2010 CTPG 2020 Draft Final Study Plan: Phase 2

February 10, 2010

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1 Executive Summary

1.1 Background

The California Transmission Planning Group (CTPG) is a forum for conducting joint transmission planning studies consistent with Federal Energy Regulatory Commission (FERC) Order 890 principles, and for coordinating CTPG members' transmission planning activities. CTPG members include both transmission owners and transmission operators and are subject to North American Electric Reliability Corporation (NERC)/Western Electricity Coordinating Council (WECC) transmission planning standards. The purpose of the 2010 CTPG 2020 Study is to develop a state-wide transmission plan that identifies the transmission infrastructure needed to reliably and efficiently meet, by year 2020, the state's 33% Renewable Portfolio Standard (RPS) goal. The 2010 statewide plan is intended to be truly conceptual, not prescriptive. The CTPG is not a generation or transmission project decision-making body. The conceptual plan will require further consideration and analysis by the CTPG members as part of their own respective approval processes.

As reflected in this Phase 2 study plan, CTPG has sought to be responsive to stakeholders and other entities with roles in the planning and implementation of transmission development, including the Renewable Energy Transmission Initiative (RETI) and state energy agencies. The CTPG will continue to utilize several stakeholder involvement forums to receive this valuable input.

1.2 Overview

The 2010 CTPG 2020 Study includes elements of California's Renewable Energy Transmission Initiative (RETI) conceptual transmission plan that was developed to facilitate access to RETI-identified Competitive Renewable Energy Zones (CREZs); transmission planning information from its members as well as stakeholders input. The CTPG will use this planning information and stakeholder input to conduct a number of analysis scenarios to enable the completion of a state-wide conceptual transmission plan that will provide a basis for "least regrets" decisions in the subsequent planning phases by CTPG members. The CTPG has revised its processes to complete the 2010 CTPG 2020 Study in three phases. A draft of the Phase 1 study results has been posted to the CTPG website, presented formally to stakeholders, and has received the benefit of stakeholder input. The final Phase 1 study report will be posted to the CTPG website by approximately February 15, 2010. This Phase 2 Study Plan is designed to build on the work completed in Phase 1 and reflect stakeholder input by incorporating additional planning assumptions and scenarios to be studied in Phase 2 and Phase 3. The Draft Phase 2 Study Plan is posted to the CTPG website and has been formally presented to stakeholders for input. The present document is the Draft Final Phase 2 Study Plan and includes the incorporation of stakeholder input to date.

A. Study Scope

In evaluating the performance of the transmission system with increased levels of renewable resources, it is important to understand and prepare for what may happen under adverse system conditions, as well as during expected system conditions. In Phase 2, like Phase 1, the CTPG will conduct contingency-based power flow analysis and transient stability analysis of the grid configuration for the following cases that represent forecasted adverse and normal conditions:

Phase 2 like Phase 1 includes variations of the following cases:

- Case A: 2020 Northern California adverse weather (90/10) case
- Case B: 2020 Southern California adverse weather (90/10) case

Phase 2 will also include the following additional study cases

- Case F: 2020 California Autumn light weather
- Case OTC: Adverse weather case with identified "Once Through Cooling" resources off line

B. Grid Configuration

Like the Phase 1 studies, the Phase 2 studies will utilize the WECC's 2019 Heavy Summer (HS) case. This base case is the latest available data for the WECC interconnected system for the 2020 time frame. A WECC full-loop representation will be used that includes the Western United States, Western Canada and the system of Comisión Federal de Electricidad (CFE) of Baja California, Mexico. At the request of stakeholders, the WECC HS will be changed in Phase 2 to remove the Green Path Project which is no longer being considered by the LADWP and the addition of a recently approved third circuit to the Barren Ridge/Haskell Canyon/Renaldi planned upgrades.

C. Reliability Criteria

The CTPG will utilize NERC/WECC transmission planning standards to determine the list of potential transmission system violations that require mitigation. At this time, the CTPG will provide wire recommendations only. The CTPG will not be conducting a deliverability analysis to determine the necessary improvements and operating methodology for delivery of renewables to fulfill Resource Adequacy eligibility, and to provide integration capability for variable generation renewables, such as pumped storage or other methods. These types of analysis will be completed by the entity responsible for each particular proposed transmission improvement utilizing its own analysis assumptions. The CTPG may perform this type of analysis in future studies.

The CTPG will also not be performing an alternative analysis for mitigating the need for a new or upgraded transmission line with protection control systems in the 2010 study plan. This alternative analysis will be completed by the entity responsible for each particular proposed transmission improvement utilizing its own analysis assumptions and mitigation policies and practices. The CTPG may perform this alternative analysis in future studies.

D. Net Short Input Assumptions

In Phase 1, the CTPG identified the amount of renewable energy resource additions, the "net short", that will be required between 2010 and 2020 to meet the 33% RPS. In Phase 2, CTPG is working with RETI to update estimates of other miscellaneous renewable resource additions and clarifying other differences in assumptions to update the net short estimates that will be applied to the renewable resource portfolios modeled in Phase 2. It is expected that this updated approach will have the effect of slightly reducing the renewable energy needed to meet RPS targets.

E. Renewable Generation Portfolios

The CTPG recognizes that there remains uncertainty about the renewable generation portfolios that will be realized in 2020. To address this uncertainty, the CTPG will evaluate alternative renewable generation portfolios as a basis for determining the impact of those alternatives on the state-wide conceptual transmission plan.

In response to stakeholder input, Phase 2 will evaluate a different commercial interest portfolio of renewable generation based on the generation interconnection queues of CTPG members. For the CAISO queue, approximately 15,300 MW of resources were selected based on whether they have completed or are due to complete interconnection agreements or have otherwise posted financial security. The remainder of the CTPG planning entities, (IID, LADWP, SMUD, TANC, and TID), have selected approximately 4,700 MW of proposed projects that are considered to be the most advanced in the respective approval processes. While the total queue numbers have been determined, there is still some adjustment to the renewable capacity determination by CREZ; the CTPG will provide that data when it is finalized (see Table 3 below) and is expected to be within the next week.

The CTPG is also consulting with RETI on additional renewable resource portfolios to evaluate. These portfolios will include a core of projects considered more likely to reach implementation (due, e.g., to evidence of commercial interest) that will be held constant in each portfolio combined with the addition of variations on other distributed and (in-state and out-of-state) central station renewable projects to achieve the balance of the "net short". At this time, these scenarios will likely be analyzed in Phase 3.

Also in response to stakeholder input, as part of Phase 2, the CTPG is preparing a "Northern" scenario and a "Desert Southwest" scenario. It is expected that these two portfolios will identify the impact on the state's transmission needs if some of the 33% RPS goal was achieved with additional renewable resources from northern California and out-of-state.

F. Generation Re-Dispatch

As renewable generation production is increased to reach 33% RPS, an equal amount of fossil fuel generation is turned down (re-dispatched or decremented) to balance load in each period modeled. Phase 1 studies used heat rate as the basis for re-dispatch, with high heat rate units, turned down first. Generally the higher the heat rate the higher the cost to generate energy. Phase 2 will continue to utilize this re-dispatch methodology and will also consider a re-dispatch methodology based on fuel type & technology as a proxy for re-dispatch to minimize carbon emissions. Phase 1 employed a 70/30 split for the reduction of fossil fuel generation located within California and units outside the state. Phase 2 will continue with this assumption for both the heat rate and fuel type & technology methods. Phase 3 may investigate other proposed ratios for the in and out of state split for select cases.

G. Methodology Comparison to RETI

At the request of stakeholders, Section 6 of this study plan includes a comparison between the methodologies that were utilized by the RETI in their development of the RETI California conceptual transmission plan and the methods used by the CTPG.

2 Phase 2 Study Plan Overview

2.1 Objectives

The CTPG is committed to developing a conceptual California state-wide transmission plan to meet, by year 2020, the state's 33% RPS goal. This transmission plan will seek to leverage a diverse portfolio of renewable energy generation technologies including wind, geothermal, small hydro, biomass and solar thermal and solar photovoltaic available to supply projected electricity demand in California from now to beyond 2020.

As reflected in this Phase 2 study plan, CTPG has sought to be responsive to stakeholders and other entities with roles in the planning and implementation of transmission development, including the Renewable Energy Transmission Initiative (RETI) and state energy agencies.

An important further qualification of the CTPG process and the state-wide conceptual plan that is being developed is that CTPG is not a transmission or generation project decision-making body. Such decisions will be made by the relevant CTPG member entities in accordance with their own processes for such decisions. Thus the 2010 statewide plan is intended to be truly conceptual, not prescriptive, in line with the CTPG role as a forum for statewide collaboration on planning. As such, the CTPG regularly requests and utilizes information from its members and from other state agencies on renewable projects that represent a snapshot of their respective generation interconnection queue processes, and has sought to make assumptions on how to aggregate such projects into a portfolio that achieves a state-wide 33% RPS. This snapshot is only being used to facilitate studies to determine potential state-wide transmission needs.

2.2 Study Scope

The CTPG is developing a state-wide transmission plan using multiple renewable resource portfolios and generation re-dispatch scenarios to determine the transmission system improvements that are needed to support the state's 33% RPS and maintain the transmission system reliability in accordance with industry standards. The 2010 CTPG 2020 study will be conducted in three phases. Each phase is intended to build on the previous phase by refining and adding additional scenarios and assumptions and testing the sensitivity of these scenarios and assumptions. At the completion of the 2010 CTPG Study, the CTPG expects to provide a list of transmission system improvements that can provide the basis for "least regrets" renewable transmission planning to the respective CTPG planning entities. These entities will then conduct operational, deliverability, and alternative analysis utilizing their respective policies and practices.

The identification of transmission system improvements that may be required by an expected change in generation resources or the grid configuration begins with snapshot analysis of grid performance under forecast system conditions. The North American Electric Reliability Corporation (NERC) Standards TPL-001 through -003 requires that the transmission system be "planned such that the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecast system demands". The CTPG will address the potential violations of NERC/WECC reliability standards at the network level only. Potential violation at the local load center level will be reported in the study and addressed by the entity responsible for local load center reliability. For the initial phase of the CTPG work, on- and off-peak studies were conducted to help frame system needs while accommodating increased renewable resource development. In evaluating the performance of the transmission system with increased levels of renewable resources, it is important to understand and prepare for what may happen under adverse system conditions, as well as during expected system conditions. Adverse conditions include high load hours when solar output will be at peak levels. Adverse conditions may also occur during lower load hours when wind generation is high but the amount of on-line dispatchable generation is relatively low. By testing a range of possible resource scenarios, in each phase across these same cases, the most accurate statewide transmission plan will be developed.

Phase 2 like Phase 1 includes variations of the following cases that represent forecasted adverse and normal conditions:

- Case A: 2020 Northern California adverse weather (90/10) case
- Case B: 2020 Southern California adverse weather (90/10) case

Phase 2 will also include the following additional study cases

- Case F: 2020 Autumn Case
- Case OTC: Adverse weather case with identified "Once Through Cooling" resources off line

Cases A and B include those transmission additions that are in the WECC 2019 Heavy Summer seed case as well as certain transmission elements that will allow for the interconnection of new renewable resources. Case A and B assume that major upgrades are built including Midpoint-Devers-Valley, Tehachapi Segments 1-11, the Barren Ridge/Haskell Canyon/Rinaldi upgrades, upgrades in the Owens Valley, and new substations and six network transmission lines in the southern Nevada-Los Angeles area corridor.

Case A incorporates forecasted Northern California adverse summer weather peak loads (90/10) for year 2020. Case B incorporates forecasted Southern California adverse summer weather peak loads (90/10) for year 2020.

The studies for the cases will be performed using the following general steps.

Step 0: Develop Benchmark Base Case

- WECC 2019 cases as seed for scenarios
- Reflect transmission system configuration expected in 2020
- Update California demand according to scenario
- Re-dispatch path flows according to scenario
- Perform detailed contingency analysis to confirm reliability criteria is met

Step 1: Add Renewable Projects

- Model renewable projects at 0 MW output – CAISO and POU queue projects
- Modify grid to provide CREZ connections – Gen-tie and collector lines
- Perform detailed contingency analysis to confirm reliability criteria is met
- Identify and review limiting constraints or violations

Step 2: Dispatch Renewable Projects

- Dispatch renewable projects to anticipated output for each scenario
- Decrease an equal amount of fossil fuel generation
- Perform detailed contingency analysis to meet reliability criteria
- Identify and review limiting constraints or violations
- Identify transmission additions that will mitigate identified reliability criteria violations. These additions may include elements of the RETI Phase 2A conceptual transmission plan.

The case nomenclature uses a letter designation for scenarios followed by a number representing the particular step. Case A0 for example would be Scenario A with the modeling required in Step 0.

Case A2 will assess additional transmission that will mitigate identified reliability criteria violations during a northern California 1-in-10 year peak assuming 33% RPS goals are met but without stressing path flows. Case B2 will assess additional transmission that will mitigate identified reliability criteria violations for a southern California 1-in-10 year peak assuming 33% RPS goals are met but without stressing path flows. Case F will assess the transmission that will mitigate reliability criteria violations that are identified with the addition of new renewable resources assuming renewable generation levels and loads that would be expected in the fall of each year.

Case OTC is a sensitivity study to evaluate the transmission system impacts of the retirement of Once-Through Cooling (OTC) generators in northern and southern California. Case OTC utilizes the A and B cases as a starting point and then assumes that OTC units are off-line. Based on CAISO's presentation "Impacts on Electric System Reliability from Restrictions on Once-Through Cooling in California" in November 2008,[1] the OTC generation plants in CAISO control area are as follows:

[1] Available at http://www.caiso.com/208b/208b8ac831b00.pdf.

Area	OTC Units Off Line
Northern California (Excluding Diablo Canyon Nuclear Plant) Total 5,499 MW	Humboldt – 105MW Contra Costa – 674MW Pittsburg – 1311MW Potrero – 206MW Morro Bay – 673MW Moss Landing – 2530MW
Southern California (Excluding San Onofre Nuclear Plant) Total 8,516 MW	Alamitos – 2010MW El Segundo – 670MW Encina – 950MW Huntington Beach – 904MW Mandalay – 430MW Ormond Beach – 1516MW Redondo Beach – 1343MW South Bay – 693MW
Los Angeles Basin (LADWP)	Haynes –TBD MW Harbor – TBD MW Scattergood – TBD MW

With these resource assumptions, Case OTC will assess additional transmission needs that will mitigate identified reliability criteria violations for a northern and southern California 1-in-10 year peak assuming 33% RPS goals are met without stressing path flows.

Cases A, B, F and OTC may also identify certain Category C reliability criteria violations and that further study is required to identify suitable mitigation, such as controlled load drop and/or generator tripping, for these conditions. However, the CTPG has decided it will not evaluate the feasibility of such operation measures (See Section 3.1 Reliability Criteria for this discussion.) It is important to note these cases do not assess deliverability of off-peak conditions.

2.3 Grid configuration

Similar to Phase 1, the Phase 2 studies will be performed using the WECC's 2019 Heavy Summer case. This case is the latest available data for the WECC interconnected system for the 2020 time frame. A WECC full-loop representation will be used; and includes the Western United States, Western Canada and the system of Comisión Federal de Electricidad (CFE) of Baja California, Mexico.

As part of the study process some adjustments are anticipated between phases. For Phase 2 the following adjustments are to be implemented:

- Removal of the proposed Green Path North project. LADWP has stated that this project will not be pursued.
- The addition of a recently approved third circuit to the Barren Ridge/Haskell Canyon/Renaldi planned upgrades.

Table 1 lists the major transmission upgrades in the seed 2019 WECC Base Case that were assumed in-service for all CTPG cases in this study and subsequent additions and subtractions.

Table 1: Transmission Upgrades included in the 2019 "Heavy Summer" Seed Case and Transmission Additions/Subtractions made to the Seed Case

Upgrades with Key Regulatory Approvals and Environmental Permits	Upgrades without Key Regulatory Approvals and Environmental Permits	Upgrades Removed
-Tehachapi Segments 1-3 - Sunrise Powerlink project -Tehachapi Segments 4-11	- New Colorado River ("Midpoint") 500 kV substation looping in existing 500 kV Palo Verde-Devers #1 line. - 500 kV Colorado River-Devers #2 line - 500 kV Devers-Valley #2 line - Expand Barren Ridge 230 kV substation. Upgrade existing 230 kV Owens Gorge-Rinaldi line from Barren Ridge to Haskell Canyon with double circuit 230 kV towers. Add Barren Ridge-Haskell Canyon #2 line on open side of towers - Upgrade existing 230 kV Owens Gorge-Rinaldi line from Haskell Canyon to Rinaldi - Add 230 kV Castaic-Haskell Canyon #2 line on open side of towers - Loop existing 230 kV Coachella Valley-Devers line into Mirage substation creating 230 kV Mirage-Devers #2 line. - Reconductor 230 kV Mirage-Devers #2 line from 393 MVA to 494 MVA.	Green Path North

3 General Guidelines and Criteria

The CTPG will conduct contingency-based power flow analysis for the cases described in the previous section. The General Electric Positive Sequence Load Flow program (GE-PSLF) will be used in conjunction with in-house Engineer Programming Control Language (EPCL) routines to help analyze the study results.

3.1 Reliability Criteria

The Phase 2 study will use the following study methodology and criteria:

1. In the pre-contingency state and with all facilities in-service, the Bulk Electric System (BES) shall demonstrate transient, dynamic, and voltage stability. Facility ratings shall not be exceeded and uncontrolled separation shall not occur.
2. Starting with all facilities in-service and following single and double contingencies, the BES shall demonstrate transient, dynamic, and voltage stability. Facility ratings shall not be exceeded and uncontrolled separation shall not occur.
3. The single contingency analysis shall meet requirements R2.2 and R2.3 of NERC Reliability Standard FAC-010-1.
4. The double contingency analysis shall meet the requirements R2.4 and R2.5 and Regional Differences E.1 of FAC-010-1.

NERC Standard FAC-010-1 (E.1 R.1.2.5) provides that for double contingencies, the controlled interruption of electric supply (load shedding), the planned removal of certain generators (generation dropping), and/or the curtailment of firm power transfers may be necessary to maintain the overall security of the interconnected transmission system. These system adjustments can be made either manually or automatically via protection control systems. The CTPG will not be performing an alternative analysis for mitigating the need for a new or upgraded transmission line with protection control systems in the 2010 study plan. This alternative analysis will be completed by the entity responsible for each particular proposed transmission improvement utilizing its own analysis assumptions and mitigation policies and practices. The CTPG may perform this type of analysis in future studies.

Similarly, the CTPG will not be conducting a deliverability analysis to determine the necessary improvements and operating methodology for delivery of renewables to fulfill Resource Adequacy eligibility, and to provide integration capability for variable generation renewables, such as through pumped storage or other methods. This analysis will be completed by the entity responsible for each particular proposed transmission improvement utilizing its own analysis assumptions. The CTPG may perform this type of analysis in future studies.

All Facilities must be operating within their applicable post-contingency thermal, frequency, and voltage limits. The only exceptions to remaining within applicable ratings are: 1) a common mode outage of two generating units connected to the same switchyard and 2) the loss of multiple bus sections as a result of bus-tie breaker failure or delayed clearing due to a single line to ground fault.

For double contingency analysis, the CTPG will monitor all elements at 200 kV and higher, plus any additional critical lower voltage elements to determine potential reliability standards violations. Study results will document all elements that demonstrate a thermal loading of the facility applicable rating at 100% and above.

The NERC/WECC standards provide a framework from which computer simulation studies will be performed to model forecasted system conditions and evaluate the system performance. The following standards will be used for reliability assessments and standards compliance:

1. NERC Reliability Standards
   - TPL-001: System Performance Under Normal Conditions
   - TPL-002: System Performance Following Loss of a Single BES Element
   - TPL-003: System Performance Following Loss of Two or More BES Elements
2. WECC
   - Reliability Criteria For Transmission System Planning
   - Voltage Stability Criteria, Under voltage Load Shedding Strategy, and Reactive Power Reserve Monitoring Methodology
3. Each member's and balancing authority's specific planning criteria

3.2 Power Flow Contingency Analysis Guidelines

Power flow contingency analysis will be performed for each scenario consistent with the standards referenced in the previous section to identify thermal overload conditions. Note that additional contingencies may be added based upon engineering judgment for particular runs.

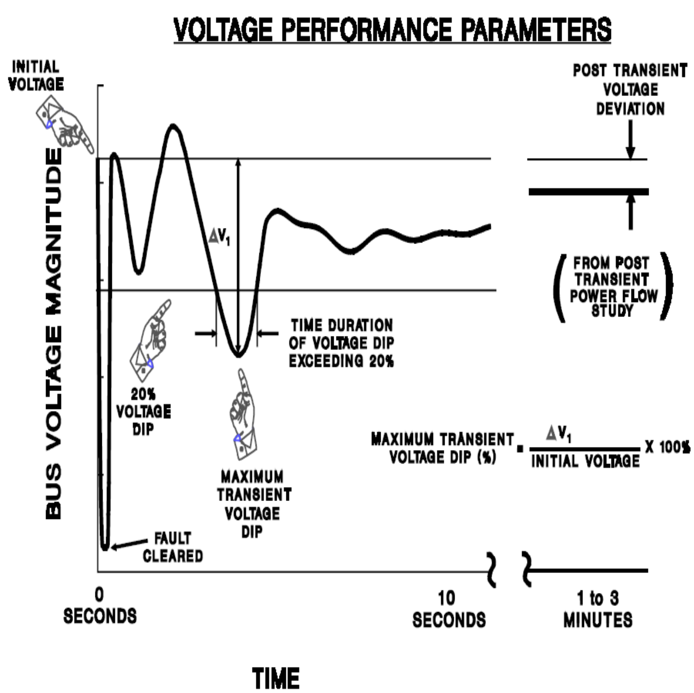
3.3 Transient Stability Analysis Guidelines

Transient stability studies will be performed to establish stability transfer limits and ensure system stability following a critical fault on the system and to facilitate the development of the dynamic voltage support requirements, if required.

- Machine Representation
    - For the stability analysis, resources consistent with the time period studied will be dispatched to meet the load requirements in the base cases. Representation of turbine generators will be consistent with available turbine generator data. The base case power system stabilizers that are normally in-service within the WECC system will be modeled for the Heavy Summer operating period studied. For new generator technologies that do not yet have specific representations, the study group will make reasonable assumptions and select the closest existing generator representation.
- Load Representation
    - Studies will be conducted with at least 20% of the total load represented in the WECC system as induction motor load.
- System Disturbances
    - All N-1 and credible N-2 system disturbances will be simulated.
- Fault Clearing Time
    - Faults on the transmission lines being evaluated will be cleared in accordance with guidelines provided by the facility owners.
- Under frequency Load-Shedding Simulated
    - The frequency will be monitored at key buses. If any stability run causes the frequency to drop sufficiently such that relays will "pick up", the under frequency load-shedding data will be reviewed and updated as necessary.
- Series Capacitors
    - Series capacitor modeling during transient conditions is indicated by the switching sequences.
- Unit Tripping
    - Unit tripping of other utility generation and pumping loads on under-frequency will be modeled in accordance with WECC guidelines or those provided by the appropriate facility owner.
- Generator Voltage Ride Through
    - Generator voltage ride through as per the WECC regional standard.
- Evidence of System Stability: The following WECC Disturbance-Performance criteria will be used:

WECC DISTURBANCE-PERFORMANCE TABLE OF ALLOWABLE EFFECTS ON OTHER SYSTEMS

NERC and WECC Categories	Outage Frequency Associated with the Performance Category (outage/year)	Transient Voltage Dip Standard	Minimum Transient Frequency Standard	Post Transient Voltage Deviation Standard (See Note 2)
A	Not Applicable	Nothing in addition to NERC		
B	≥ 0.33	Not to exceed **25%** at load buses or **30%** at non-load buses. Not to exceed **20% for more than 20 cycles** at load buses.	Not below **59.6** Hz for 6 cycles or more at a load bus.	Not to exceed **5%** at any bus.
C	0.033 – 0.33	Not to exceed **30%** at any bus. Not to exceed **20% for more than 40 cycles** at load buses.	Not below **59.0** Hz for 6 cycles or more at a load bus.	Not to exceed **10%** at any bus.
D	< 0.033	Nothing in addition to NERC		



3.4 Voltage Stability Analysis Guidelines

Post-transient studies will be performed to ensure the WECC Voltage Stability Criteria will be met following credible outages within the system. Certain contingencies may activate Remedial Action Schemes (RAS)/Special Protection Schemes (SPS) which will be included in the switching sequences as appropriate. The post-transient voltage deviations shall meet the WECC/NERC Planning Standards except for SCE area which allows 7% voltage drop for N-1 contingencies.

The following assumptions apply to post-transient voltage stability studies:

- All loads will be modeled as constant MVA during the first few minutes following an outage or disturbance.
- Remedial actions such as generator dropping, load shedding and blocking of automatic generation control (AGC) will be considered as appropriate.
- Shunt capacitors (132 MVAR) at Adelanto and Marketplace will be used if the post-transient voltage deviation exceeds 5% at those buses. Although modeled as shunt capacitors the actual devices are automatically controlled SVCs.
- Shunt capacitors in the SCE service area will be modeled according to the SCE Centralized Grid Capacitor Control to be provided by SCE.
- All automatic switching will be allowed if the switching action can be completed within the post-transient study time frame.

4 Input Assumptions

This section describes the key input assumptions to the Phase 2 study plan, including updates to the CTPG members' aggregate renewable energy planning target (net short), CTPG members' peak demands, and the new renewable generation portfolios and sensitivities to be studied.

4.1 Updates to the 2020 Renewable Energy Planning Target (Net Short)

In Phase 1, the CTPG identified the amount of renewable energy resource additions, "net short", that will be required between 2010 and 2020 to meet the 33% RPS goal for the state of California.[2] Further description of these assumptions is available in the CTPG Phase 1 study plan and final report. In Phase 2, CTPG is working with RETI to update estimates of other miscellaneous renewable resource additions and clarifying other differences in assumptions to update the net short estimates that will be applied to the renewable resource portfolios modeled in Phase 2. It is expected, this updated approach will have the effect of slightly reducing the renewable energy needed to meet RPS targets.

[2]In Phase 1, CTPG used the 2020 energy forecast of the CEC's 2009 Integrated Energy Policy Report (IEPR), which resulted in an estimated 289,697 GWh of retail load in the state of California subject to the state's renewable goal. Under that assumption, assuming a 33% RPS goal in year 2020, load serving entities would be required to obtain a total of 95,600 GWh of renewable energy in order to meet the target, of which approximately 53,605 GWh would be acquired from resources over and above existing and new renewables and other miscellaneous additions – the net short. This net short requirement is now being modified in Phase 2, as described in this section and shown in the third column of Table 2.

As of this writing, CTPG and RETI continue to clarify a few data points, but will complete this work by the start of the Phase 2 modeling phase. Table2 compares CTPG's Phase 1 study estimated renewable energy production and net short with the 2009 RETI Phase 2A calculation (which utilized a prior CEC demand forecast for 2020, and hence is higher than the more recent CEC forecast used for the CTPG estimate) and the preliminary updated 2010 RETI calculation that will be used in CTPG Phase 2. When the updated net short data is finalized, CTPG will complete this table and provide an explanation. Note that the energy and peak load numbers provided below reflect the CEC's projection of the impact of the California Solar Initiative (CSI), and other behind-the-meter distributed generation, on retail loads. To the extent any of CTPG's Phase 2 scenarios assume larger behind-the-meter impacts from distributed generation, or includes other in-front-of-the meter distributed generation, modeled loads in the power flow cases will be reduced accordingly.[3]

Table 2: CTPG 2020 Planning Target (Net Short)

	CTPG Phase 1 (GWh)	RETI Phase 2A (GWh)	RETI updated (GWh)
Forecast Retail Load subject to California's renewable goals:	289,697	301,974	
Renewable Portfolio Standard (RPS) Goal:	33%	33%	33%
Renewable Portfolio Standard (RPS) Energy Requirement:	**95,600**	**99,651**	
Existing and New Renewables expected to be on line by end of 2009:	39,324	36,807	
Miscellaneous renewable resource additions:	2,670	3,134	
	41,995	**39,941**	
Net Short:	**53,605**	**59,710**	**52,764****
Identified Renewable Resource Additions:	55,535	95,536*	
Total Renewable Energy Production:	**97,529**	**135,477***	
Identified Renewable Energy as a Fraction of Retail Sales:	**33.70%**	**44.9%***	

*For purposes of developing a conceptual transmission plan that addresses uncertainties in the location of renewable resource development, RETI Phase 2A planned for renewable resource additions equal to approximately 1.6 times the RETI Phase 2A net short.

** This is a provisional estimate provided by RETI.

4.2 Peak Demand

In Phase 1, CTPG used peak demand forecasts for "1-in-2" and "1-in-10" summer weather conditions in 2020 provided by the individual members. In Phase 2, the scenarios modeled will use the assignments to each area used in the CEC IEPR 2009 forecast for peak demands consistent with the assumptions of the CTPG renewable net short calculation.[4]

[3] As noted elsewhere in this document, distributed generation poses modeling challenges that will eventually need to be addressed. For now, CTPG intends to simply model distributed generation by reducing loads.
[4] Available at http://www.energy.ca.gov/2009publications/CEC-200-2009-012/CEC-200-2009-012-SF-REV.PDF

Table 3 provides the data from the CEC forecast for each area for the 1-in-2 and 1-in-10 year peak demand forecasts for year 2020.

Table 3: Year 2020 Peak Demand based on CEC 2009 forecast

Area	CEC PEAK DEMAND (MW)	
	1-in-2-year	1-in-10-year
SDG&E	5,157	5,673
LADWP BA	6,912	7,501
IID BA	1,256	1,354
SCE	26,875	29,240
PG&E	24,626	26,423
SMUD BA	5,196	5,679
TID BA	776	829
Total	**70,798**	**76,699**

4.3 Renewable Generation Portfolios

CTPG recognizes that there remains uncertainty about the renewable generation portfolios that will be realized in 2020 under the State's RPS. To address this uncertainty, CTPG will evaluate alternative renewable generation portfolios as a basis for determining the impact of those alternatives on the state-wide conceptual transmission plan. This section reviews the portfolio used in Phase 1 and then describes additional portfolios that will be examined in Phase 2. CTPG will consult further with stakeholders, RETI and state agencies to determine additional portfolios for consideration in Phase 3.

Review of CTPG Phase 1 Renewable Generation Portfolio

In Phase 1, load serving entities supplying the majority of California retail loads provided renewable procurement scenarios reflecting anticipated plans, installed capacity, and in some cases the expected renewable dispatch at time of peak. In other cases CTPG used generic factors to relate nameplate capacity to expected renewable dispatch for the hour of study (e.g., peak hour, off-peak hour). These generic factors were from RETI's CREZ- and technology-specific hourly/monthly renewable energy output profiles. These hourly/monthly output profiles were also employed to determine the annual capacity factors used to estimate CREZ- and technology-specific renewable energy generation in year 2020. Rooftop PV and other distribution-level generation were considered as a reduction to load.

The renewable procurement scenarios upon which CTPG's initial study work was based reflect a quantity and pattern of renewable resource development that is not the same as that used by RETI to develop its Phase 2A conceptual transmission plan.[5] The two portfolios are compared

[5] The RETI data was developed at the direction of the RETI Stakeholder Steering Committee and reflects: (1) RETI's Phase 2A identified renewable "net short," (2) the desire of utilizing, on a comparable basis, all of the identified CREZs to meet the "net short", and (3) the RETI Stakeholder Steering Committee's decision to adjust the RETI-identified economically feasible renewable resource development potential to approximate a 1.6 times the

in Table 4, below. In Phase 2A, RETI developed its estimates based on economically feasible renewable development potential, not on actual commercial interest in that potential. In contrast, the CTPG Phase 1 procurement plans – which to a significant degree are based on signed Power Purchase Agreements (PPAs) – suggest that the actual quantities, mix and location of renewable resource additions may be significantly different than what was developed by RETI.[6] Also, RETI considered out-of-state renewable resource development potential in British Columbia, Washington, Oregon, Nevada, Arizona and Baja. As is evident from the data collected by the CTPG, California load serving entities' plans include adding renewable resources located in Idaho and Montana.

Phase 2 -- Generation Interconnection Queue-based Portfolio

Phase 2 introduces a different form of commercially-based renewable portfolio, based on generation interconnection queues. As shown in Table 4, this portfolio is different both from CTPG Phase 1 and from RETI Phase 2A. Each new generation project seeking to inject power into a transmission system must go through an interconnection process. This section provides some background on generation interconnection to explain the selection of the renewable resources identified in this portfolio.

The interconnection process generally serves two central functions. First, it identifies the equipment additions and upgrades necessary to provide the new generation facility with the level of transmission service it has requested and to ensure that the addition of the new generation facility will not degrade or otherwise negatively impact system reliability. Second, the interconnection process allocates the cost responsibility for the infrastructure identified during the interconnection studies. In order to accomplish these functions in an orderly and non-discriminatory manner, transmission providers utilize an interconnection queue. The process culminates in the execution of an interconnection agreement that covers relevant items such as the construction schedule for transmission facilities and other operational requirements.

The rules and requirements governing the interconnection process, including the queue, are established by FERC for the California ISO as well as those municipal utilities that utilize the transmission service offered by the ISO and provide reciprocal transmission service to ISO utilities. In 2003, FERC required greater standardization for interconnecting generation facilities larger than 20 MW (called Large Generation Interconnection Procedures, or LGIP); while similar rules were established for generators below that size (Small Generation Interconnection Procedures, or SGIP).[7] As such, the ISO and many municipal utilities apply

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RETI "net short" quantity of renewable energy. According to RETI, this adjustment is a "success factor" adjustment. CTPG did not adjust or modify any of the reported RETI data. As described above, the CTPG renewable resource data was supplied by load serving members of the CTPG.

[6] Not all entities serving retail loads in California that are subject to California's renewable resource goals supplied renewable procurement plans to CTPG. CTPG's draft Phase 1 report lists those load serving entities that supplied renewable procurement plans to CTPG, and those that did not.

[7] Order No. 2003, 104 FERC ¶ 61,103 (2003) [18 CFR Part 35]. The ISO rules for large generation interconnection is in Appendix Y of the CAISO Tariff http://www.caiso.com/2495/2495959721820.pdf

interconnection procedures based upon these requirements, as well as subsequent modifications to facilitate the interconnection process.[8]

In response to stakeholder input, the Phase 2 commercial interest approach will utilize the renewable generation interconnection queues of CTPG members. The criteria that will be used for the CAISO queue will be to include project they are in the following stages in their interconnection process:

1. For Serial interconnection studies (LGIP and SGIP) – All renewable projects with all interconnection studies completed and that have either signed or are in process of signing their interconnection agreement.
2. All remaining renewable projects in the ISO Transition Cluster (after posting of financial securities).

These criteria were chosen both to limit the set of resources needed to achieve 33% RPS, and to focus on projects that are in the most advanced state of development or have otherwise demonstrated the highest financial commitment. For the CAISO queue, approximately 15,300 MW of resources are expected to be selected based on the above criteria. Phase 2 will also add the proposed renewable generation projects and associated transmission for renewable energy projects from the other CTPG planning entities (IID, LADWP, SMUD, TANC, and TID) to make up the balance of the 33% RPS. It is expected these projects will provide approximately 4700 MW of installed renewable capacity. The remainder of any needed capacity will be provided by imports. The projects are considered by the respective planning entities to be the most advanced in their respective approval processes. At this time the final list of projects and the corresponding installed capacity are being finalized and are not included in the table below. After the projects are finalized the table will be updated.

In order to provide the most accurate model for the Phase 2 studies, the CTPG will also include non-renewable generation projects from the interconnection queues that either under construction, have received CEC approval, or have signed PPAs. The list of non-renewable projects will also be included at a future date.

If the aggregate of the CAISO queue projects and the other state planning agency projects plus renewable imports[9] exceed the 33% RPS requirement, the CAISO queue projects will be scaled proportionally so that the aggregate with the other state planning entities' proposed projects will equal 33%. If the aggregate does not equal 33%, the CTPG will increase out-of-state imports to reach the 33% RPS.

[8] Generation projects in the ISO queue that have progressed through the system impact study or beyond under the serial approach are referred to as the Serial Group. Generation Projects assigned to the first cluster are referred to as the Transition Cluster and any projects received in subsequent clusters will be evaluated through a standard annual process.

[9] CTPG's Phase 2 studies will include scenarios that reflect (a) the out-of-state renewable resources modeled in Phase 1, (b) a high Northwest renewable import scenario (see below) and (c) a high Desert Southwest renewable import scenario (see below).

Table4: Comparison of Renewable Generation Portfolio for CTPG Phase 1, RETI Phase 2A and CTPG Phase 2 –Queue

	CTPG Phase 1		RETI Phase 2A*		CTPG Phase 2-Queue Portfolio		
Location (Region/CREZ)	Installed Capacity (MW)	Identified Annual Renewable Energy Production (GWh)	Maximum Potential Installed Capacity adjusted for success rate (MW)	Identified Potential Annual Renewable Energy Production adjusted for success rate (GWh)	Requested Capacity in CAISO LGIP/SGIP (MW)	Requested Capacity in Non-CAISO queues (MW)	Identified Annual Renewable Energy Production (GWh)
Alberta	0	0	0	0	TBD	TBD	TBD
British Columbia	0	0	340	1849	TBD	TBD	TBD
Washington	963	2594	0	0	TBD	TBD	TBD
Montana	413	1111	N/A	N/A	TBD	TBD	TBD
Idaho	130	350	N/A	N/A	TBD	TBD	TBD
Oregon	1637	4408	392	3062	TBD	TBD	TBD
Round Mountain-A	0	0	101	710	TBD	TBD	TBD
Round Mountain-B	78	319	49	196	TBD	TBD	TBD
Lassen North	873	2262	387	999	TBD	TBD	TBD
Lassen South	0	0	108	292	TBD	TBD	TBD
Montana	0	0	0	0	TBD	0	0
Wyoming	0	0	0	0	TBD	0	0
Colorado	0	0	0	0	TBD	0	0
Utah	0	0	0	0	TBD	0	0
Nevada N	0	0	115	822	TBD	TBD	TBD
Nevada C	239	1886	352	2624	TBD	TBD	TBD
Nevada S	217	502	N/A	N/A	TBD	TBD	TBD
Owens Valley	0	0	370	954	TBD	TBD	TBD
Inyokern	242	467	642	1669	TBD	TBD	TBD
Kramer	344	988	1693	4370	TBD	TBD	TBD
Mountain Pass	768	1777	438	1145	TBD	TBD	TBD
San Bernardino – Baker	825	1870	969	2299	TBD	TBD	TBD
Barstow	850	1985	617	1546	TBD	TBD	TBD
Pisgah	3248	7763	673	1658	TBD	TBD	TBD
San Bernardino – Lucerne	174	560	800	2150	TBD	TBD	TBD
Twenty-nine Palms	0	0	477	1219	TBD	TBD	TBD
Victorville	0	0	432	1128	TBD	TBD	TBD
Tehachapi	3868	10189	5514	15716	TBD	TBD	TBD
Fairmont	345	862	929	2734	TBD	TBD	TBD
Needles	0	0	122	313	TBD	TBD	TBD

	CTPG Phase 1		RETI Phase 2A*		CTPG Phase 2-Queue Portfolio		
Iron Mountain	0	0	1297	3065	TBD	TBD	TBD
West Texas	0	0	0	0	TBD	TBD	TBD
New Mexico	0	0	0	0	TBD	TBD	TBD
Arizona	333	740	0	0	TBD	TBD	TBD
Riverside East	1562	3471	2785	6725	TBD	TBD	TBD
Palm Springs	147	500	203	685	TBD	TBD	TBD
Imperial North-A	352	2775	1370	10626	TBD	TBD	TBD
Imperial North-B	*386*	*1843*	483	1190	TBD	TBD	TBD
Imperial South	*466*	*1091*	981	2420	TBD	TBD	TBD
Imperial East	15	43	429	1045	TBD	TBD	TBD
Baja-B (Santa Catarina)	0	0	2632	8931	TBD	TBD	TBD
Baja-A (La Rumorosa)	0	0	2368	8035	TBD	TBD	TBD
San Diego South	0	0	179	508	TBD	TBD	TBD
San Diego North Central	0	0	74	195	TBD	TBD	TBD
San Diego	23	171	N/A	N/A	TBD	TBD	TBD
Humboldt	11	82	N/A	N/A	TBD	TBD	TBD
Solano	408	1248	236	756	TBD	TBD	TBD
Cuyama	0	0	211	471	TBD	TBD	TBD
Carrizo North	0	0	422	896	TBD	TBD	TBD
Carrizo South	1545	3429	1024	2197	TBD	TBD	TBD
Santa Barbara	92	249	114	312	TBD	TBD	TBD
Total	**20553**	**55535**	**30327**	***95536***	TBD	TBD	TBD

* For purposes of developing a conceptual transmission plan that addresses uncertainties in the location of renewable resource development, RETI planned for renewable resource additions equal to approximately 1.6 times the RETI net short.

CTPG notes that the generation interconnection queues are continuously updated, as generators enter and leave the queue and as interconnection studies move forward. This means that updated studies will continue to be performed by the CTPG in future studies to reflect these changes and the effect on the state-wide transmission plan.

RETI-Based 33% RPS Portfolios

CTPG has committed to work with RETI to evaluate additional renewable generation portfolio scenarios. These portfolios are being developed by RETI and the CPUC jointly, building from earlier work by both entities. As of this writing, the expectation is that the RETI scenarios will not be available for Phase 2 and thus will be evaluated in CTPG Phase 3. However, this Phase 2 study plan will provide some initial description of how these scenarios are currently being developed. Based upon meetings with RETI, the CTPG understands that the proposed RETI scenarios will be constructed as described below.

In 2009, the CPUC created 4 alternative renewable portfolios for its jurisdictional entities under a 33% RPS, initially for purposes of conducting implementation analysis.[10] These portfolios were later adjusted to account for the CEC 2009 load forecast and used by the California ISO in statistical studies and production simulations to provide an initial estimate of 33% RPS operational requirements. In 2010, the CPUC, now in consultation with RETI, is further adjusting these portfolios to account for updated information on resource availability and cost, technology viability in the 2020 timeframe, environmental considerations, contracting status, and other factors. The objective is to establish a "discounted core" of new renewable resources that are considered to have a high likelihood of implementation and should therefore be included as a subset of all of the resource portfolios being modeled. Reasonable distributions of additional less certain renewable resource additions would then be added to this "discounted core" to construct several 33% RPS scenarios.

Other Renewable Generation Portfolios

The modeling of additional out of state renewables was an explicit concern of stakeholders. It is assumed that load serving entities will replace portions of their existing fossil out of state contracts with new renewable contracts, or that renewable energy will displace some fossil energy in current portfolios.

As currently proposed, Phase 2 will include two additional renewable resource scenarios that will include out of state renewable resources. These scenarios are the "Northern" scenario and a "Desert Southwest" scenario. It is expected that these two scenarios will allow identification of in-state transmission upgrades that would mitigate reliability criteria violations associated with access to large amounts of out-of-state resources or of resources that are presently outside of existing California Balancing Area Authorities.

The objective of the Northern resource scenario is be to identify transmission upgrades that will mitigate reliability criteria violations that may arise if the renewable resource mix for California was changed such that the renewable resources modeled in Northern California or north of California and committed to California load serving entities in Phase 1 were to change from 18% of total renewable resources to about 25% of total renewables. For this scenario the COI path flow will be approximately 4,800 MW and the Northern California hydro levels will be at approximately 60% of installed capacity prior to the addition of any renewable resources. In general the suggested amounts of additional renewables to be modeled in the proposed case are as follows:

- Pacific Northwest – 1,500 MW of wind connected to Malin/Captain Jack
- Northeastern California – 1,000 MW, 60% wind and 40% solar, (located in Lassen County)[11] assumed to be interconnected with the COI facilities at Round Mountain and/or Olinda

[10]California Public Utilities Commission (CPUC), "33% Renewables Portfolio Standard: Implementation Analysis Preliminary Results," June 2009. This report can be found at http://www.cpuc.ca.gov/NR/rdonlyres/1865C207-FEB5-43CF-99EB-A212B78467F6/0/33PercentRPSImplementationAnalysisInterimReport.pdf

[11]Based on projects located in Lassen County in the NV Energy interconnection queue as of January 12, 2010 (see attached) and on expressions of interest to the Lassen Municipal Utility District

- Northern Nevada – 1,000 MW, 60% wind and 40% geothermal,[12] assumed to be interconnected with the COI facilities at Round Mountain and/or Olinda

For the Northern resource scenario, in-state renewable resources in Southern California would be decremented to accommodate the additional Northern renewable resources. At this time, the resources to be decremented are being identified by the involved parties and will be provided at a later date.

The objective of the Southwest resource scenario is to identify transmission upgrades that will mitigate reliability criteria violations that may arise if the renewable resource mix for California was changed such that the out-of-state renewable resources modeled in the desert southwest and committed to California load serving entities in Phase 1 were to change from 2% of total renewable resources to about 5% of total renewable resources. In general, the suggested amounts of additional renewables to be modeled in the proposed case are as follows:

- Arizona – 750 MW of solar connected at Palo Verde, Southern Nevada – 750 MW of solar connected to El Dorado

For the Desert Southwest resource scenario, in state renewable resources in Southern California would be decremented to accommodate the additional Desert Southwest renewable resources. At this time, the resources to be decremented are being identified by the involved parties and will be provided at a later date.

Phase 3 of the CTPG study may address additional sensitivities regarding higher levels of renewable imports or specific new renewable configurations coming from out of state.

4.4 Renewable Generation Production Profiles

As noted above in Phase 1, CTPG used a combination of sources to establish production profiles for renewable resources. Based on the location of each CREZ, and the mix of renewable resources within each CREZ, CTPG members have developed estimates of the expected energy output of each CREZ for the specific study conditions assumed for the power flow cases. These estimates are based on actual hourly output data for similar technologies in similar locations.[13] In Phase 2, this information will continue to be used.

Wind and solar generation modeled in the studies are represented as fixed production profiles. There is no consideration given in the analysis to dispatch control of renewable resource output (i.e., generation re-dispatch as discussed for fossil units in Section 5.1.), as may ultimately be needed to mitigate over-generation, congestion or ramp constraints on the rest of the generation

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[12]Based on projects located in northern Nevada in the NV Energy interconnection queue as of January 12, 2010.
[13]For a review of the production assumptions for each CREZ by renewable technology, see California ISO, "2020 Renewable Transmission Conceptual Plan Based on Inputs from the RETI Process Study Results," September 15, 2009, available at http://www.caiso.com/242a/242ae729af70.pdf

fleet caused by variable renewable generation. Evaluation of renewable integration requirements will be completed separately by each planning entity.

5 Generation Re-Dispatch

As renewable generation production is increased, an equal amount of fossil fuel generation is required to be turned down (or decremented). Fossil fuel generation was selected for reduction because of economics. With renewable generation mandated to occupy 33% of the electricity energy market in California, fossil fuel generation must compete to remain in the market. The least efficient fossil fuel units will be the most likely to shut down by 2020. Phase 1 studies used heat rate as the basis for reduction priority with high heat rate units backing down first. Generally, the higher the heat rate the higher the cost to generate energy. The CTPG will continue utilizing this methodology in Phase 2.

Some fossil fuel generation because of their location (i.e. must run or local capacity requirement) may provide local benefits which can override economic considerations. Renewable integration during real time operations may also require more fossil fuel generation to remain on-line to address intermittency issues. Fossil fuel generation developed as peakers may also remain in the generation fleet though they typically have higher heat rates. Although these are significant elements in precisely predicting which particular set of generators will be shut down by 2020 but may not be critical in the determination of the transmission upgrades required to meet a 33% RPS. The location of the renewable generation rather than the corresponding decremented fossil fueled generation is the more significant factor in determining where reliability criteria violations are likely to occur and the transmission additions that will mitigate the violations.

Another re-dispatch method is based on minimizing the carbon footprint, i.e., turning down units with the highest carbon emissions per megawatt-hour. Obtaining timely emissions data for power plants throughout the WECC was not feasible for Phase 2 but may be considered in Phase 3. In additional, assigning an economic consequence to a generator carbon footprint would be speculative prior to the finalization of state and federal legislation and rule making. Though heat rate is a measure of efficiency, there is a correlation to green house gas emissions. For generators using the same fossil fuel, coal for example, the heat rate of similar vintage coal plants could also rank the amount of green house gas produced. A high heat rate would imply the burning of more fuel and therefore more emissions. This is only an approximation since the emission controls at a plant and the specific type of coal used can be significant factors in determining green house gas emissions. Reduction based on fossil fuel type can be a proxy for reduction by carbon footprint until more data is available.[14]

Although, Phase 2 will continue to primarily utilize the heat rate method to reduce fossil generation, select scenarios will also employ a fuel type and technology method to gauge the sensitivity of this particular method in changing the reliability criteria violations that are found

[14] We also note that stakeholders have proposed using a carbon tax to effect carbon reductions in the re-dispatch. One of the difficulties in this approach is deciding the level of the tax; to re-dispatch coal plants, such a tax would have to be sufficiently high. Nevertheless, this could be an alternative approach to emissions rates, although one that presumably would reach similar results.

and the transmission additions that mitigate such violations. The following provides a description of these methods.

1. Heat Rate. Fossil fuel generation is decremented in a merit-order fashion (least economic reduced first). This merit order was established through the use of heat rate data obtained from the WECC Transmission Expansion Planning & Policy Committee's (TEPPC's) 2017 economic database. Table5 shows an example of the fossil fuel generation decremented to offset the first block of renewable generation. This particular block is split 70/30 between units in California and those outside the state. Units in the block are decremented equally until all units in the block are turned off. Decrements below minimum output level are not allowed; i.e., the unit is turned off. Units in the next block are then reduced in the same fashion. Nuclear and hydro units are not decremented in the summer peak cases but may be reduced for the off peak cases.

Table 5: Fossil Generation Decrement Example - First Block

Internal (In California)			
Name	**Unit**	**Nameplate (MW)**	**FL H.R. (mmBtu/MWh)**
Mandalay	3	130	16.065
Ellwood	1	54	15.125
Olive	1	44	13.953
Long Beach	1	65	13.106
Long Beach	2	65	13.106
Long Beach	3	65	13.106
Long Beach	4	65	13.106
RAMCO OY	1	42	13.009
Grayson	8b	70	13.009
Goose	2	48	13.009
Lambie	1	48	13.009
	Total	**696 MW**	

External (Out of State)			
Name	**Unit**	**Nameplate (MW)**	**FL H.R. (mmBtu/MWh)**
Ocotillo GT1	1	56	14
Ocotillo GT2	1	56	14
Yucca CT1	1	19	14
Yucca CT2	1	19	14
WPhx GT1	1	56	14
WPhx GT2	1	56	14
Reeves	1	40	13.613
	Total	**302 MW**	

2. Fuel Type & Technology. This method is an approximation of reducing fossil fuel generation based on minimizing carbon emissions. This proxy method reduces generators based on fuel type & technology. First to re-dispatch will be coal followed by oil, gas and combined cycle units. Within each fuel type or technology the units with the highest heat rate is backed down first. Blocks of fossil fuel generation are decremented to offset renewable generation. Units in the block are decremented equally until all units in the block are turned off. Decrements below minimum output level are not allowed; i.e., the unit is turned off. Units in the next block are then reduced in the same fashion.

Phase 1 employed a 70/30 split for the reduction of fossil fuel generation located within California and units outside the state. Phase 2 will continue with this assumption for both the "Heat Rate" and "Fuel Type & Technology" methods. Phase 3 may investigate other proposed ratios for the in and out of state split for selected cases.

6 Methodology comparison to RETI

At the requested of stakeholders, the CTPG is including a discussion of the comparison of the CTPG methodologies to those used by RETI in their Phase 2A report. As noted in the prior CTPG study plans and reports, there are both similarities and differences between the CTPG and the RETI assumptions and methodology, as represented in its Phase 2A report. Also, as discussed above, the CTPG will continue to coordinate with RETI in refining to the CTPG planning assumptions and scenarios.

6.1 Transmission System Analysis

RETI used input from RETI participants, including CTPG members, to identify potential transmission upgrades. However, this input did not have the benefit of power flow and transient analysis. RETI performed a "generation shift factor" analysis to determine the transmission needs for their proposed renewable resource plan. The CTPG is performing power flow and transient analysis that is significantly more accurate at measuring the electric system performance and for determining transmission system needs.

6.2 Net Short and Input Assumptions

When comparing CTPG Phase 1 to the RETI Phase 2A, both RETI and CTPG have utilized CEC sources for the forecast of retail energy sales for the state. CTPG and RETI differ slightly in the estimates of expected renewable resources additions by the end of 2009. RETI Phase 2A also assumed that 160% of the renewable energy needed to achieve the 33% RPS should be modeled to account for potential uncertainties. RETI developed its estimates based on economically feasible renewable development potential, rather than an actual commercial interest in that potential. In addition RETI considered out-of-state renewable resource development potential in British Columbia, Washington, Oregon, Nevada, Arizona and Baja. As is evident from the data collected by the CTPG, California load serving entities' plans include adding renewable resources located in Idaho and Montana. As discussed below, Phase 2 introduces a different form of commercially-based renewable portfolio, namely, a portfolio based on generation interconnection queues.

The CTPG has instead identified sufficient renewable resources to achieve 33% RPS and then identified transmission elements that would mitigate identified reliability criteria violations with this amount of installed renewable generating capacity.

There is some overlap between the transmission additions included in the RETI Phase 2A conceptual transmission plan and those identified in CTPG's Phase 1 conceptual transmission plan (see the draft 2010 Phase 1 CTPG 2020 Study Report for a comparison table of RETI Phase 2A and CTPG Phase 1 transmission elements).[15] This results in a smaller set of transmission elements than identified by RETI. CTPG studies will continue to provide those comparisons.

More recently, as described above, CTPG has begun to work with RETI to identify other needed modeling assumptions, including RETI's views on the determination of the net short and the renewable resource portfolios to be modeled.

[15] Available at http://www.ctpg.us/public/images/stories/pdfs/2010_phase_1_ctpg_2020_study_report_011310.pdf