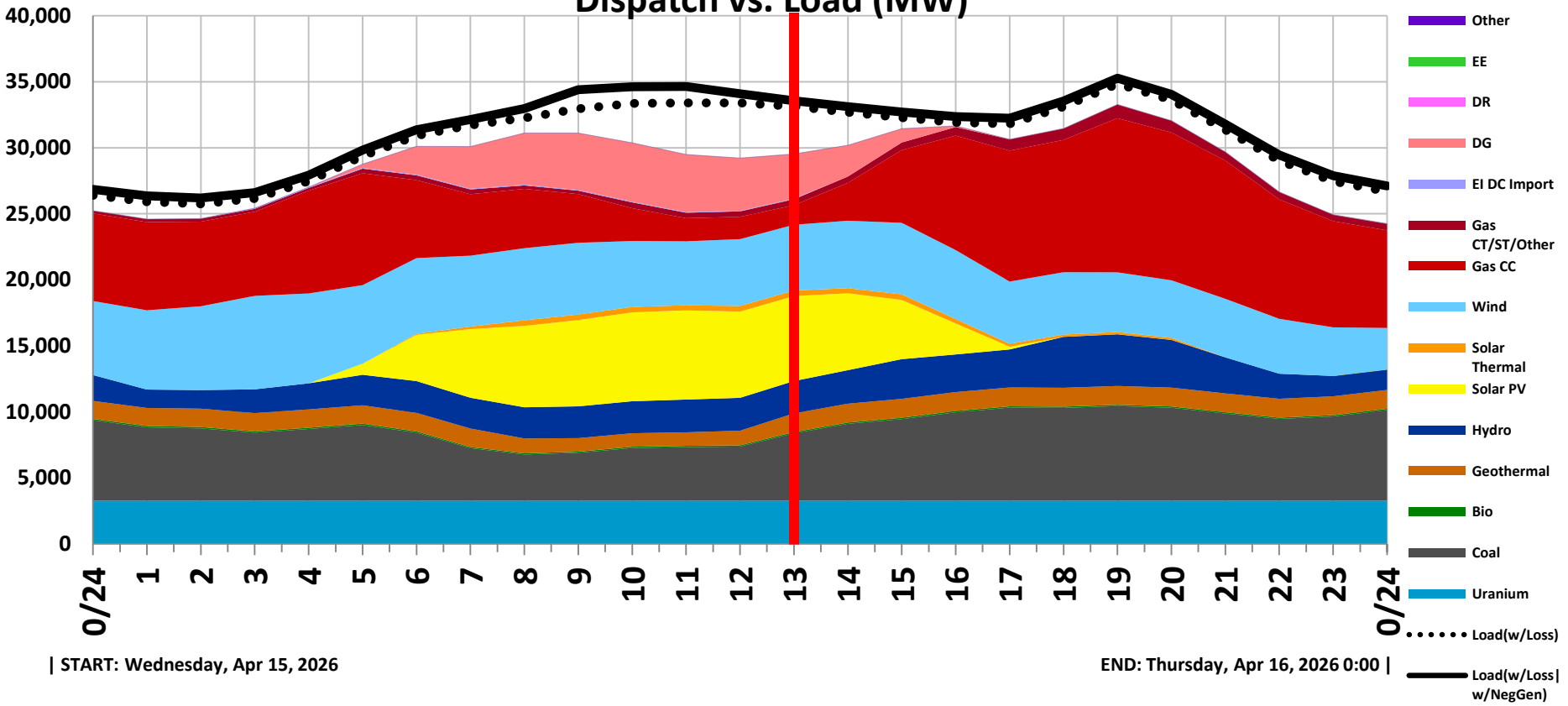


Clean Power Plan Utility Plans Scenario: WestConnect Areas Generator Dispatch vs. Load (MW)



April 15th @ 13:00

Clean Power Plan Aggressive Scenario: WestConnect Areas Generator Dispatch vs. Load (MW)



April 15th @ 13:00

Powerflow Analysis Process for Exported Conditions

1. Export hours meeting similar criteria from simulations
2. Achieve power flow steady-state solution
3. Match dynamic data
   - Leverage latest data from dynamic data verification effort
4. Run contingency analysis & Double Palo Verde outage and transient stability run
   - Same assumptions as the regional assessment
5. Review of models and results
6. Iterate models and analysis based on findings
7. Finalize assessment and conclusions

PLANNING PROCESS NEXT STEPS

2016-17 Regional Planning Process Next Steps

- Finalize regional needs assessment report
- Finalize scenario models and conduct assessment, look for regional "opportunities"
  - Evaluation of scenario-driven opportunities at direction of PMC in 2017
- Establish "more efficient or cost effective" solution methodology through which regional projects will be evaluated
  - Assigned to Project Selection Task Force
- Issue 2016-17 Regional Transmission Plan in late 2017
  - Compilation of prior planning documents

Opportunities for Participation

- WestConnect held two stakeholder meetings during 2016, and one so far in 2017
- All PMC & Subcommittee meetings are open with opportunity for stakeholder input
- Comment on interim reports and draft 2016-17 Regional Transmission Plan are welcome
- Email distribution lists and stakeholder meeting in Q4

Upcoming Meetings

- **PS/CAS/PMC Meetings**:
  - March 14-15, 2017, Salt Lake City, UT (Energy Strategies offices)
- **2017 WestConnect Stakeholder Meetings:**
  - November 16, 2017, Tempe, AZ *(tentative)*

Questions?

Presenter Contact Information:
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Keegan Moyer, kmoyer@energystrat.com
Charlie Reinhold, reinhold@ctcweb.net

NORTHERN TIER TRANSMISSION GROUP (NTTG)

REGIONAL PLANNING UPDATE

Western Planning Regions
Annual Interregional Coordination Meeting

Portland, OR
February 23, 2017

Agenda

- NTTG Regional Planning Overview & Schedule
- NTTG's Annual Interregional Information and Key ITP Considerations
- NTTG's Draft Regional Transmission Plan (DRTP)
  - Assumptions and System Representation
  - ITP Submissions and Coordinated ITP Assumptions
  - Base Case Development and Change Case Selection
  - 2016-2017 DRTP – Project Selection
  - Other Analysis: Public Policy Considerations
- Upcoming Meetings and Opportunities for Stakeholder Input

Northern Tier Transmission Group

Participating Utilities

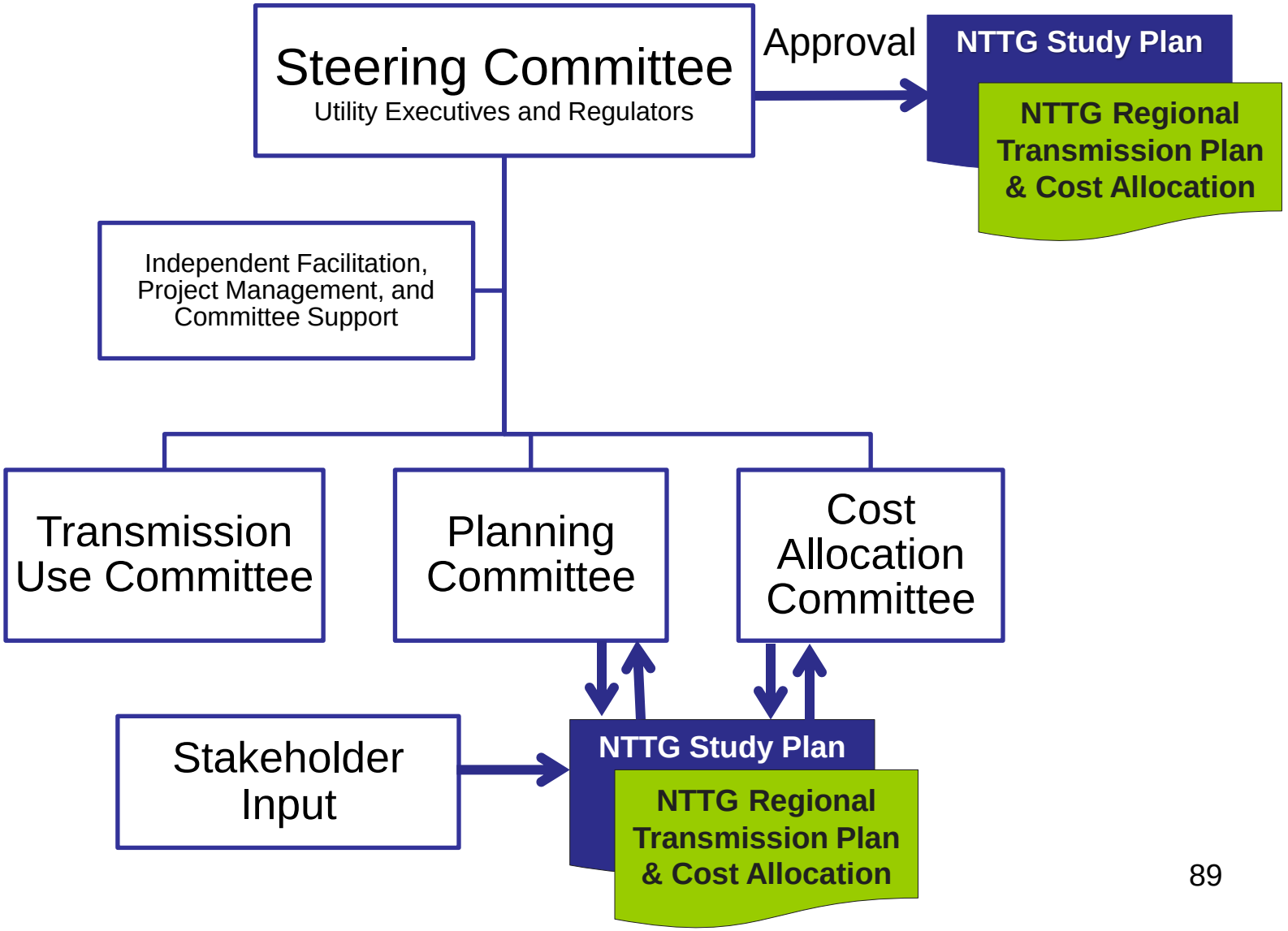
Deseret Power Electric Cooperative
Idaho Power
Montana Alberta Tie Line (MATL)
NorthWestern Energy
PacifiCorp
Portland General Electric
Utah Associated Municipal Power Systems

4,308,200 customers served
29,239 miles of transmission

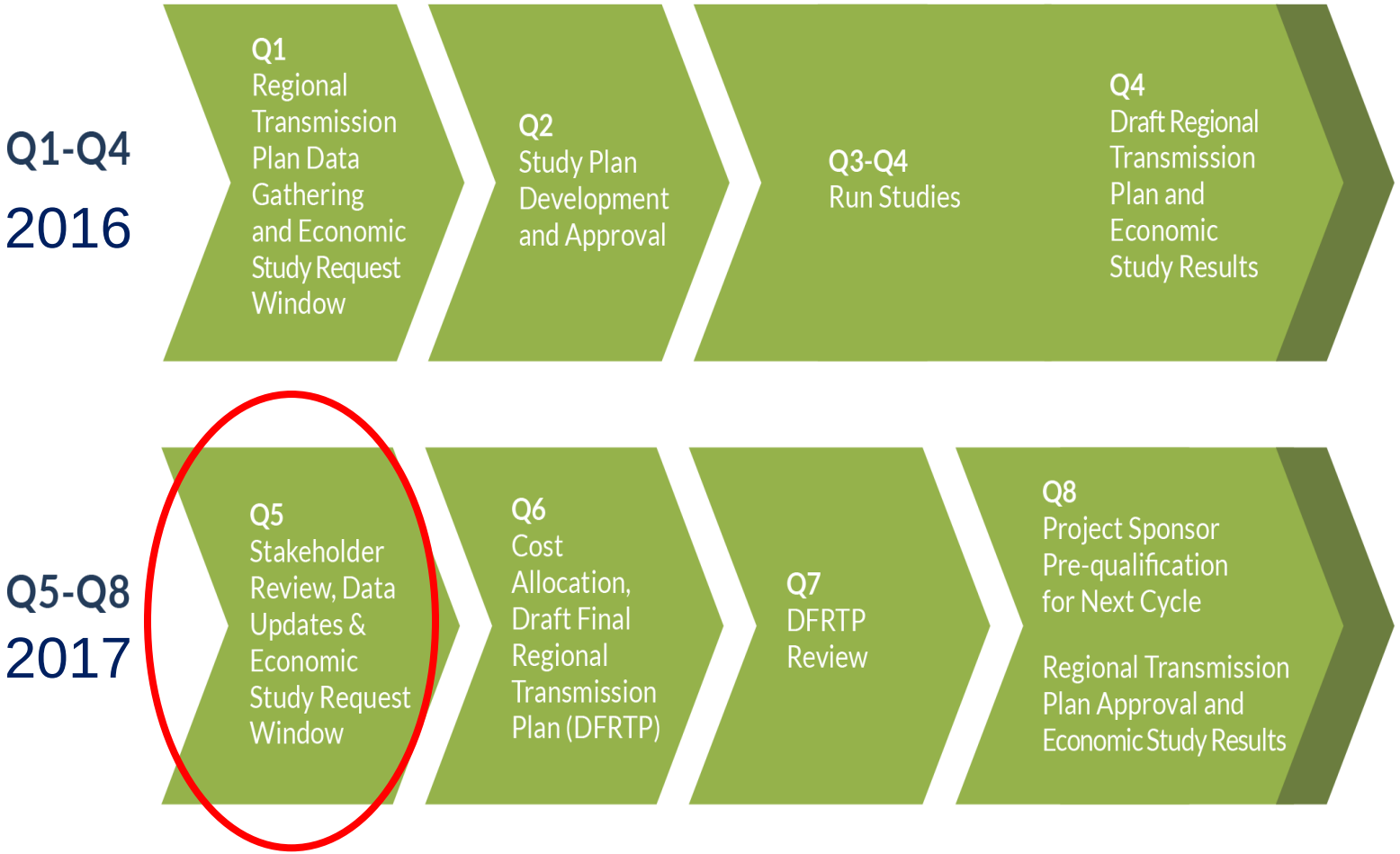
Participating State Representatives

Idaho Public Utilities Commission
Montana Consumer Counsel
Montana Public Service Commission
Oregon Public Utility Commission
Utah Office of Consumer Services
Utah Public Service Commission
Wyoming Public Service Commission

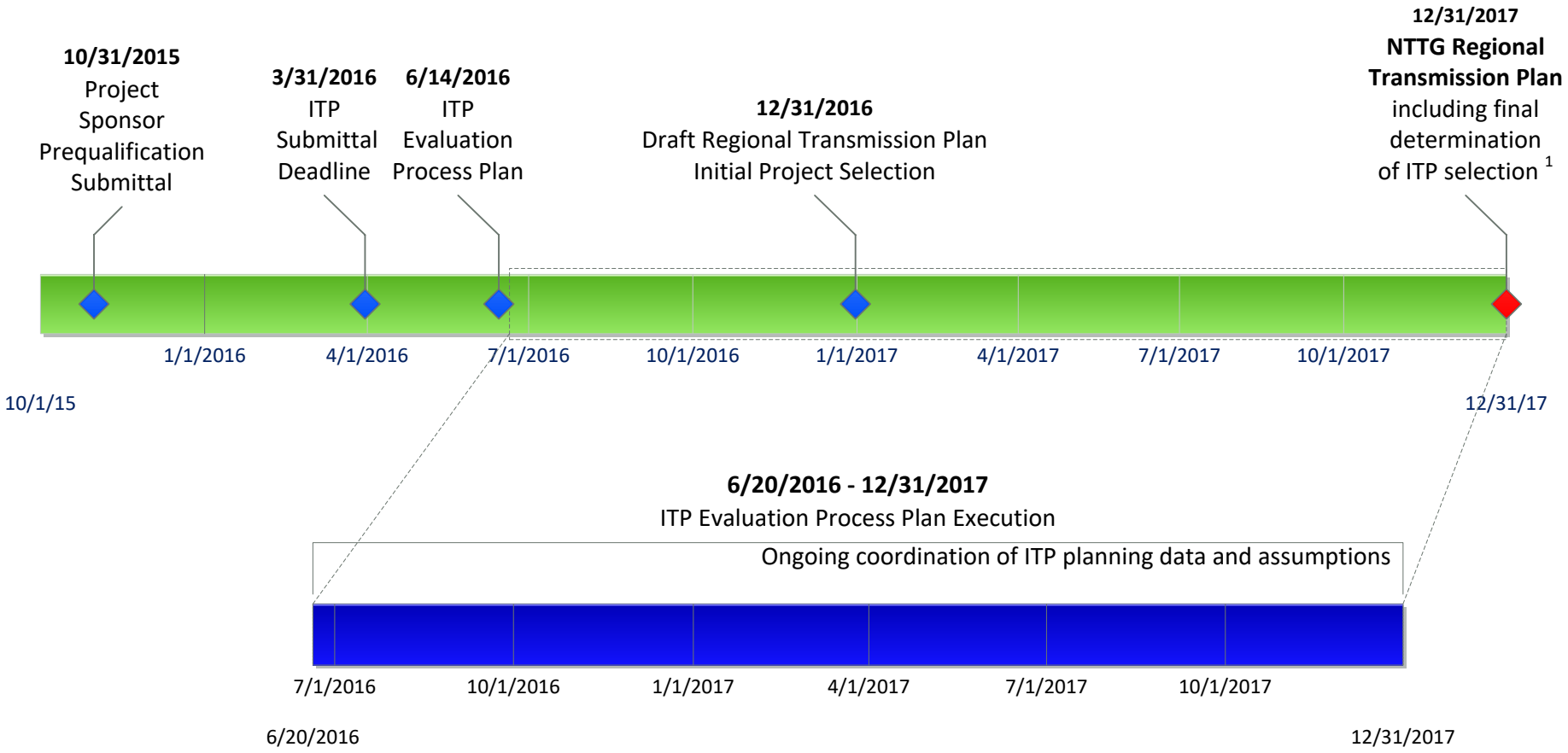
NTTG Structure



NTTG 2016-2017 Planning Cycle



Key NTTG Dates for ITPs



[1] Depending on each region's process, the completion of ITP determination may go beyond this date due to various factors such as re-evaluation process

Recent Annual Interregional Information

As part of NTTG's interregional coordination efforts, NTTG has posted and shared the following:

- 2016-2017 Biennial Study Plan
- A list of submitted Interregional Transmission Projects that satisfied the NTTG submission and information requirements
- 2016-17 Q4 Draft Regional Transmission Plan – Study Findings

Key ITP Considerations

- Any stakeholder may submit data to be evaluated as part of the NTTG Regional Transmission Plan

- NTTG's plan evaluates whether transmission needs within the NTTG footprint may be satisfied on a regional or interregional basis more efficiently or cost effectively than through local planning processes

- NTTG's Regional Transmission Plan is not a construction plan – it provides valuable insights and information for stakeholders and developers to consider and use in their respective decision making processes

NORTHERN TIER
TRANSMISSION GROUP

2016-17 Draft Regional Transmission Plan

System Representation and Plan Assumptions

NTTG 2016-17
Draft Regional Transmission Plan

- The plan proposes a strategy to meet the transmission needs of the NTTG region in year 2026.

- The plan aims to reliably meet the region's future transmission needs in a manner that is more efficient or cost-effective than an Initial Regional Plan, and

- Is comprised of a combination of the funding Transmission Providers' local transmission plans.

Transmission Plan Analysis

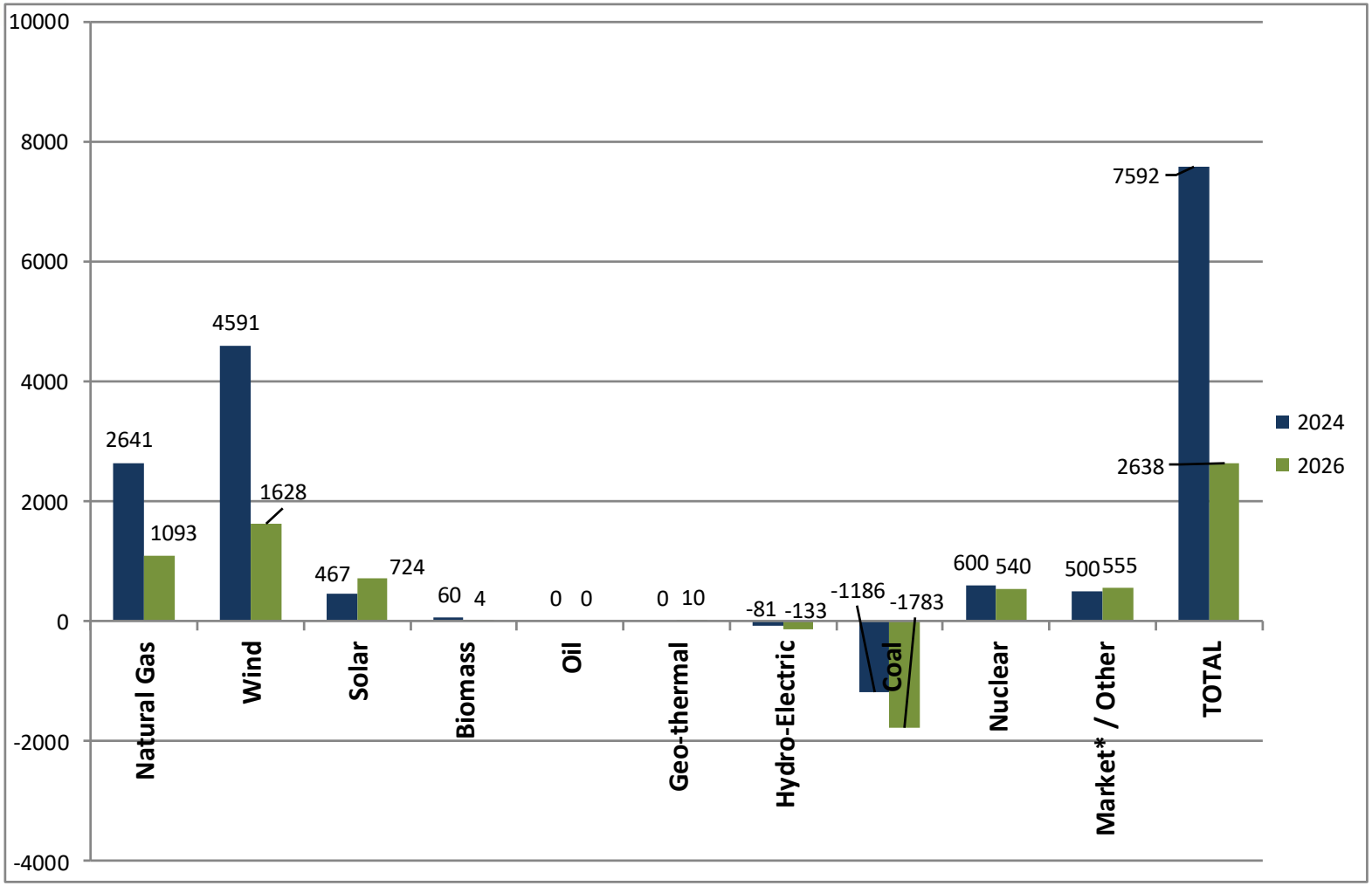
- Developed the Regional Transmission Plan through analysis
  - reliability (power flow)
  - Transmission Capacity and
  - benefit (changes in capital costs, losses, and reserves)

- of
  - Initial Regional Plan (IRTP)
  - IRTP without uncommitted projects
  - Alternative projects

Load Submissions

SUBMITTED BY:	2015 Actual Peak Demand (MW)	2024 Summer Load Data Submitted in Q1 2014 (MW)	2026 Summer Load Data Submitted in Q1 2016 (MW)	Difference (MW) 2024-2026
Deseret G&T	Included in PacifiCorp East			
Idaho Power	3,730	4,193	4,346	153
NorthWestern	1,790	1,774	1,992	218
PacifiCorp	12,634	14,002	13,414	-588
Portland General	3,958	3,933	3,885	-48
UAMPS	Included in PacifiCorp East			
TOTAL	22,112	23,902	23,637	-265

Resource Submissions



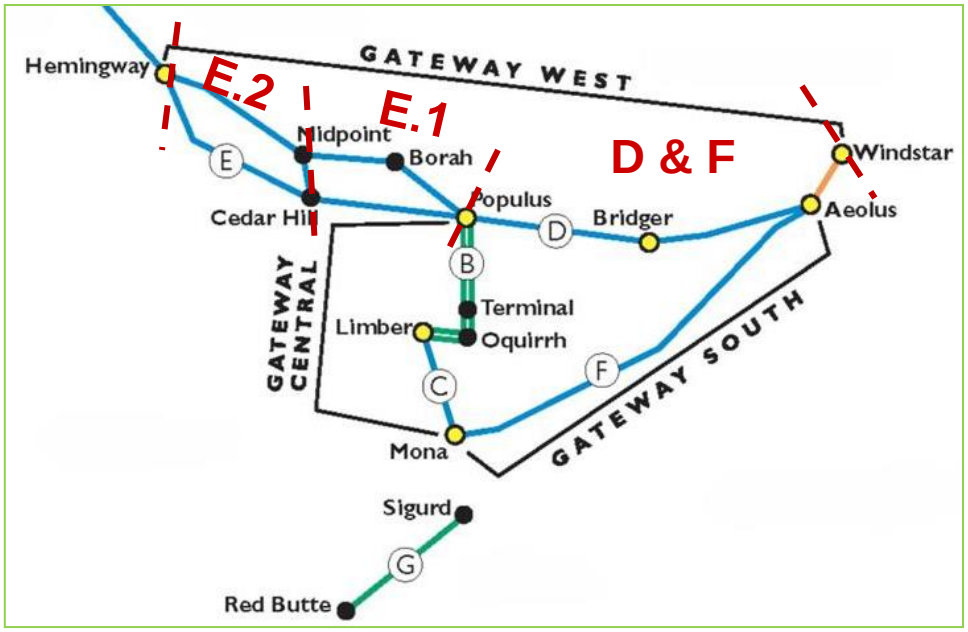
Transmission Additions by 2026

Sponsor	From	To	Voltage	Circuit	Type	Regionally Significant[1]	Committed	Projects
Deseret G&T	Bonanza	Upalco	138 kV	2	LTP	No	No	New Line
Idaho Power	Hemingway	Boardman/ Longhorn	500 kV	1	LTP & pRTP	Yes	No	B2H Project
	Hemingway	Bowmont	230 kV	2	LTP	Yes	No	New Line (associated with Boardman to Hemingway)
	Bowmont	Hubbard	230 kV	1	LTP	Yes	No	New Line (associated with Boardman to Hemingway)
	Cedar Hill	Hemingway	500 kV	1	LTP	Yes	No	Gateway West Segment #9 (joint with PacifiCorp East)
	Cedar Hill	Midpoint	500 kV	1	LTP	Yes	No	Gateway West Segment #10
	Midpoint	Borah	500 kV	1	LTP	Yes	No	(convert existing from 345 kV operation)
	King	Wood River	138 kV	1	LTP	No	No	Line Reconductor
	Willis	Star	138 kV	1	LTP	No	No	New Line
Enbridge	SE Alberta		DC	1	LTP	Yes	No	MATL 600 MW Back to Back DC Converter
PacifiCorp East	Aeolus	Clover	500 kV	1	LTP & pRTP	Yes	No	Gateway South Project – Segment #2
	Aeolus	Anticline	500 kV	1	LTP & pRTP	Yes	No	Gateway West Segments 2&3
	Anticline	Jim Bridger	500 kV	1	LTP & pRTP	Yes	No	345/500 kV Tie
	Anticline	Populus	500 kV	1	LTP & pRTP	Yes	No	Gateway West Segment #4
	Populus	Borah	500 kV	1	LTP	Yes	No	Gateway West Segment #5
	Populus	Cedar Hill	500 kV	1	LTP	Yes	No	Gateway West Segment #7
	Antelope	Goshen	345 kV	1	LTP	Yes	No	Nuclear Resource Integration
	Antelope	Borah	345 kV	1	LTP	Yes	No	Nuclear Resource Integration
	Windstar	Aeolus	230 kV	1	LTP & pRTP	Yes	No	Gateway West Segment #1W
	Oquirrh	Terminal	345 kV	2	LTP	Yes	Yes	Gateway Central
	Cedar Hill	Hemingway	500 kV	1	LTP	Yes	No	Gateway West Segment #9 (joint with Idaho Power)
PacifiCorp West	Wallula	McNary	230 kV	1	LTP	Yes	Yes	Gateway West Segment A
Portland General	Blue Lake	Gresham	230 kV	1	LTP	No	No	New Line
	Blue Lake	Troutdale	230 kV	1	LTP	No	No	Rebuild
	Blue Lake	Troutdale	230 kV	2	LTP	No	No	New Line
	Horizon	Springville Jct	230 kV	1	LTP	No	No	New Line (Trojan-St Marys-Horizon)
	Horizon	Harborton	230 kV	1	LTP	No	No	New Line (re-terminates Horizon Line)
	Trojan	Harborton	230 kV	1	LTP	No	No	Re-termination to Harborton
	St Marys	Harborton	230 kV	1	LTP	No	No	Re-termination to Harborton
	Rivergate	Harborton	230 kV	1	LTP	No	No	Re-termination to Harborton
	Trojan	Harborton	230 kV	2	LTP	No	No	Re-termination to Harborton

Gateway Project Submission

Gateway Project has been split into 3 sub-projects to better match regional plans

1. Segment D and F
2. Segment E.1 (Populus west to Midpoint/Cedar Hill)
3. Segment E.2 (Midpoint/Cedar Hill west to Hemingway)



Transmission Service Obligations

Submitted by	MW (1)	Start Date	POR	POD
Idaho Power	500/200	2021	Northwest	IPCo
	250/550	2022	LaGrande	BPASEID
PacifiCorp East	540	2024	Antelope	Network
	887	2026	Miners, Point of Rocks	Network

(1) Summer/Winter

Public Policy Requirements

Resources submitted to NTTG [or TEPPC] support the following state statutory targets for percentage of renewable energy generation:

- California 33% by 2020
- Montana 15% by 2015
- Oregon 25% by 2025
- Utah 20% by 2025
- Washington 15% by 2020

NORTHERN TIER
TRANSMISSION GROUP

Interregional Project Submissions

Interregional Project Submissions

- NTTG received three Interregional Transmission Project (ITP) submittals
  - Cross-Tie
  - Great Basin (SWIP-North)
  - TransWest Express

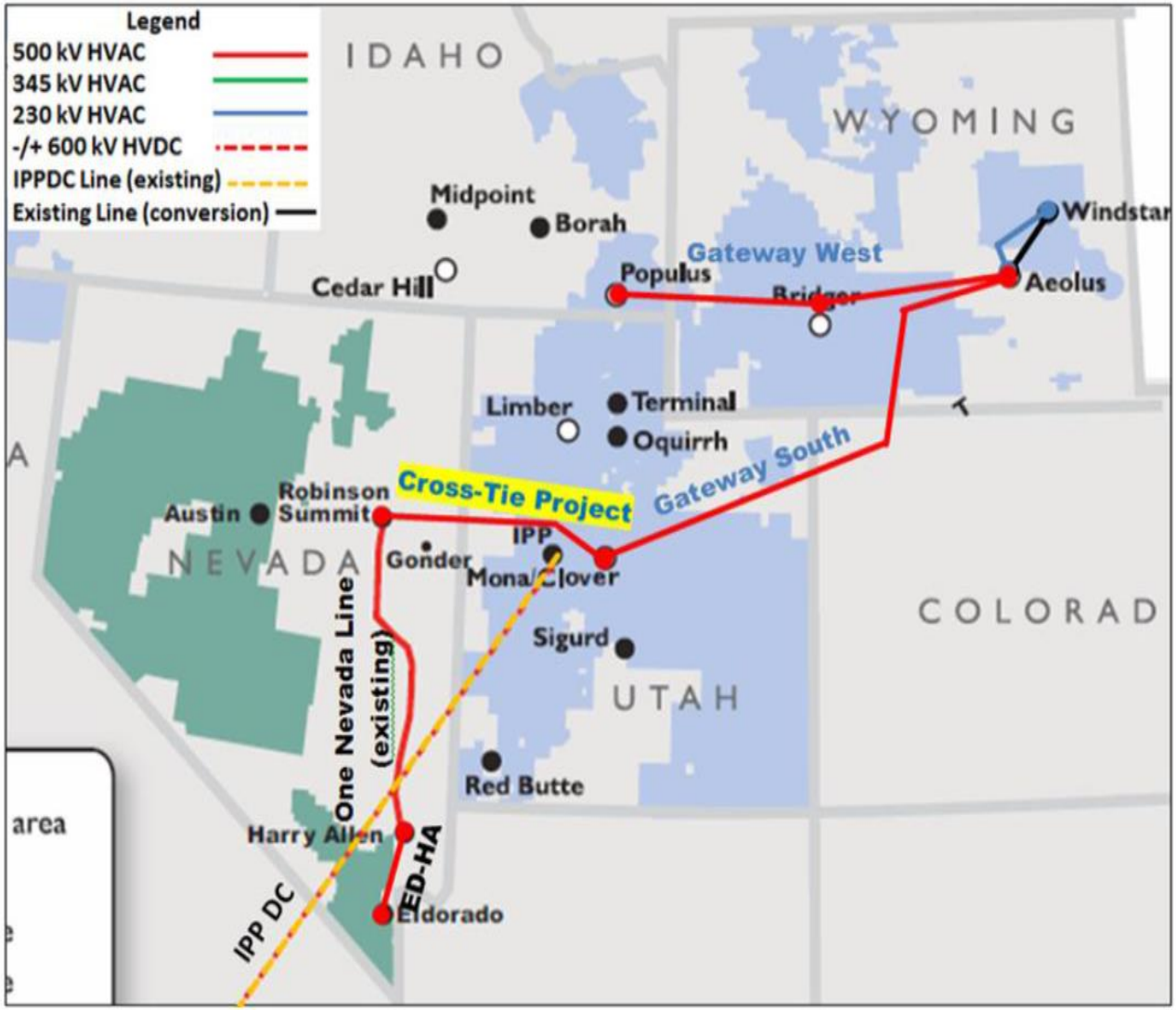
- Relevant Planning Regions coordinated and agreed on common ITP interfaces for each region's evaluation of the ITPs

Cross-Tie Transmission Project

- Submitted by TransCanyon
- Sponsored Project
- NTTG cost allocation: not requested
- Clover, UT to Robinson Summit, NV
- 500 kV, AC
- Common ITP Assumptions:
  - Phase Shifters in Gonder Area
  - Series Compensated to Las Vegas Area
  - 500 kV line extended from Harry Allen to Eldorado
  - 1500 MW of new wind resource in Wyoming (may test at 2000 MW to align with CAISO studies)

Cross-Tie

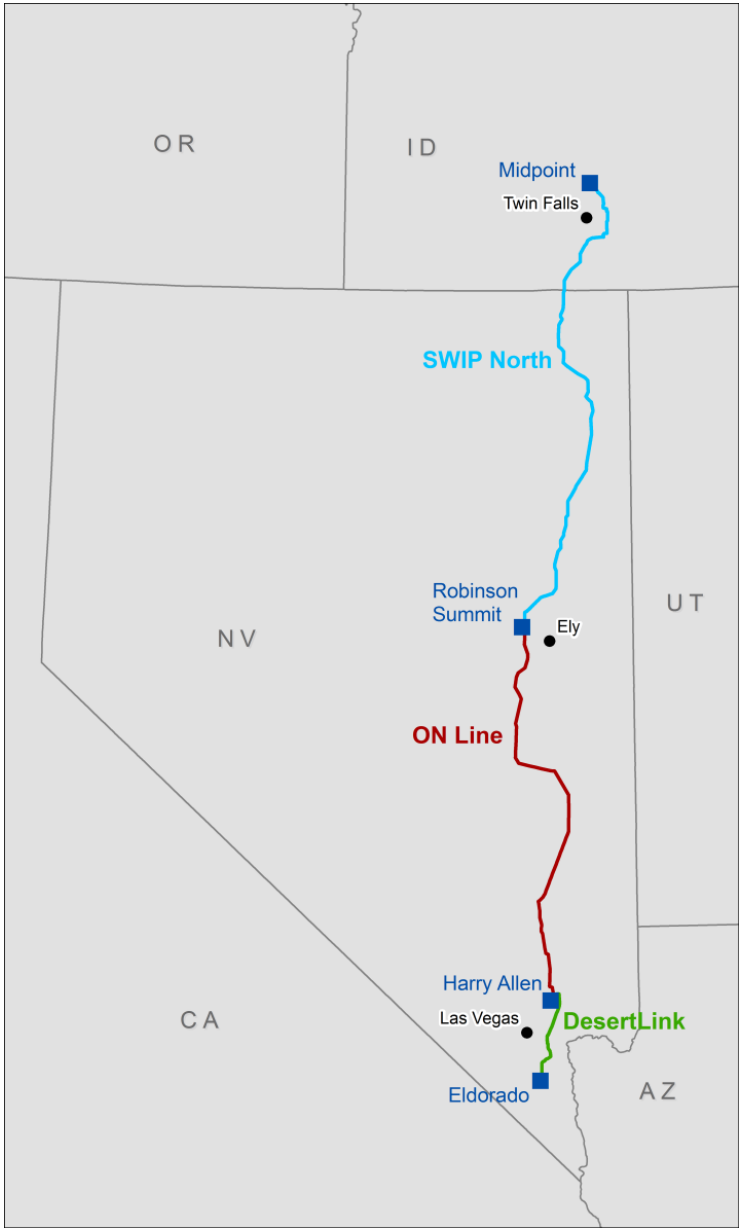
Figure 1 Cross-Tie Transmission Project Overview



SWIP-North Transmission Project

- Submitted by Great Basin Transmission
- Sponsored Project
- NTTG Cost Allocation: Did not meet requirements for the 2016-2017 cycle
- Midpoint, ID to Robinson Summit, NV
- 500 kV, AC
- Common ITP assumptions include:
  - Series Compensated to Las Vegas Area
  - 500 kV line extended from Harry Allen to Eldorado
  - Phase Shifters in Gonder Area
  - 2000 MW of new wind resource in Wyoming

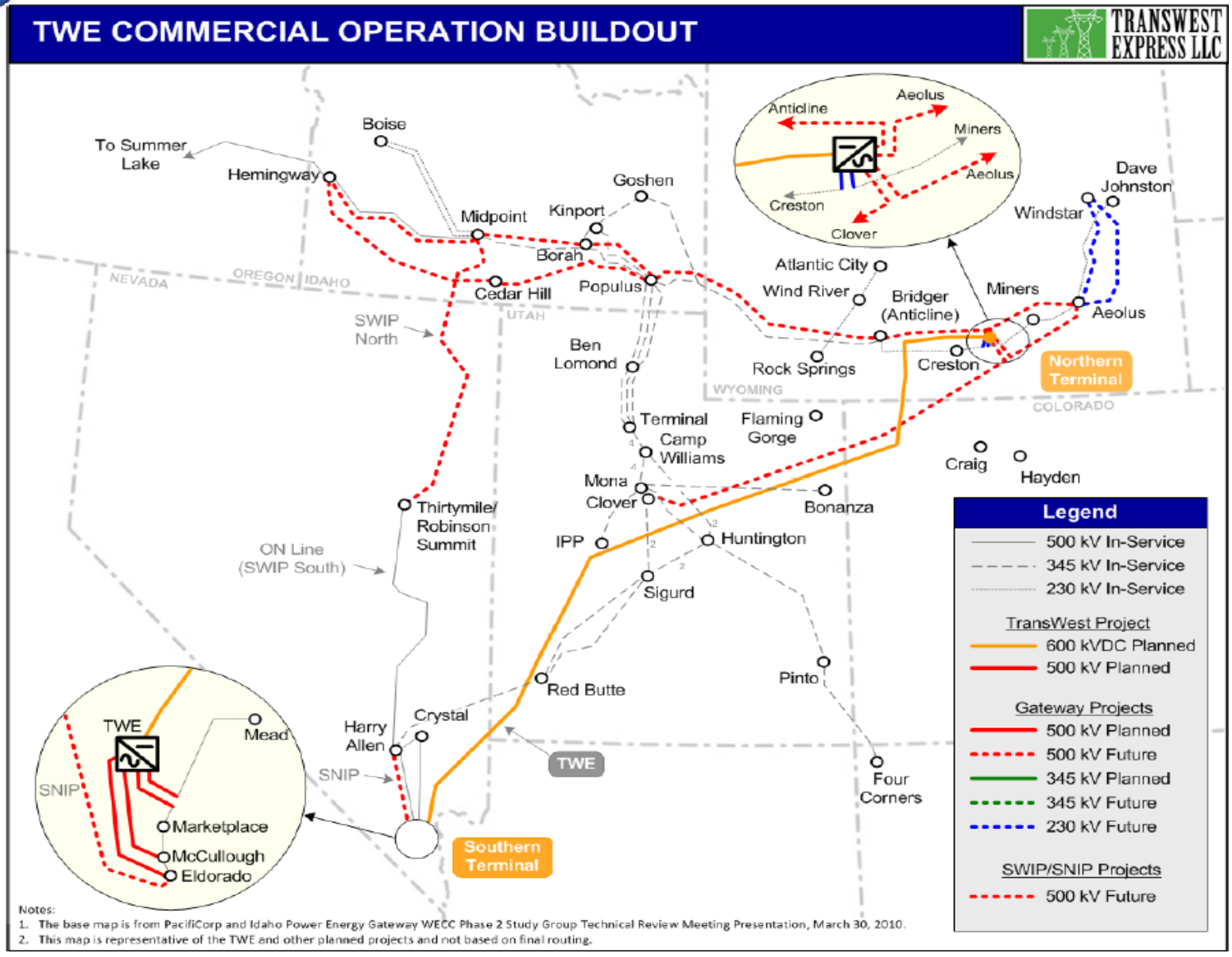
SWIP-North


OR
ID
Midpoint
Twin Falls
SWIP North
Robinson
Summit
Ely
NV
UT
ON Line
Harry Allen
Las Vegas
DesertLink
CA
Eldorado
AZ

TransWest Express Transmission Project

- Submitted by TransWest Express
- Sponsored Project
- NTTG Cost Allocation: not requested
- Sinclair, WY to Boulder City, NV
- ±600 kV, DC
- Common ITP Assumptions:
  - 2-230 kV interconnections to Wyoming system
  - DC line rated for 1500/2000 MW
  - 2000 MW of new wind resource in Wyoming with balancing CT

TransWest Express



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Base Case Development and Change Case Selection

Power Flow Cases Selected

- Selection of Base Cases
  - A. Peak coincident Summer Load condition
  - B. Peak coincident Winter Load condition
  - C. High westbound Path 8 flows
  - D. Boardman to Hemmingway (Longhorn)
    1. High Import flows to Idaho
    2. High export flows from Idaho
  - E. Conditions with high flows across the TOT2 path
  - F. High Wyoming Wind condition

  – Conditions where persistent congestion observed

Revised Change Case Matrix

Case	B2H*	Gateway S*	Gateway W*	Antelope Projects	SWIP N	Cross-Tie	TWE	Case(s):
null								A B D1 D2 F
pRTP	X	X	D					A B D1 D2 F
iRTP	X	X	X	X				A B D1 D2 F
CC1	X							A B D1 D2 F
CC2		X		X				A D2 E F
CC3		X	X					A D2 E F
CC4	X		X	X				A D1 D2 E F
CC5							X	A B D1 D2 F
CC6						X		A B D1 D2 F
CC7					X			A B D1 D2 F
CC8							X	E+RPS
CC9		X					X	E+RPS
CC20		X	X				X	E+RPS
CC10						X		E+RPS
CC11		X				X		E+RPS
CC18		X	X			X		E+RPS
CC12					X			E+RPS
CC13			X		X			E+RPS
CC19		X	X		X			E+RPS
CC14		X	X		X	X		E+RPS
CC15			X		X		X	E+RPS
CC16		X				X	X	E+RPS
CC17		X	X		X	X	X	E+RPS
CC21	X	X	A					D2 F
CC22	X	X	B					D2 F
CC23	X	X	C					F

* B2H and Alternate P in the pRTP are similar to B2H, Gateway S and Gateway W in the 2016-17 Q1 data submittals

A	iRTP without Midpoint-Hemingway #2 and Cedar Hill-Midpoint
B	iRTP without Borah-Midpoint Uprate and Populus-Borah
C	iRTP without Midpoint-Hemingway #2, Cedar Hill-Midpoint and Populus-Borah
D	iRTP without Midpoint-Hemingway #2, Cedar Hill-Midpoint, Populus-Cedar Hill-Hemingway, Populus-Borah and Midpoint-Borah Uprate
	The change case was run with and without B2H

NTTG Technical Analysis

- Once base cases were developed and change cases selected, the following analysis was performed:
  - Reliability (power flow)
  - Stability (dynamics)
  - Economic Metrics (benefits)
    - Energy Losses
    - Change in Reserves
    - Annual Capital Costs
  - Impacts to Neighboring Planning Regions reviewed
- Further discussion of these analyses is summarized next…

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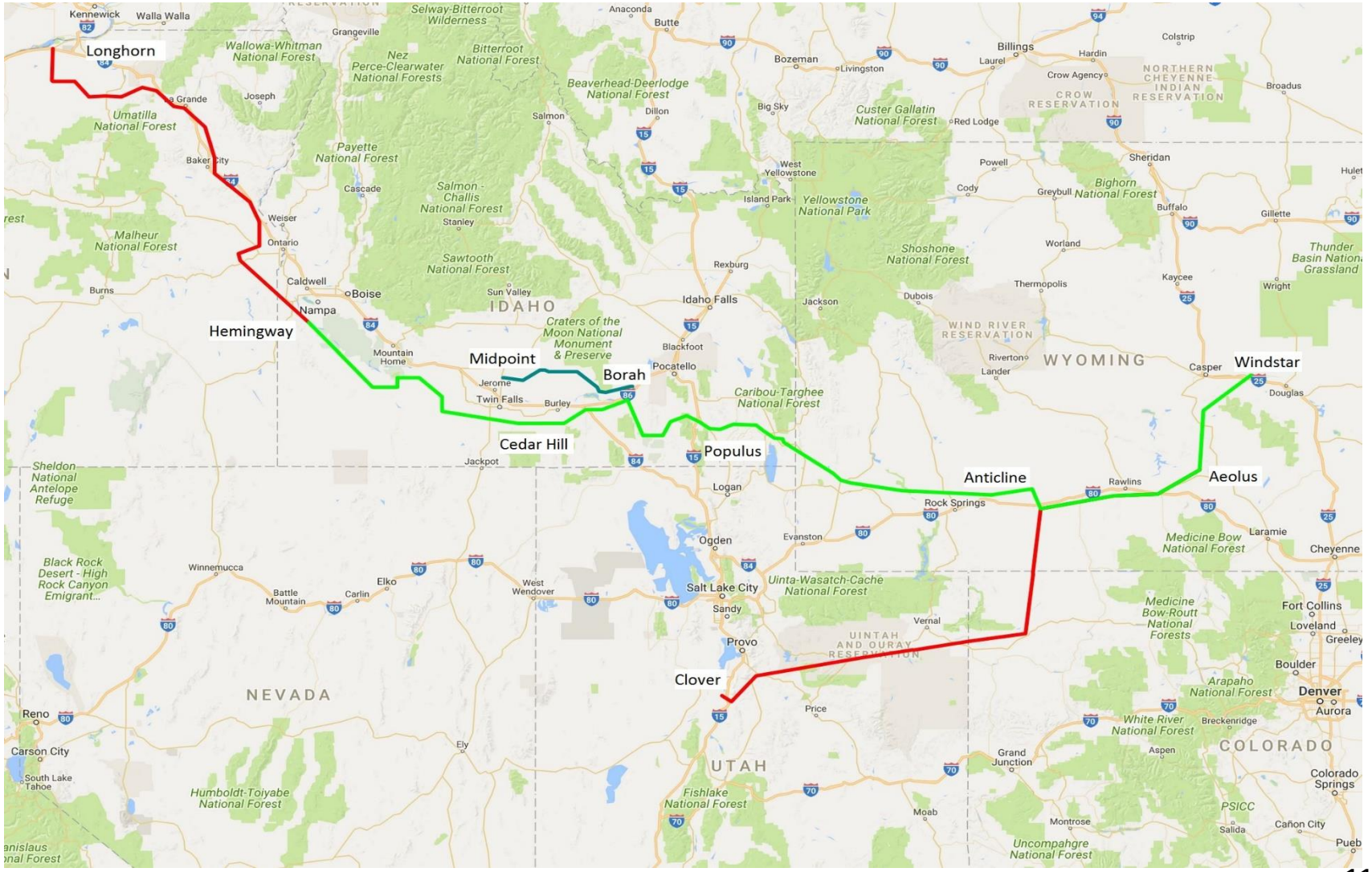
2016-2017
Draft Regional Transmission Plan
Project Selection

Draft Regional Transmission Plan (DRTP)

- Based on the reliability and economic considerations previously discussed, the most efficient and cost-effective plan based on the studies performed is the Change Case (CC23) plan consisting of:
  - IRTP with the following non-Committed projects:
    - Boardman/Longhorn – Hemingway 500 kV
    - Gateway West – Segment D (Populus – Windstar) and Gateway South – Segment F (Aeolus – Clover)
    - Selected portions of Gateway West – Segment E.1 and E.2; specifically, Populus – Cedar Hill 500 kV and Cedar Hill – Hemingway 500 kV
    - Antelope Transmission (Antelope-Borah, Antelope-Goshen)

DRTP – CC23 Projects



Draft Regional Transmission Plan – Impacts on Other Regions

- In developing the DRTP, using a system model representing the entire Western Interconnection, no negative impacts to other regions were identified.

- Technical studies indicated that the DRTP would support each of the Interregional Transmission Projects (ITPs) submitted; however, none of the ITPs satisfied a Northern Tier regional need

Draft Regional Transmission Plan – Cost Allocation

- None of the projects selected into the DRTP will have costs allocated.

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Other Technical Analysis

Public Policy Consideration Analysis

- Public Policy Considerations (PPCs) are those relevant factors that are not established by local, state, or federal laws or regulations

- Stakeholders may submit requests for Public Policy Consideration during Q1

- Results may inform the NTTG Regional Transmission Plan, but will not result in the inclusion of additional projects in the Plan

Public Policy Consideration Scenario Evaluated

- Scenario Evaluated
  - Understand the transmission implications of replacing approximately 1500 MW of Coal with Wind; of particular concern are the west-bound flows from Montana to the Northwest on Path 8

- Status:
  - Created powerflow cases based on High Path 8 case. Replaced Colstrip 3 with 1494 MW of wind capacity added. Modeling 0%, 35% and 100% output levels
  - Applied Dynamics data from Heavy Summer case
  - Complete analysis of this powerflow and dynamics work and perform addition sensitivities with a synchronous condenser and a 250 MW gas turbine in the Billings area

2016-17 Q5 Data Submittals

- Tariff Deadline for Q1 and Q5 data submittals has been revised from the end of January to the end of March.
- No Q5 updated data has been submitted to date.

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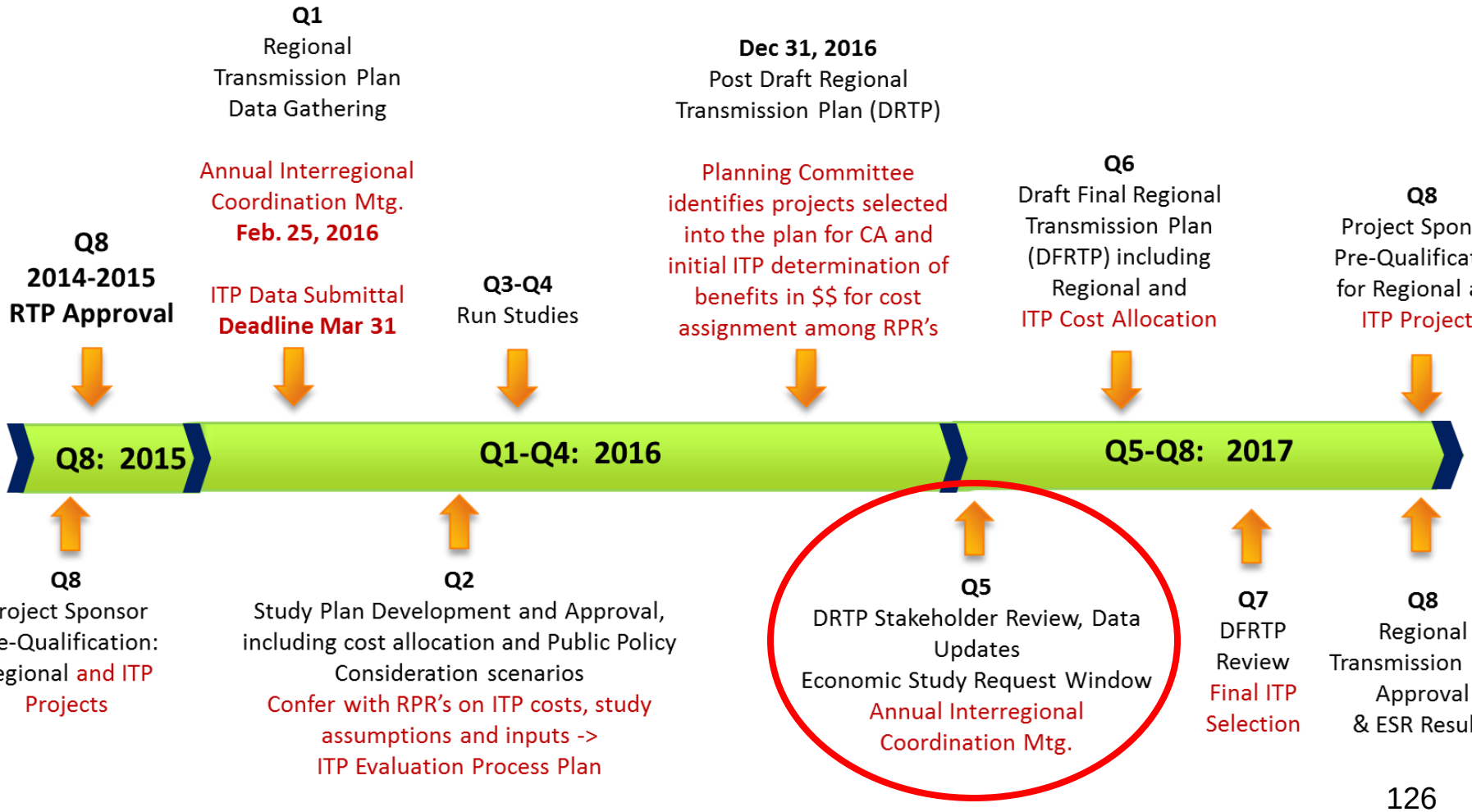
Next Steps and Stakeholder Opportunities

NTTG 2016-2017 Planning and ITP Evaluation Process



Upcoming 2017 Data Submittal Milestones

Project Information	
• Updated Project Data	Mar. 31, 2017
• Economic Study Requests	Mar. 31, 2017
Projects Seeking Cost Allocation	
• Project Sponsor Pre-Qualification Data Submittal	Oct. 31, 2017

2017 Stakeholder Meetings

2017 Stakeholder Meetings	Date
Q5 Stakeholder Meeting – PDX	April 12th
Q6 Stakeholder Meeting – BOI	June 29th
Q7 Stakeholder Meeting – BZM	Sep. 19th
Q8 Stakeholder Meeting – SLC	Dec. 7th

2018 Data Submittal Milestones

Projects Seeking Consideration in NTTG Regional Transmission Plan	
• Project Submittal Deadline	Mar 31, 2018
Qualified Project Sponsors Seeking Cost Allocation	
• Project Submittal Deadline	Mar 31, 2018
• Additional Cost Information Submittal Deadline	Mar 31, 2018
Other Data Gathering Deadlines	
• Request for Public Policy Consideration Analysis	Mar 31, 2018
• Economic Study Request Deadline	Mar 31, 2018

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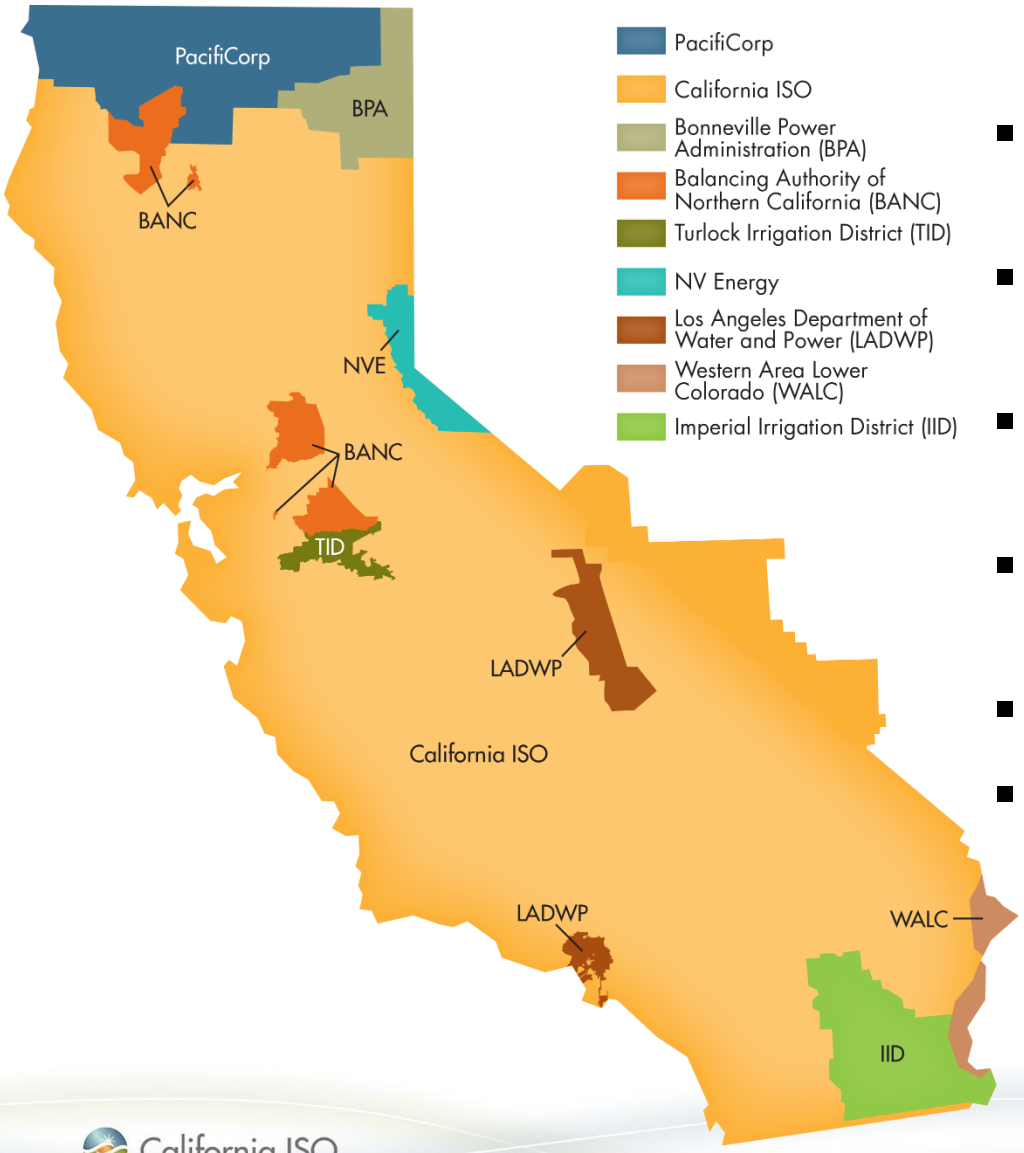
Thank You!

Annual Interregional Information

Neil Millar
Executive Director, Infrastructure Development

2016-2017 Transmission Plan
February 23, 2017

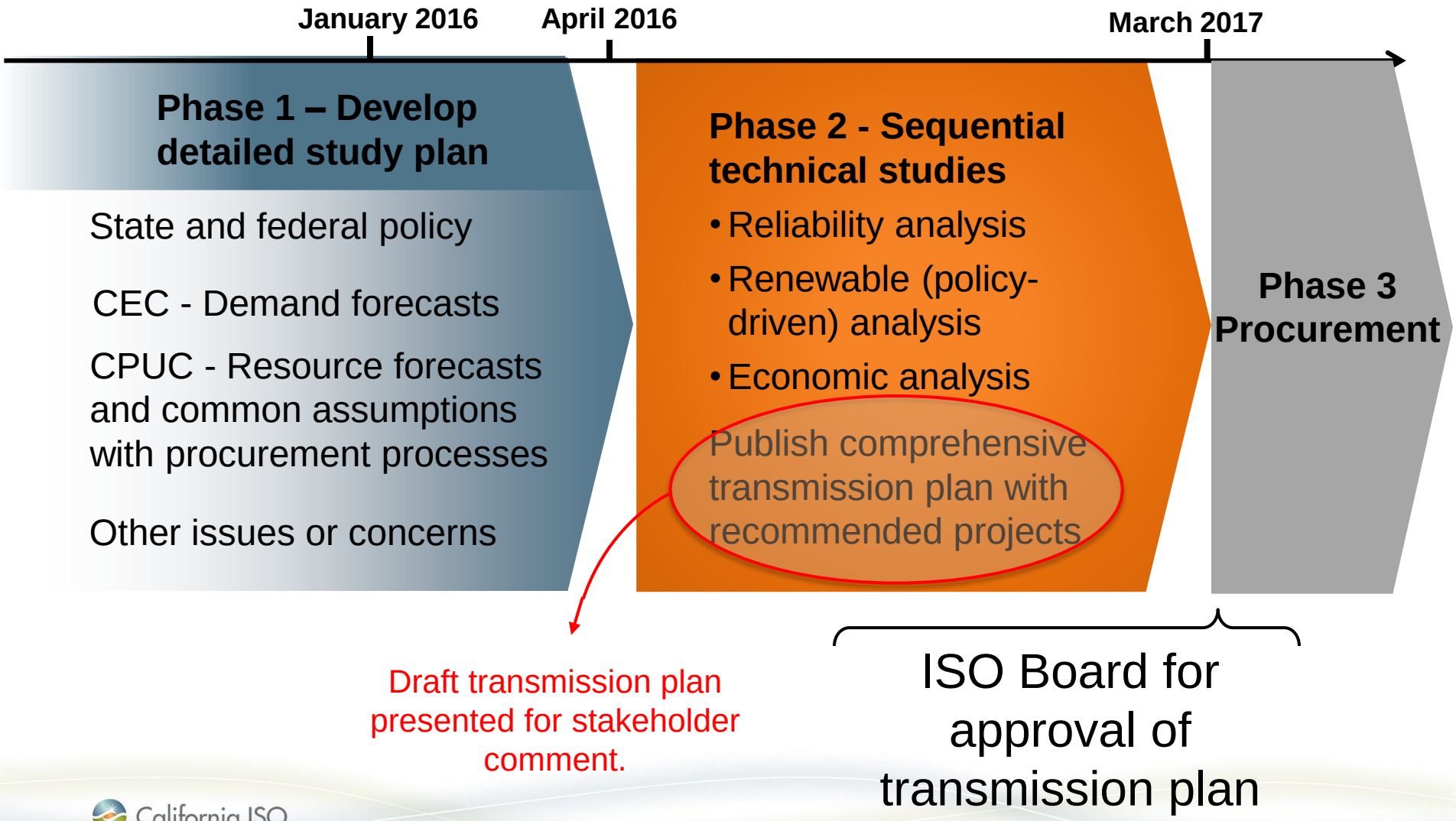
California ISO by the numbers



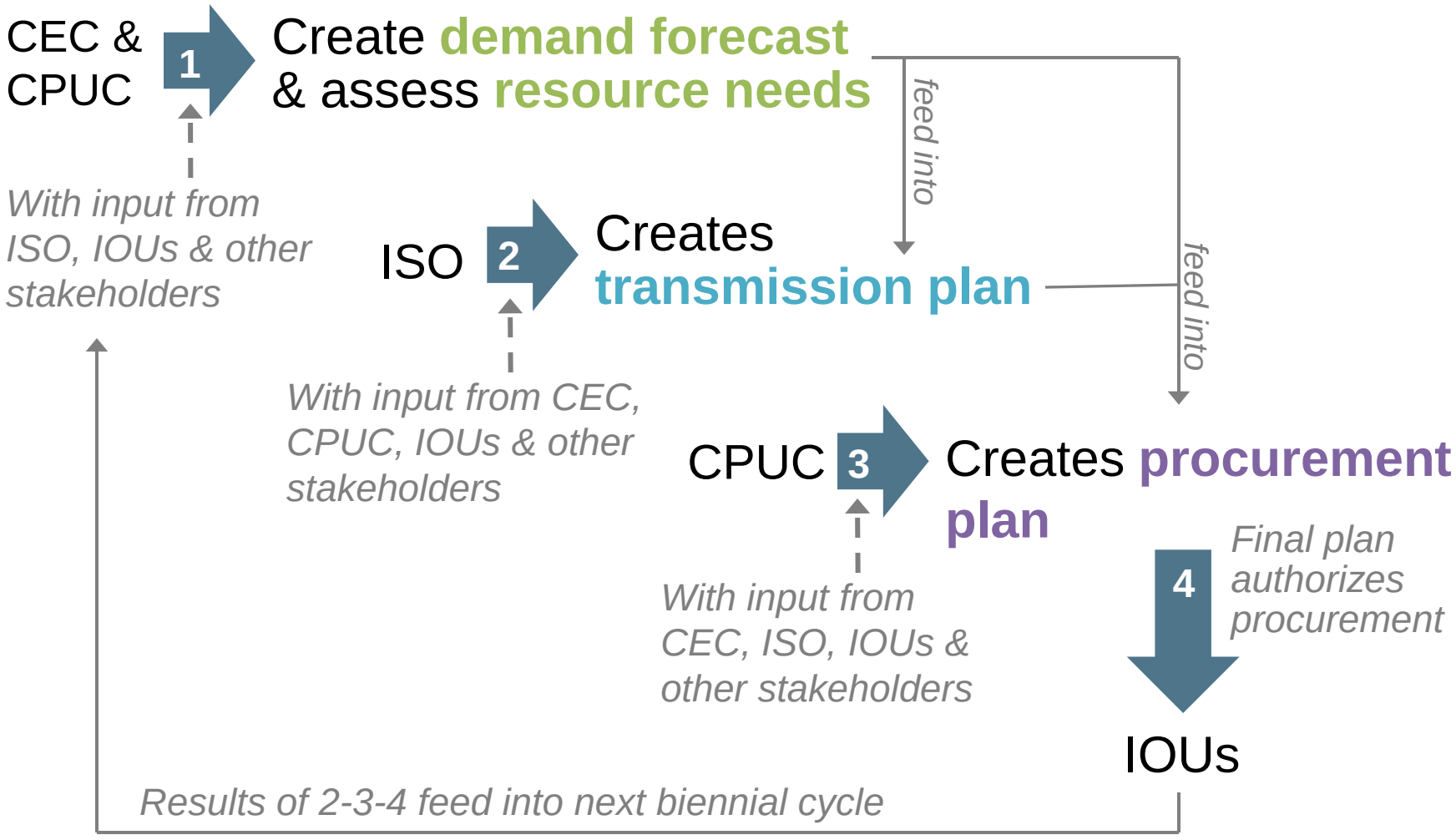
- **73,306** MW of power plant capacity (installed capacity)
- **50,270** MW record peak demand (July 24, 2006)
- **27,488** market transactions per day (2015)
- **25,685** circuit-miles of transmission lines
- **30 million** people served
- **240 million** megawatt-hours of electricity delivered annually (2015)

As of Nov. 2016

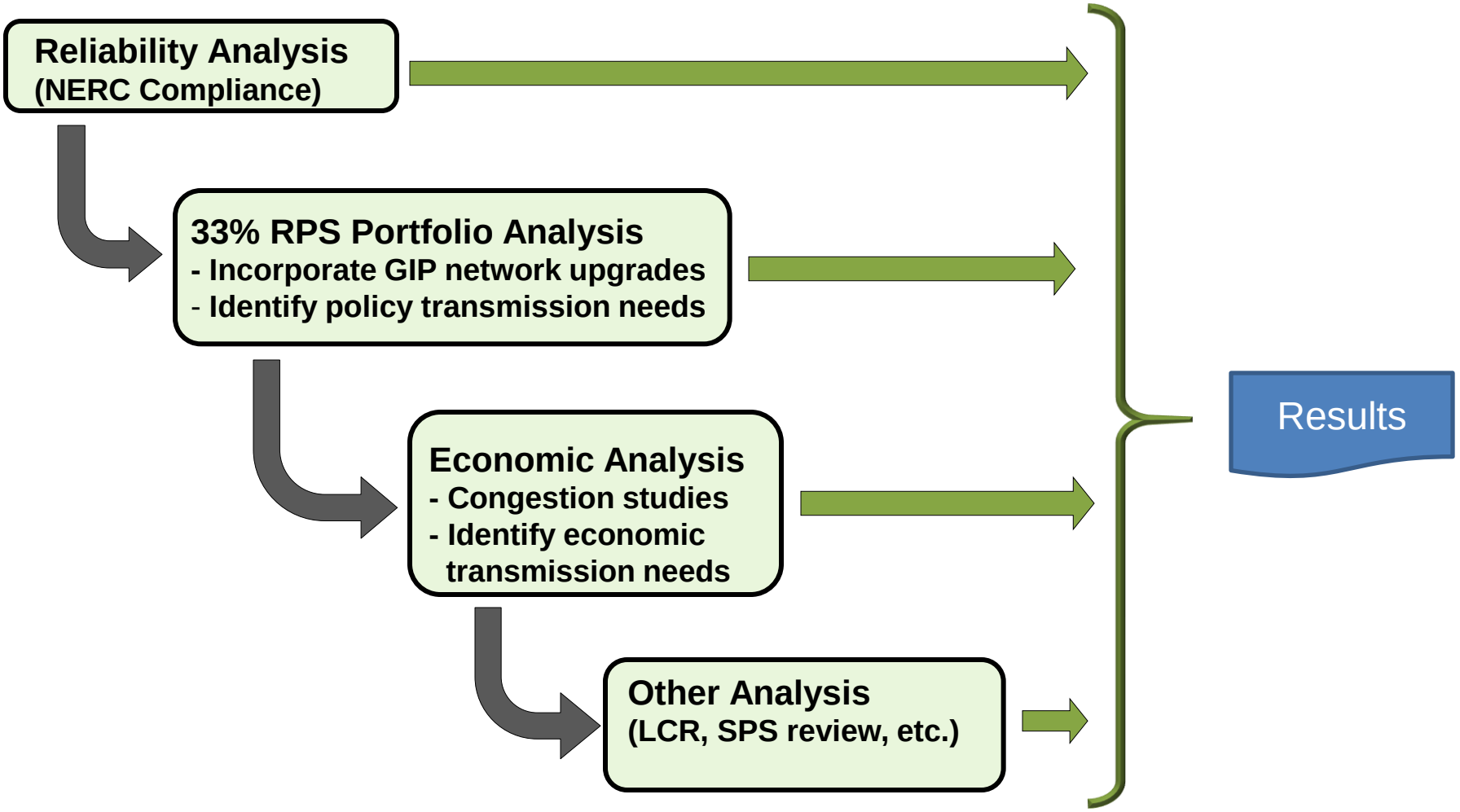
2016-2017 Transmission Planning Process



Planning and procurement overview



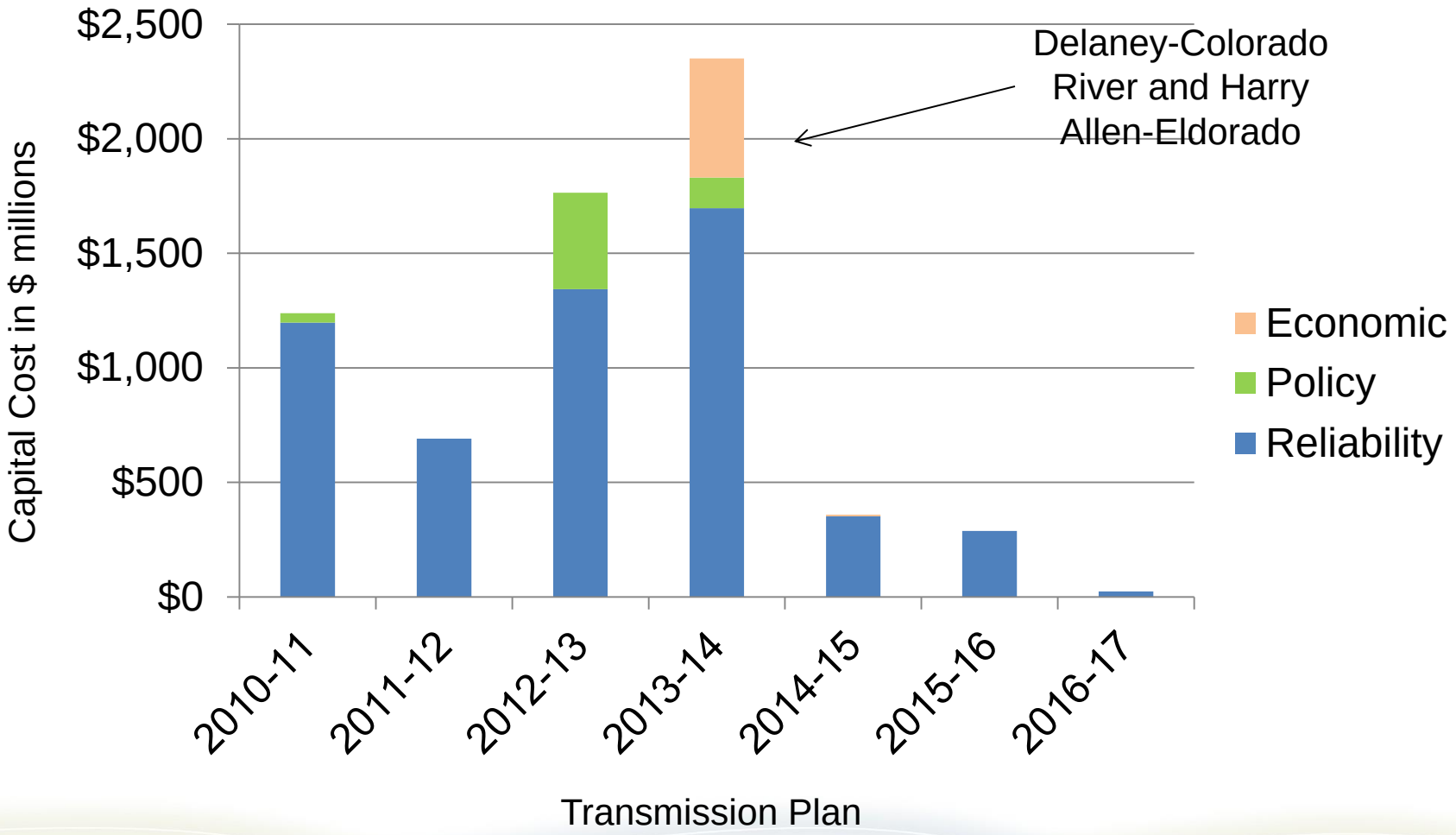
Development of 2016-2017 Annual Transmission Plan



Emphasis in the transmission planning cycle:

- A very light capital program, as:
  - reliability issues are largely in hand
    - load forecasts declining from previous years
    - behind the meter generation forecasts increasing from previous projections
  - policy work was limited to 33% RPS and portfolios are not yet available for moving beyond 33% (for approvals)
  - economic studies not showing any material new opportunities inside the ISO footprint
- Two capital projects totaling $24 million were identified
- Review of previously approved projects continues
  - 13 projects cancelled and additional projects under further review
- Continued emphasis on preferred resources, and increased maturity of study processes
- Special studies looking at emerging issues preparing for grid transitioning to low carbon future

Transmission approvals over the last 7 years – over 30 projects a year until 2014-2015:



Renewable Portfolio Standard Policy Assumptions

- Portfolio direction received from the CPUC and CEC on June 13, 2016:

  “Recommend reusing the "33% 2025 Mid AAEE" RPS trajectory portfolio that was used in the 2015-16 TPP studies, as the base case renewable resource portfolio in the 2016-17 TPP studies”

  “Given the range of potential implementation paths for a 50 percent RPS, it is undesirable to use a renewable portfolio in the TPP base case that might trigger new transmission investment, until more information is available.”

- The ISO focused only on the Imperial, Baja and Arizona areas due to changes in transmission plans in the Imperial Irrigation District from the 2015-2016 Transmission Plan.

- Portfolios to be used in the ISO’s informational 50% RPS special studies were provided by CPUC staff.

Policy and Economic driven solutions:

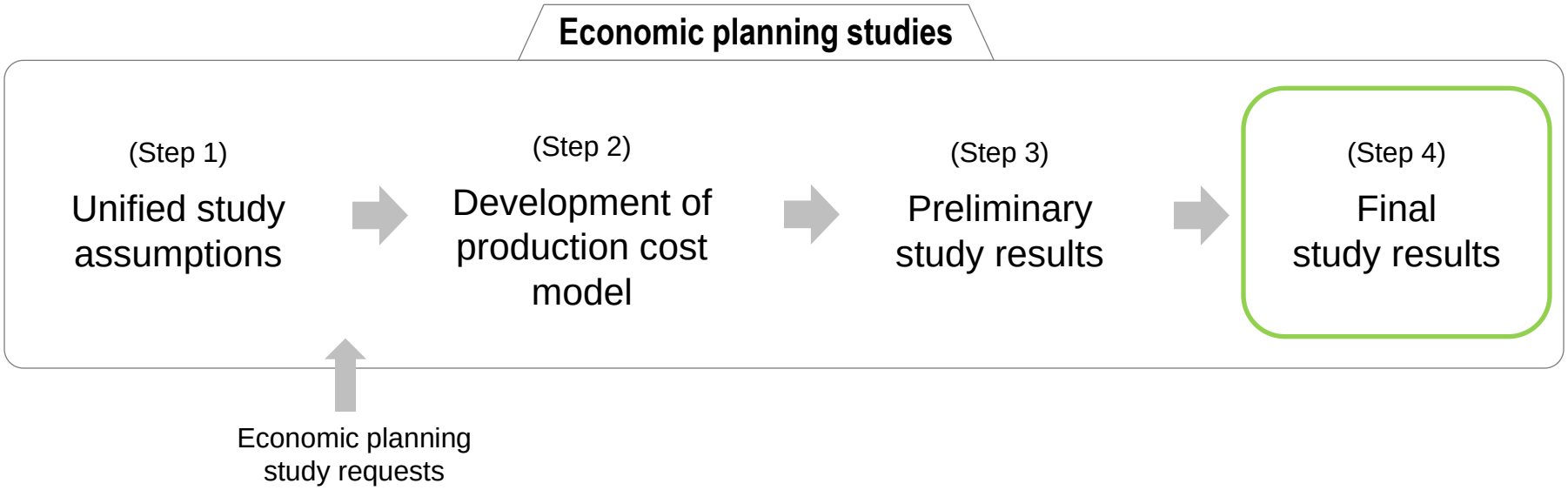
- There were no policy-driven requirements identified
  - A marginal potential overload was identified that could be mitigated by a modest 20 MW reduction in deliverability
  - Given the modest shortfall in deliverability and the objective of reviewing reinforcement requirements when 50% policy renewable generation portfolios are available, mitigations are not recommended at this time for policy purposes
- There were no economically driven requirements identified

Six special studies were undertaken in this cycle:

- Update on Continuation of frequency response efforts through improved modeling *(in progress – update today)*
- Risks of early economic retirement of gas fleet
- 50% Renewable Generation (in-state analysis and coordination)
- Other studies underway
  - 50% Renewable Generation (out of state and Interregional Transmission Project evaluation) *(February 28, 2017 stakeholder session)*
  - Large scale storage benefits *(February 28, 2017 stakeholder session)*
  - Slow response resources in local capacity areas *(moving to parallel track anticipated, technical results will continue)*
  - Gas/electric reliability coordination *(presented in November 2017 stakeholder session)*

Economic Planning Study

Steps of economic planning studies



Summary

- No economic upgrade recommended for approval in the 2016~2017 planning cycle
- COI modeling was enhanced
  - Provided an enhanced framework for any future studies on COI congestion
- Congestion analysis and economic assessment in future planning cycles to take into account
  - Improved WECC production cost modeling
  - Further consideration of suggested changes to ISO economic modeling
  - Further clarity on 50% renewable energy goal
  - Interregional transmission planning process

50% RPS Special Study– In-state Results and Status of Out of State Studies

Primary objectives

- to continue investigating the transmission impacts of moving beyond 33 percent RPS assuming procurement based on
  - Deliverability Status – Energy Only (EODS) or Full Capacity (FCDS)
  - Resource location – In-state or Out-of-state (OOS)

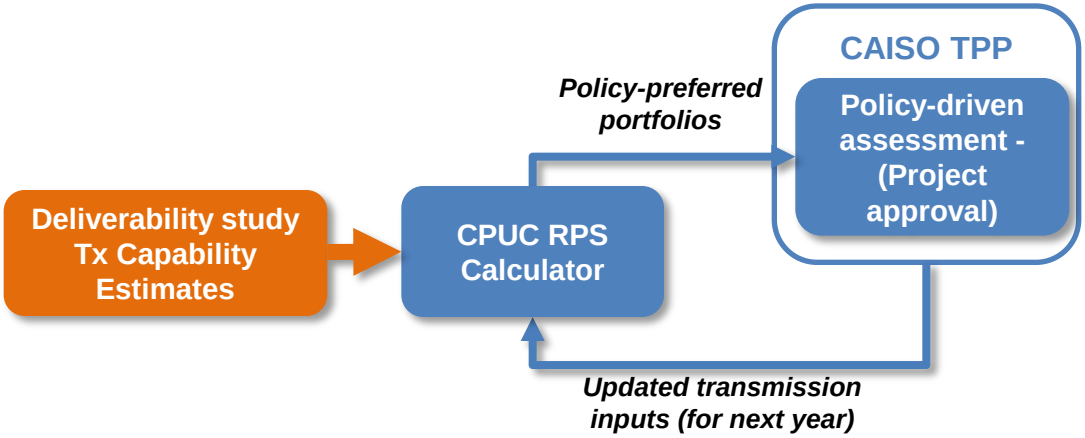
- to test the transmission capability estimates used in RPS calculator v6.2 and update these for future portfolio development

- to examine the transmission implications of meeting part of the 50 percent RPS obligation by relying on renewable resources outside of California and foster a higher degree of coordination with regional planning entities for the OOS portfolio modeling and assessment

- does not provide basis for procurement/build decisions in 2016-17 TPP cycle;
- is intended to be used to develop portfolios for consideration by ISO in future TPP cycles; and,
- explores potential policy direction on various related issues but does not attempt to predict how those issues will ultimately be addressed.

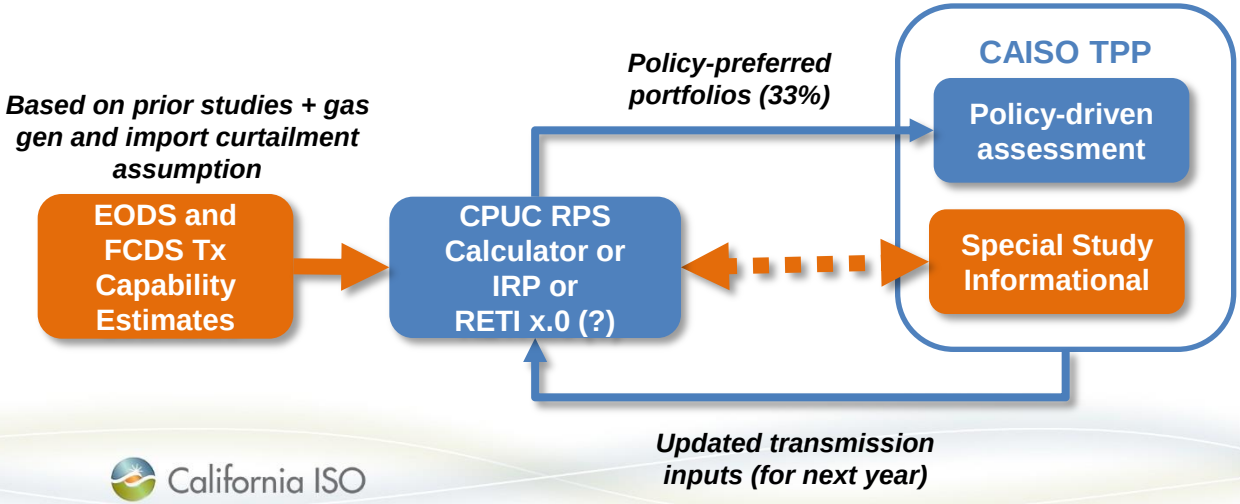
50% RPS special study is an informational effort intended to inform resource development in the future

Existing policy-driven planning process



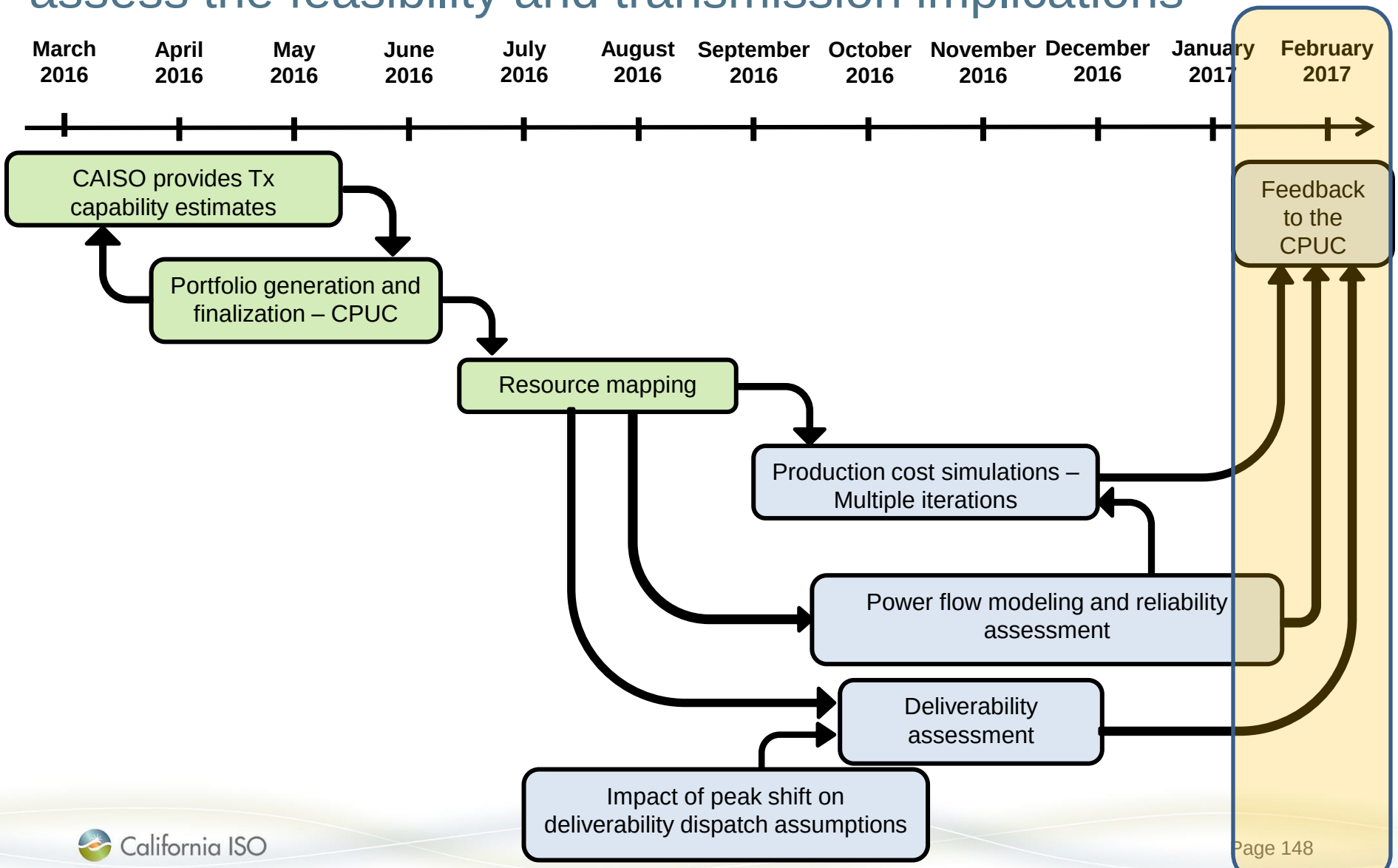
- Iterative process used to achieve 33% RPS goals
- This process results in policy-driven transmission upgrade approval
- Most procured generation assumed to have FCDS

Iterative process used to test and refine 50% RPS portfolios

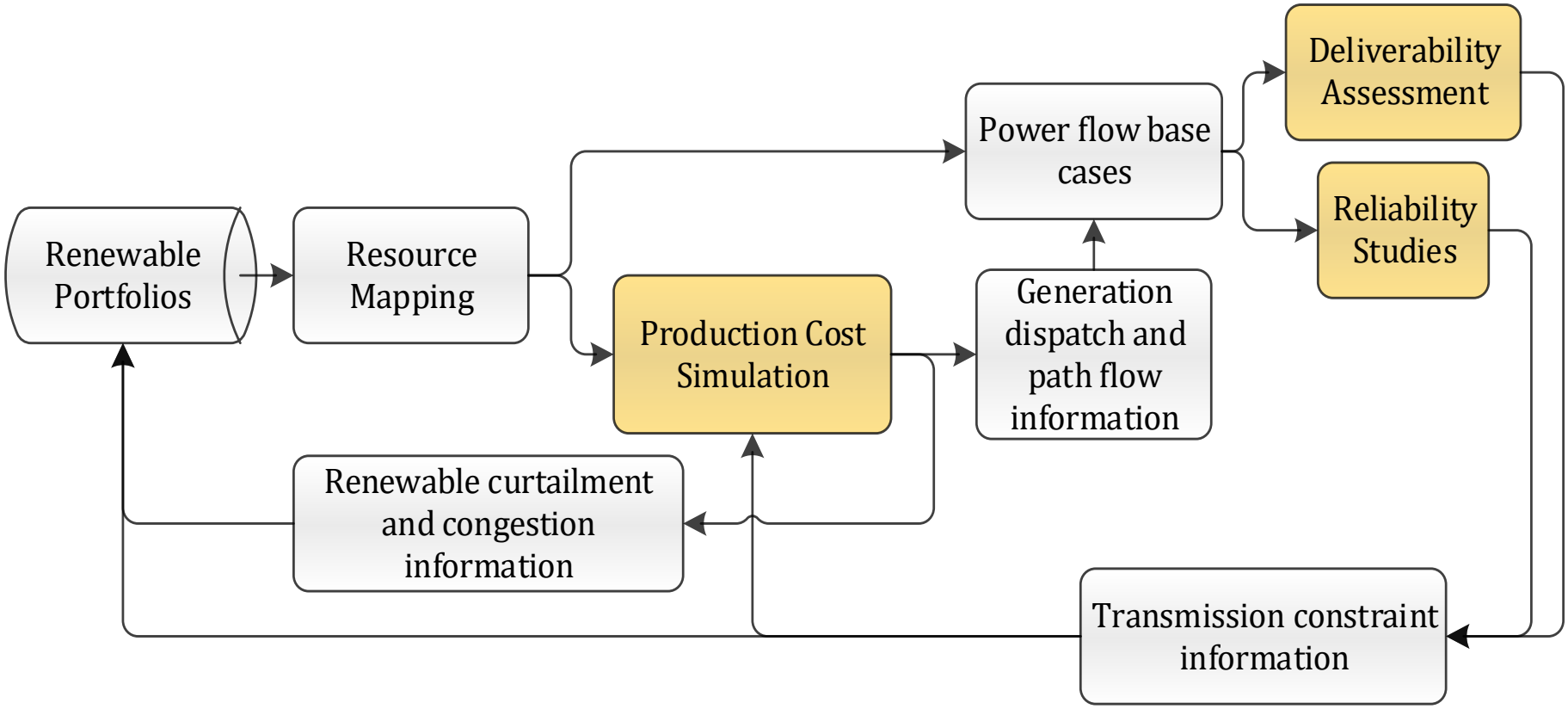


- Strictly an informational effort
- Procured gen assumptions based on geography (in-state or OOS) and deliverability status (EODS or FCDS)
- ***Objective***
  - To test and revise the transmission (Tx) capability numbers provided by CAISO
  - Preliminary transmission stress-test

50% RPS portfolios provided by the CPUC were used to assess the feasibility and transmission implications



The study is an iterative process that ties together three types of technical assessments



The study scope involves evaluation of four portfolios across three key performance metrics

Portfolio Assumptions

	In-state FCDS	In-state EODS	Out-of-state FCDS	Out-of-state EODS
Geography	CA - only	CA - only	CA + out-of-state	CA + out-of-state
Deliverability	FCDS	EODS	FCDS	EO
Out-of-state resources	None	None	WY and NM wind	WY and NM wind

Performance Assessment

Assessment	In-state Full Capacity (FCDS)	In-state Energy Only (EODS)	Out-of-state FCDS/EODS
Reliability Assessment	✓	✓	✓
Deliverability Assessment	✓	✗	✓
Production Cost Simulation	✓	✓	✓

Initial transmission capability estimates in CA

Sacramento River Valley
Tx Capability: FCDS unknown
EODS ~2,100 MW

Lassen and round Mountain
Tx Capability: FCDS unknown
EODS ~1,250 MW

Solano
Tx Capability: FCDS unknown
EODS ~879 MW

Kramer and Inyokern
Tx Capability: FCDS 0 MW
EODS ~412 MW

Central Valley North and Los Banos
Tx Capability: FCDS ~130 MW
EODS ~1,889 MW

Westlands
Tx Capability: FCDS ~1823 MW
EODS ~3,121 MW

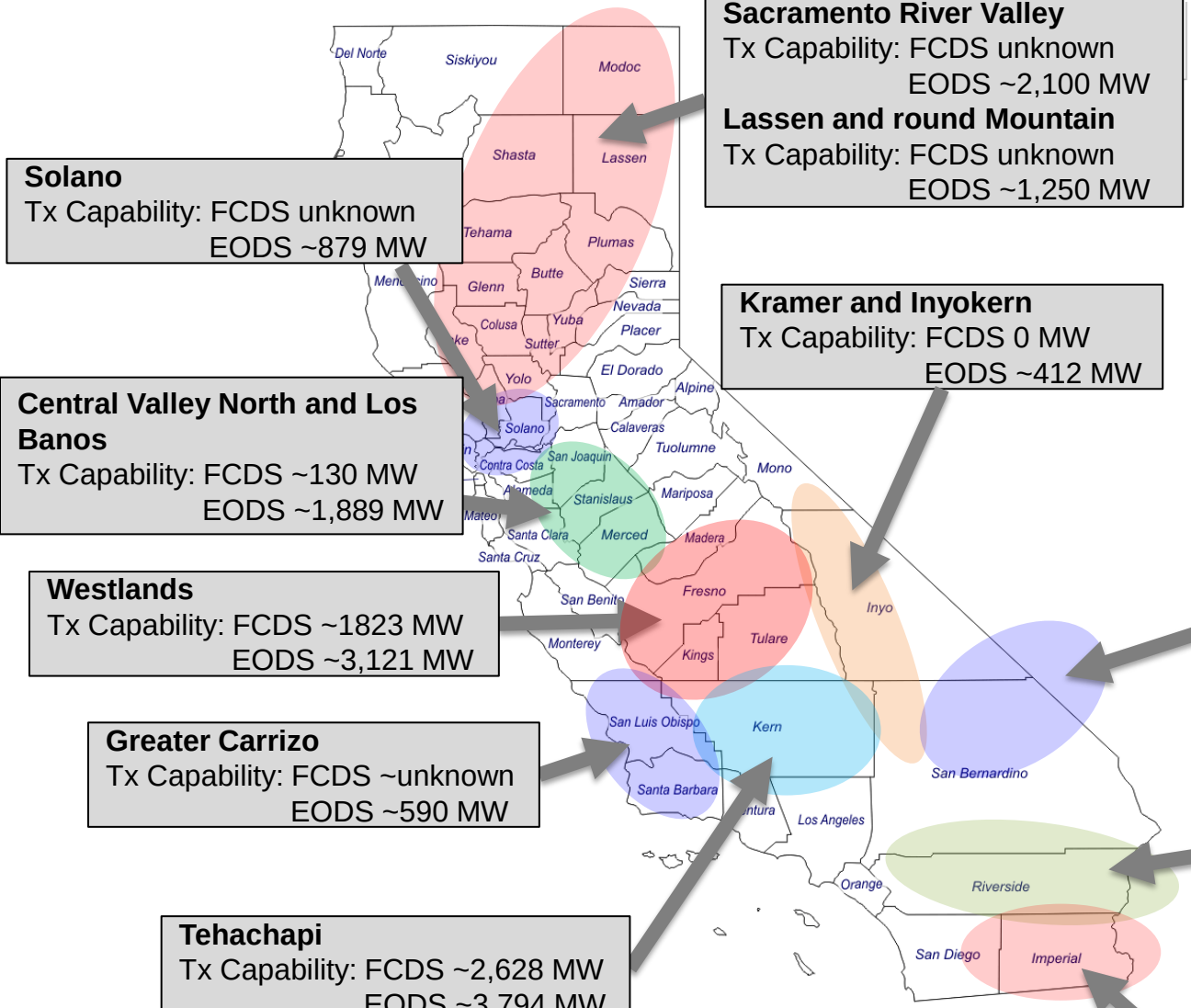
Nevada SW, Mountain Pass and Eldorado
Tx Capability: FCDS ~535 MW
EODS ~2,735 MW

Greater Carrizo
Tx Capability: FCDS ~unknown
EODS ~590 MW

Riverside East and Palm Springs
Tx Capability: FCDS ~523 MW
EODS ~1,849 MW

Tehachapi
Tx Capability: FCDS ~2,628 MW
EODS ~3,794 MW

Greater Imperial
Tx Capability: FCDS ~523 MW
EODS ~1,849 MW

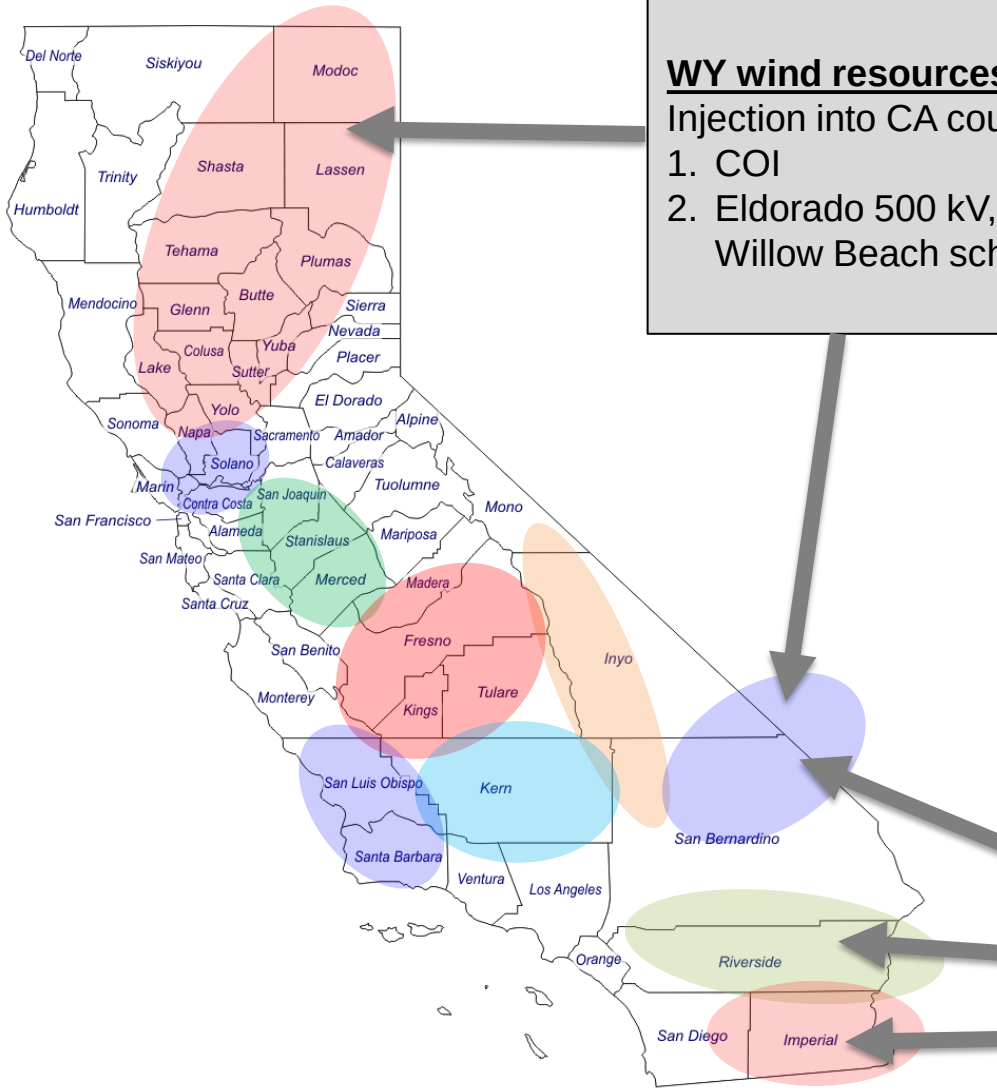


Starting estimates used as an input to RPS calculator for generating the 50% portfolios

Assumption: Latent system capacity, conventional generation curtailment, some import reduction, and modest transmission-related renewable curtailment

Note – impacts on the California system of out of state imports were tested by assuming specific injection points into California

Expected injection points from out-of-state resources into CA



WY wind resources (~2,000 MW)
Injection into CA could primarily utilize –
1. COI
2. Eldorado 500 kV, Mead 230 kV and Willow Beach scheduling points

NM wind resources (~2,000 MW)
Injection into CA could primarily utilize –
1. Palo Verde corridor

Out-of-state portfolio assessment – Interregional coordination

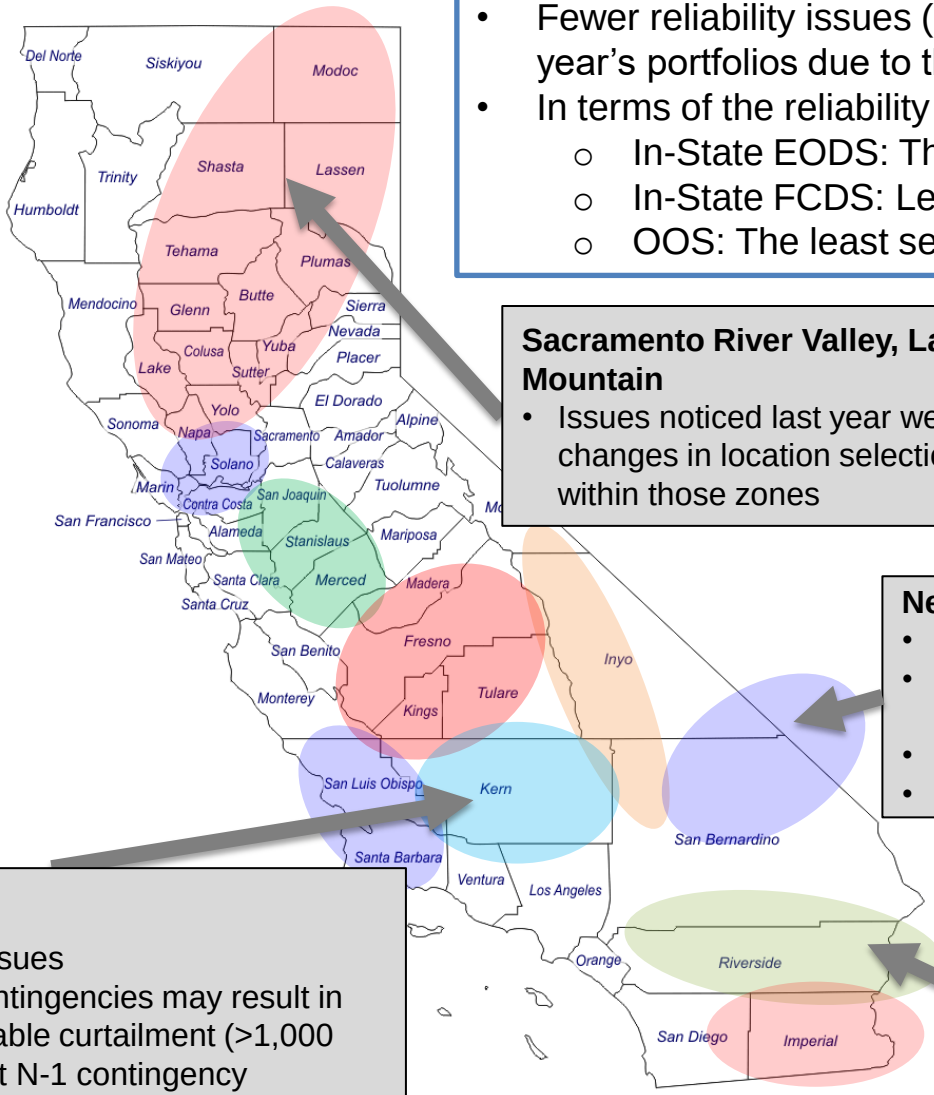
- NTTG and WestConnect provided resource location information for ~2,000 MW wind in WY and ~2,000 MW wind in NM
- Out-of-state portfolio models were shared with the western planning regions as part of the interregional coordination work
- CAISO is working with subject matter experts from the other western planning regions on reviewing production simulation results to identify specific stressed system conditions to be considered in the CAISO assessment
- NTTG provided transmission system contingencies to test the impact of the out-of-state portfolio on the affected part of the NTTG area
- CAISO continues to work with WestConnect on identifying certain system contingencies to test the out-of-state portfolio on the affected part of the WestConnect area
  - During 2017 WestConnect will run a “High Renewables” scenario that models a California 50% out-of-state case

Out-of-state portfolio assessment – evaluation of system outside of CA

- Key hours were selected from 2015-2016 TPP production simulation runs to focus on CA imports and CA transmission utilization
- ISO studies indicate consideration of additional hours are needed to account for changing resource assumptions outside of CA
- Additional production simulation modeling is needed to identify transmission constraints outside of CA
- Additional production simulation “hours” that are reflective of the WY and NM regions are needed to test resource delivery from these areas
  - An update will be provided in the February 28 stakeholder meeting

Reliability impact on CA transmission

- Fewer reliability issues (mostly local) compared to last year's portfolios due to the reduced size of portfolios
- In terms of the reliability impacts on CA transmission –
  - In-State EODS: The most severe
  - In-State FCDS: Less severe
  - OOS: The least severe



Sacramento River Valley, Lassen and round Mountain

- Issues noticed last year were eliminated due to changes in location selection for resources within those zones

Nevada SW, Mountain Pass and Eldorado

- In-State EODS issues
- Issues noticed in Eldorado and VEA system under N-0 and N-1 conditions
- Severe overload in VEA
- May results in curtailment >600 MW

Tehachapi

- In-State EODS issues
- Several N-1-1 contingencies may result in significant renewable curtailment (>1,000 MW) after the first N-1 contingency
- Challenges in taking maintenance outages

Riverside East and Palm Springs

- Issues noticed last year eliminated due to halving of resource amounts in these zones

Summary of reliability assessment of 50% portfolios - adequate interconnection capability

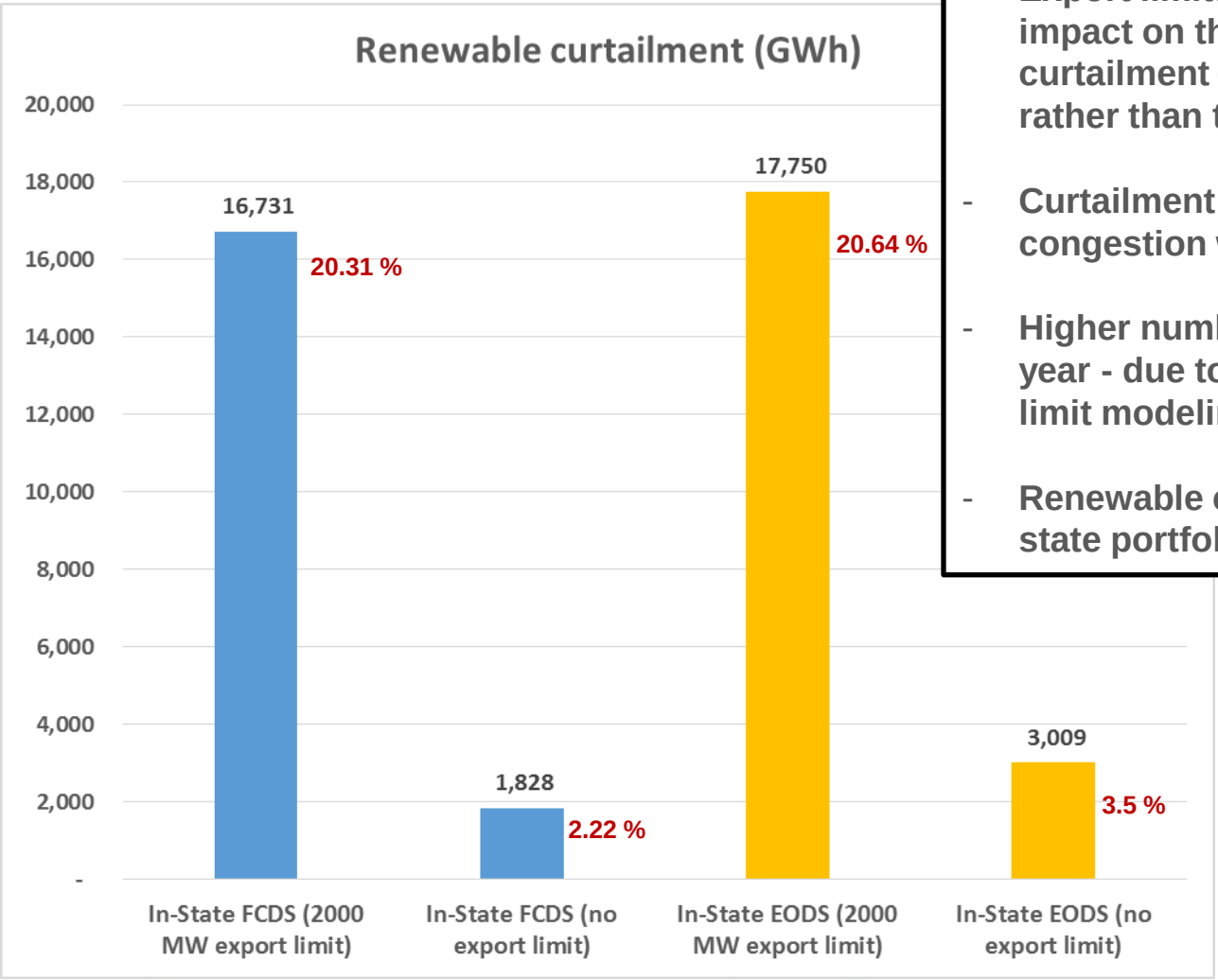
- Fewer reliability issues (mostly local) compared to last year's portfolios due to the reduced size of portfolios
  - In-state EODS portfolio is more severe than In-state FCDS in certain areas
  - OOS portfolio resulted in the least number of reliability issues within CA
- Potential mitigation measures
  - Moderate generation redispatch under N-1 conditions
  - Local upgrades triggered through GIDAP
  - Series compensation balancing on P26 in certain hours
  - Reactive power absorption capability
- In Tehachapi area, several N-1-1 contingencies may result in significant renewable curtailment
  - A potential challenge for taking maintenance outages

Purpose of the Deliverability Assessment

- Preliminarily evaluate the incremental transmission needs beyond the 33% for the 50% renewable portfolio
- Not intended for making any transmission planning project approval decisions

- The ISO requested information from CPUC to begin consideration of potential adjustments to the input assumptions to the study on a preliminary basis.
- Information was utilized to gain insight into potential adjustments that may be needed to the input assumptions for future deliverability assessments.
- This experimental work was intended to directionally evaluate the incremental transmission needs beyond 33 percent renewable.
- Preliminary information was utilized to explore a preliminary methodology and is not intended to be used for making any transmission planning project approval decisions and is focused only on moving beyond 33 percent RPS to 50 percent RPS.

Total renewable curtailment by portfolio



- Export limits had a significant impact on the amount of renewable curtailment – over-supply related rather than transmission related
- Curtailment due to transmission congestion was modest
- Higher numbers compared to last year - due to enhanced ISO export limit modeling
- Renewable curtailment in out-of-state portfolio is yet to be analyzed

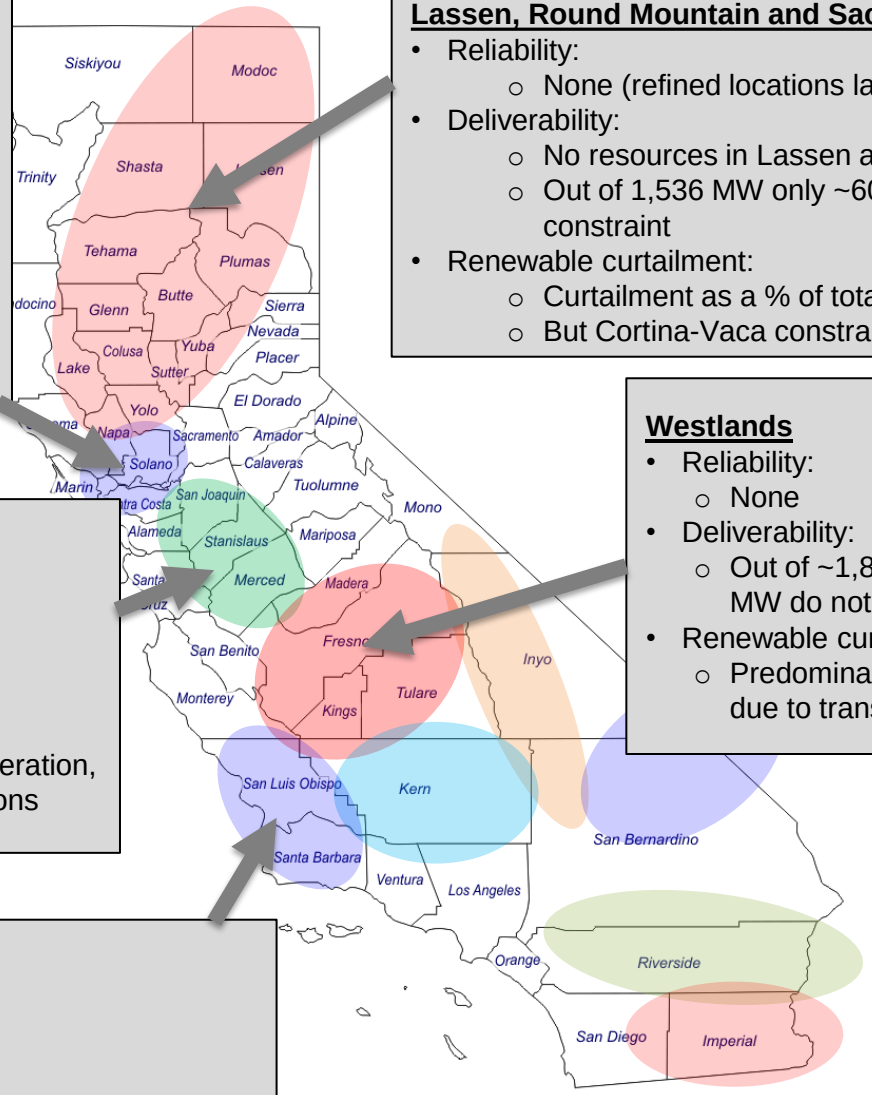
Summary of In-State portfolio assessment – Northern

Solano
- Reliability:
  - None
- Deliverability:
  - Out of 1,500 MW, approximately 1,200 MW do not contribute to a constraint
- Renewable curtailment:
  - Predominantly due to over-generation, not due to transmission limitations

Lassen, Round Mountain and Sac River Valley
- Reliability:
  - None (refined locations last year)
- Deliverability:
  - No resources in Lassen and Rnd Mtn
  - Out of 1,536 MW only ~600 MW do not contribute to a constraint
- Renewable curtailment:
  - Curtailment as a % of total capacity is minor
  - But Cortina-Vaca constraint could be an expensive one

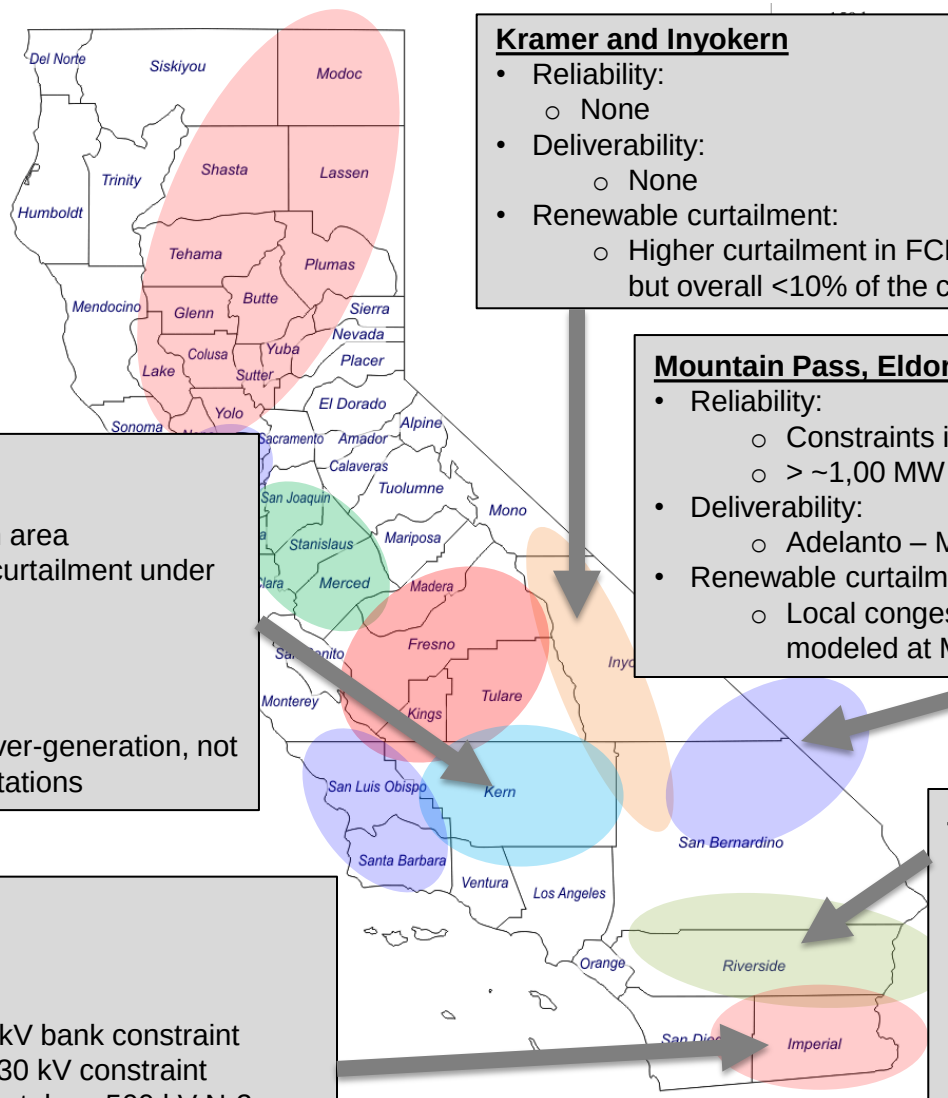
Westlands
- Reliability:
  - None
- Deliverability:
  - Out of ~1,823 MW, approximately 1,600 MW do not contribute to a constraint
- Renewable curtailment:
  - Predominantly due to over-generation, not due to transmission limitations (~8%)

Cantal Valley and Los Banos
- Reliability:
  - None
- Deliverability:
  - None
- Renewable curtailment:
  - Predominantly due to over-generation, not due to transmission limitations



Greater Carrizo
- Reliability:
  - None
- Deliverability:
  - None
- Renewable curtailment:
  - Predominantly due to over-generation, not due to transmission limitations
  - Mainly in EODS portfolio

Summary of In-State portfolio assessment – Southern CA



Kramer and Inyokern

- Reliability:
  - None
- Deliverability:
  - None
- Renewable curtailment:
  - Higher curtailment in FCDS portfolio, but overall <10% of the capacity

Mountain Pass, Eldorado, VEA and Southwestern NV

- Reliability:
  - Constraints in VEA and East of Pisgah area
  - > ~1,00 MW curtailment may be needed
- Deliverability:
  - Adelanto – Marketplace 500 kV N-2 constraint
- Renewable curtailment:
  - Local congestion due to large resources modeled at Merchant 230 kV on EODS portfolio

Tehachapi

- Reliability:
  - Overloads in Magunden area
  - More than ~1,900 MW curtailment under N-1-1
- Deliverability:
  - None
- Renewable curtailment:
  - Predominantly due to over-generation, not due to transmission limitations

Greater Imperial

- Reliability:
  - None
- Deliverability:
  - Miguel 230/500 kV bank constraint
  - IV – El Centro 230 kV constraint
  - Adelanto – Marketplace 500 kV N-2 constraint
- Renewable curtailment:
  - Predominantly due to over-generation, not due to transmission limitations

Riverside East and Palm Springs

- Reliability:
  - None (refined locations last year)
- Deliverability:
  - IV – El Centro 230 kV constraint
  - Adelanto – Marketplace 500 kV N-2 constraint
- Renewable curtailment:
  - Predominantly due to over-generation, not due to transmission limitations

Summary of conclusions

Assessment	Key Takeaways		
	In-state FCDS	**In-state EO**	**Out-of-state**
Reliability assessment	• Fewer reliability issues because portfolio resource amounts in most of the zones were less than the amounts at which transmission constraints were expected.	• Tehachapi, Mountain Pass and Eldorado, VEA and Nevada SW zones may experience pre-contingency curtailment under certain scenarios	• The least severe portfolio in terms of reliability issues on CA transmission system • Studies indicate the need for considering different snapshots that take into account the changing resource assumptions outside of CA
Deliverability assessment	• In Northern CA, Solano, Sacramento River Valley and Westlands zones experienced deliverability constraints • In Southern CA, area-wide constraints would limit delivery or resources from Eldorado and Mountain Pass, VEA, Southwestern NV, Riverside East and Greater Imperial zones • There were no transmission capability estimates to start with in some Northern CA zones. These can now be established.	N/A	• Sufficient import capacity exists to delivery out-of-state resources from a scheduling point within CAISO BA to CAISO loads • Deliverability of out-of-state resources up to the CAISO scheduling point was not tested
Renewable curtailment	• Export limits had a significant impact on the amount of renewable curtailment – over-supply related rather than transmission related • More renewable curtailment observed in EODS portfolio than FCDS portfolio • Curtailment due to CA transmission congestion was modest but it did increase with relaxation of export constraint		• Additional production simulation modeling is needed to identify transmission constraints outside of CA

Next steps

- CAISO will work with the CPUC and the CEC to incorporate the findings and conclusions into future portfolio development
- Out-of-state portfolio assessment
  - Additional production cost analysis is needed to assess transmission constraints outside of CA that result from WY and NM energy delivery to CA
  - An update on this portfolio assessment will be provided in the February 28 stakeholder meeting
- Potential assessments in 2017
  - Out-of-state scenarios based on updated assumptions
  - Coordination with western planning regions on ITP evaluation
  - Further work on deliverability assumptions

Risks of Early Economic Retirement of Gas-Fired Generation

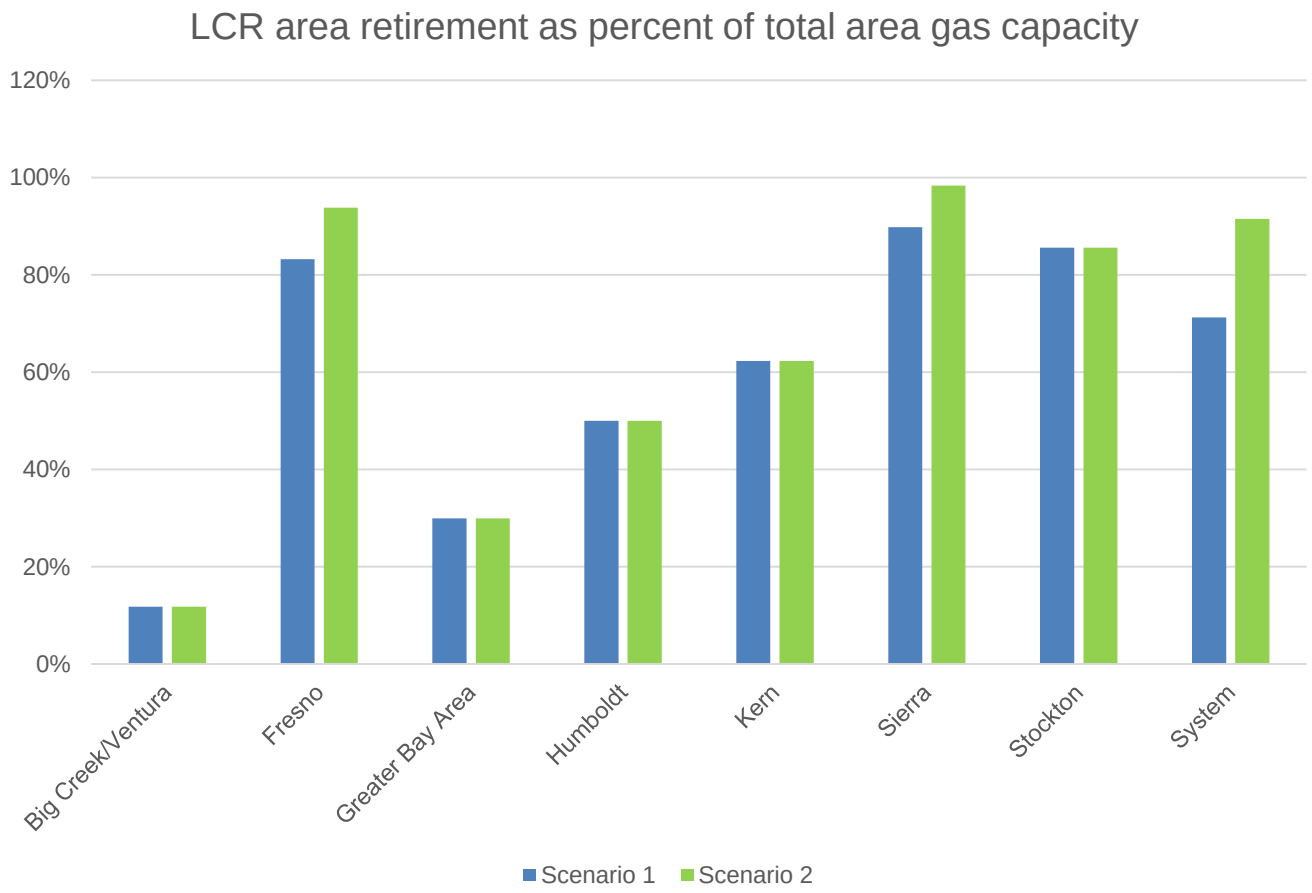
Background Information

- There is potential for an economic early retirement of gas generation due to the increasing levels of renewable generation interconnecting to the electrical grid.
- The study scope and methodology were presented at the ISO 2016-2017 transmission planning process second stakeholder meeting on September 21-22, 2016
  - https://www.caiso.com/Documents/Day2Presentation-2016-2017TransmissionPlanningProcess-PreliminaryReliabilityResults.pdf
- Preliminary screening methodology to identify areas of potential early retirement using the ISO's 2016-2017 production cost models (PCM) with 50% renewable portfolios was also presented.

Study Scope

- Identify the incremental path flow impacts (congestion from PCM) of the retirement scenarios on California transfer paths.
- Identify high level potential path flow impacts on the California transfer paths and the associated RAS (IRAS) using power flow analysis.
- Identify potential system level impacts on ancillary services and flexibility requirements.

Methodology and Resulting Scenarios



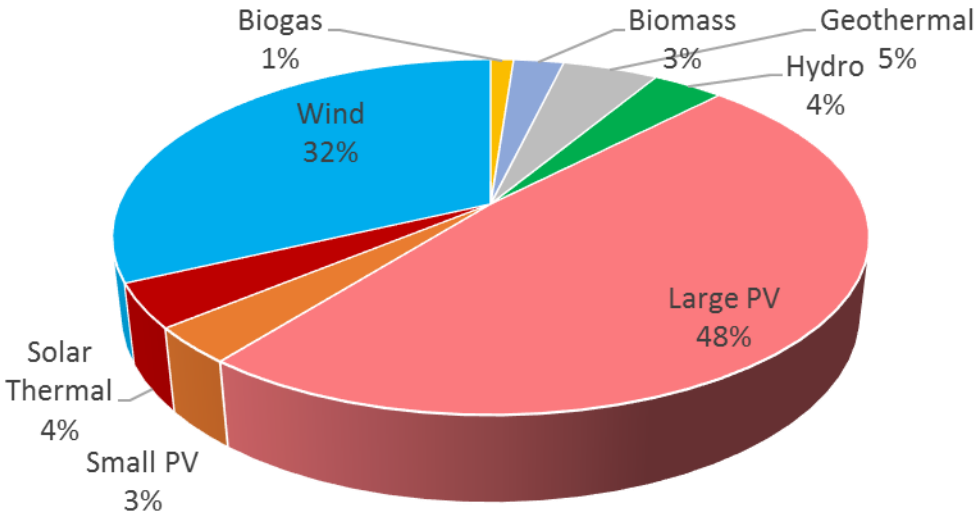
Total Expected Retirement

Scenario 1= 8265 MW

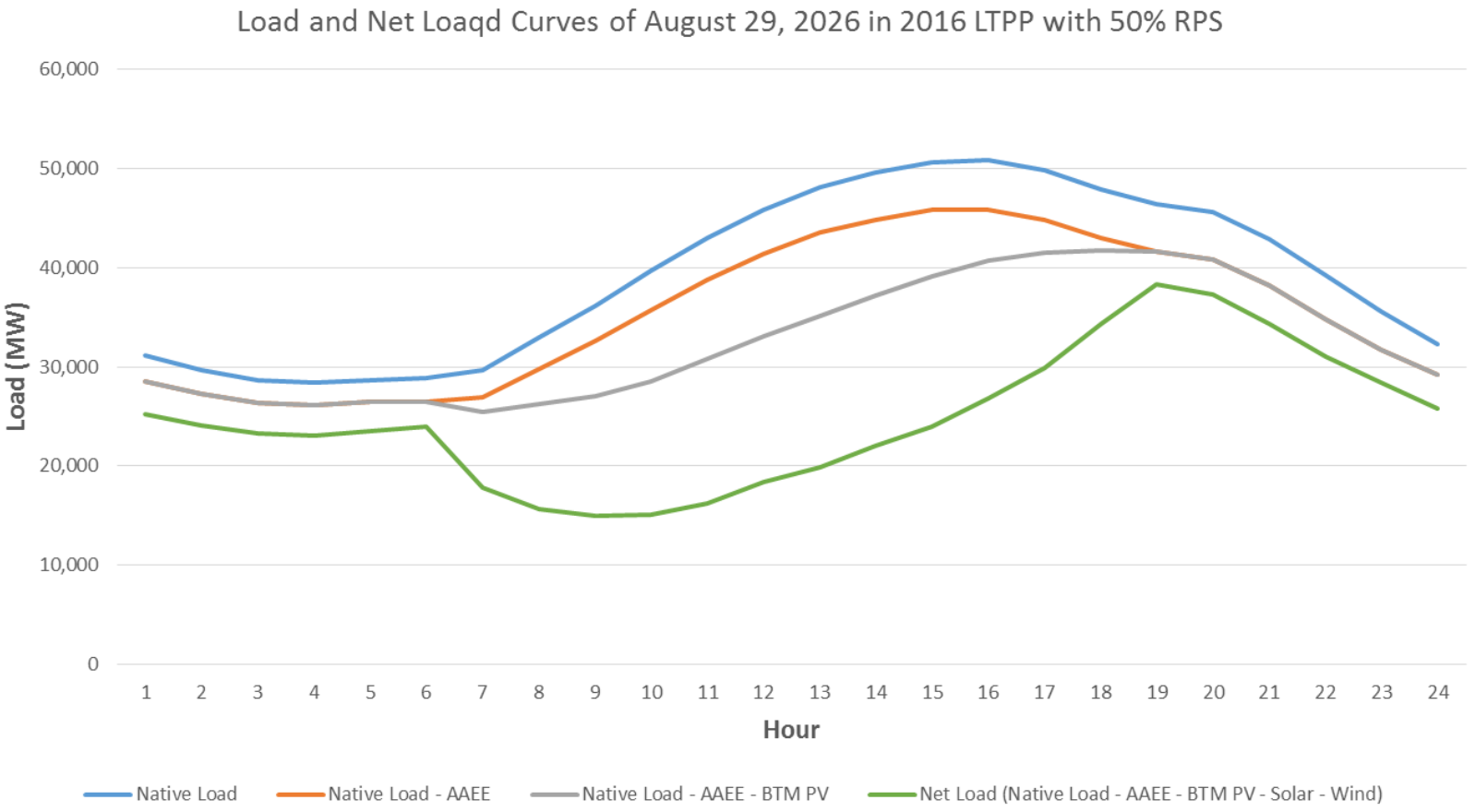
Scenario 2= 9658 MW

Potential Impact on system level requirements

The 50% RPS portfolio – solar is the dominant resource



Net load on the annual peak net load day – illustration of peak shifting due to solar generation



Summary of Findings

- Unlimited renewable curtailment masks the need for flexible capacity during downward ramping in the morning and upward ramping in the afternoon
- The shortfalls in load-following and reserves reflect the insufficiencies of capacity
- Capacity insufficiencies occur in early evening after sunset, which is the new peak (net) load time
- Capacity sufficiency issues start to emerge between 4,000 to 6,000 MW of retirement, considering some uncertainties in forecasts.

Frequency Response Assessment-Generation Modeling Special Study

Drivers for the Study

- Frequency response studies of the 2015-2016 Transmission Plan showed optimistic results regarding frequency response
- Actual measurements of the generators' output were lower that the generators' output in the simulations
- Therefore models update and validation is needed
- New NERC Standards MOD-032-1 and MOD -033-1 require to have accurate validated models
- MOD-032-1 - data submission by equipment owners to their Transmission Planners and Planning Coordinators to support the Interconnection-wide cases
- MOD-033-1 - requires each Planning Coordinator to implement a documented process to perform model validation within its planning area.
- Generation owners are responsible for providing the data, and the ISO is responsible for the model validation

Study Methodology

- Identify missing models or missing model components, also
- Units modeled with obsolete models no longer supported by WECC
- Models that have deficiencies and require upgrades - by comparison of the real time measurements and the simulation results, or if measurements are not available, by unrealistic performance in the simulations
- Identify generators modeled with generic models with typical parameters and obtain more accurate models of the units
- This task is performed in coordination with the System Operations who will provide the real-time measurement data.
- Updated models reported to WECC to be included in the dynamic stability model database.
- Details provided in June 13, 2016 Stakeholder Call material and at the Stakeholder meeting in September 2016

Models with concerns

- Reviewed WECC Dynamic Master File and identified old models, missing models, models with wrong type, or models with typical generic data.
- Based on the transient stability study results for the 2016-2017 TPP, identified renewable projects that were tripped by under- or over-voltage and frequency protection with three-phase faults even if they were supposed to have Fault-Ride-Through Capability.
- Identified thermal units that showed oscillations in transient stability simulations with three-phase faults in their vicinity, most likely caused by errors in exciter models or incorrect tuning (high gains)
- Based on the frequency response studies performed for the 2015-2016 TPP, identified several hydro units with inadequately high frequency response.
- Identified around 400 generators with issues needing resolution by generation owners

Conclusions

- Due to the discrepancies between dynamic stability simulations and actual system performance, dynamic stability models need to be updated and validated
- The ISO successfully identified which models need update and is working with the PTOs on the update of the models
- Not having PMU with high resolution on the generating plants appears to be a significant obstacle in validating dynamic stability models and in obtaining correct models. Installing more PMUs will improve the validation process.
- The ISO needs to continue the work on model validation and on updating dynamic stability models.

Future Work

- Analyze responses from the generation owners and update the dynamic database
- Perform dynamic stability simulations to ensure that the updated models demonstrate adequate dynamic stability performance
- Send updated validated models to WECC so that the WECC Dynamic Masterfile could be updated
- Perform validation of models based on real-time contingencies and studies with modeling of behind the meter generation
- Investigate measures to improve the ISO frequency response post contingency. Various contingencies and cases may need to be studied

2016-2017 Transmission Planning Process Next Steps

- Comments due March 3, 2017
  - regionaltransmission@caiso.com
- Stakeholder meeting on February 28, 2017
  - 2016-2017 TPP
    - 50% RPS Special Study – Out of State Portfolio Update
    - Benefits Analysis of Large Energy Storage Special study
  - 2017-2018 Draft Study Plan
- ISO Board Meeting on March 15-16, 2017

Coordination of Planning Data and Information between the WPR and WECC

Gary DeShazo – CAISO

Vijay Satyal - WECC

Key Events During 2016

- ITP submittals
  - Relevant planning regions prepared evaluation and coordination plans
  - ITP submittals considered commensurate with WPR regional processes
- WECC Board approval
  - Reliability Assessment Committee
  - Anchor Data Set

WECC Board Resolutions

- Immediate implementation of the RAC and ADS as a WECC corporate priority
- RAC
  - Chairman has been selected
  - Subcommittee Governing Bodies currently being identified
- A detailed implementation schedule is due by February 28, 2017

Benefits of Creating RAC

Improved Efficiency

- Reduced number of committees reduces Member time requirements
- Reduced WECC staff resources required to support
- Committees Focused stakeholder participation in reliability assessment activities

Improved Effectiveness

- Focused reliability assessment expertise
- Broad understanding of potential reliability risks
- Consistent application of reliability assessments
- Consistent data and assumptions

Improved Strategic Alignment

- Alignment with WECC 3-Year Operating Plan
- Integrated annual reliability assessment study program

Benefits of Creating the ADS

Improved Efficiency

- Single repository of accurate and consistent data
- Reduced duplication of data collection processes

Improved Effectiveness

- Common foundation for planning and reliability assessments by regions
- Reliability assessments by WECC and stakeholders

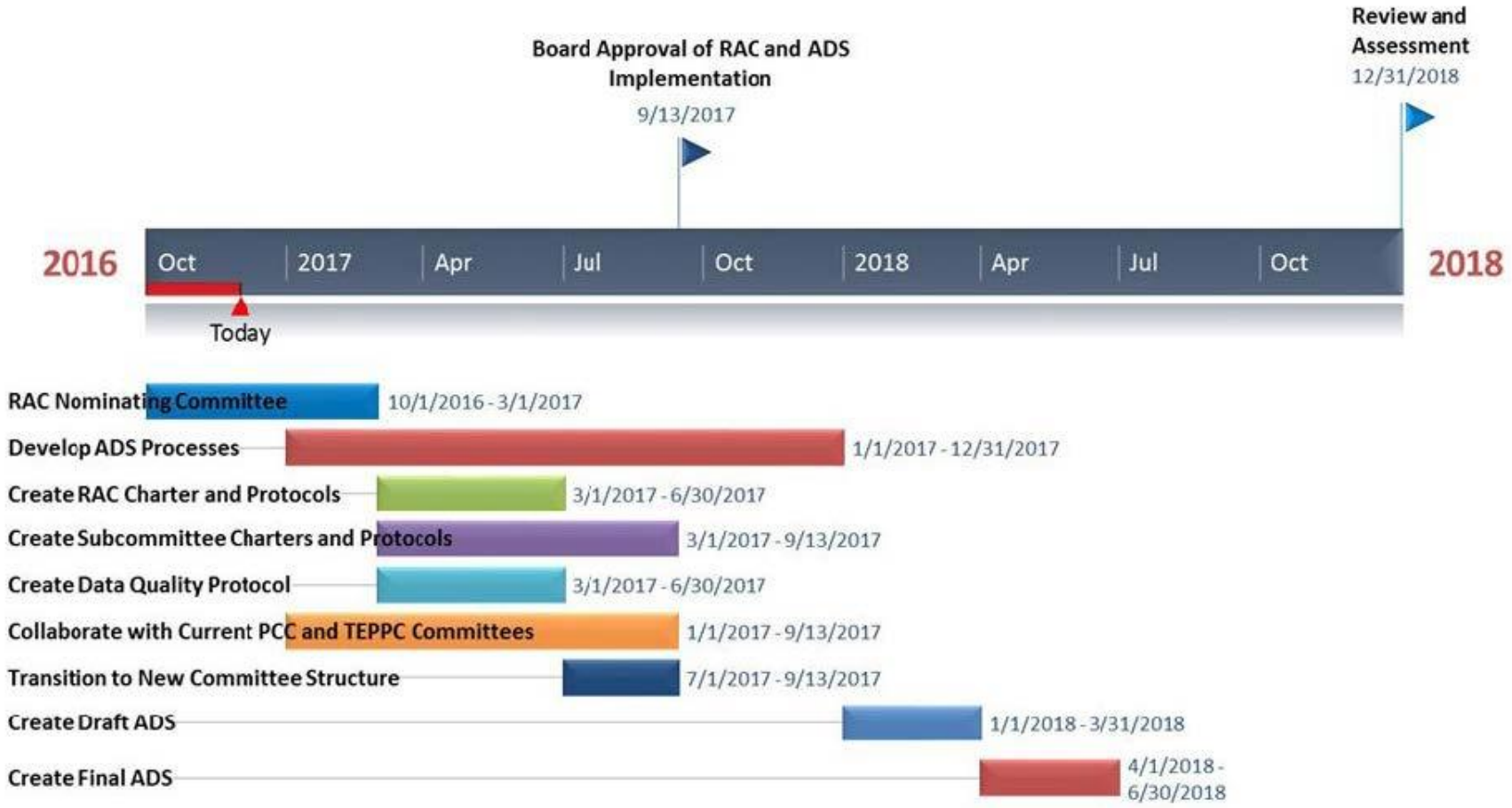
Improved Strategic Alignment

- Integration of power flow and production cost models

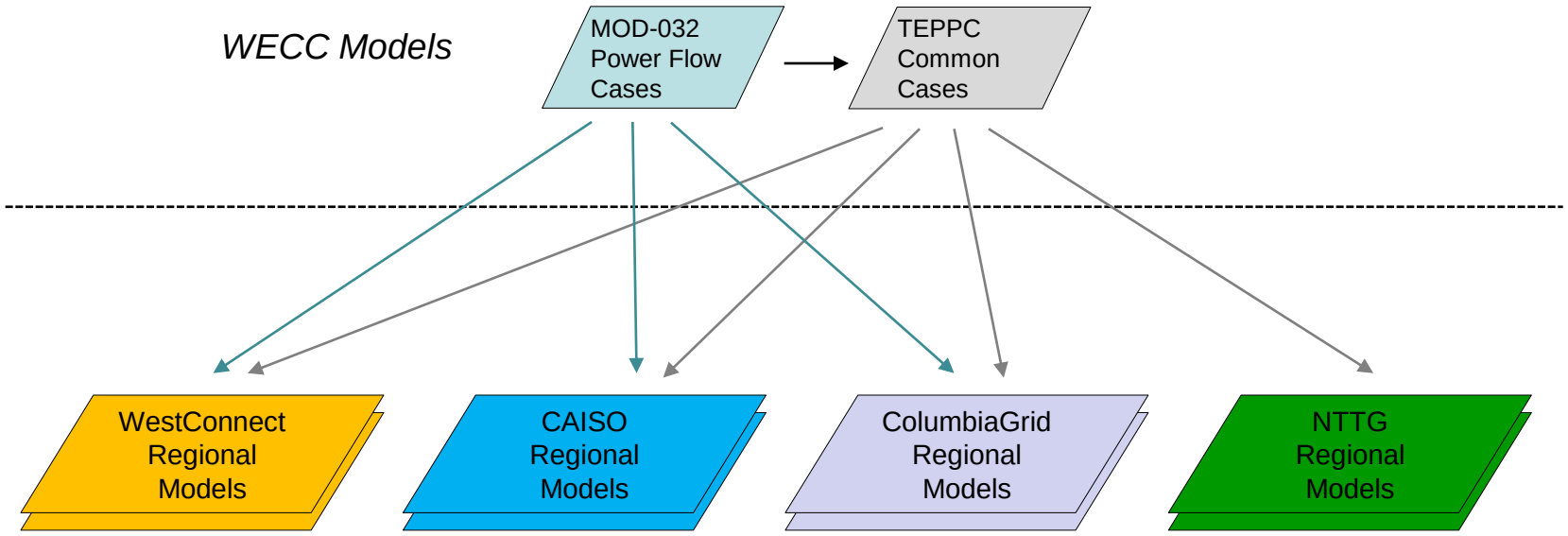
Background on the ADS

- What is the ADS?
  - A 10th-year power flow and production cost model representation of the load, resource, and transmission topology of the Western Interconnection consistent with regional plans of the four Western Planning Regions (WPR)
- How will the regions use the ADS?
  - It will serve as a foundation for all four WPR's (10-year) regional assessments
    - 2028 ADS will be used as a foundation for the 2028 WPR planning
  - In this capacity, the ADS will enable a coordinated evaluation of any ITPs submitted in 2018
- How will WECC use the ADS?
  - WECC will use the ADS to conduct its PF, PCM and dynamic studies for reliability assessments

Implementation of ADS



Our “as-is” processes

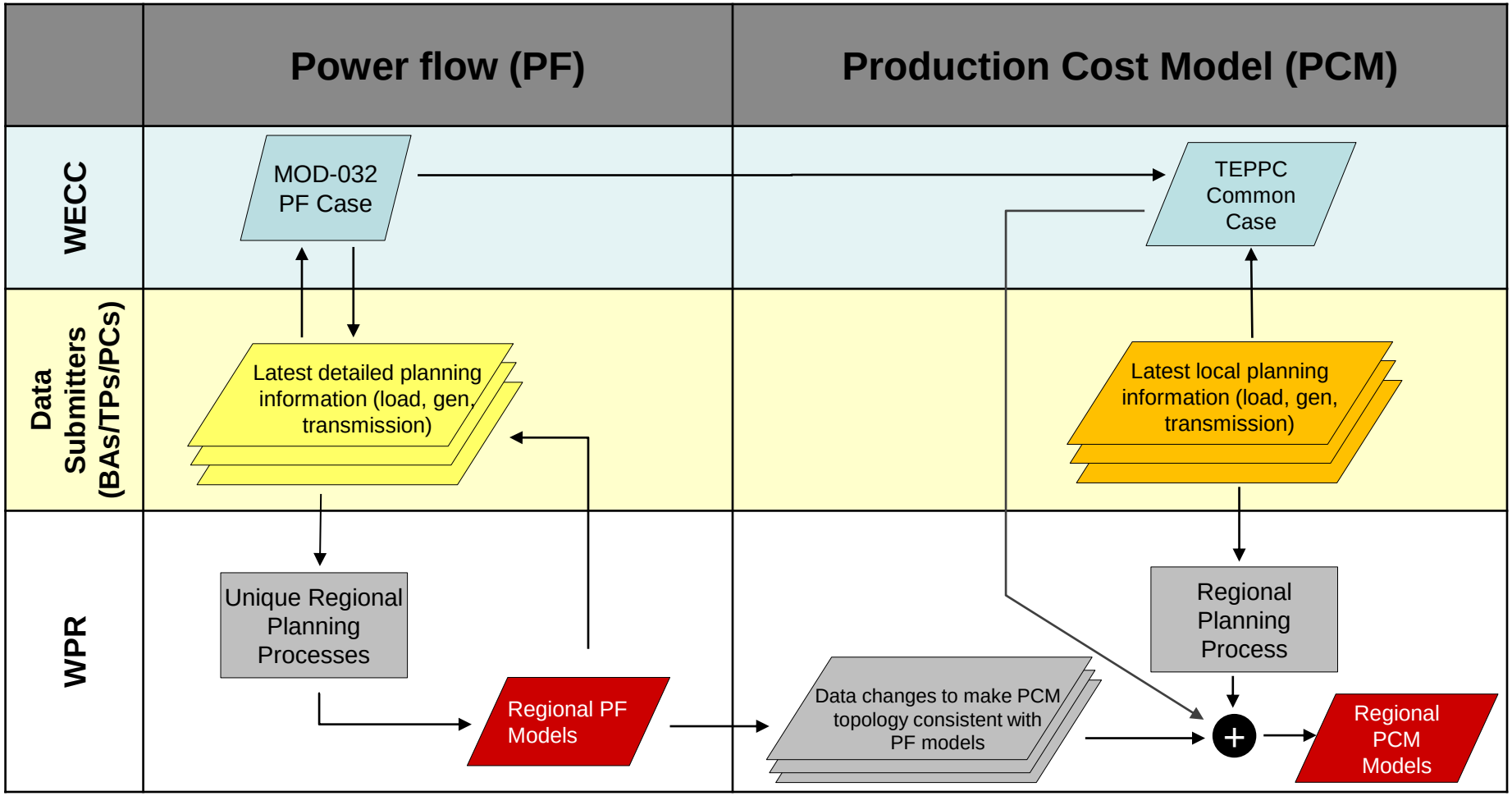


Order 1000 Regional Planning Processes and Interregional Coordination

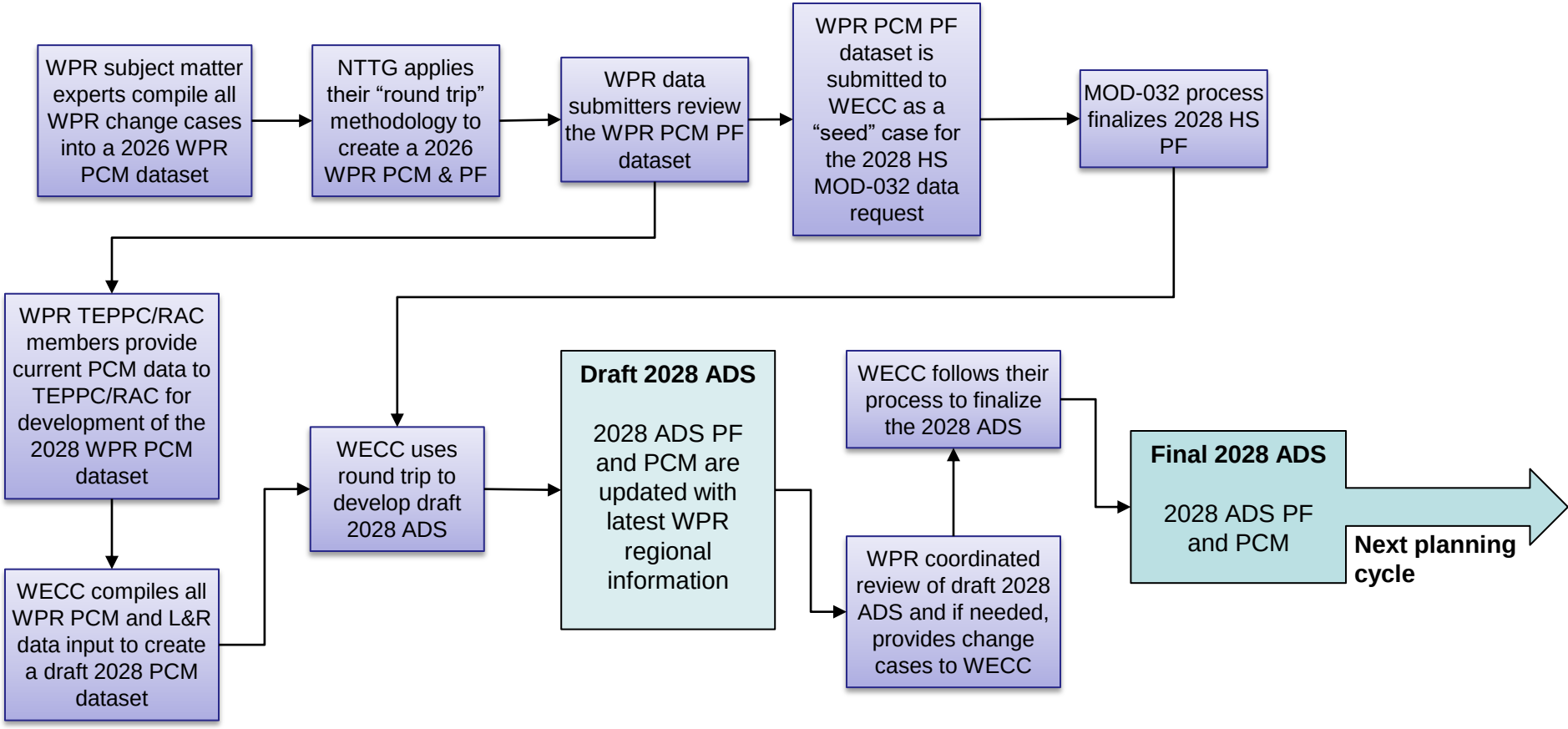
General ADS process flow

1. Planning regions complete regional transmission plans
2. WECC audits ADS data submittals and compiles the draft ADS
3. Planning regions and stakeholders review draft ADS
4. WECC compiles and posts final ADS
5. Next ADS cycle

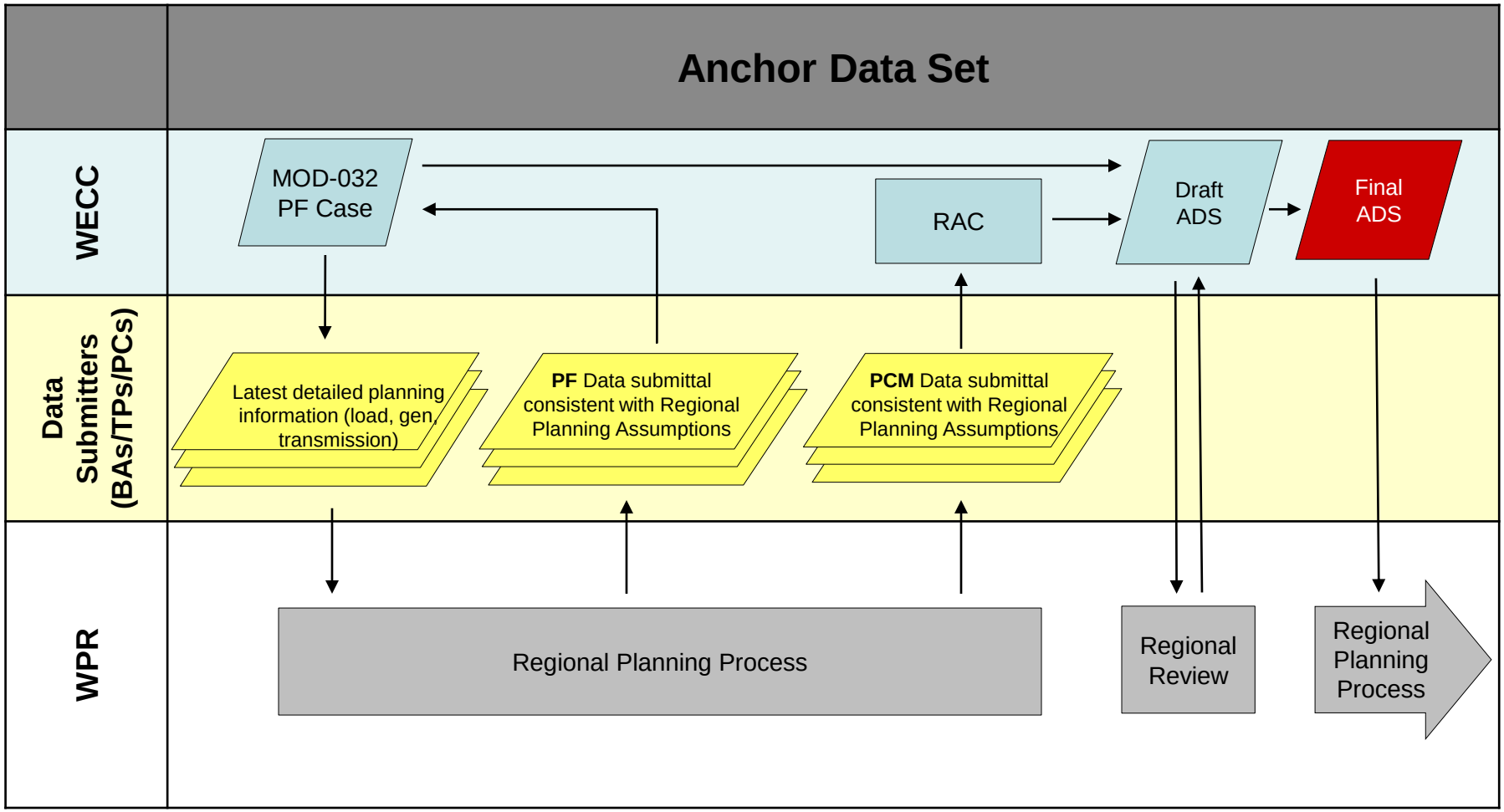
High level view of the pre-2017 power flow and PCM data process flow



WPR/WECC proposed process workflow during 2017



High level view of the post-2017 ADS process flow



Open Discussion

Review of Key Points, Action Items, and Assignments

Larry Furumasu
ColumbiaGrid

Closing Remarks & Next Meeting

Paul Didsayabutra
ColumbiaGrid

Next Steps

- Comments may also be submitted by email to order1000@columbiagrid.org
- Comments can be submitted through March 9, 2017
- Next Annual Interregional Coordination Meeting
  - Hosted by CAISO
  - February 22, 2018 (Tentative)

Thank You