2012/2013 Transmission Planning Process Unified Planning Assumptions and Study Plan

March 30, 2012

Table of Contents

1. Introduction

As set forth in Section 24 of the California ISO tariff on the Transmission Planning Process and in the Transmission Planning Process (TPP) Business Practice Manual (BPM), the TPP is conducted in three phases. This document is being developed as part of the first phase of the TPP, which entails the development of the unified planning assumptions and the technical studies to be conducted as part of the current planning cycle. In accordance with revisions to the TPP that were approved by FERC in December 2010, this first phase also includes specification of the public policy objectives the ISO will adopt as the basis for identifying policy-driven transmission elements in phase 2 of the TPP, as well as initiation of the development of a conceptual statewide transmission plan that will be an input to the comprehensive planning studies and transmission plan developed during phase 2. If you would like to learn more about the ISO's TPP, please go to Section 24 of the California ISO tariff located at http://www.caiso.com/rules/Pages/Regulatory/Default.aspx or the Transmission Planning Process BPM at http://www.caiso.com/rules/Pages/BusinessPracticeManuals/Default.aspx .

The objectives of the unified planning assumptions and study plan are to clearly articulate the goals of, and agree upon assumptions for, the various public policy and technical studies to be performed as part of phase 2 of the TPP cycle. These goals and assumptions will in turn form the basis for ISO approval of specific transmission elements and projects identified in the 2012/2013 comprehensive transmission plan at the end of phase 2.

2. Overview of 2012/2013 Stakeholder Process Activities and Communications

Section 2 of this document presents general information regarding stakeholder activities and communications that will occur during this planning cycle.

2.1 Stakeholder Meetings and Market Notices

During each planning cycle, the ISO will conduct at least four stakeholder meetings to present and acquire stakeholder input on the current planning effort. These stakeholder meetings are scheduled and designed around major activities in Phase I and Phase II of the TPP. Additional meetings for each stage may be scheduled as needed. These meetings provide an opportunity for the ISO to have a dialogue with the stakeholders regarding planning activities and to establish the foundation upon which stakeholders may comment and provide other necessary input at each stage of the TPP.

The current schedule for all three phases of the 2012/2013 transmission planning cycle is provided in Table 2-1. Should this schedule change or other aspects of the 2012/2013 transmission planning cycle require revision; the ISO will notify stakeholders through an ISO market notice which will provide stakeholders information about revisions that have been made. As such, the ISO encourages interested entities to register to receive transmission planning related market notices. To do so, go to: http://caiso.com/1c67/1c678de462d10.html and submit the Market Notice Subscription Form.

Table 2-1 Schedule for the 2012/2013 planning cycle

No	Due Date	2012/2013 Activity	Phase
1	December 15, 2011	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.	I
2	January 16, 2012	PTO's, neighboring balancing authorities, regional/sub-regional planning groups and stakeholders provide ISO the information requested in the December 15 letter and market notice (see no.1 above)	I
3	February 21, 2012	The ISO develops the draft Study Plan and posts it on its website	I
4	February 28, 2012	The ISO hosts public stakeholder meeting #1 to discuss the contents in the Study Plan with stakeholders	I
5	March 13, 2012	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	I
6	Last week in March	The ISO specifies a provisional list of high priority economic planning studies, finalizes the Study Plan and posts it on the public website	I
7	Q2	ISO Initiates the development of the Conceptual Statewide Plan	I
11	March 26, 2012	Post CPUC portfolios (one week prior to stakeholder meeting)	II
12	April 2, 2012	The ISO hosts stakeholder meeting for the CPUC to present the portfolios	II
13	April 16, 2012	Comment period for stakeholders to submit comments on the public stakeholder meeting discussing portfolios	II
14	May 15, 2012	The ISO finalizes the portfolios and post on public website	II
15	July/August	ISO posts the Conceptual Statewide Plan on its website and issues a market notice announcing the posting	II
16	August/September	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)	II
17	August 15, 2012	Request Window opens	II
18	August 15, 2012	The ISO posts preliminary reliability study results and mitigation solutions	II
19	September 14, 2012	PTO's submit reliability projects to the ISO	II
20	September 26 – 27, 2012	The ISO hosts public stakeholder meeting #2 to discuss the study results, PTO's reliability projects, and the Conceptual Statewide Plan with stakeholders	II
21	September 27 – October 11, 2012	Comment period for stakeholders to submit comments on the public stakeholder meeting #2 material	II
22	October 15, 2012	Request Window closes	II
23	End of October 2012	ISO post final reliability study results and mitigation solutions	II
24	December 4, 2012	The ISO posts an update on the preliminary policy driven & economic planning study results on its website	II

No	Due Date	2012/2013 Activity	Phase
25	December 11 - 12, 2012	The ISO hosts public stakeholder meeting #3 to provide the updates on the preliminary policy driven & economic planning study results	II
26	December 12 – 21, 2012	Comment period for stakeholders to submit comments on the public stakeholder meeting #3 material	II
27	January 2013	The ISO posts the draft comprehensive Transmission Plan on the public website	II
28	February 2013	The ISO hosts public stakeholder meeting #4 to discuss the transmission project approval recommendations, identified transmission elements, and the content of the comprehensive Transmission Plan	II
29	Three weeks following the public stakeholder meeting #4	Comment period for stakeholders to submit comments on the public stakeholder meeting #4 material	II
30	March 2013	The ISO finalizes the comprehensive Transmission Plan and presents it to the ISO Board of Governors for approval	II
31	End of March	ISO posts the Final Board-approved comprehensive Transmission Plan on its site	II
32	April 2, 2013 – June 1, 2013	If applicable, the ISO solicits proposals to finance, construct, and own economically driven and category 1 policy driven elements identified in the comprehensive Transmission Plan (No. 24 above)	III
33	No later than June 7, 2013	The ISO posts the list of interested project sponsors received	III
34	No later than June 21, 2013	The ISO posts the list of qualified project sponsors who met the established criteria	III
35	July 15, 2013	Deadline for joint project sponsor notifications	III
36	No later than September 15, 2013	The ISO posts the list of approved project sponsors	III
37	No later than October 15, 2013	The ISO releases a detailed report on the approved project sponsors selected	III

2.2 Stakeholder Comments

The ISO will provide stakeholders with an opportunity to comment on all meetings and posted materials. Stakeholders are requested to submit comments in writing to regionaltransmission@caiso.com within two weeks after the stakeholder meetings. The ISO will post these comments on the ISO Website and will provide responses to these comments no later than in the final transmission plan. Stakeholder comments received during each planning cycle and corresponding responses from the ISO may be summarized in appendix of the annual transmission plan.

2.3 Availability of Information

The ISO website is the central place for public and non-public information. For public information, the "Transmission Planning" section located at http://www.caiso.com/1f42/1f42d6e628ce0.html on the ISO website will be considered as the main page for documents related to 2012/2013 transmission planning cycle. Additionally, the ISO has created a secured website to store confidential or otherwise restricted data (https://portal.caiso.com/tp/Pages/default.aspx), such as Critical Energy Infrastructure Information (CEII). In order to gain access to this secured website, each individual must have a Non-Disclosure Agreement (NDA) executed with the ISO.
The procedures governing access to different classes of protected information is set forth in Section 9.2 of the Transmission Planning BPM (BPM). As indicated in that Section, access to specified information may be limited depending on whether a requesting entity meets certain criteria set forth in the ISO tariff, engages in "marketing, sales, or brokering" of energy, is a Western Electricity Coordinating Council (WECC) member, or otherwise satisfies requirements for the disclosure of CEII data. Generally, to the extent other requirements are met, the ISO will require as a condition of access execution of the ISO non-disclosure agreement (NDA) and, if the data relates to WECC information and the requesting entity is not a WECC member, the WECC NDA. The NDA application and instructions are available on the ISO website at http://caiso.com/1f42/1f42d6e628ce0.html under the *Regional Transmission NDA* subheading.

3. Public Policy Objectives and the Conceptual Statewide Transmission Plan

With FERC's approval of the ISO's revised TPP in December 2010, two important new elements were incorporated into phase 1 of the TPP. These two new elements – the specification of public policy objectives for transmission planning, and the development of a conceptual statewide plan as an input for consideration in developing the ISO's comprehensive transmission plan – are discussed in this section.

3.1 Public Policy Objectives

The revised TPP created a category of transmission additions and upgrades to enable the ISO to plan for and approve new transmission needed to support state or federal public policy requirements and directives. The impetus for the "policy-driven" category was the recognition that California's renewable energy goal would drive the development of substantial amounts of new renewable supply resources over the next decade, which in turn would drive the majority of new transmission needed in the same time frame. It was also recognized that new transmission needed to support the state's renewable energy goal would most likely not meet the criteria for the two predominant transmission categories of reliability and economic projects.

Evaluating the need for policy-driven transmission elements begins in phase 1 with the ISO's specification, in the context of the unified planning assumptions and study plan, of the public policy objectives it proposes to adopt for transmission planning purposes in the current cycle. For the 2012/2013 cycle, the overarching public policy objective is the state's mandate for 33% renewable energy by 2020. For purposes of the TPP study process, this high-level objective is comprised of two sub-objectives: first, to support the delivery of 33% renewable energy over the course of all hours of the year, and second, to support Resource Adequacy (RA) deliverability status for the renewable resources outside the ISO balancing authority area that are needed to achieve the 33% energy goal. Either of these sub-objectives could lead to the identification and approval of policy-driven transmission elements in the ISO's 2012/2013 comprehensive transmission plan.

3.1.1 Achieving 33% renewable energy on an annual basis

The state's mandate for 33% renewable energy by 2020 refers to the share of total electricity consumed by California consumers over the course of a year that is provided by renewable resources. In the context of the transmission planning studies, the question to be investigated is whether a specified portfolio of renewable supply resources, in conjunction with the conventional resource fleet expected to be operating, will deliver a mix of energy over all 8760 hours of the year that is at least 33% supplied by the renewable portfolio on an annual basis. Through the studies the ISO performs to address this question, the ISO could identify policy-driven transmission additions or upgrades that are necessary in order to achieve the 33% renewable share of annual consumption by 2020.

3.1.2 Supporting RA deliverability status for needed renewable resources outside the ISO balancing authority area

Deliverability for the purpose of a resource providing RA capacity is a distinct requirement and is integral to achieving the 33% RPS policy goal. Resources that are connected directly to the ISO grid can establish deliverability through the ISO's annual process to determine Net Qualifying Capacity (NQC) for each resource for the upcoming RA compliance year (i.e., calendar year). A new resource seeking to interconnect to the ISO grid can elect Full Capacity deliverability status in its interconnection request, and this election triggers a study process to identify any network upgrades needed for deliverability and ultimately leads to the construction of the needed network upgrades by the relevant PTO whose system needs to be upgraded.

For resources outside the ISO, however, there is no way under the current rules for the resource to obtain RA deliverability status. Rather, in conjunction with the annual NQC process the ISO assesses the Maximum Import Capability (MIC) at each intertie, and then conducts a multi-step process whereby load-serving entities inside the ISO can utilize shares of the MIC to procure external capacity to meet their RA requirements. Moreover, the determination of the intertie MIC values is based not on an assessment of maximum physical import capability in each area, but only on historic energy schedules under high-load system conditions. This approach has resulted in extremely small values for certain interties. As a result, areas outside the ISO that are rich in renewable energy potential and have been included in the ISO's 33% supply portfolios, have raised concerns that they will be unable to develop their projects if they are unable to offer RA capacity to their potential LSE buyers. The ISO therefore will include, in this TPP cycle, the policy objective of expanding RA import capability in those areas outside the ISO BAA where (a) renewable resources are needed in the 33% RPS base case portfolio[1] to meet the state's 33% RPS target, and (b) the RA import capability under the current MIC rules is not sufficient to enable these resources to provide RA capacity.

This particular sub-objective requires a different study approach than that required for the previous sub-objective. The fundamental concept behind RA is that the ISO should be able to utilize all the designated RA capacity simultaneously to provide energy and reserve capacity when needed to meet peak system demand. Pursuant to this concept, the assessment of deliverability focuses on the simultaneous operation of available internal RA capacity and import of external RA energy by designated RA capacity during system peak hours. Because this type of study is different than the studies needed for the previous sub-objective, the RA deliverability assessment could result in the ISO identifying different needed policy-driven transmission elements.

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[1] Further discussion of the development of 33% RPS supply portfolios is provided in section 3.3 of this paper

3.2 Conceptual Statewide Transmission Plan

Per the ISO tariff section 24.2, during Phase 1 the ISO will initiate the development of a conceptual statewide transmission plan. The plan will typically be completed during Phase 2 of the TPP, at which time it will become an input to the study process whereby the ISO evaluates the need for policy-driven transmission elements. The ISO incorporated an annual conceptual statewide transmission plan into its revised TPP proposal in conjunction with the provision for public policy-driven transmission, based on the recognition that public policies such as the 33% RPS, which could necessitate the development of new transmission infrastructure, might not apply to the ISO Controlled Grid alone, but could apply to the entire state (or possibly an even broader geographic region). For this reason, although the ISO's responsibility is to plan and approve transmission projects for the ISO Controlled Grid, a statewide perspective, in collaboration with other California transmission providers if possible, on how to develop needed new transmission to most efficiently meet the statewide 33% RPS mandate would clearly be a valuable input into the ISO's TPP. At the same time, although such a plan would be useful in providing a broad geographic view of needed transmission development, the plan would be "conceptual" in the sense that it would be for informational purposes only and not binding on any of the California transmission providers as to which projects to approve. This qualification regarding the conceptual nature of the plan reflects the fact that each California transmission provider is responsible for approving transmission for the ISO Controlled Grid.

During the 2012/2013 TPP cycle the ISO will consider the latest California Transmission Planning Group (CTPG) plan.

4. Technical Studies

In this planning cycle, the following technical studies will be conducted by the ISO in a public stakeholder process:

- Reliability Assessment to identify needed reliability projects
- 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 to identify needed upgrades
- Local Capacity Requirements
- Updates to the 2011/2012 evaluation of the reliability impact to the ISO's controlled grid due to State Water Resources Control Board (SWRCB)'s Once Through Cooling Policy if new information regarding generation implementation plan or official CEC load forecast is available
- Central California Study

4.1 Reliability Assessments

The ISO will analyze the need for transmission upgrades and additions in accordance with NERC Standards and WECC/ISO reliability criteria. Reliability assessments are conducted annually to ensure that performance of the system under the ISO controlled grid will meet or exceed the applicable reliability standards. The term "Reliability Assessments" encompasses several technical studies such as power flow, transient stability, and voltage stability studies. The basic assumptions that will be used in the reliability assessments are described in sections 4.1.1-4.1.16 Generally, these include the scenarios being studied, assumptions on the modeling of major components in power systems (such as demand, generation, transmission network topology, and imports), contingencies to be evaluated, reliability standards to be used to measure system performance, and software or analytical tools.

4.1.1 Study Areas

The reliability assessments will be performed on the bulk system (north and south) as well as the local areas under the ISO controlled grid. Figure 4-1 shows the approximate geographical locations of these study areas. The full-loop power flow base cases that model the entire WECC interconnection will be used in all cases. These 16 study areas are shown below.

- Entire northern California (bulk) system – voltages 230 kV and higher in the PG&E system
- PG&E Local Areas:
    - Humboldt area:
    - North Coast and North Bay areas:
    - North Valley area:
    - Central Valley area (which includes Sierra, Sacramento, and Stockton divisions):
    - Greater Bay area:

  - San Joaquin Valley area (which includes Yosemite, Fresno and Kern divisions): and
  - Central Coast and Los Padres areas.
- Entire southern California (bulk) system
- SCE local areas:
  - Metro area;
  - Big Creek Corridor;
  - Antelope-Bailey area;
  - North of Lugo area;
  - East of Lugo area; and
  - Eastern area.
- San Diego Gas Electric (SDG&E) area
- Valley Electric Association (VEA) area

Figure 4-1: Approximated geographical locations of the study areas

4.1.2 Frequency of the study

The reliability assessments are performed annually as part of the ISO's TPP.

4.1.3 Reliability Standards and Criteria

The 2012/2013 transmission plan will span a 10-year planning horizon and will be conducted to ensure the ISO-controlled-grid is in compliance with the North American Electric Reliability Corporation (NERC) standards, WECC regional criteria, and ISO planning standards across the 2013-2022 planning horizon.

4.1.3.1 NERC Reliability Standards

System Performance Reliability Standards (TPL-001 to TPL – 004)

The ISO will analyze the need for transmission upgrades and additions in accordance with NERC reliability standards, which set forth criteria for system performance requirements that must be met under a varied but specific set of operating conditions. The following TPL NERC reliability standards are applicable to the ISO as a registered NERC planning authority and are the primary driver of the need for reliability upgrades:[2]

- TPL-001: System Performance Under Normal Conditions (category A);
- TPL-002: System Performance Following Loss of a Single Bulk Electric System (BES) Element (category B);
- TPL-003: System Performance Following Loss of Two or More BES Elements (category C); and
- TPL-004: System Performance Following Extreme BES Events (category D).

4.1.3.2 WECC Regional Criteria

The WECC TPL system performance criteria are applicable to the ISO as a planning authority and set forth additional requirements that must be met under a varied but specific set of operating conditions.[3]

4.1.3.3 California ISO Planning Standards

The California ISO Planning Standards specify the grid planning criteria to be used in the planning of ISO transmission facilities.[4] These standards cover the following:

- address specifics not covered in the NERC reliability standards and WECC regional criteria;
- provide interpretations of the NERC reliability standards and WECC regional criteria specific to the ISO-controlled grid; and
- identify whether specific criteria should be adopted that are more stringent than the NERC standards or WECC regional criteria.

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[2] http://www.nerc.com/page.php?cid=2%7C20
[3] http://compliance.wecc.biz/application/ContentPageView.aspx?ContentId=71
[4] http://www.caiso.com/Documents/TransmissionPlanningStandards.pdf

4.1.4 Study Horizon

The studies that comply with TPL- 001, TPL- 002, and TPL- 003 will be conducted for both the near-term (2013-2017) and longer-term (2018-2022) per the requirements of the reliability standards. According to the requirements under the TPL- 004 standard, the studies that comply with the extreme events criteria will only be conducted for the short-term scenarios (2013 -2017) per the requirement of the reliability standard.

4.1.5 Study Years

Within the identified near and longer term study horizons the ISO will be conducting detailed analysis on 2014, 2017 and 2022[5]. If in the analysis it is determined that additional years are required to be assessed the ISO will consider conducting studies on these years or utilized past studies[6] in the areas as appropriate.

4.1.6 Study Scenarios

The study scenarios cover critical system conditions driven by several factors such as:

<u>Generation:</u>
Existing and future generation resources are modeled and dispatched to reliably operate the system under stressed system conditions. More details regarding generation modeling is provided in section 4.1.9.

<u>Demand Level:</u>
Since most of the ISO footprint is a summer peaking area, summer peak conditions will be evaluated in all study areas. However, winter peak, spring peak, spring off-peak, summer off-peak or summer partial-peak will also be studied for areas in where such scenarios may result in more stress on system conditions. Examples of these areas are the coastal sub-transmission systems in the PG&E service area (e.g. Humboldt, North Coast/North Bay, San Francisco, Peninsula and Central Coast), which will be studied for both the summer and winter peak conditions. Table 4-1 lists the scenarios that will be conducted in this planning cycle.

<u>Stressed Import path flows:</u>
For system normal conditions (TPL-001), the study assumes that high import flows that are required to serve load in addition to internal generation resources to each study area are modeled in the base cases. This assumption represents a stressed system operating condition. This ensures that transmission facilities supporting load in these study areas can be adequately utilized under a variety of plausible system conditions to reliably serve load. Section 4.1.13 lists the MW flow on major import paths that will be modeled in the study.

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[5] Requirement R1.3.1 of TPL-001 and R1.3.2 of TPL-002, TPL-003 and TPL-004 states: *"Cover critical system conditions and study years as deemed appropriate by the responsible entity."*
[6] Requirement R1.3.1 of TPl-001, TPL-002, TPL-003 and TPL-004 states: "Be supported by a current or past study and/or system simulation…"

Table 4-1: Summary of Study Scenarios in the ISO Reliability Assessment

Study Area	2014	2017	2022
Northern California (PG&E) Bulk System*	Summer Peak Summer Light Load	Summer Peak Summer Off-Peak	Summer Peak Summer Light Load
Humboldt	Summer Peak Winter Peak Summer Light Load	Summer Peak Winter Peak Summer Off-Peak	Summer Peak Winter Peak
North Coast and North Bay	Summer Peak Winter peak Summer Light Load	Summer Peak Winter peak Summer Off-Peak	Summer Peak Winter peak
North Valley	Summer Peak Summer Light Load	Summer Peak Summer Off-Peak	Summer Peak
Central Valley (Sacramento, Sierra, Stockton)	Summer Peak Summer Light Load	Summer Peak Summer Off-Peak	Summer Peak
Greater Bay Area	Summer Peak Winter peak - (SF & Peninsula) Summer Light Load	Summer Peak Winter peak - (SF & Peninsula) Summer Off-Peak	Summer Peak Winter peak - (SF Only)
San Joaquin Valley (Yosemite, Fresno, Kern)	Summer Peak Summer Light Load	Summer Peak Summer Off-Peak Summer Partial Peak	Summer Peak
Central Coast & Los Padres	Summer Peak Winter Peak Summer Light Load	Summer Peak Winter Peak Summer Off-Peak	Summer Peak Winter Peak
Consolidated Southern California	Summer Peak Summer Light Load	Summer Peak Spring Off-Peak	Summer Peak Summer Light Load
Southern California Edison (SCE) area	Summer Peak Summer Light Load	Summer Peak Spring Off-Peak	Summer Peak
San Diego Gas and Electric (SDG&E) area	Summer Peak Summer Light Load	Summer Peak Summer Off-Peak	Summer Peak
Valley Electric Association	Summer Peak Summer Light Load	Summer Peak Summer Off-Peak	Summer Peak

Note:
- Peak load conditions are the peak load in the area of study.
- Off-peak load conditions are approximately 50-65 per cent of peak loading conditions, such as weekend.
- Light load conditions are the system minimum load condition.
- Partial peak load condition represents a critical system condition in the region based upon loading, dispatch and facilities rating conditions.

4.1.7 Contingencies:

In addition to the system under normal conditions (TPL-001), the following contingencies will be evaluated as part of the study. These contingencies lists will be made available on the ISO secured website

Loss of a single bulk electric system element (BES) (TPL-002 - Category B)
The assessment will consider all possible Category B contingencies based upon the following:

- Loss of one generator (B1)[7]
- Loss of one transformer (B2)
- Loss of one transmission line (B3)
- Loss of a single pole of DC lines (B4)
- Loss of the selected one generator and one transmission line (G-1/L-1)[8], where G-1 represents the most critical generating outage for the evaluated area
- Loss of a both poles of a Pacific DC Intertie

Loss of two or more BES elements (TPL-003 - Category C)
The assessment will consider the Category C contingencies with the loss of two or more BES elements which produce the more severe system results or impacts based on the following:

- Breaker and bus section outages (C1 and C2)
- Combination of two element outages with system adjustment after the first outage (C-3)
- All double circuit tower line outages (C5)
- Stuck breaker with a Category B outage (C6 thru C9)
- Loss of two adjacent transmission circuits on separate towers[9]

Extreme contingencies (TPL-004 - Category D)
The assessment will consider the Category D contingencies of extreme events which produce the more severe system results or impact as a minimum based on the following:

- Loss of 2 nuclear units[10]
- Loss of all generating units at a station.
- Loss of all transmission lines on a common right-of-way
- Loss of substation (One voltage level plus transformers)
- Certain combinations of one element out followed by double circuit tower line outages.

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[7] Includes per California ISO Planning Standards – V Loss of Combined Cycle Power Plant Module as a Single Generator Outage Standard.
[8] Per California ISO Planning Standards – IV Combined Line and Generator Outage Standard.
[9] Per requirement R1.1 of WECC Regional Criterion TPL-001-WECC-CRT-2 System Performance Criterion
[10] Per requirement R1.2 of WECC Regional Criterion TPL-001-WECC-CRT-2 System Performance Criterion

4.1.8 Study Base Cases

The power flow base cases from WECC will be used as the starting point of the ISO transmission plan base cases. Table 4-2 shows WECC base cases will be used to represent the area outside the ISO control area for each study year. For dynamic stability studies, the latest WECC Master Dynamics File (from February 2012) will be used as a starting point.

Table 4-2: Summary of WECC Base Cases used to represent system outside ISO

Study Year	Season	WECC Base Case							
		PG&E Case	Series	SCE Case	Series	SDG&E Case	Series	VEA Case	Series
2014	Summer Peak	2014HS3-SA		2014HS3-SA	2010	2012HS4		2014HS3-SA	
	Winter Peak	2014-15HW2A		-		-		-	
	Summer Light	TBD		2014-15HW2A	2010	12HSP1A1		2014-15HW2A	
2017	Summer Peak	2017HS1A		2017HS1A	2011	2017HS1		2017HS1A	
	Winter Peak	2014-15HW2A		-		-		-	
	Summer Off-Peak	TBD		-		2016HW2		-	
	Summer Partial Peak	2017HS1A		-		-		-	
	Spring Off-Peak	-		2015-16HW2A	2011	-		2015-16HW2A	
2022	Summer Peak	2021HS1A		2021HS1A	2010	2017HS1		2021HS1A	
	Winter Peak	2021HS1A		-		-		-	
	Summer Light	TBD		2022LS1SA	2011	2016HW2		-	

During the course of developing the transmission plan base cases, the portion of areas that will be studied in each WECC base case will be updated by the latest information provided by the PTOs. After the updated topology has been incorporated, the base cases will be adjusted to represent the conditions outlined in the Study Plan. For example, a 2017 summer peak base case for the northern California will use 17hs2a1 base case from WECC as the starting point. However, the network representation in northern California will be updated with the latest information provided by the PTO followed by some adjustments on load level or generation dispatch to ensure the case represents the assumptions described in this document. This practice will result in better accuracy of network representation both inside and outside the study area.

4.1.9 Generation Projects

In addition to generators that are already in-service, new generators will be modeled in the studies as generally described below. Depending on the status of each project, new generators will be assigned to one of the five levels below:

- Level 1: Under construction

- Level 2: Regulatory approval received
- Level 3: Application under review
- Level 4: Starting application process
- Level 5: Press release only

Based on this classification, the following guidelines will be used to model new generators in the base cases for each study.

Up to 1-year Operating Cases: Only generation that is under construction (Level 1) and has a planned in-service date within the time frame of the study will be modeled in the initial power flow case.

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 will be modeled in the initial power flow case. Generation in pre-construction phase will be modeled off-line but will be available as a non-wire mitigation option.

Renewable generation with all permitting and necessary transmission approved and expected to be in-service within 5-years may also be modeled in the relevant cases. Given the data availability, generic dynamic data may be used for this future generation.

In addition to the generation modeling criteria described above, while modeling renewable generation for 2013 through 2017, CPUC's discounted core and ISO's interconnection agreement status will be utilized as criteria for modeling specific generation.

6-10-year Planning Cases: Only generation that is under construction or has received regulatory approval (Levels 1 and 2) will be modeled in the area of interest of the initial power flow case. If additional generation is required to achieve an acceptable initial power flow case, then generation from Levels 3, 4, and 5 may be used. However, Level 3, 4, and 5 generation should only be used when they are outside the area of study, so that the generation's impact on the facility addition requirements will be minimized.

Generation included in the previous year's baseline scenario described in Section 24.4.6.6 of the ISO Tariff will also be included in the 10-year Planning Cases. Given the data availability, generic dynamic data may be used for the future generation.

Thermal generation projects in construction or pre-construction phase: For the latest updates on new generation projects, please refer to CEC website under the licensing section (http://www.energy.ca.gov/sitingcases/all_projects.html) the ISO relies on other databases to track the statuses of additional generator projects to determine the starting year new projects may be modeled in the base cases. Table 4-3 lists new thermal generation projects in construction or pre-construction phase that will be modeled in the base cases.

Table 4-3: New generation projects included in the ISO near-term reliability assessment

No	Project	Capacity (MW)	First Year to be Modeled	PTO Area
1	Lodi Energy Center (Construction)	255	2013	PG&E
2	Tracy Combined Cycle (Construction)	145	2013	PG&E
3	Mariposa Peaker (Construction)	196	2013	PG&E
4	Marsh Landing (Construction)	774*	2013	PG&E
5	Walnut Creek Peaker (Construction)	500	2013	SCE
6	Los Esteros Combined Cycle (Construction)	120	2014	PG&E
7	Russel City – East Shore EC (Construction)	600	2013	PG&E
8	Oakley Generation Station (Construction)	624	2014	PG&E
9	El Segundo Power Redevelopment (Construction)	570	2014	SCE
10	Sentinel Peaker (Construction)	850	2014	SCE
11	Genesis Solar Energy Project (Construction)	250	2014	SCE
12	Ivanpah Solar (Construction)	370	2013-2014	SCE
13	Henrietta PP CC Expansion (Pre-Construction)	25	2013	PG&E

Generation Retirements: A list of generators that are assumed to be retired is provided in Table 4-4. These generators will be removed or will not be dispatched starting in the year they are assumed to be retired.

Table 4-4: Generator retirements

No	Project	Capacity (MW)	First Year to be retired
1	Huntington Beach 3	220	2012
2	Huntington Beach 4	220	2012
3	Contra Costa 6	337	2013*
4	Contra Costa 7	337	2013*
5	Kearny Peakers	135	2014
6	Miramar GT1 and GT2	36	2014
7	El Cajon GT	16	2014
8	El Segundo 3	335	2014**

Notes: * Contra Costa units 6 and 7 are scheduled to be retired when the Marsh Landing generation project is commercially available.

** El Segundo unit 3 is scheduled to be retired when the El Segundo Power Redevelopment project is commercially available.

4.1.10 Transmission Projects

The transmission projects that the ISO has approved will be modeled in the study. This includes existing transmission projects that have been in service and future transmission projects that have received ISO approval in the 2011/2012 or earlier ISO transmission plans. Currently, the ISO anticipates the 2011/2012 transmission plan will be presented to the ISO board of governors for approval in March 2011. Once the plan is approved by the board, a complete list of transmission projects will be included in the final Study Plan.

4.1.11 Demand Forecast

The assessment will utilize the revised mid-case California Energy Demand Forecast 2012-2022 released by California Energy Commission (CEC) dated February 2012. The CEC forecast information is available on the CEC website at:
http://www.energy.ca.gov/2012_energypolicy/documents/index.html

In general, the following are guidelines on how load forecasts are used for each study area.

- The 1-in-10 load forecasts will be used in each local area study in the PG&E service area for the areas studied.
- The 1-in-5 load forecast will be used for studies that address regional transmission facilities (i.e. bulk system)
- The 1-in-10 load forecasts will be used in each local area study in SCE service area
- The 1-in-10 load forecasts will be used in each local area study in SDG&E service area

Since load forecasts from the CEC are generally provided for a larger area, these load forecasts may not contain bus-level load forecasts which are necessary for reliability assessment. Consequently, the augmented local area load forecasts developed by the participating transmission owners (PTOs) will also be used where the forecast from the CEC does not provide detailed load forecasts. Descriptions of the methodologies used by each of the PTOs to derive bus-level load forecasts using CEC data as a starting point are described below.

- Pacific Gas and Electric Service Area:
  The method used to develop the PG&E base case loads is an integrative process that extracts, adjusts and modifies the information from the transmission and distribution systems and municipal utility forecasts. The melding process consists of two parts. Part 1 deals with the PG&E load. Part 2 deals with the municipal utility loads.
    - PG&E Loads in Base Case
      The method used to determine the PG&E loads is similar to the one used in the 2011-2012 studies. The method consists of determining the division loads for the required 1-in-5 system or 1-in-10 area base cases as well as the allocation of the division load to the transmission buses.
      Determination of Division Loads
      The annual division load is determined by summing the previous year division load and the current division load growth. The initial year for the base case

development method is based heavily on the most recent recorded data. The division load growth in the system base case is determined in two steps. First, the total PG&E load growth for the year is determined. Then this total PG&E load growth is allocated to the division, based on the relative magnitude of the load growths projected for the divisions by PG&E's distribution planners. For the 1-in-10 area base case, the division load growth determined for the system base case is adjusted to the 1-in-10 temperature using the load temperature relation determined from the most recent load and temperature data of the division.

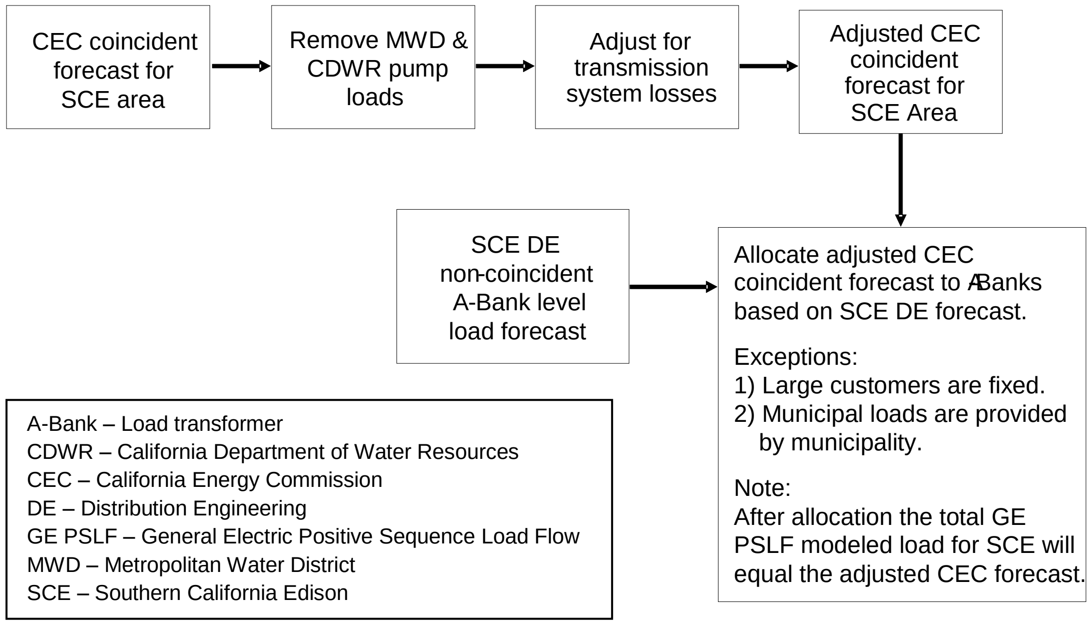
<u>Allocation of Division Load to Transmission Bus Level</u>
Since the base case loads are modeled at the various transmission buses, the division loads developed need to be allocated to those buses. The allocation process is different depending on the load types. PG&E classifies its loads into four types: conforming, non-conforming, self-generation and generation-plant loads. The conforming, non-conforming and self-generation loads are included in the division load. Because of their variability, the generation-plant loads are not included in the division load. Since the non-conforming and self-generation loads are assumed to not vary with temperature, their magnitude would be the same in the 1-in-2 system, 1-in-5 system or the 1-in-10 area base cases of the same year. The remaining load (the total division load developed above, less the quantity of non-conforming and self-generation load) is the conforming load, which is then allocated to the transmission buses based on the relative magnitude of the distribution level forecast.

- Muni Loads in Base Case
  Municipalities provide PG&E their load forecast information. If no information is provided, PG&E supplements such forecast. For example, if a municipal utility provided only the 1-in-5 loads, PG&E would determine the 1-in-2 and 1-in-10 loads by adjusting the 1-in-5 loads for temperature in the same way that PG&E would for its load in that area.

  For the 1-in-5 system base cases, the 1-in-5 loads are used. For the 1-in-10 area base cases, the 1-in-10 loads are used if the municipal loads are in the area of the area base case, otherwise, the 1-in-2 loads would be used.

Southern California Edison Service Area:

Following are the steps in developing SCE's A-Bank load models –



- San Diego Gas and Electric Service Area:
  The substation load forecast reflects the actual, measured, maximum coincident load on the substation distribution transformers. This max load is obtained either from SCADA historical data or in a few cases from mechanical charts. That measured max load is then weather normalized to produce the adverse substation load. The adverse substation loads are then adjusted across SDG&E so that area loads plus losses sum to the CEC 90/10 forecast. Thus, two substation loads for each distribution bus are modeled: the adverse load, and the coincident load. The difference between the adverse and coincident loads includes about 3% of transmission losses - while simulating a single substation or zone peak, transmission losses are neglected because the system is not adjusted to reflect a system-wide coincident peak.

  The distribution substation annual load forecast uses the actual peak load on the low side of each substation bank transformer or transformers if running in parallel. Once the peaks are determined, weather factors, i.e. normalizing and 'adversing' factors are applied to the peaks.

  The Normalizing Factor is used to take the Total MVA for the summer and adjust it to a normal year (50/50) value.
    - 50/50 value – the value you would expect 5 years out of 10.
    - If the weather condition on the summer peak date was abnormally hot, the normalizing factor would be <1.0.

- If the weather condition on the summer peak date was abnormally cool, the normalizing factor would be >=1.0
- Normalized Peak = Total Peak MVA * Normalizing Factor

The Adverse Factor takes the normalized peak value and 'adverses' it up to what the load would be if the peak occurred in an adverse year.

- The adverse peak is the adjusted peak that would be expected 1 out of 10 years.
- Adverse Peak = Normalized Peak * Adverse Factor

The distribution substation annual forecast submitted to transmission planning is an Adverse Peak forecast. The distribution substation forecast will always be higher than the system forecast which is a coincident forecast that is 'adversed'. The distribution circuits are de-coupled from the substation banks and buses, and are therefore not used to complete the substation forecast.

4.1.12 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. These include generators, capacitors, static var compensators (SVCs) and other devices. In addition, Table 4-5 provides a list of key reactive power resources that will be modeled in the studies. For the complete list of these resources, please refer to the base cases which are available through the ISO secured website.

Table 4-5: Summary of key reactive resources modeled in ISO reliability assessments

Substation	Capacity (Mvar)
Gates	225
Los Banos	225
Gregg	150
McCall	132
Mesa	100
Metcalf	350
Olinda	200
Table Mountain	454
Devers 230kV and Devers 500kV	156 MVAR; and 605 MVAR (based on 525kV)*
Sunrise San Luis Rey 230 kV	63
Southbay / Bay Boulevard 69 kV (expected in 2014)	100
Miraloma	158
Suncrest (expected in 2012)	126

* Dynamic capability

4.1.13 Operating Procedures

Operating procedures, for both normal (pre-contingency) and emergency (post-contingency) conditions, are modeled in the studies. Please refer to http://www.caiso.com/thegrid/operations/opsdoc/index.html for the list of publicly available Operating Procedures.

4.1.14 Firm Transfer

Power flow on the major paths represents the firm transfer that will be modeled in the study. In general, the northern California (PG&E) system has 4 interties with the outside system and southern California. Out of these 4 ties, Path 66 (COI) and Path 26 are two major transfer paths that wheel large amounts of power between northern California and its neighbors. Consequently, Table 4-6 lists the capability and power flows that will be modeled in each scenario on these paths in the northern area assessment[11].

Table 4-6: Major Path flows in northern area (PG&E system) assessment[12]

Path	Path Flow (MW)			
	Summer Peak	Summer Off-Peak	Winter Peak	Spring Off-peak
Path 15 (S-N)	N/A	5400	1000	TBD
Path 26 (N-S)	4000	1500-2000	2800	800
Path 66 (N-S)	4800	N/A	TBD	1500

For the summer off-peak cases in the northern California study, Path 15 flow is adjusted to a level close to its rating limit of 5400 MW (S-N). This is typically done by increasing the import on Path 26 (S-N) into the PG&E service territory. The Path 26 is adjusted between 1500-2000 MW to maintain the stressed Path 15 as well as to balance the loads and resources in northern California

Similarly, Table 4-7 lists the range for major path flows in the southern California system (SCE and SDG&E system) studies that were modeled in the prior cycle under various system conditions. They are expected to be similar for the current planning cycle but exact numbers won't be available until the power flow cases are completed.

11 These path flows will be modeled in all base cases.

12 The winter coastal base cases in PG&E service area will model Path 26 flow at 2,800 MW (N-S) and Path 66 at 3,800 MW (N-S)

Table 4-7: Major Path flows in southern area (SCE and SDG&E system) assessment

Paths	Flow Range (MW)
Path 26 (N-S)	-3000 to 4,000
PDCI	900 to 3,100
West of River	5,000 to 9,700
East of River	3,900 to 6,000
Path 42	150 to 1000
Path 61	550 to 1900
South of San Onofre	628 to 801
ISO - Mexico (CFE)	-5 to 5
IID-SDGE	-25 to 676

4.1.15 Protection System

To help ensure reliable operations, many remedial action schemes (RAS) or special protection systems (SPS) have been installed in some areas. Typically, these systems trip load and/or generation by strategically tripping circuit breakers under select contingencies after detecting overloads. Some SPS are designed to operate upon detecting unacceptable low voltage conditions caused by certain contingencies. Table 4-8 below lists major new and existing RAS/SPS that will be included in the study.

Table 4-8: List of key protection systems modeled in the study

RAS / SPS Name	Descriptions
Middletown UVLS	Trip Middletown substation load under low voltages conditions.
Humboldt SPS	Trip load in Humboldt under low voltages conditions
Alameda Overload SPS	Drops City of Alameda load following the overload of Oakland cables.
Bay Area UVLS	Trip local distribution load. When detects low 230 kV voltage at Newark, Monta Vista, San Mateo.
Bay Meadows OL SPS	Trip one or two Bay Meadows distribution feeders. After loss of any San Mateo - Bay Meadows 115 kV line.
Eastshore 230/115 kV TB #1 and #2 Overload SPS	T&LO, and initiate breaker failure on the associated transformer high and low side breakers if loading above emergency rating. Scheme is normally cut out except for specific clearances.
Evergreen - San Jose B OL	Trip San Jose CBs 112, 122 following the OL on Evergreen - San Jose B
Gilroy Energy Center SPS	Trip up to 51 MW gen at Gilroy Energy Center if OL on Llagas - Morgan Hill or Llagas - Metcalf 115 kV lines.
Grant - Eastshore OL SPS	Trip Grant feeder breakers 1105 & 1108 if OL on Grant - Eastshore #1, #2

RAS / SPS Name	Descriptions
Metcalf - El Patio OL SPS	Trip El Patio CB 142 (El Patio - SJ A) if Load > 960 A on either Metcalf - El Patio #1 or #2 115 kV line.
Metcalf SPS	Trip load and curtail generation following the loss of Moss Landing - Metcalf or Metcalf – Tesla
Monta Vista N-2 OL SPS	Trip Monta Vista - Jefferson #1 and #2 230 kV lines following loss of both Monta Vista #3 & #4 230 kV lines.
Moraga - Oakland J OL SPS	Trip Oakland J CB 122 (Jenny) if load > 750 A on Moraga - J
Newark Dumbarton OL SPS	Trip Dumbarton CB 132 if OL on Newark - Dumbarton 115
San Francisco RAS	Trip Area Load after NERC Cat D loss of area generation or transmission.
South of San Mateo SPS	Trip up to 600 MW of load in the peninsula if 115 kV Line OL caused by N-2 230 kV outages.
Caribou SPS	Trips Caribou area generations if overload on the Caribou-Palermo 115 kV line or if the Caribou-Table Mountain 230 kV line trips.
MWD Eagle Mountain Thermal Overload Protection Scheme	The thermal overload relay will trip Eagle Mountain-Julian Hinds if an overload is detected on the Iron Mountain-Eagle Mountain 230 kV line.
West-of-Devers RAS	The West-of-Devers RAS includes tripping of two Devers 500/230 kV AA transformer banks or the remaining West-of-Devers 230 kV line under certain system configurations
South of Lugo (SOL) N-2 SPS	This remedial action scheme was put in operation in June 2005 to trip up to 3 “A” station loads (Mira Loma, Padua, and part of Chino) for a total of about 1100MW to 1400MW if any two 500 kV lines were lost on the South of Lugo path.
Mariposa UVLS	Trip load in the area if under voltages detected
Ashlan 230 kV UVLS	Trip load in the area if under voltages detected
McCall 230 kV UVLS	Trip load in the area if under voltages detected
Stagg UVLS	Monitor the Stagg 230 kV bus voltage and curtail load to mitigate post-contingency low voltage problems which could result from a sustained outage to the Tesla - Stagg and Tesla – Eight Mile Road 230 kV Line.
Blythe Energy RAS	Trip generation or transmission line to mitigate thermal overload or low voltage condition.
Low Voltage Load Shedding (LVLS) Scheme.	This remedial action scheme was put in operation in the mid-1980’s to prevent a low-voltage condition resulting from the simultaneous loss of the Lugo-Mira Loma 2&3 and Lugo-

RAS / SPS Name	Descriptions
	Serrano (or Lugo-Mira Loma 1, after Lugo-Serrano is looped in at Mira Loma) 500 kV
Yolo 115 kV UVLS	Trip load in the woodland area if under voltages detected
Figarden 230 kV UVLS	Trip load in the area if under voltages detected
500kV TL 50001 IV Generator SPS	Trip generation at CLR II and TDM under contingency conditions
Miguel transformer protection	Monitors the loss of transformer and the loading on the remaining transformer
Otay Mesa – Tijuana SPS	A redundant scheme is installed to protect the line from loading above its continuous rating

4.1.16 Control Devices

Several control devices will also be modeled in the studies. These control devices are:

- All shunt capacitors in SCE and other areas
- Static Var Compensators at several locations such as Potrero, Newark, Rector, Devers substations
- DC transmission line such as PDCI, IPPDC, and Trans Bay Cable Projects

4.1.17 Proposed Demand Response Programs and information the ISO received from data request

According to tariff Section 24.3.3(a), the ISO sent a market notice to interested parties seeking suggestions about demand response programs and generation or non-transmission alternatives that should be included as assumptions in the study plan. In response, the ISO received demand response information for consideration in planning studies. Currently, the ISO is evaluating this data and will provide more information as to whether it will be used in the technical studies in this planning cycle.

4.1.18 Study Tools

Basically, the GE PSLF is the main study tool for evaluating system performance under normal conditions and following the outages (contingencies) of transmission system components for steady state, post-transient and transient stability studies. However, other tools such as DSA tools software may be used in other studies such as voltage stability, small signal stability analyses and transient stability studies. The studies in the local areas focus on the impact from the grid under system normal conditions and following the Categories B, C, and D outages of equipment at the voltage level 60 through 230 kV. In bulk assessments, governor power flow will be used to evaluate system performance under normal conditions and following the contingencies of equipment at voltage level 230 kV and higher.

4.1.19 Study Methodology

The section explains the methodology that will be used in the study:

Power Flow Contingency Analysis

The ISO will perform power flow contingency analyses based on the ISO Planning Standards[13] which are based on the NERC reliability standards and WECC regional criteria for all local areas studied in the ISO controlled grid. The transmission system will be evaluated under normal system conditions NERC Category A (TPL 001), against normal ratings and normal voltage ranges, as well as emergency conditions NERC Category B (TPL 002), C (TPL 003) and D (TPL 004) contingencies against emergency ratings and emergency voltage range as identified in Section 4.1.6.

Depending on the type and technology of a power plant, several G-1 contingencies represent an outage of the whole power plant (multiple units)[14]. Examples of these outages are combined cycle power plants such as Delta Energy Center and Otay Mesa power plant. Such outages are studied as G-1 contingencies.

Line and transformer bank ratings in the power flow cases will be updated to reflect the rating of the most limiting component. This includes substation circuit breakers, disconnect switches, bus position related conductors, and wave traps.

Power flow studies will be performed in accordance with PRC-023 to determine which of the facilities (transmission lines operated below 200 kV and transformers with low voltage terminals connected below 200 kV) in the Planning Coordinator Area are critical to the reliability of the Bulk Electric System to identify the facilities below 200 kV that must meet PRC-023 to prevent potential cascade tripping that may occur when protective relay settings limit transmission loadability.

Post Transient Analyses

Post Transient analyses will be conducted to determine if the system is in compliance with the WECC Post Transient Voltage Deviation Standard in the PG&E, SCE, and SDG&E area bulk system assessments and if there are thermal overloads on the bulk system.

Post Transient Voltage Stability Analyses

Post Transient Voltage stability analyses will be conducted as part of bulk system assessment for the outages for which the power flow analyses indicated significant

[13] California ISO Planning Standards are posted on the ISO website at http://www.caiso.com/docs/09003a6080/14/37/09003a608014374a.pdf

[14] Per California ISO Planning standards V Loss of Combined Cycle Power Plant Module as a Single Generator Outage Standard

voltage drops, using two methodologies: Post Transient Voltage Deviation Analyses and Reactive Power Margin analyses.

Post Transient Voltage Deviation Analyses

Contingencies that showed significant voltage deviations in the power flow studies will be selected for further analysis using WECC standards of 5% voltage deviation for "N-1" contingencies and 10% voltage deviation for "N-2" contingencies.

Voltage Stability and Reactive Power Margin Analyses

As per WECC regional criterion, voltage stability is required for the area modeled at a minimum of 105% of the reference load level or path flow for system normal conditions (Category A) and for single contingencies (Category B). For multiple contingencies (Category C), post-transient voltage stability is required at a minimum of 102.5% of the reference load level or path flow. The approved guide for voltage support and reactive power, by WECC TSS on March 30, 2006, will be utilized for the analyses in the ISO controlled grid. According to the guideline, load will be increased by 5% for Category B and 2.5% for Category C contingencies and will be studied to determine if the system has sufficient reactive margin. This study will be conducted in the areas that have voltage and reactive concerns throughout the system including Rio Oso, Fresno, and Southern California, including the L.A. Basin or other substations such as Eagle Mountain and Julian Hinds 230 kV, Metropolitan Water District (MWD) and San Diego areas.

Transient Stability Analyses

Transient stability analyses will also be conducted as part of bulk area system assessment for critical contingencies to determine if the system is stable and exhibits positive damping of oscillations and if transient stability criteria as in Table 4-9 are met.

Table 4-9: WECC Transient Stability Criteria

<table>
<tr><th>Performance Level</th><th>Disturbance</th><th>Transient Voltage Dip Criteria</th><th>Minimum Transient Frequency</th></tr>
<tr><td rowspan="4">B</td><td>Generator</td><td rowspan="4">Max V Dip – 25%
Max Duration of V Dip Exceeding 20% - 20 cycles
Not to exceed 30% at non-load buses.</td><td rowspan="4">59.6 Hz for 6 cycles or more at a load bus.</td></tr>
<tr><td>One Circuit</td></tr>
<tr><td>One Transformer</td></tr>
<tr><td>PDCI</td></tr>
<tr><td rowspan="3">C</td><td>Two Generators</td><td rowspan="3">Max V Dip – 30% at any bus.
Max Duration of V Dip Exceeding 20% - 40 cycles at load buses</td><td rowspan="3">59.0 Hz for 6 cycles or more at a load bus.</td></tr>
<tr><td>Two Circuits</td></tr>
<tr><td>IPP DC</td></tr>
</table>

In addition, the reliability assessment included the following study assumptions:

Power Factor Assumption

In the SCE area assessment, an active to reactive power (WATT / VAR) ratio of 25-to-1 (or power factor of 0.999) measured at the high side of the A-Bank (230/115 kV or 230/66 kV) will be assumed for the SCE transmission substation loads. The value of this ratio recorded for the last five years has ranged between 35 to 1 in 2006 to a leading power factor from 2008 through 2010.

The increase in the WATT/VAR ratio is a result of SCE commitment to its program to optimize reactive power planning and capacitor bank availability during heavy summer peak load periods in its distribution and sub-transmission systems. The objective of the SCE's reactive power program was to ensure a WATT/VAR ratio of 25 to 1.

Recent Historical System WATT / VAR Ratio:

The WATT / VAR ratio recorded for SCE transmission substation loads during the annual peak load for the past five years are as follows:

- 2006 – 35
- 2007 – 52
- 2008 – leading power factor
- 2009 – leading power factor
- 2010 – leading power factor

In the SDG&E area, power factors at all substations will be modeled using the most recent historical values obtained at peak loads. Bus load power factor for the year 2013 and 2014 will be modeled based on the actual peak load data recorded in the EMS system. For the subsequent study years a power factor of 0.992 will be used. GE PSLF is the main tool for this study.

The technical studies mentioned in this section will be used for identifying mitigation plans for addressing reliability concerns. As per section 24.4.6.2 of the tariff, the ISO, in coordination with each Participating TO with a PTO Service Territory will, as part of the Transmission Planning Process and consistent with the procedures set forth in the Business Practice Manual, 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, Remedial Action Schemes, appropriate Generation, interruptible Loads, storage facilities or reactive support.

4.2 Policy Driven 33% RPS Transmission Plan Analysis

4.2.1 Study methodology

The goal of the 33% renewable resource analysis is to identify the transmission needed to meet the 33% renewable resource target in the study year which, for this cycle, is 2022.

In the last planning cycle, the ISO performed the 33% renewable resource analysis for 2021. To perform that study, a comprehensive planning methodology was developed that included the following key steps and that will be used in this planning cycle:

1) Establish renewable portfolios to be studied that are aligned closely with the portfolios developed by CPUC and used by the ISO in its renewable integration studies. In accordance with tariff Section 24.4.6.6, the renewable portfolios will reflect such considerations as environmental impact, commercial interest and available transmission capacity, among other criteria. Multiple portfolios have previously been developed, but may need to be updated.
2) Conduct production simulation for each of the developed portfolios using the ISO unified economic assessment database with renewable portfolios modeled. The production simulation results are used to facilitate the development of power flow scenarios for the power flow and stability assessments.
3) Conduct comprehensive power flow and stability assessments including
    - Contingency analysis using regular power flow (GE PSLF)
    - Voltage stability assessment using governor power flow (post-transient)
    - Transient stability using GE PSLF
    - Deliverability assessment
    - Utilization assessment based on production simulation
4) Categorize any identified transmission upgrade or addition elements based on the tariff Section 24.4.6.6 requirements.

In the 2012/2013 planning cycle, similar methodology will be used to identify the transmission need to meet 33% RPS in 2022.

4.2.2 Study scope

The study scope of the 33% renewable resource analysis in this planning cycle includes the following items:

- Develop ISO 2022 power flow base case starting from 2022 reliability base cases to model different load conditions based on the study methodology and assumptions.
- Establish portfolios to be studied.
- Review 33% renewable transmission plan assumptions (status of projects not approved should be assessed for likelihood of moving ahead).
- Model those portfolios in production, power flow, and stability models
- Run production model and use results to guide flow and dispatch assumptions in power flow model

- Analyze stressed power flow models for peak, off-peak and other scenarios if needed. These should capture conditions for the CAISO's controlled grid and the entire Western Interconnection that show stressed patterns including cases possibly in different seasons. The peak load scenario uses CEC 1-in-5 coincident peak load.
- Update 33% RPS transmission plan based on findings.
- Several sensitivity cases may be created to evaluate different scenarios as part of the comprehensive plan analysis

4.2.3 Coordination with Phase II of GIP

According to tariff Section 24.4.6.5 and in order to better coordinate the development of potential infrastructure from transmission planning and generation interconnection processes, beginning with the 2012/2013 planning cycle, the ISO may coordinate the TPP with GIP studies. In general, Network Upgrades and associated generation identified during the Interconnection Studies will be evaluated and possibly included as part of the TPP. The details of this process are described below.

<u>LGIP Network Upgrade Criteria for TPP Assessment</u>
Beginning with the 2012/2013 planning cycle, GIP Network Upgrades may be considered for potential modification in the TPP if the Network Upgrade:

- ➢ Consists of new transmission lines 200 kV or above and have capital costs of $100 million or more;
- ➢ Is a new 500 kV substation that has capital costs of $100 million or more; or
- ➢ Has a capital cost of $200 million or more.

<u>Notification of Network Upgrades being assessed in the TPP</u>
In approximately June – July 2012, the ISO will publish the list of GIP Network Upgrades that meet at least one of these criteria and have been selected for consideration in TPP Phase 2. The comprehensive Transmission Plan will contain the results of the ISO's evaluation of the identified GIP Network Upgrades. GIP Network Upgrades evaluated by the ISO but not modified as part of the comprehensive Transmission Plan will proceed to Generator Interconnection Agreements (GIAs) through the GIP and will not be further addressed in the TPP. Similarly, GIP Network Upgrades that meet the tariff criteria but were not evaluated in the TPP will proceed to GIAs through the GIP.

All generation projects in the Phase II cluster study have the potential to create a need for GIP Network Upgrades. As a result, the ISO may need to model some or all of these generation projects and their associated transmission upgrades in the TPP base cases for the purpose of evaluating alternative transmission upgrades. However, these base cases will be considered sensitivity base cases in addition to the base cases developed under the Unified Planning Assumptions. These base cases will be posted on the ISO protected web-site for stakeholder review. Study results and recommendations from these cases will be incorporated in the comprehensive transmission plan.

4.3 Local Capacity Requirement (LCR)

The local capacity studies focus on determining the minimum MW capacity requirement within each of local areas inside the ISO Balancing Authority Area. The Local Capacity Area Technical Study determines capacity requirements used as the basis for procurement of resource adequacy capacity by load-serving entities for the following resource adequacy compliance year and also provides the basis for determining the need for any ISO "backstop" capacity procurement that may be needed once the load-serving entity procurement is submitted and evaluated.

Scenarios: The local capacity studies will be performed at least 2 scenarios for each local capacity area:

- Summer Peak 2013 – Local Capacity Area Technical Study only
- Summer Peak 2017 – Long-Term Local Capacity Requirements

Please note that in order to meet the CPUC deadline for capacity procurement by CPUC-jurisdictional load serving entities, the ISO will complete the short-term LCR (Peak 2013 scenarios) approximately by May 1, 2012. Long-term LCR studies will be conducted later in the year.

Load Forecast: The CEC load forecast is the primary source of future demand modeled in the base cases. However, since the primary focus of the LCR study is to determine capacity requirements in the local areas, load forecasts in each local area, described in section 4.1.10, will be used in the study.

Transmission Projects: ISO-approved transmission projects will be modeled in the base case. These are the same transmission project assumptions that are used in the reliability assessments and discussed in the previous section.

Imports: The LCR study models historical imports in the base case; the same as those used in the RA Import Allocation process

Methodology: A study methodology documented in the LCR manual will be used in the study. This document is posted on ISO website at http://www.caiso.com/Documents/Local%20capacity%20requirements%20process%20-%20studies%20and%20papers

Tools: GE PSLF version 18 will be used in the LCR study.

Since LCR is part of the overall ISO Transmission Plan, both the short-term and long-term LCR reports will be posted on the 2012/2013 ISO Transmission Planning Process webpage.

4.4 Economic Planning Study

The ISO will perform an Economic Planning Study as part of the current planning cycle to identify potential congestion and propose mitigation plans. The study will quantify the economic benefits for the ISO ratepayers based on Transmission Economic Assessment Methodology (TEAM). Production simulation is the main tool for this study.

The Economic Planning Study will be based on the same assumptions as the Reliability Assessment and 33% RPS Transmission Plan Analysis. The Economic Planning Study will conduct 8760 hourly analysis for year 2017 (the 5th planning year) and 2022 (the 10th planning year) respectively through production simulation.

As part of the requirements under the ISO tariff and Business Practice Manual, Economic Planning Study Requests based on the 2011-2012 transmission plan were submitted to the ISO during the comment period following the stakeholder meeting to discuss this Study Plan. The ISO will evaluate the Study Requests that were received and determine the High Priority Study Requests that will be studied during the 2012-2013 cycle (see tariff Section 24.3.4.2). Table 4.10 lists the Study Requests the ISO received for this planning cycle.

Table 4-10 Economic Planning Study Requests Submitted

No	Project Description	Submitted By
1	Between Southern Nevada and the other load centers in Southern California.	Zephyr Power Transmission, LLC
2	DC transmission system to provide transmission capacity between the Intermountain and Desert Southwest regions, including California	TransWest Express, LLC
3	Delaney-Colorado River 500 kV	Arizona Power Service (APS)

4.5 Long-Term Congestion Revenue Rights (LT CRR)

The ISO is obligated to ensure the continuing feasibility of Long Term CRRs (LT-CRRs) that are allocated by the ISO over the length of their terms. As such, the ISO, as part of its annual TPP cycle, shall test and evaluate the simultaneous feasibility of allocated LT-CRRs, including, but not limited to, when acting on the following types of projects: (a) planned or proposed transmission projects; (b) Generating Unit or transmission retirements; (c) Generating Unit interconnections; and (d) the interconnection of new Load. While the ISO expects that released LT-CRRs will remain feasible during their full term, changes to the interconnected network will occur through new infrastructure additions and/or modifications to existing infrastructure. To ensure that these infrastructure changes to the transmission system do not cause infeasibility in certain LT-CRRs, the ISO shall perform an annual Simultaneous Feasibility Test (SFT) analysis to demonstrate that all released CRRs remain feasible. In assessing the need for transmission additions or upgrades to maintain the feasibility of allocated LT- CRRs, the ISO, in coordination with the PTOs 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, Remedial Action Schemes, constrained-on Generation, interruptible loads, reactive support, or in cases where the infeasible LT- CRRs involve a small magnitude of megawatts, ensuring against the risk of any potential revenue shortfall using the CRR Balancing Account and uplift mechanism in Section 11.2.4 of the ISO tariff.

4.6 Once Through Cooling

Approximately 30% of California's in-state generation capacity (gas and nuclear power) uses coastal and estuarine water for once through cooling. On May 4, 2010, the State Water Resources Control Board adopted a statewide policy on the use of coastal and estuarine waters for power plant cooling. The policy established uniform, technology-based standards to implement federal Clean Water Act section 316(b), which require that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact. The policy was approved by the Office of Administrative Law on September 27, 2010 and became effective on October 1, 2010. The policy required the owner or operator of an existing non-nuclear fossil fuel power plant using once-through cooling to submit an implementation plan to the SWRCB. The implementation plans specified an alternative that would achieve compliance by a date specified for each facility identified in the policy.

Nuclear units may also seek to establish site specific requirements for best technology available. The policy directed Pacific Gas and Electric Company and Southern California Edison to conduct special studies to investigate alternatives for the nuclear units to meet the requirements of the policy, including the costs for these alternatives. The SWRCB requires that the report on these special studies be submitted by October 1, 2013.

The ISO anticipates that the SWRCB policy will cause the majority of gas-fired generating units using once through cooling to come offline in order to retrofit or repower using alternative cooling technologies, or retire. The policy may also have an impact on the relicensing of units at San Onofre Nuclear Generating Station or Diablo Canyon Power Plant. In the 2011/2012 TPP, the ISO assessed the long-term (2021) reliability impact to the ISO controlled grid and identified ranges of generation capacity need, for generation located at the existing OTC generating sites, to meet ISO's local reliability criteria

Another consideration arising from the SWRCB policy is the connection between generating units using once-through cooling and renewable integration. Many of the units using once-through cooling technology have characteristics that support renewable integration. Replacement infrastructure will need to retain or improve these capabilities (whether by the repowered plants or replacement capacity). It will be essential to sequence any retrofit or repowering efforts or retirements in a manner consistent with the operational requirements created by an expanding portfolio of renewable resources. The process of complying with the SWRCB once-through cooling policy is thus another factor to consider in preparing the power system for higher levels of renewable resources.

For purposes of the 2012/2013 transmission planning process, the ISO intends to continue its collaborative study efforts examining the SWRCB policy with various state agencies as well as stakeholders if there are significant updates for renewable generation assumptions from the California Public Utility Commission, or new adopted demand forecast from the California Energy Commission or further updates on generation implementation plans in response to the State Water Resources Control Board's Policy on OTC generation are available. The idea behind this process is to provide updates, as needed, on the OTC/AB 1318 study results for 2021 that were completed and presented at the December 8th, 2011 stakeholder meeting.

In addition to the above, the ISO also plans to examine reliability impact to the electric grid in the absence of the two nuclear generating stations within its balancing authority area (i.e., Diablo Canyon Power Plant and San Onofre Generating Station). This study will be built upon the reliability assessments performed in the previous 2011/2012 planning cycle to determine the long-term need of non-nuclear thermal generation located at the existing OTC power plants. Local and system grid reliability impact due to the absence of these two base-load nuclear generating stations will be evaluated. Long-term studies will be performed to include state-mandate on 33% RPS in the study assumptions. Similar to the study approach for reliability assessment of non-nuclear OTC generation in the 2011/2012 transmission planning process, the reliability assessment with the absence of the SONGS and Diablo Canyon nuclear power plants will be performed. This assessment will be done at the same time as 2012/2013 planning cycle; however may be document in a separate study report.

Tools

The ISO will use GE PSLF version 18 for this analysis.

4.7 AB 1318

Assembly Bill 1318 (AB 1318, Perez, Chapter 285, Statutes of 2009) requires the Air Resources Board (ARB), in consultation with the ISO, CEC, CPUC, and the SWRCB to prepare a report for the Governor and Legislature that evaluates the electrical system reliability needs of the South Coast Air Basin and recommends the most effective and efficient means of meeting those needs while ensuring compliance with state and federal law. In 2010, the ISO, in collaboration with the state agencies, prepared an interim report: Draft Work Plan on the Assessment of Electrical System Reliability Needs in

South Coast Air Basin and Recommendations on Meeting those Needs[15]. This report summarizes existing reliability studies for the ISO-Controlled Grid in the South Coast Air Basin. In 2011, the ISO collaborated with the stage agencies to perform studies needed to provide inputs for the final AB 1318 study report that the ARB is responsible for completing and submitting to the state legislature and the Governor's Office. The first half of 2012 time frame will be dedicated for completing this report with a July 2012 target date from the ARB.

4.8 Central California Study

A detailed assessment of the Central California area will be undertaken as a part of the 2012/2013 planning cycle. The ISO will develop a scope for the study that will be an addendum to the 2012/2013 Study Plan and will provide stakeholders an opportunity to provide comments on the study scope.

The transmission system in Central California not only supplies the Fresno area but also facilitates power transfers across the entire state trough it but also the interconnections to other jurisdictions. The potential needs within the Central California bulk system are multi-faceted where modifications to the bulk system in the area may produce a wide variety of potential benefits for the system. Potential benefits of the project may relate to one of or a combination of the following drivers, consistent with the approaches applied throughout the transmission planning process:

- Reliability;
- Economic;
- Policy; and/or
- Renewable integration.

The assessment of the Central California area will consider the generation portfolios that will be used for the 2012/2013 transmission planning and will include, but not limited to:

- A comprehensive analysis associated with renewable integration
- Consideration of operational flexibility of the Helms pumps

[15] http://www.arb.ca.gov/energy/esr-sc/0215-workshop/ab_1318_draft_work_plan.pdf

5. Contact Information

This section lists the Subject Matter Experts (SMEs) for each technical study or major stakeholder activity addressed in this document. In addition to the extensive discussion and comment period during and after various ISO Transmission Plan-related Stakeholder meetings, stakeholders may contact these individuals directly for any further questions or clarifications.

Table 5-1: SMEs for Technical Studies in 2012/2013 ISO Transmission Plan

Item/Issues	SME	Contact
Reliability Assessment in PG&E	Bryan Fong	bfong@caiso.com
Reliability Assessment in SCE	Haifeng Liu	hliu@caiso.com
Reliability Assessment in SDG&E	Sushant Barave	sbarave@caiso.com
Reliability Assessment in VEA	Frank Chen	fchen@caiso.com
33% RPS Transmission Plan Analysis	Yi Zhang	yzhang@caiso.com
Local Capacity Requirements	Catalin Micsa	cmicsa@caiso.com
Economic Planning Study	Xiaobo Wang	xbwang@caiso.com
Long-term Congestion Revenue Rights	Chris Mensah-Bonsu	cmensah@caiso.com
Once-through Cooling & AB1318 Study	David Le	Dle@caiso.com

6. Stakeholder Comments and ISO Responses

All the comments the ISO received from stakeholders on the 2012/2013 draft study plan and ISO's responses are posted at: http://www.caiso.com/planning/Pages/TransmissionPlanning/2012-2013TransmissionPlanningProcess.aspx.