



Agenda

Unified Planning Assumptions & Study Plan

Jody Cross

Stakeholder Engagement and Policy Specialist

*2018-2019 Transmission Planning Process Stakeholder Meeting
February 28, 2018*

2018-2019 Transmission Planning Process Stakeholder Meeting - Agenda

Topic	Presenter
Introduction	Jody Cross
Overview & Key Issues	Jeff Billinton
Reliability Assessment	Binaya Shrestha
Economic Assessment	Yi Zhang
LCR Studies	Catalin Micsa
Wrap-up & Next Steps	Jody Cross



Overview

Unified Planning Assumptions & Study Plan

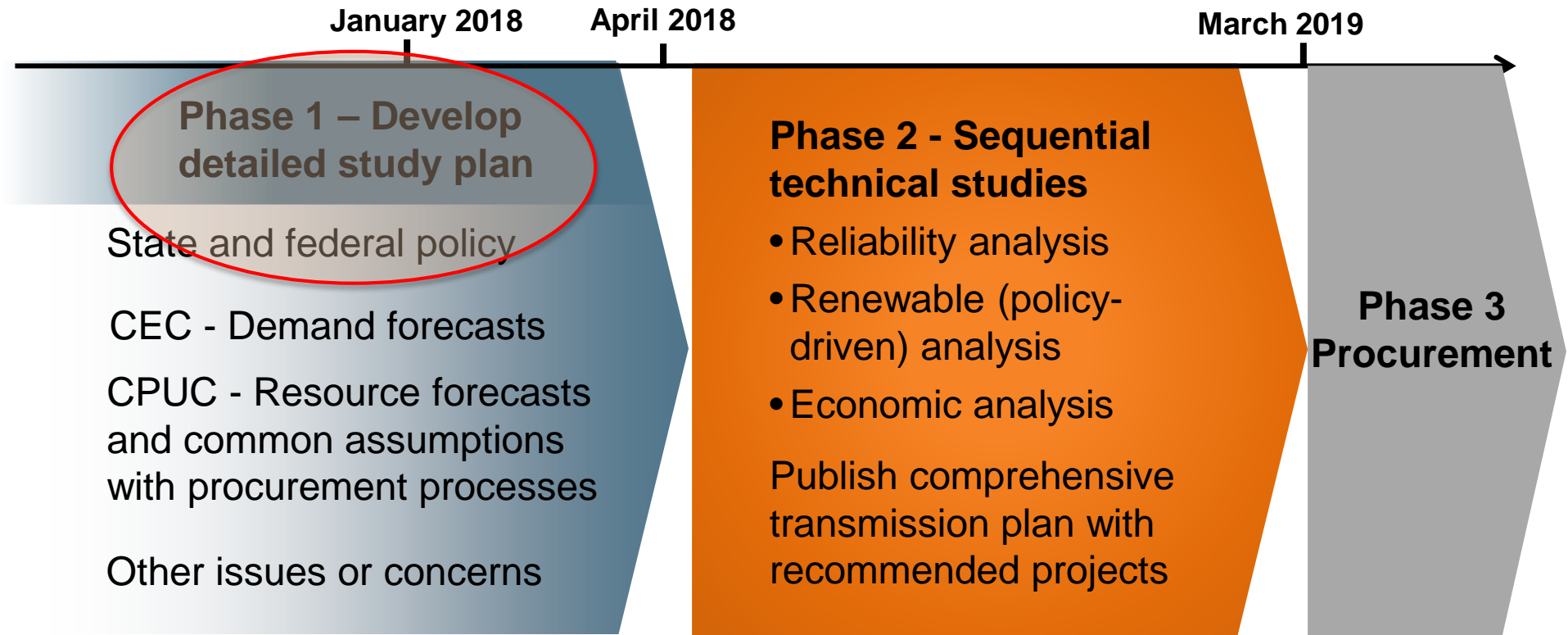
Jeff Billinton

Manager, Regional Transmission - North

2018-2019 Transmission Planning Process Stakeholder Meeting

February 28, 2018

2018-2019 Transmission Planning Process

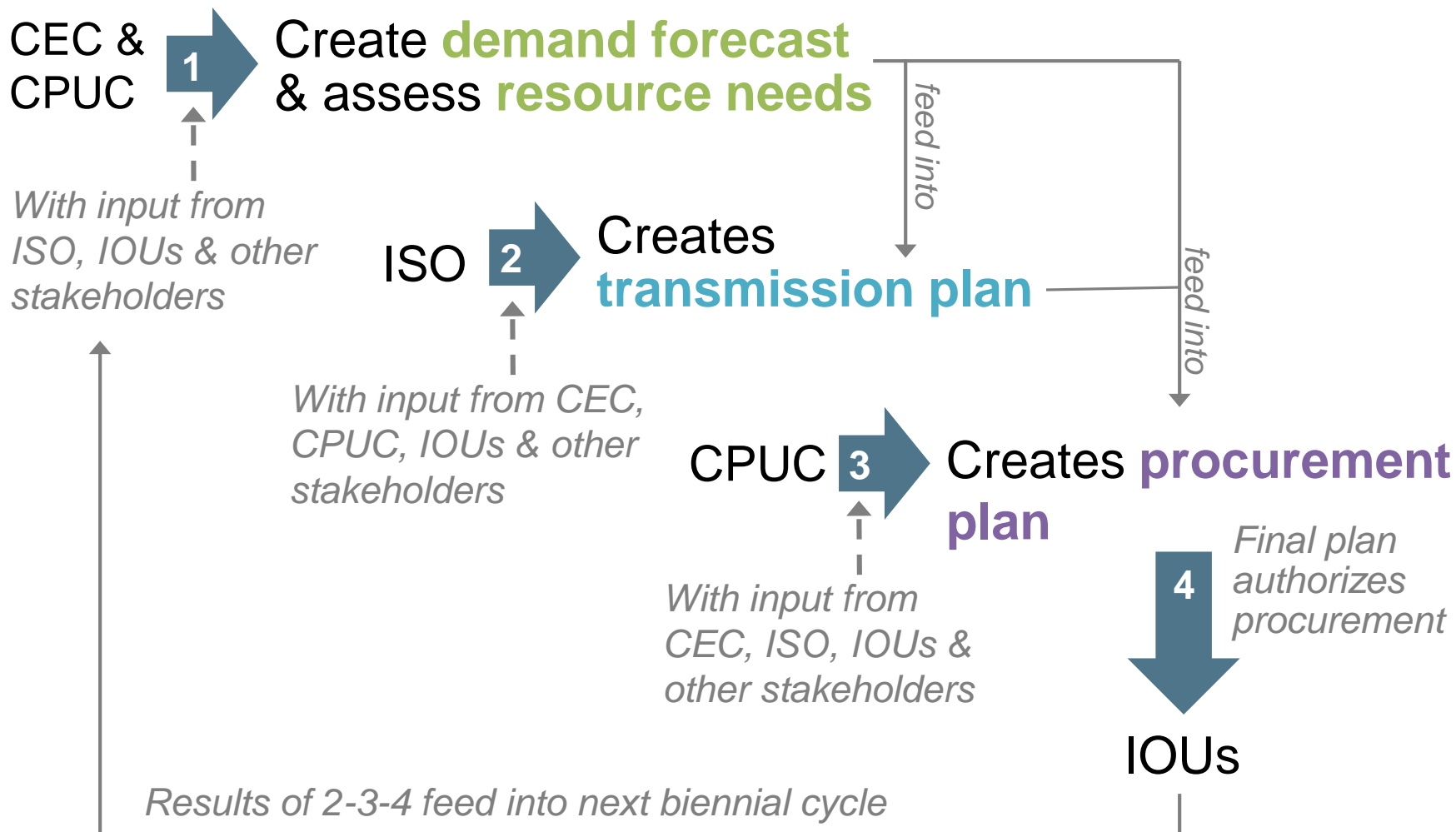


ISO Board for approval of transmission plan

2018-2019 Transmission Plan Milestones

- Draft Study Plan posted on February 22
- Stakeholder meeting on Draft Study Plan on February 28
- Comments to be submitted by March 14
- Final Study Plan to be posted on March 31
- Preliminary reliability study results to be posted on August 15
- Stakeholder meeting on September 20 and 21
- Comments to be submitted by October 5
- Request window closes October 15
- Preliminary policy and economic study results on November 16
- Comments to be submitted by November 30
- Draft transmission plan to be posted on January 31, 2019
- Stakeholder meeting on February
- Comments to be submitted within two weeks after stakeholder meeting
- Revised draft for approval at March Board of Governor meeting

Planning and procurement overview



2018-2019 Transmission Plan Study Plan

- Reliability Assessment to identify reliability-driven needs
- Policy Assessment
 - No base portfolio will be transmitted to the ISO as part of the 2018-2019 TPP policy-driven assessment
 - The IRP 42 MMT Scenario portfolio will be studied as a sensitivity in the 2018-2019 TPP policy-driven assessment to identify Category 2 transmission based on the CPUC IRP Reference System Plan
- Economic Planning Study to identify needed economically-driven elements
- Local Capacity Requirements
 - Near-Term;
 - Mid-Term; and
 - Long-Term
- Long-term Congestion Revenue Rights
- Special Studies

Key Issues in 2018-2019 Transmission Plan Cycle:

- Focus on renewable integration issues – both in-front-of and behind-the-meter resources
- A major economic study being focused on local capacity areas
- Special studies targeting:
 - ISO support for CPUC proceeding re Aliso Canyon
 - Potential for increasing opportunities for transfers of low carbon electricity with the PAC Northwest, and for PAC Northwest Hydro to play role in reducing dependence on resources impacted by Aliso Canyon
- Interregional projects will be addressed as per tariff-defined processes:
 - The ISO is not planning additional “special study” efforts at this time focusing on out-of-state renewables given the recently completed studies spanning the 2016-2017 and 2017-2018 planning cycles.

Study Information

- Final Study Plan will be published March 31st
- Base cases will be posted on the Market Participant Portal (MPP)
 - For reliability assessment in Q3
- Market notices will be sent to notify stakeholders of meetings and any relevant information
- Stakeholder comments
 - Stakeholders requested to submit comments to:
regionaltransmission@caiso.com
 - Stakeholder comments are to be submitted within two weeks after stakeholder meetings
 - ISO will post comments and responses on website

Questions

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Reliability Assessment Unified Planning Assumptions & Study Plan

Binaya Shrestha
Regional Transmission Engineer Lead

2018-2019 Transmission Planning Process Stakeholder Meeting
February 28, 2018

Planning Assumptions

- Reliability Standards and Criteria
 - California ISO Planning Standards
 - NERC Reliability Criteria
 - TPL-001-4
 - NUC-001-2.1
 - WECC Regional Criteria
 - TPL-001-WECC-CRT-3

Planning Assumptions

(continued)

- Study Horizon
 - 10 years planning horizon
 - near-term: 2019 to 2023
 - longer-term: 2024 to 2028
- Study Years
 - near-term: 2020 and 2023
 - longer-term: 2028

Study Areas



- **Northern Area - Bulk**
- **PG&E Local Areas:**
 - Humboldt area
 - North Coast and North Bay area
 - North Valley area
 - Central Valley area
 - Greater Bay area:
 - Greater Fresno area;
 - Kern area;
 - Central Coast and Los Padres areas.
- **Southern Area – Bulk**
- **SCE local areas:**
 - Tehachapi and Big Creek Corridor
 - North of Lugo area
 - East of Lugo area;
 - Eastern area; and
 - Metro area
- **SDG&E area**
 - Bulk transmission
 - Sub-transmission
- **Valley Electric Association area**
- **ISO combined bulk system**

Transmission Assumptions

- Transmission Projects
 - Transmission projects that the ISO has approved will be modeled in the study base case
 - Projects recommended to proceed with revised scope will be modeled with the revised scope
 - Canceled and on-hold projects will not be modeled
- Reactive Resources
 - The study models the existing and new reactive power resources in the base cases to ensure that realistic reactive support capability will be included in the study
- Protection Systems
 - The major new and existing SPS, safety nets, and UVLS that will be included in the study
 - Continue to include RAS models and work with PTOs to obtain remaining RAS models.
- Control Devices
 - Several control devices were modeled in the studies

Load Forecast Assumptions

Energy and Demand Forecast

- California Energy Demand Revised Forecast 2018-2030 adopted by California Energy Commission (CEC) on February 21, 2018 will be used:
 - Using the Mid Baseline LSE and Balancing Authority Forecast spreadsheets
 - Additional Achievable Energy Efficiency (AAEE) and Additional Achievable PV (AAPV)
 - Consistent with CEC 2017 IEPR
 - Mid AAEE/AAPV will be used for system-wide studies
 - Low AAEE/AAPV will be used for local studies
 - CEC forecast information is available on the CEC website at:
http://www.energy.ca.gov/2017_energy_policy/documents/

Load Forecast Assumptions

Energy and Demand Forecast (continued)

- Load forecasts to be used for each of the reliability assessment studies.
 - 1-in-10 weather year, mid demand baseline case with low AAEE/AAPV load forecasts will be used in PG&E, SCE, SDG&E, and VEA local area studies including the studies for the local capacity requirement (LCR) areas
 - 1-in-5 weather year, mid demand baseline case with mid AAEE/AAPV load forecast will be used for bulk system studies

Load Forecast Assumptions

Methodologies to Derive Bus Level Forecast

- The CEC load forecast is generally provided for the larger areas and does not provide the granularity down to the bus-level which is necessary in the base cases for the reliability assessment
- The local area load forecast are developed at the bus-level by the participating transmission owners (PTOs) .
- Descriptions of the methodologies used by each of the PTOs to derive bus-level load forecasts using CEC data as a starting point are included in the draft Study Plan.

Load Forecast Assumptions

Self-Generation

- PV component of the self-generation in the CEC demand forecast will be modeled explicitly in the 2018-2019 TPP base cases.
 - Amount of the self-generation PV to be modeled will be based on 2017 IEPR data.
 - Location to model self-generation PV will be identified based on location of existing behind-the-meter PV, information from PTO on future growth and behind-the-meter PV capacity by forecast climate zone information from CEC.
 - Output of the self-generation PV will be selected based on the time of day of the study using the end-use load and PV shapes for the day selected.
 - Composite load model CMPLDWG will be used to model the self-generation PV.

Load Forecast Assumptions

AEE & AAPV

- AEE will be modeled using the CEC provided busbar allocations.
- AAPV will be modeled explicitly similar to the baseline self-gen PV.
 - Amount of the AAPV to be modeled will be based on 2017 IEPR data.
 - Location to model AAPV will be identified based on analysis developed by the CPUC and in working with the three IOUs.
 - Output of the AAPV will be selected based on the time of day of the study using the end-use load and PV shapes for the day selected.

Supply Side Assumptions

- Continued coordination with CPUC Integrated Resource Plan (IRP) on supply side assumptions
 - CPUC draft Unified Resource Adequacy and Integrated Resource Plan Inputs and Assumptions – Guidance for Production Cost Modeling and Network Reliability Studies
 - http://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/UtilitiesIndustries/Energy/EnergyPrograms/ElectPowerProcurementGeneration/irp/2018/1Unified_IA_main_draft_20180220.pdf
 - Renewable resources based upon the IRP 50% RPS Default Scenario
 - Mapping of resource locations based the following provided to the CPUC by the CEC
 - » http://docketpublic.energy.ca.gov/PublicDocuments/17-MISC-03/TN222569_20180215T155902_Energy_Commission_Staff_Proof_of_Concept_Report_to_CPUC_Staff.pdf

Generation Assumptions

- One-year operating cases
- 2-5-year planning cases
 - Generation that is under construction (Level 1) and has a planned in-service date within the time frame of the study;
 - Conventional generation in pre-construction phase with executed LGIA and progressing forward will be modeled off-line but will be available as a non-wire mitigation option.
 - OTC repowering projects will be modeled in lieu of existing resources as long as they have power purchase approval from the CPUC or other Local Regulatory Agency (LRA).
 - The contracted resources considered to be baseline assumptions for selecting the CPUC's Default Portfolio will be utilized for modeling specific generation.
- 6-10-year planning cases
 - The CPUC's Default Portfolio
- Retired generation is modeled offline and disconnected in appropriate study years

Generation Assumptions

Generation Retirements

- Nuclear Retirements
 - Diablo Canyon will be modeled off-line based on the OTC compliance date
- Once Through Cooled Retirements
 - Separate slide below for OTC assumptions
- Renewable and Hydro Retirements
 - Assumes these resource types stay online unless there is an announced retirement date.
- Other Retirements
 - Unless otherwise noted, assumes retirement based resource age of 40 years or more. List included in Appendix A of the draft study plan.

Generation Assumptions

OTC Generation

Modeling of the once-through cooled (OTC) generating units follows the State Water Resources Control Board (SWRCB)'s Policy on OTC plants with the following exception:

- Generating units that are repowered, replaced or having firm plans to connect to acceptable cooling technology, as illustrated in Table 4.7-5 in the draft study plan; and
- All other OTC generating units will be modeled off-line beyond their compliance dates, as illustrated in Table 4.7-5, or per proposed retirements by the generation owners to proceed on repowering projects that have been approved by the state regulatory agencies.

Generation Assumptions

CEC permitted resources or CPUC-approved long-term procurement resources (Thermal and Solar Thermal)

PTO Area	Project	Capacity (MW)	First Year to be Modeled
PG&E	-	-	-
SCE	Huntington Beach Energy Project Unit 6 (CCGT) *	644	2020
	Alamitos Energy Center Unit 8 (CCGT) *	640	2020
SDG&E	Carlsbad Peakers*	500	2019

Notes:

*These projects have received PPTA approvals from the CPUC as part of Long Term Procurement Plan (LTPP) process.

Preferred Resources

Demand Response

- Demand Response
 - Only program that can be relied upon to mitigate post first contingency are counted
 - DR that can be relied upon participates, and is dispatched from, the ISO market in sufficiently less than 30 minutes (implies that programs may need 20 minutes response time to allow for other transmission operator activities) from when it is called upon
 - DR capacity will be allocated to bus-bar using the method defined in D.12-12-010, or specific bus-bar allocations provided by the IOUs.
 - The DR capacity amounts will be modeled offline in the initial reliability study cases and will be used as potential mitigation in those planning areas where reliability concerns are identified.
 - Section 6.6 of the CAISO 2017-2018 Transmission Plan provides a status update on the progress to identify the necessary characteristics for slow response local capacity resources, such that the resources can be relied upon to meet reliability needs.

Preferred Resources

Energy Storage

- Energy Storage
 - Amounts consistent with D.13-10-040
 - Energy storage that will be procured by SCE and SDG&E to fill the local capacity amounts authorized under the CPUC 2012 LTPP decision is subsumed within the 2020 procurement target
 - The transmission-connected storage projects recommended for approval in the 2017-2018 Transmission Plan as regulated transmission asset will be modeled
 - Not included in starting cases (no location data available), unless already procured by the LSEs as part of the LTPP process
 - Locational information to be provided by CPUC for storage procured to-date
 - Effective busses will be identified using the residual capacity for potential development after reliability concerns have been identified

Major Path Flows and Interchange

Northern area (PG&E system) assessment

Path	Transfer Capability/SOL (MW)	Scenario in which Path will be stressed
Path 26 (N-S)	4,000	Summer Peak
PDCI (N-S)	3,220	
Path 66 (N-S)	4,800	
Path 15 (N-S)	-5,400	Summer Off Peak
Path 26 (N-S)	-3,000	
Path 66 (N-S)	-3,675	Winter Peak

Southern area (SCE & SDG&E system) assessment

Path	Transfer Capability/SOL (MW)	Target Flows (MW)	Scenario in which Path will be stressed
Path 26 (N-S)	4,000	4,000	Summer Peak
PDCI (N-S)	3,220	3,220	
West of River (WOR)	11,200	5,000 to 11,200	Summer Peak
East of River (EOR)	10,100	4,000 to 9,600	Summer Peak
San Diego Import	2,850	2,400 to 3,500	Summer Peak
SCIT	17,870	15,000 to 17,870	Summer Peak
Path 45 (N-S)	400	0 to 250	Summer Peak
Path 45 (S-N)	800	0 to 300	Off Peak

Study Scenarios - *Base Scenarios*

Study Area	Near-term Planning Horizon		Long-term Planning Horizon
	2020	2023	2028
Northern California (PG&E) Bulk System	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak	Summer Peak, Spring Off-Peak, Winter Off-Peak
Humboldt	Summer Peak, Winter Peak Spring Off-Peak	Summer Peak, Winter Peak Spring Off-Peak	Summer Peak Winter Peak
North Coast and North Bay	Summer Peak, Winter Peak Spring Off-Peak	Summer Peak, Winter Peak Spring Off-Peak	Summer Peak Winter peak
North Valley	Summer Peak, Spring Off-Peak	Summer Peak, Spring Off-Peak	Summer Peak
Central Valley	Summer Peak, Spring Off-Peak	Summer Peak, Spring Off-Peak	Summer Peak
Greater Bay Area	Summer Peak, Winter peak - (SF & Peninsula), Spring Off-Peak	Summer Peak, Winter peak - (SF & Peninsula), Spring Off-Peak	Summer Peak, Winter peak - (SF Only)
Greater Fresno	Summer Peak, Spring Off-Peak	Summer Peak, Spring Off-Peak	Summer Peak
Kern	Summer Peak, Spring Off-Peak	Summer Peak, Spring Off-Peak	Summer Peak
Central Coast & Los Padres	Summer Peak, Winter Peak Spring Off-Peak	Summer Peak, Winter Peak Spring Off-Peak	Summer Peak Winter Peak
Southern California Bulk Transmission System	Summer Peak, Spring Off-Peak	Summer Peak, Spring Off-Peak	Summer Peak
SCE Metro Area	Summer Peak, Spring Off-Peak	Summer Peak, Spring Off-Peak	Summer Peak
SCE Northern Area	Summer Peak, Spring Off-Peak	Summer Peak, Spring Off-Peak	Summer Peak
SCE North of Lugo Area	Summer Peak, Spring Off-Peak	Summer Peak, Spring Off-Peak	Summer Peak
SCE East of Lugo Area	Summer Peak, Spring Off-Peak	Summer Peak, Spring Off-Peak	Summer Peak
SCE Eastern Area	Summer Peak, Spring Off-Peak	Summer Peak, Spring Off-Peak	Summer Peak
SDG&E main transmission	Summer Peak, Spring Off-Peak	Summer Peak, Spring Off-Peak	Summer Peak
SDG&E sub-transmission	Summer Peak, Spring Off-Peak	Summer Peak, Spring Off-Peak	Summer Peak
Valley Electric Association	Summer Peak, Spring Off-Peak	Summer Peak, Spring Off-Peak	Summer Peak

Study Scenarios - Base Scenarios Definition and Renewable Dispatch

PTO	Scenario	Day/Time			BTM-PV			Transmission Connected PV			Transmission Connected Wind		
		2020	2023	2028	2020	2023	2028	2020	2023	2028	2020	2023	2028
PG&E	Summer Peak	8/10 HE 18	8/14 HE 19	8/14 HE 19	18%	3%	3%	9%	1%	1%	38%	67%	67%
PG&E	Spring Off peak	4/5 HE 12	4/6 HE 13	4/16 HE 13	79%	84%	85%	99%	98%	99%	5%	2%	3%
PG&E	Winter Off peak	-	-	2/13 HE 4	-	-	0%	-	-	0%	-	-	17%
PG&E	Winter peak	10/15 HE 19	10/3 HE 18	10/3 HE 19	0%	1%	0%	0%	0%	0%	4%	3%	3%
SCE	Summer Peak	9/3 HE 16	8/31 HE 16	8/31 HE 16	47%	48%	48%	52%	53%	53%	36%	21%	21%
SCE	Spring Off peak	4/9 HE 13	-	-	75%	-	-	97%	-	-	1%	-	-
SCE	Spring Off peak	-	4/17 HE 20	-	-	0%	-	-	0%	-	-	69%	-
SDG&E	Summer Peak	9/3 HE 19	8/31 HE 19	8/31 HE 19	0%	0%	0%	0%	0%	0%	31%	1%	1%
SDG&E	Spring Off peak	4/12 HE 13	-	-	77%	-	-	97%	-	-	1%	-	-
SDG&E	Spring Off peak	-	4/17 HE 20	-	-	0%	-	-	0%	-	-	5%	-
VEA	Summer Peak	9/3 HE 16	8/31 HE 16	8/31 HE 16	47%	48%	48%	52%	53%	53%	-	-	-
VEA	Spring Off peak	4/9 HE 13	-	-	75%	-	-	97%	-	-	-	-	-
VEA	Spring Off peak	-	4/17 HE 20	-	-	0%	-	-	0%	-	-	-	-

Study Scenarios - Sensitivity Studies

Sensitivity Study	Near-term Planning Horizon		Long-Term Planning Horizon
	2020	2023	2028
Summer Peak with high CEC forecasted load	-	PG&E Bulk PG&E Local Areas Southern California Bulk SCE Northern SCE North of Lugo SCE East of Lugo SCE Eastern SCE Metro SDG&E Main	-
Off peak with heavy renewable output and minimum gas generation commitment	-	PG&E Bulk PG&E Local Areas Southern California Bulk SCE Northern SCE North of Lugo SCE East of Lugo SCE Eastern SCE Metro SDG&E Main	-
Summer Peak with heavy renewable output and minimum gas generation commitment	PG&E Bulk PG&E Local Areas Southern California Bulk SCE Northern SCE North of Lugo SCE East of Lugo SCE Eastern SCE Metro SDG&E Main	-	-
Summer Off-peak with heavy renewable output and minimum gas generation commitment (renewable generation addition)	-	VEA Area	-
Retirement of QF Generations	-	-	PG&E Local Areas

Study Base Cases

- WECC base cases will be used as the starting point to represent the rest of WECC

Study Year	Season	WECC Base Case
2020	Summer Peak	20hs2a1
	Winter Peak	21hw1a1
	Spring Off-Peak	21LSP1a1
2023	Summer Peak	23HS2a1
	Winter Peak	23HW1a1
	Spring Off-Peak	23HW1a1
2028	Summer Peak	28HS1a1
	Winter Peak	28HW1a1
	Spring Off-Peak	26LSP1Sa
	Winter Off-Peak	28HS1a1

Contingencies

- **Normal conditions (P0)**
- **Single contingency (Category P1)**
 - The assessment will consider all possible Category P1 contingencies based upon the following:
 - Loss of one generator (P1.1)
 - Loss of one transmission circuit (P1.2)
 - Loss of one transformer (P1.3)
 - Loss of one shunt device (P1.4)
 - Loss of a single pole of DC lines (P1.5)
- **Single contingency (Category P2)**
 - The assessment will consider all possible Category P2 contingencies based upon the following:
 - Loss of one transmission circuit without a fault (P2.1)
 - Loss of one bus section (P2.2)
 - Loss of one breaker (internal fault) (non-bus-tie-breaker) (P2.3)
 - Loss of one breaker (internal fault) (bus-tie-breaker) (P2.4)

Contingencies

(continued)

- **Multiple contingency (Category P3)**

- The assessment will consider the Category P3 contingencies with the loss of a *generator unit* followed by system adjustments and the loss of the following:
 - Loss of one generator (P3.1)
 - Loss of one transmission circuit (P3.2)
 - Loss of one transformer (P3.3)
 - Loss of one shunt device (P3.4)
 - Loss of a single pole of DC lines (P3.5)

- **Multiple contingency (Category P4)**

- The assessment will consider the Category P4 contingencies with the loss of multiple elements caused by a stuck breaker (non-bus-tie-breaker for P4.1-P4.5) attempting to clear a fault on one of the following:
 - Loss of one generator (P4.1)
 - Loss of one transmission circuit (P4.2)
 - Loss of one transformer (P4.3)
 - Loss of one shunt device (P4.4)
 - Loss of one bus section (P4.5)
 - Loss of a bus-tie-breaker (P4.6)

Contingencies

(continued)

- **Multiple contingency (Category P5)**

- The assessment will consider the Category P5 contingencies with delayed fault clearing due to the failure of a non-redundant relay protecting the faulted element to operate as designed, for one of the following:
 - Loss of one generator (P5.1)
 - Loss of one transmission circuit (P5.2)
 - Loss of one transformer (P5.3)
 - Loss of one shunt device (P5.4)
 - Loss of one bus section (P5.5)

- **Multiple contingency (Category P6)**

- The assessment will consider the Category P6 contingencies with the loss of two or more (non-generator unit) elements with system adjustment between them, which produce the more severe system results.

- **Multiple contingency (Category P7)**

- The assessment will consider the Category P7 contingencies for the loss of a common structure as follows:
 - Any two adjacent circuits on common structure¹⁴ (P7.1)
 - Loss of a bipolar DC lines (P7.2)

Contingency Analysis

(continued)

- **Extreme contingencies (TPL-001-4)**
 - As a part of the planning assessment the ISO assesses Extreme Event contingencies per the requirements of TPL-001-4;
 - however the analysis of Extreme Events will not be included within the Transmission Plan unless these requirements drive the need for mitigation plans to be developed.

Technical Studies

- The planning assessment will consist of:
 - Power Flow Contingency Analysis
 - Post Transient Analysis
 - Post Transient Stability Analysis
 - Post Transient Voltage Deviation Analysis
 - Voltage Stability and Reactive Power Margin Analysis
 - Transient Stability Analysis

Corrective Action Plans

- The technical studies mentioned in this section will be used for identifying mitigation plans for addressing reliability concerns.
- As per ISO tariff, identify the need for any transmission additions or upgrades required to ensure System reliability consistent with all Applicable Reliability Criteria and CAISO Planning Standards.
 - In making this determination, the ISO, in coordination with each Participating TO with a PTO Service Territory and other Market Participants, shall consider lower cost alternatives to the construction of transmission additions or upgrades, such as:
 - acceleration or expansion of existing projects,
 - demand-side management,
 - special protection systems,
 - generation curtailment,
 - interruptible loads,
 - storage facilities; or
 - reactive support

Questions?

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Economic Assessment Unified Planning Assumptions & Study Plan

Yi Zhang
Regional Transmission Engineering Lead - Economic

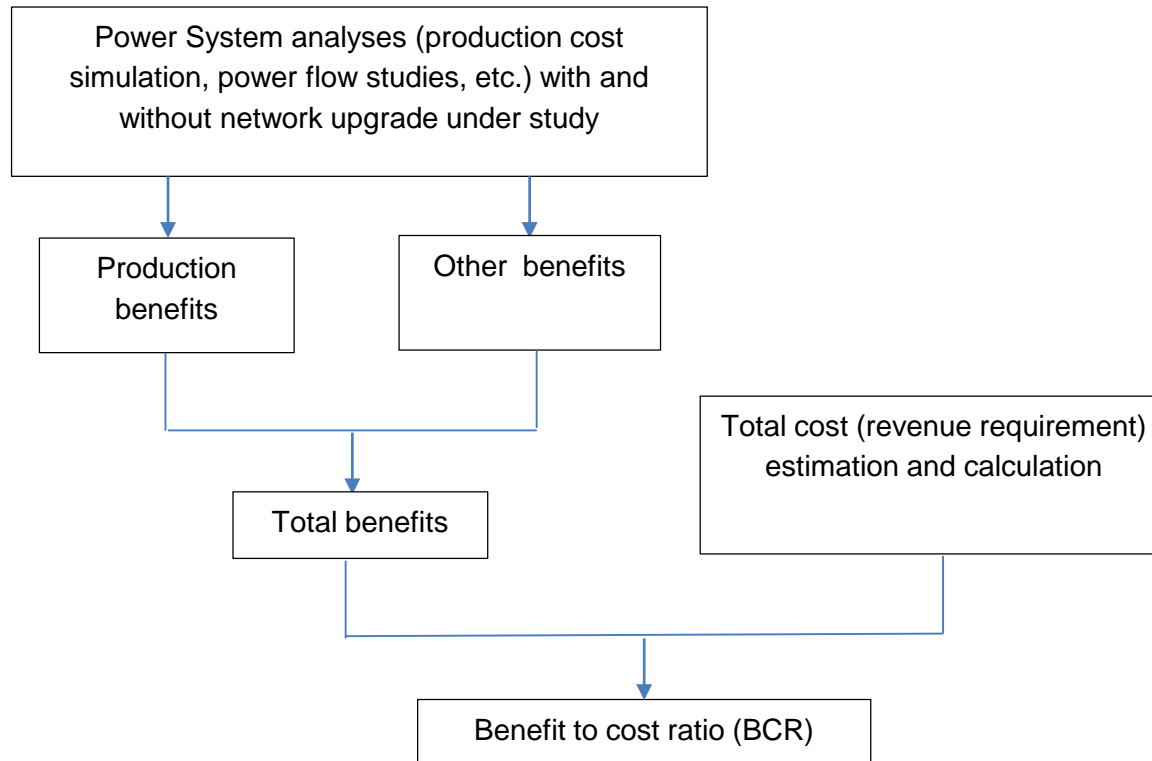
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Economic planning study

- ISO economic planning study follows ISO tariff and TEAM methodology to do the following studies
 - Congestion and production benefit assessment
 - Local capacity areas assessment
 - Study request evaluation

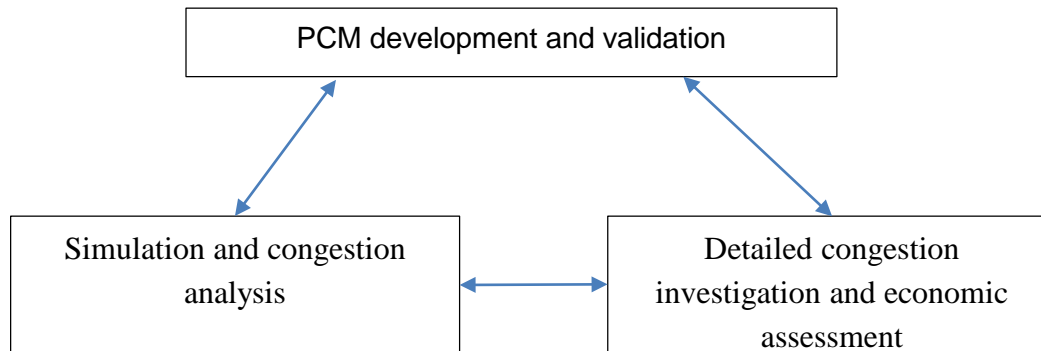
Overview of economic planning methodology

- ISO's economic planning study follows the updated TEAM documentation updated in 2017
- Study approach:



Congestion and production benefit assessment

- Production cost simulation is used for congestion analysis and production benefit assessment



- The PCM development will start from ADS (anchor data set) for 2028
 - Update network models for the ISO system
 - Model transmission constraints and system constraints for the ISO system
 - Update forecast data and operation data as needed

Local capacity areas assessment

- The ISO is undertaking a review of the existing local capacity areas in the 2018-2019 planning cycle
 - Identify potential transmission upgrades that would economically lower gas-fired generation capacity requirements
- It is not realistic to assess all existing areas and sub-areas in one planning cycle. Targeting assess half of the areas
- Economic assessment will be conducted

Economic planning study requests

- Economic Planning Study Requests are to be submitted to the ISO during the comment period of the draft Study Plan
- The ISO will consider the Economic Planning Study Requests as identified in section 24.3.4.1 of the ISO Tariff

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Local Capacity Requirement Studies Unified Planning Assumptions & Study Plan

Catalin Micsa

Senior Advisor Regional Transmission Engineer

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February 28, 2018

Existing ISO Local Capacity Requirement (LCR) Areas and OTC Plants



Near-Term Local Capacity Requirement (update)

Scope plus Input Assumptions, Methodology and Criteria

The scope of the LCR studies is to reflect the minimum resource capacity needed in transmission constrained areas in order to meet the established criteria.

For latest study assumptions, methodology and criteria see the October 31, 2017 stakeholder meeting. This information along with the 2019 LCR Manual can be found at:

<http://www.caiso.com/informed/Pages/StakeholderProcesses/LocalCapacityRequirementsProcess.aspx>.

Note: The ISO LCR process has been delayed this year with the adoption of the CEC Energy Demand Forecast 2018-2030 being adopted this year on February 21

General LCR Transparency

- Base Case Disclosure
 - ISO has published the LCR base cases on the ISO Market Participant Portal
(<https://mpp.caiso.com/tp/Pages/default.aspx>)
 - Access requires WECC/ISO non-disclosure agreements
(<http://www.caiso.com/1f42/1f42d6e628ce0.html>)
- Publication of Study Manual (Plan)
 - Provides clarity and allows for study verification
(<http://www.caiso.com/Documents/2019LocalCapacityRequirementsFinalStudyManualdocx.pdf>)
- ISO to respond in writing to questions raised (also in writing) during stakeholder process
(<http://www.caiso.com/informed/Pages/StakeholderProcesses/LocalCapacityRequirementsProcess.aspx>)

Near-Term LCR Study Schedule

CPUC and the ISO have determined overall timeline

- Criteria, methodology and assumptions meeting Oct. 31, 2017
- Submit comments by November 14, 2017
- Posting of comments with ISO response by the December 12, 2017
- Base case development started in December 2017
- Receive base cases from PTOs January 2018
- Publish base cases January 19, 2018 – comments by Feb. 2nd
- Receive and incorporate CEC load forecast February 21-28th
- Draft study completed by March 28, 2018
- ISO Stakeholder meeting April 9, 2018 – comments by the 16th
- ISO receives new operating procedures April 16, 2018
- Validate op. proc. – publish draft final report April 23, 2018
- ISO Stakeholder call May 1, 2018 – comments by the 8th
- Final 2019 LCR report May 15, 2018



Long-Term Local Capacity Requirement Studies

Long-Term Local Capacity Requirement

- Based on the alignment of the ISO transmission planning process with the CEC Integrated Energy Policy Report (IEPR) demand forecast and the CPUC Integrated Resource Plan (IRP), the Long-Term LCR assessment is to be evaluated ***every two years.***
 - In the 2016-2017 transmission planning process all LCR areas within the ISO BAA were evaluated for long-term assessment.
- In the 2018-2019 transmission planning process all LCR areas within the ISO BAA will be evaluated for long-term assessment.

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Next Steps

Unified Planning Assumptions & Study Plan

Jody Cross

Stakeholder Engagement and Policy Specialist

*2018-2019 Transmission Planning Process Stakeholder Meeting
February 28, 2018*

2018-2019 Transmission Planning Process

Next Steps

- Comments due March 14, 2018
 - regionaltransmission@caiso.com
- Final Study Plan will be posted on March 31, 2018

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