Agenda

2015-2016 Transmission Planning Stakeholder Meeting

Tom Cuccia
Sr. Stakeholder Engagement and Policy Specialist
February 23, 2015

2015-2016 Draft Study Plan Stakeholder Meeting - Today's Agenda

Topic	Presenter
Opening	Tom Cuccia
Introduction & Overview - 50% Renewable Energy Goal for 2030	Jeff Billinton Neil Millar
Reliability Assessment	Catalin Micsa
Local Capacity Requirement (LCR) Studies - Near-Term - Long-Term	 Catalin Micsa David Le
Special Studies - Potential Risk of Over-Generation	 Irina Green
33% Transmission RPS Assessment	Sushant Barave
Economic Planning Study	Yi Zhang
Western Planning Regions – Regional Status Updates	WestConnect ColumbiaGrid Northern Tier Transmission Group
Next Steps	Jeff Billinton

Unified Planning Assumptions & Study Plan
Transmission Planning Process Overview

2015-2016 Transmission Planning Stakeholder Meeting

Jeff Billinton
Manager, Regional Transmission - North
February 23, 2015

2015-2016 Transmission Planning Process

March 2015 — **March 2016** — **October 2016**

Coordination of Conceptual Statewide Plan

ISO Board Approval of Transmission Plan

Phase 1

Development of ISO unified planning assumptions and study plan

- **Incorporates State and Federal policy requirements and directives**
- **Demand forecasts, energy efficiency, demand response**
- **Renewable and conventional generation additions and retirements**
- **Input from stakeholders**
- **Ongoing stakeholder meetings**

Phase 2

Technical Studies and Board Approval

- **Reliability analysis**
- **Renewable delivery analysis**
- **Congestion analysis**
- **Publish comprehensive transmission plan**
- **ISO Board approval**

Phase 3

Receive proposals to build identified policy and economic transmission projects.

Continued regional and sub-regional coordination

Schedule and Milestones

Phase	No	Due Date	2015-2016 Activity
Phase 1	1	December 15, 2014	The ISO sends a letter to neighboring balancing authorities, sub-regional, regional planning groups requesting planning data and related information to be considered in the development of the Study Plan and the ISO issues a market notice announcing a thirty-day comment period requesting demand response assumptions and generation or other non-transmission alternatives to be considered in the Unified Planning Assumptions.
	2	January 15, 2015	PTO's, neighboring balancing authorities, regional/sub-regional planning groups and stakeholders provide ISO the information requested No.1 above.
	3	February 17, 2015	The ISO develops the draft Study Plan and posts it on its website
	4	February 23, 2015	The ISO hosts public stakeholder meeting #1 to discuss the contents in the Study Plan with stakeholders
	5	February 23 - March 9, 2015	Comment period for stakeholders to submit comments on the public stakeholder meeting #1 material and for interested parties to submit Economic Planning Study Requests to the ISO
	6	March 31, 2015	The ISO specifies a provisional list of high priority economic planning studies, finalizes the Study Plan and posts it on the public website
	7	Q1	ISO Initiates the development of the Conceptual Statewide Plan

Schedule and Milestones (continued)

Phase	No	Due Date	2015-2016 Activity
Phase 2	8	August 15, 2015	Request Window opens
	9	August 15, 2015	The ISO posts preliminary reliability study results and mitigation solutions
	10	September 15, 2015	PTO's submit reliability projects to the ISO
	11	September/October	ISO posts the Conceptual Statewide Plan on its website and issues a market notice announcing the posting
	12	September 21 – 22, 2015	The ISO hosts public stakeholder meeting #2 to discuss the reliability study results, PTO's reliability projects, and the Conceptual Statewide Plan with stakeholders
	13	September 22 – October 6, 2015	Comment period for stakeholders to submit comments on the public stakeholder meeting #2 material
	14	October 15, 2015	Request Window closes
	15	October/November	Stakeholders have a 20 day period to submit comments on the Conceptual Statewide Plan in the next calendar month after posting conceptual statewide plan (i.e. August or September)
	16	October 30, 2015	ISO post final reliability study results
	17	November 12, 2015	The ISO posts the preliminary assessment of the policy driven & economic planning study results and the projects recommended as being needed that are less than $50 million.
	18	November 16 - 17, 2015	The ISO hosts public stakeholder meeting #3 to present the preliminary assessment of the policy driven & economic planning study results and brief stakeholders on the projects recommended as being needed that are less than $50 million.
	19	November 17 – December 1, 2015	Comment period for stakeholders to submit comments on the public stakeholder meeting #3 material
	20	December 17 – 18, 2015	The ISO to brief the Board of Governors of projects less than $50 million to be approved by ISO Executive
	21	January 2016	The ISO posts the draft Transmission Plan on the public website
	22	February 2016	The ISO hosts public stakeholder meeting #4 to discuss the transmission project approval recommendations, identified transmission elements, and the content of the Transmission Plan
	23	Approximately three weeks following the public stakeholder meeting #4	Comment period for stakeholders to submit comments on the public stakeholder meeting #4 material
	24	March 2016	The ISO finalizes the comprehensive Transmission Plan and presents it to the ISO Board of Governors for approval
	25	End of March, 2016	ISO posts the Final Board-approved comprehensive Transmission Plan on its site

Schedule and Milestones (continued)

Phase	No	Due Date	2015-2016 Activity
Phase 3	26	April 1, 2016	If applicable, the ISO will initiate the process to solicit proposals to finance, construct, and own elements identified in the Transmission Plan eligible for competitive solicitation

Note: The schedule for Phase 3 will be updated and available to stakeholders at a later date.

2015-2016 Transmission Planning Process Study Plan

- Reliability Assessment to identify reliability-driven needs
- Local Capacity Requirements
  - Near-Term; and
  - Long-Term
- Special Studies
  - 50% Renewable Energy Goal for 2030
  - Over Generation Frequency Response Assessment
- 33% by 2020 renewable resource analysis to identify needed policy-driven elements
- Economic Planning Study to identify needed economically-driven elements
- Long-term Congestion Revenue Rights

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
  - For 33% renewable energy assessment in Q4
- Market notices will be sent to notify stakeholders of meeting 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

Coordination of input assumptions

- Coordinated with CEC and CPUC:
  - CEC 2013 Integrated Energy Policy Report
    - California Energy Demand Updated Final Forecast 2015-2025
  - Continued coordination between TPP and CPUC LTPP
  - ISO anticipates receiving the RPS portfolios for 2015-2016 transmission planning process from the CPUC/CEC in February

Unified Planning Assumptions & Study Plan
50% Renewable Energy Goal for 2030 (Special Study)

2015-2016 Transmission Planning Process Stakeholder Meeting

Neil Millar
Executive Director, Infrastructure Development

February 23, 2015

Governor Brown's announcement of a 50% renewable energy goal for California:

- The 50% renewable energy goal target date is 2030
- Considerable detail about the goal and how it will be assessed remains to be resolved
- It is not yet a formal state approved policy requirement, so in accordance with the ISO tariff, the ISO cannot use it as a basis for approving policy-driven transmission
- The ISO and the state energy agencies want to explore informational analysis to understand potential transmission implications of increased grid connected renewable generation – to the extent the goal ultimately calls for such generation

The ISO is therefore coordinating with the CPUC to perform a special study in the 2015-2016 TPP:

- The special study will:
  - be for information purposes only - will not be used to support a need for policy-driven transmission in the 2015-2016 planning cycle;
  - provide information regarding the potential need for public policy-driven transmission additions or upgrades to support a state 50% renewable energy goal; and
  - will help inform the state's procurement processes about the cost impacts of achieving 50% renewable energy goal
- The CPUC raised this study and discussed underlying issues in the recent February 10th and 11th RPS Calculator workshop

The Special Study will build on the 33% RPS work, but explore different approaches:

- Purely as a “boundary” study assumption, the ISO anticipates receiving a sensitivity portfolio based on a 50% RPS
- Transmission needs for 33% RPS have been based on providing full capacity deliverability status, which reduced but did not preclude possible curtailment
- In going beyond 33%, the special study will explore a new approach and assume the incremental renewable generation to be energy-only.
  - The study will estimate the expected amount of congestion-related curtailment of renewables that would likely result.
  - The study will also consider what transmission could then be rationalized based on cost effectively reducing renewables curtailment (from a customer perspective)

Special Study - Schedule

- The ISO is coordinating with the CPUC on obtaining portfolios for the 50% renewable energy goal to be used in the special study.

- Analysis will be initiated in August

- Preliminary results will be provided at the November TPP stakeholder meeting.

Unified Planning Assumptions & Study Plan
Reliability Assessment

2015-2016 Transmission Planning Process Stakeholder Meeting

Catalin Micsa
Lead Regional Transmission Engineer
February 23, 2015

Planning Assumptions

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

Planning Assumptions (continued)

- Study Horizon
  - 10 years planning horizon
    - near-term: 2016 to 2020
    - longer-term: 2021 to 2025

- Study Years
    - near-term: 2017 and 2020
    - longer-term: 2025

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**
- **Valley Electric Association area**

Study Scenarios

Study Area	Near-term Planning Horizon		Long-term Planning Horizon
	2017	2020	2025
Northern California (PG&E) Bulk System	Summer Peak Spring Off-Peak	Summer Peak Summer Partial-Peak Spring Light Load	Summer Peak Spring Off-Peak
Humboldt	Summer Peak Winter Peak Spring Off-Peak	Summer Peak Winter Peak Spring Light Load	Summer Peak Winter Peak
North Coast and North Bay	Summer Peak Winter peak Spring Off-Peak	Summer Peak Winter Peak Spring Light Load	Summer Peak Winter peak
North Valley	Summer Peak Spring Off-Peak	Summer Peak Spring Light Load	Summer Peak
Central Valley	Summer Peak Spring Off-Peak	Summer Peak Spring Light Load	Summer Peak
Greater Bay Area	Summer Peak Winter peak - (SF & Peninsula) Spring Off-Peak	Summer Peak Winter peak - (SF & Peninsula) Spring Light Load	Summer Peak Winter peak - (SF Only)
Greater Fresno	Summer Peak Spring Off-Peak	Summer Peak Spring Light Load	Summer Peak
Kern	Summer Peak Spring Off-Peak	Summer Peak Spring Light Load	Summer Peak
Central Coast & Los Padres	Summer Peak Winter Peak Spring Off-Peak	Summer Peak Winter Peak Spring Light Load	Summer Peak Winter Peak
Southern California Bulk Transmission System	Summer Peak Spring Off-Peak	Summer Peak Spring Light Load	Summer Peak Summer Partial-Peak
Southern California Edison (SCE) area	Summer Peak Spring Off-Peak	Summer Peak Summer Light Load	Summer Peak
San Diego Gas & Electric (SDG&E) area	Summer Peak Spring Off-Peak	Summer Peak Spring Light Load	Summer Peak
Valley Electric Association	Summer Peak Summer Off-Peak	Summer Peak Summer Light Load	Summer Peak

Reliability Assessment Sensitivity Studies

Sensitivity Study	Near-term Planning Horizon		Long-Term Planning Horizon
	2017	2020	2025
Summer Peak with high CEC forecasted load	-	-	PG&E Local Areas SCE Metro SCE Northern SDG&E Area
Summer Peak with heavy renewable output	-	PG&E Bulk PG&E Local Areas SCE Bulk SCE Northern SCE North of Lugo SCE East of Lugo SCE Eastern SDG&E Area	-
Summer Off-peak with heavy renewable output (generation addition)	-	VEA Area	-
Summer Peak with OTC plants replaced	-	SCE Metro Area	-
Summer Peak with low hydro output	-	SCE Northern Area	-
Retirement of QF Generations	-	-	PG&E Local Areas

Contingency Analysis

- **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)
    - Loss of both poles of the Pacific DC Intertie (WECC exemption)

- **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)

Contingency Analysis (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)
    - Loss of both poles of the Pacific DC Intertie (WECC exemption)

- **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)

Contingency Analysis (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 Event Table

New Category	Old Category	Description
P0	Cat A	System intact
P1	Cat B	Single contingency (Fault of a shunt device- fixed, switched or SVC/STATCOM is new)
P2	Cat C1, C2	Single event which may result in multiple element outage. Open line w/o fault, bus section fault, internal breaker fault
P3	Cat C3[1]	Loss of generator unit followed by system adjustments + P1. No load shed is allowed
P4	Cat C	Fault + stuck breaker events
P5	n/a	Fault + relay failure to operate (new)
P6	Cat C3	Two overlapping singles (not generator)
P7	Cat C5, C4	Common tower outages; loss of bipolar DC

1. Loss of generator unit followed by system adjustment + line outage was and ISO Category B

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.

Base Case Assumptions

- WECC base cases will be used as the starting point to represent the rest of WECC
- Transmission Assumptions
  - ISO-approved transmission projects
  - Transmission upgrades to interconnect new modeled generation

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.
  - CPUC's discounted core and ISO's interconnection agreement status will be utilized as criteria for modeling specific renewable generation
- 6-10-year planning cases
  - CPUC RPS portfolio generation included in the baseline scenario
- Retired generation is modeled in appropriate study areas

New CEC approved resources

PTO Area	Project	Capacity (MW)	First Year to be Modeled
PG&E	Oakley Generation Station (Construction)	624	2018
SCE	Blyth Solar Energy Center (Construction)	485	2015
	Huntington Beach Energy Project (Pre-Construction)	939	2019
SDG&E	Carlsbad (Pre-Construction)	633	2018
	Pio Pico Energy Center (Pre-Construction)	318	2017

Note: The ISO will be conducting the studies in the 2015-2016 TPP with Oakley, Huntington Beach Energy and Carlsbad off-line in the base case. The ISO will may also conduct sensitivity studies with these generating station resources on-line as needed.

Generation Retirements

- Nuclear Retirements
  - Diablo Canyon will be modeled on-line and is assumed to have obtained renewal of licenses to continue operation
- 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.

Generation Retirements

PTO Area	Project	Capacity (MW)	First Year to be retired
PG&E	GWF Power Systems 1-5	100	2013
	Morro Bay 3	325	2014
	Morro Bay 4	325	2014
SCE	SONGS 2 & 3	2246	2013
	El Segundo 3	335	2013
	Huntington Beach 3 & 4	450	2013
	McGen	118	2014
	Kerrgen	26	2014
SDG&E	Kearny Peakers	135	2017
	Miramar GT1 and GT2	36	2017
	El Cajon GT	16	2017

OTC Generation

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:

- Base-load Diablo Canyon Power Plant (DCPP) nuclear generation units are modeled on-line;
- Generating units that are repowered, replaced or having firm plans to connect to acceptable cooling technology, as illustrated in Table 4-4; and
- All other OTC generating units will be modeled off-line beyond their compliance dates, as illustrated in Table 4-4

Renewable Dispatch

- The ISO has done a qualitative and quantitative assessment of hourly Grid View renewable output for stressed conditions during hours and seasons of interest.
- Available data of pertinent hours was catalogued by renewable technology and location on the grid.
- The results differ somewhat between locations and seasons and was assigned to four areas of the grid: PG&E, SCE, SDG&E and VEA.

Load Forecast

- California Energy Demand Updated Final Forecast 2015-2025 adopted by California Energy Commission (CEC) on January 14, 2015 (posted February 9, 2015) will be used:
    - Using the Mid Case LSE and Balancing Authority Forecast spreadsheet of January 20, 2015

  – Additional Achievable Energy Efficiency (AAEE)
    - Consistent with CEC 2013 IEPR
    - Mid AAEE will be used for system-wide studies
    - Low-Mid AAEE will be used for local studies

  – CEC forecast information is available on the CEC website at:

http://www.energy.ca.gov/2014_energypolicy/documents/index.html#adoptedforecast

Load Forecast (continued)

- The following are how load forecasts are used for each of the reliability assessment studies.
  - 1-in-10 load forecasts will be used in PG&E, SCE, SDG&E, and VEA local area studies including the studies for the LA Basin/San Diego local capacity area.
  - 1-in-5 load forecast will be used for bulk system studies
- Methodologies used by PTOs to create bus-level load forecast were documented in the draft Study Plan

Load Forecast Methodology
PG&E

- PG&E creates bus-level load forecast (using CEC forecast as the starting point)
  - PG&E loads in the base case
    - Determination of Division Loads
    - Allocation of Division Load to Transmission Bus Level
  - Muni Loads in Base Case

Load Forecast Methodology
SCE

CEC coincident forecast for SCE area → Remove MWD, CDWR & Municipal loads → Adjust for transmission system losses → Adjusted CEC coincident forecast for SCE Area

SCE DE non-coincident A-Bank level load forecast

Allocate adjusted CEC coincident forecast to A-Banks based on SCE DE forecast.

Exceptions:
1) Large customers are fixed.
2) MWD, CDWR & Municipal loads are as specified by CEC forecast.

Note:
After allocation the total GE PSLF modeled load for SCE will equal the adjusted CEC forecast.

A-Bank – Load Transformer
CDWR – California Department of Water Resources
CEC – California Energy Commission
DE – Distribution Engineering
GE PSLF – General Electric Positive Sequence Load Flow
MWD – Metropolitan Water District
SCE – Southern California Edison

Load Forecast Methodology
SDG&E

- Utilize CEC's latest load forecast as the starting point
- SDGE's methodology to create bus-level load forecast
  - Actual peak loads on low side of each substation bank transformer
  - Normalizing factors applied for achieving weather normalized peak
  - Adversing factor applied to get the adverse peak

Load Forecast Methodology
VEA

- Utilize CEC's latest load forecast as the starting point
- VEA's methodology to create bus-level load forecast
  - Actual peak loads on low side of each substation bank transformer
  - Long range study and load plans
  - Adjust as needed

Demand Response, Energy Storage and Distributed Generation

- Demand Response
  - Two scenarios
    - Consistent with 2012 LTTP Track 4 DR assumption
    - Assuming all existing emergency DR programs will become fast-response supply resources integrated into the ISO Market
  - Allocated to bus-bar by method defined in D.12-12-010 or as provided by PTO
  - Used as potential mitigation in those planning areas where reliability concerns are identified
- Energy Storage
  - Amounts consistent with D.13-10-040
  - Not included in starting cases (no location data available)
  - Identify most effective busses for potential development after reliability concerns have been identified
- Distributed Generation
  - Identified in Commercial Interest Portfolio
  - Off-line in starting cases (conceptual data)
  - Identify DG that would mitigate identified reliability concerns

Major Path Flows

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)	3,100	
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)	3,100	3,100	
West of River (WOR)	11,200	5,000 to 11,200	N/A
East of River (EOR)	9,600	4,000 to 9,600	N/A
San Diego Import	2,850	2,400 to 3,500	Summer Peak
SCIT	17,870	15,000 to 17,870	Summer Peak

Study Methodology

- 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/Comments?

Unified Planning Assumptions & Study Plan
2015-2016 ISO Near-term LCR Studies

2015-2016 Transmission Planning Process Stakeholder Meeting

Catalin Micsa
Lead Regional Transmission Engineer
February 23, 2015

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.

Used for one year out (2016) RA compliance, as well as five year out look (2020) in order to guide LSE procurement.

For latest study assumptions, methodology and criteria see the October 30, 2014 stakeholder meeting. This information along with the 2016 LCR Manual can be found at: http://www.caiso.com/informed/Pages/StakeholderProcesses/LocalCapacityRequirementsProcess.aspx.

Note: in order to meet the CPUC deadline for capacity procurement by CPUC-jurisdictional load serving entities, the ISO will complete the LCR studies approximately by May 1, 2015.

General LCR Transparency

- Base Case Disclosure
  - ISO has published the 2016 and 2020 LCR base cases on the ISO Market Participant Portal

  (https://portal.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/2016LocalCapacityRequirementsFinalStudyManual.pdf)
- ISO to respond in writing to questions raised (also in writing) during stakeholder process

  (http://www.caiso.com/informed/Pages/StakeholderProcesses/LocalCapacityRequirementsProcess.aspx)

Summary of LCR Assumptions

- Assumptions consistent with ISO Reliability Assessment
  - Transmission and generation modeled if on-line before June 1 for applicable year of study (January 1 for Humboldt – winter peaking)
  - Use the latest CEC 1-in-10 peak load in defined load pockets
    - CEC Mid forecast
    - CEC Low-Mid AAEE
  - Maximize import capability into local areas
  - Maintain established path flow limits
  - Units under long-term contract turned on first
  - Maintain deliverability of generation and imports
  - Fixed load pocket boundary
  - Maintain the system into a safe operating range
  - Performance criteria includes normal, single as well as double contingency conditions in order to establish the LCR requirements in a local area
  - Any relevant contingency can be used if it results in a local constraint
  - System adjustment applied (up to a specified limit) between two single contingencies

LCR Criteria

- The LCR study is a planning function that currently forecasts local operational needs one year in advance

- The LCR study relies on both:
  - ISO/NERC/WECC Planning Standards
  - WECC Operating Reliability Criteria (ORC)

- Applicable Ratings Incorporate:
  - ISO/NERC/WECC Planning Standards – Thermal Rating
  - WECC ORC – Path Rating

2016 and 2020 LCR Study Schedule

CPUC and the ISO have determined overall timeline

- Criteria, methodology and assumptions meeting Oct. 30, 2014
- Submit comments by November 13, 2014
- Posting of comments with ISO response by the December 1, 2014
- Base case development started in December 2014
- Receive base cases from PTOs January 3, 2015
- Publish base cases January 15, 2015 – comments by the 29th
- Draft study completed by February 26, 2015
- ISO Stakeholder meeting March 9, 2015 – comments by the 23rd
- ISO receives new operating procedures March 23, 2015
- Validate op. proc. – publish draft final report April 7, 2015
- ISO Stakeholder meeting April 14, 2015 – comments by the 21th
- Final 2016 LCR report April 30, 2015

Unified Planning Assumptions & Study Plan
ISO 2025 Long-Term LCR Studies for the LA Basin/San Diego Local Areas

2015-2016 Transmission Planning Process Stakeholder Meeting

David Le
Senior Advisor Regional Transmission Engineer
February 23, 2015

2025 Long Term Local Capacity Requirement (LCR) Studies for the Big Creek/Ventura and the LA Basin / San Diego Areas Only

- Based on the alignment of the ISO transmission planning process with the CEC Integrated Energy Policy Report (IEPR) demand forecast and the CPUC Long-Term Procurement Plan (LTPP) proceeding, the long-term LCR assessment is to be evaluated ***every two years.***
- The 2014-2015 transmission planning process is the first year in which all ten LCR areas within the ISO BAA were evaluated for long-term assessment.
- The 2016-2017 transmission planning process is the next planning process in which all ten LCR areas will be evaluated for long-term needs.
- Due to critical nature of local capacity need for maintaining reliability in Southern California, it is prudent to perform the long-term local capacity requirements studies for the following LCR areas in this planning cycle:
  - Big Creek/Ventura Area;
  - LA Basin and San Diego Areas

Study Scope, Input Assumptions, Methodology and Criteria

- Similar to the Near-Term Local Capacity Requirement (LCR) assessment (http://www.caiso.com/Documents/Local%20capacity%20requirements%20process%20-%20studies%20and%20papers), the Long-Term Capacity Requirement studies focus on determining the minimum capacity requirements within each of the local areas
  - Scenario: local capacity requirement studies will be performed for year 10 of the planning horizon (2025)
  - Updated CPUC base portfolio for the 33% Renewable Portfolio Standards (official RPS target at this time) will be included in the study cases
  - Recently CEC-adopted 1-in-10 Mid demand forecast with Low-Mid Additional Achievable Energy Efficiency (AAEE) will be used for the studies

Resource Retirements and Additions Assumptions

- The ISO will utilize the State Water Resources Control Board (SWRCB)'s compliance schedule for assumptions on OTC generation
- Generating resources that are in service for forty years or older will be retired
- For local capacity area reliability assessment, both the amounts authorized by the CPUC from the Long Term Procurement Plan (LTPP) Tracks 1 and 4 Decisions, as well as the amounts and locations of resources from Load Serving Entities' procurement selection will be studied
  - Specific projects that have received the CPUC-approved Power Purchase Tolling Agreements (PPTAs) will be modeled in the study cases based on its latest estimates of in-service dates

Summary of Generation Retirement Assumptions for Existing Non-OTC Resources (Per CPUC LTPP Track 4 Scoping Ruling)

Generating Plant	Total Plant Capacity (MW)	Individual Unit Capacity (MW)	LCR Area	SWRCB OTC Compliance Date	Comments
Etiwanda (Non-OTC)	640	Unit 3 (320) Unit 4 (320)	LA Basin	N/A	Aging power plant assumptions (>40 yr.) per CPUC LTPP Track 4 Scoping Ruling
Long Beach (Non-OTC Refurbished Plant)	260	Unit 1 (65) Unit 2 (65) Unit 3 (65) Unit 4 (65)	LA Basin	N/A	Aging/refurbished generating plant retirement assumptions per CPUC LTPP Track 4 Scoping Ruling
Broadway Unit 3 (Non-OTC)	65	Unit 3 (65)	LA Basin	N/A	Repowered as Glenarm Unit 5 at 71 MW)
Cabrillo II (Non-OTC)	188	El Cajon (16) 9-Kearny Mesa Units (Total 136 MW) 2-Mira Mar Units (Total 36 MW)	San Diego	N/A	Future retirements (contracts considered for termination by SDG&E in the future)

Long-term LCR Study Areas for this Planning Cycle

- ISO will be conducting studies on three LCR areas as shown here

Summary of Long-Term LCR Study Assumptions

Study assumptions are similar to those of Near-Term LCR studies and ISO reliability assessment:

- Includes transmission projects that were approved by the ISO Board of Governors and ISO Management
- Transmission and generation modeled if planned to be in-service before June 1 for applicable year of study.
- Use the latest CEC-adopted Mid case 1-in-10 peak load in defined load pockets with Low-Mid AAEE
- Maximize imports into local areas
- Maintain established path flow limits
- Units under long-term contracts dispatched first to mitigate identified potential reliability concerns
- Maintain deliverability of generation and imports
- Includes fixed load pocket boundaries
- Reliability performance criteria includes normal, single as well as double contingency conditions in order to establish the LCR requirements in a local area
- Post first contingency system adjustment allowed for overlapping (i.e., N-1-1) contingencies

Potential Mitigations for Considerations

- Additional preferred resources (i.e., EE, DR or renewables) and/or energy storage
- Long-term transmission options, including potential new transmission lines
- Conventional resources

Questions/Comments?

Unified Planning Assumptions & Study Plan
Special Study – Over Generation Frequency Response Assessment

2015-2016 Transmission Planning Process Stakeholder Meeting

Irina Green
Engineering Lead, Regional Transmission - North
February 23, 2015

2014-2015 Transmission Planning Process

- Conducted the initial studies of frequency response for potential over-generation conditions with the following conclusions:
  - Acceptable frequency performance within WECC; however, the ISO's frequency response was below the ISO frequency response obligation specified in BAL-003-1
- Study results seem optimistic compared to actual system performance:
  - Actual frequency responses for some contingencies were lower than the dynamic model indicated
  - Large headroom of responsive generation modeled in study case.

2014-2015 Transmission Planning Process (continued)

- Headroom on responsive governors is a good indicator of the Frequency Response Metric, but it is not the only indicator.
  - Higher available headroom on a smaller number of governor responsive resources can result in less frequency response than lower available headroom on a larger number of governor responsive resources for the same contingency.

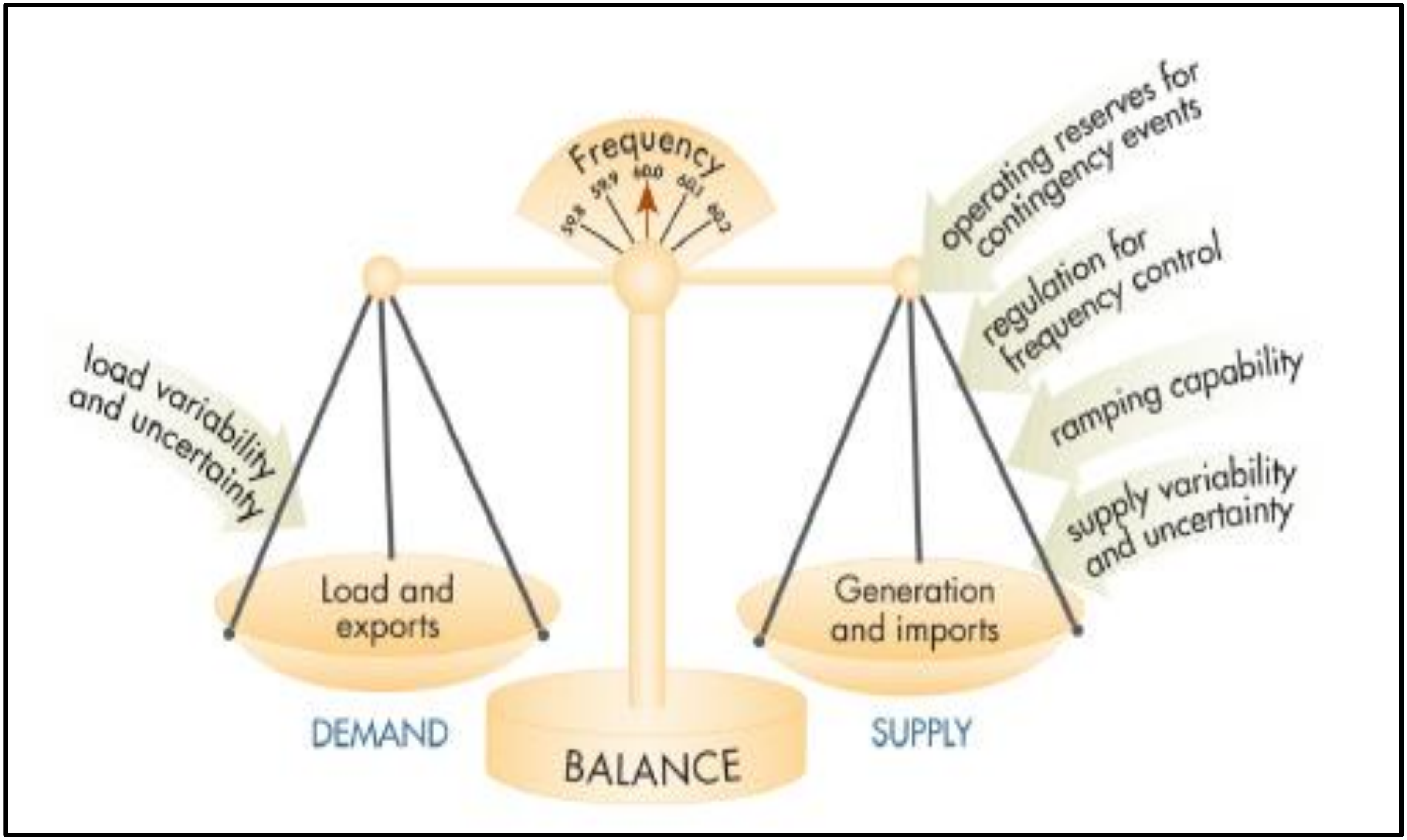
- Further model validation is needed to ensure that governor response in the simulations matches their response in the real life.

- Exploration of other sources of governor response is needed.

2015-2016 Transmission Planning Process

- The ISO will conduct further analysis to investigate measures to improve the ISO frequency response post contingency.
  - These measures may include the following:
    - load response,
    - response from storage: and frequency response from inverter-based generation.
  - Other contingencies may also need to be studied, as well as other cases with reduced headroom.
  - Future work will also include validation of models based on real-time contingencies and studies with modeling of behind the meter generation.

Continuous Supply and Demand Balance



Frequency Regulation –Governor Droop

Each generating unit will contribute to system regulation according to the overall gain set in the governor control loop

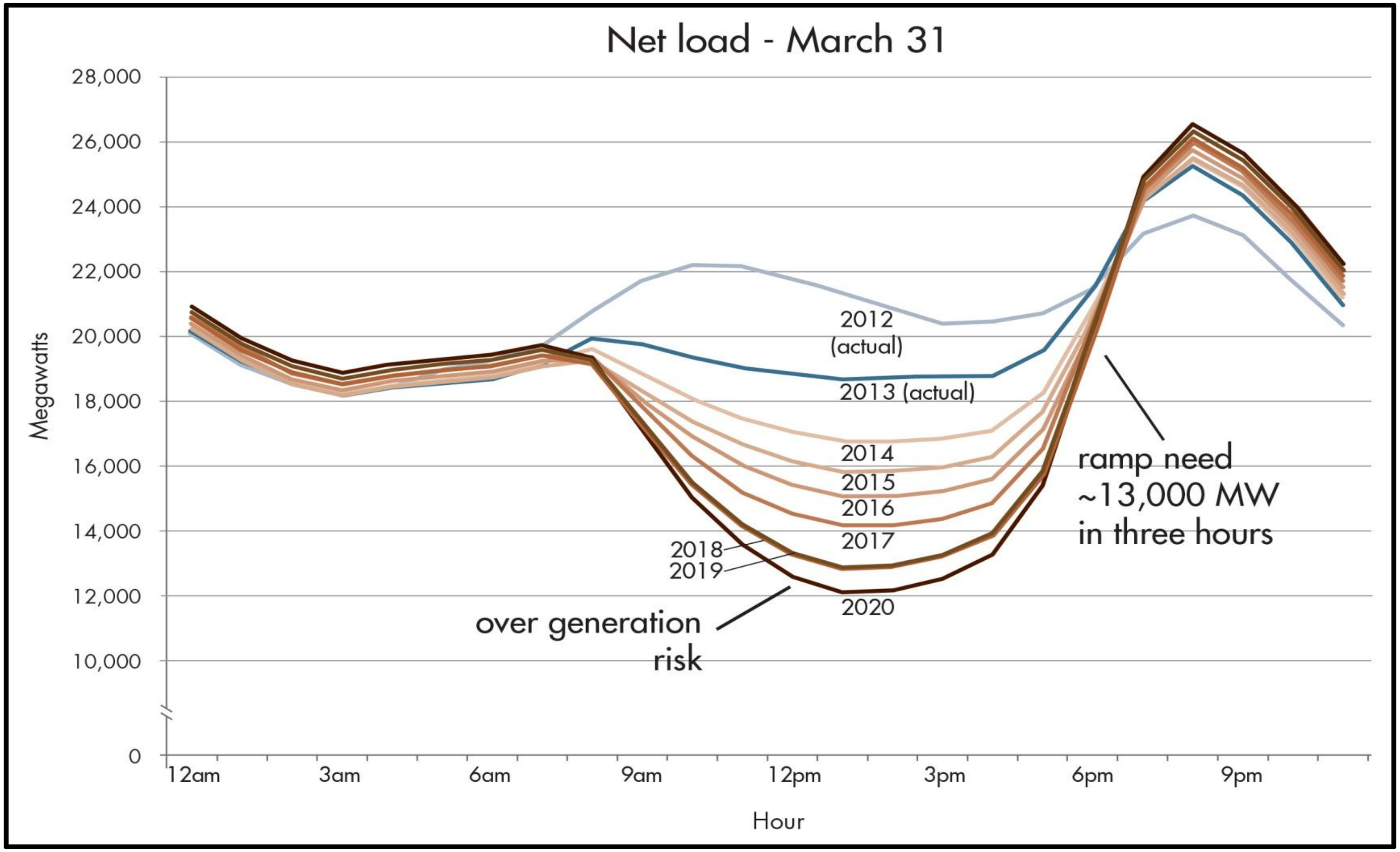
Each governor is acting to control speed, increasing power when frequency is below the set point

Droop = Change in percent frequency per change in percent output, e.g.,
f drops to 59.9 Hz, with 5% droop setting, unit responds with ([60-59.9]/60)/0.05 = 3.33% of rated power

Governor Response

- Governor response has enormous impact on frequency regulation
- Frequency regulation is largely impacted by operation (control modes, load points, etc.)
- Poor system frequency regulation can lead to load shedding, generator trips
- For meaningful studies of off nominal frequency events, it is essential to properly characterize the response of each generator
- Governors may be disabled, or operating at limit
- Droop (governor gain) may be nonlinear
- May be affected by ambient conditions
- Has deadband

Non-summer months – net load pattern changes significantly starting in 2014



Net load is the load that must be served by dispatchable resources

Over-generation occurs when there is more generation and imports into a BAA than load and exports

Prior to Over-Generation Conditions

- System Operators will exhaust all efforts to dispatch resources to their minimum operating levels
- Utilize all available DEC bids
- De-commit resources through real-time unit commitment
- Arrange to sell excess energy out of market
- Dispatch regulating resources to the bottom of their operating range
- Send out market notice and request Scheduling Coordinators to provide more DEC bids

Study contingencies and metrics

- Contingencies to be studied:
  - Simultaneous loss of two Palo Verde nuclear units – was studied in 2014-2015 TPP
  - Simultaneous loss of two Diablo Canyon nuclear units
  - PDCI bi-pole outage
  - Other?
- The impact of unit commitment on frequency response
- The impact of generator output level on governor response
  - Headroom or unloaded synchronized capacity
  - Speed of governor response
  - Number of generators with governors

Frequency Response Obligation (FRO)

- Frequency Response (FR)

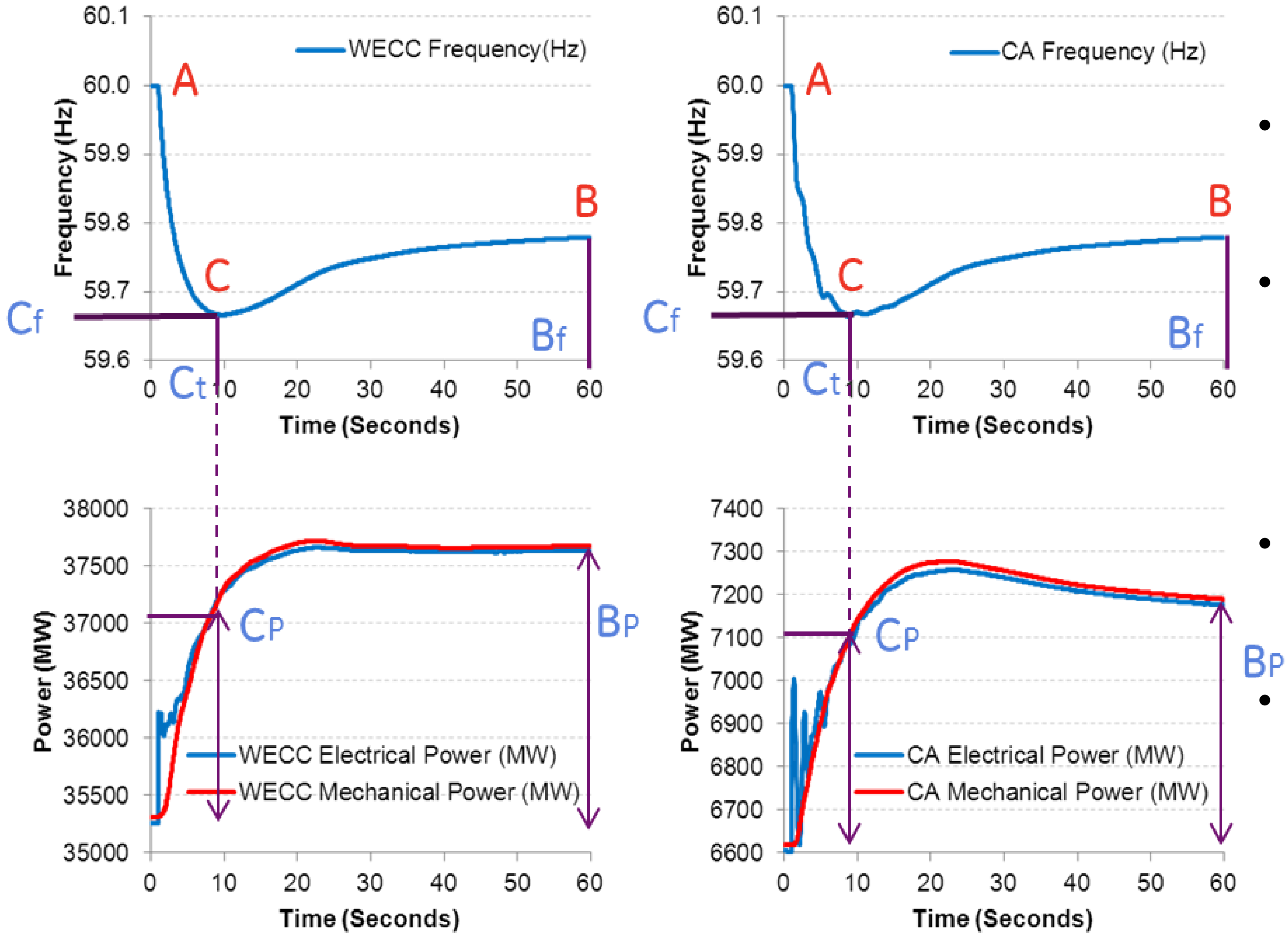
$$FR = \frac{\Delta P}{\Delta f}\left[\frac{MW}{0.1Hz}\right]$$

- FRO for the Interconnection is established in BAL-003-1 Frequency Response & Frequency Bias Setting Standard
- For WECC FRO is 949 MW/0.1Hz
- Balancing Authority FRO allocation

$$FRO_{BA} = FRO_{Int}\frac{Pgen_{BA} + Pload_{BA}}{Pgen_{Int} + Pload_{Int}}$$

- For the CAISO, FRO is approximately 30% of WECC FRO (285 MW/0.1HZ)

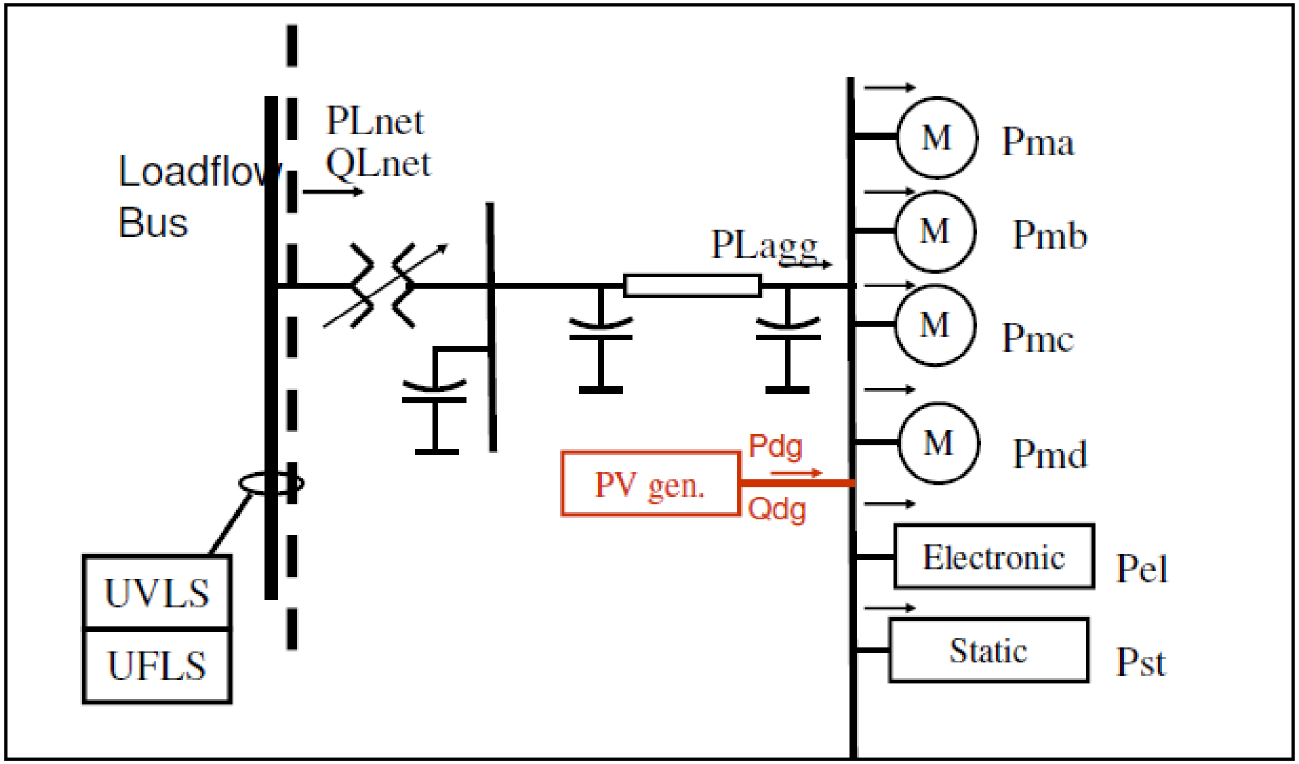
Frequency Performance Metrics



- Frequency Nadir (Cf)
- Frequency Nadir Time (Ct)
- Nadir-Based Frequency Response (Δ MW/Δfc *0.1)
- Settling Frequency (Bf)
- Settling Frequency-Based Frequency Response (Δ MW/Δfb *0.1)

Additional sensitivity studies

- Current load model - 20% of the load is modeled as induction motors with typical parameters
- Composite load model



Questions/Comments?

Unified Planning Assumptions & Study Plan

2015-2016 ISO 33% RPS Transmission Assessment

2015-2016 Transmission Planning Process Stakeholder Meeting

Sushant Barave
Senior Regional Transmission Engineer
February 23, 2015

Overview of the 33% RPS Transmission Assessment in 2015-2016 Planning Cycle

- Objective
  - Identify the policy driven transmission upgrades needed to meet the 33% renewable resource goal
- Portfolios
  - CPUC/CEC portfolios
- Load Forecast
  - CEC Mid 1-in-5 load forecast
  - CEC Mid AAEE
- Methodology
  - Power flow and stability assessments
  - Production cost simulations
  - Deliverability assessments

Portfolios

- In accordance with tariff Section 24.4.6.6, the renewable portfolios and justification for policy driven upgrades will reflect considerations, including but not limited to, environmental impact, commercial interest, risk of stranded investment, and comparative cost of transmission alternatives

- The TPP portfolios are developed by CPUC and CEC and are expected to be submitted to the ISO in February/March, 2015
  - The RPS portfolio submission letter will be posted on the ISO 2015-2016 Transmission Planning website

Portfolios

- The ISO expects to see two portfolios for the 2015-2016 TPP:
  - Commercial Interest (base case); and
  - High DG

- These portfolios, or additional ones if included with the CPUC submittal to the ISO, will be assessed in the ISO 33% RPS Transmission Assessments

Methodology – Production Simulation

- Conduct production simulation for each of the developed portfolios using the ISO unified economic assessment database

- The production simulation results are used to inform the development of power flow scenarios for the power flow and stability assessments

Methodology –Power Flow and Stability Assessments

- Power flow contingency analysis
- Voltage stability assessment (Voltage deviation, Reactive Power Margin, PV/QV analysis)
- Transient stability (Voltage deviation, Frequency deviation, stability)

Methodology –Deliverability Assessment

- Follow the same methodology as used in GIP
- Deliverability for the base portfolio and sensitivity portfolios as needed

Modeling Portfolios

- Model base commercial interest portfolio in the reliability peak and off-peak base cases for 2024
- Create additional stressed power flow models for peak, off-peak for commercial interest and additional portfolios.
- Representative GIP study data used if an equivalent resource could be matched; otherwise generic model and data will be used

Q &A

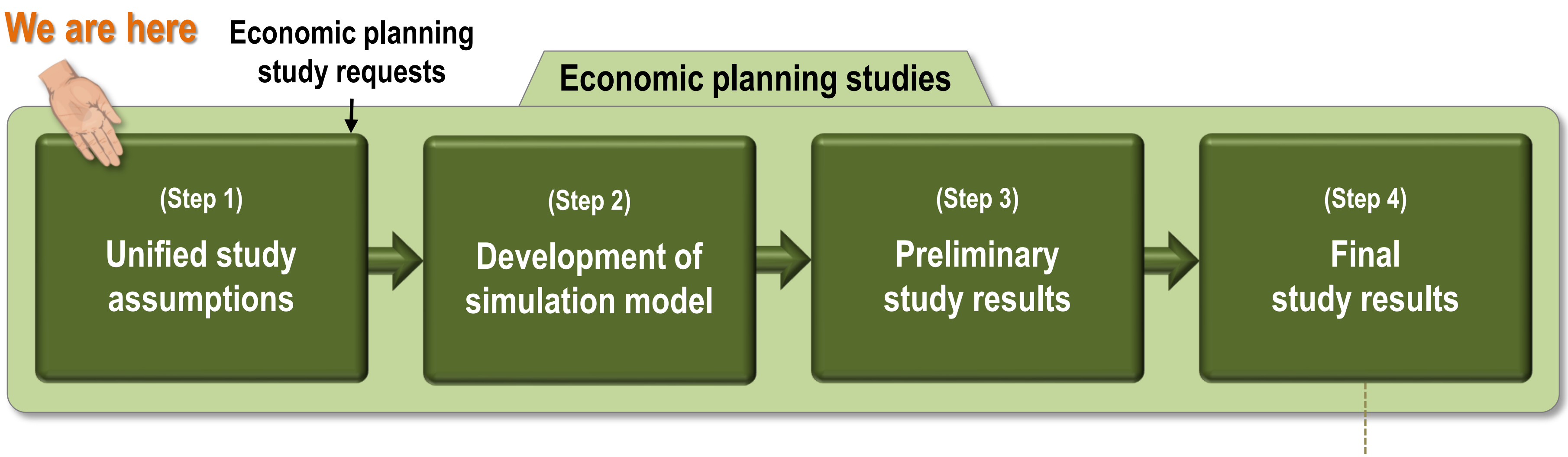
California ISO
Shaping a Renewed Future

Unified Planning Assumptions & Study Plan
Economic Planning Studies

2015-2016 Transmission Planning Process Stakeholder Meeting

Yi Zhang
Regional Transmission Engineer Lead
February 23, 2015

Steps of economic planning studies



Economic planning study

- Database development for production cost simulation
- Production cost simulation and congestion analysis
  - Will be conducted on years 2020 and 2025
- Selection of high priority studies
  - Rank congestion by severity
  - Consider economic study requests
  - Determines five high priority studies
- Detail production cost simulation and financial analysis for high priority studies

Assumptions for database development – base case

Category	Type	2015~2016 cycle
Starting database		Latest available TEPPC database release (now is TEPPC 2024 V1.4)
Load	In-state load	California Energy Demand Updated Final Forecast 2015-2025 adopted by California Energy Commission (CEC)
	Out-of-state load	Load in the latest available TEPPC database release
	Load profiles	TEPPC profiles
	Load distribution	Four seasonal load distribution patterns
Generation	RPS	CPUC/CEC 2015 RPS portfolios
	Once-Thru-Cooling	ISO 2015 Unified Study Assumptions
	Natural gas units	ISO 2015 Unified Study Assumptions
	Natural gas prices	CEC 2015 IEPR
	Other fuel prices	TEPPC fuel prices
	GHG prices	CEC 2015 IEPR
Transmission	Reliability upgrades	Approved projects
	Policy upgrades	Approved projects
	Economic upgrades	Approved projects
Other models		EIM

Economic planning study request

- Economic Planning Study Requests are to be submitted to the ISO during the comment period of the draft Study Plan.
  - February 23 to March 9, 2015

- The ISO will consider the Economic Planning Study Requests as identified in section 24.3.4.1 of the ISO Tariff.

- In evaluation of the congestion and review of the study requests, the ISO will determine the high priority studies during the 2015-2016 transmission planning cycle.

Thanks!

Your questions and comments are welcome

For written comments, please send to:
RegionalTransmission@caiso.com

Unified Planning Assumptions & Study Plan
Next Steps

2015-2016 Transmission Planning Stakeholder Meeting

Jeff Billinton
Manager, Regional Transmission - North
February 23, 2015

Next Steps – Major Milestones in 2015-2016 TPP

Date	Milestone
Phase 1	
February 23 – March 9, 2015	Stakeholder comments and economic planning study requests to be submitted to regionaltransmission@caiso.com
March 31, 2015	Post Final 2015-2016 Study Plan
Phase 2	
August 15, 2015	Post Reliability Results
August 15 - October 15, 2015	Request Window
September 21 – 22, 2015	Stakeholder Meeting – Reliability Results and PTO proposed mitigation
November 16 - 17, 2015	Stakeholder Meeting – Policy and Economic Analysis
January 2016	Post Draft 2015-2016 Transmission Plan
February 2016	Stakeholder Meeting – Draft 2015-2016 Transmission Plan
End of March 2016	Post Final 2015-2016 Transmission Plan