2010 Phase 2 CTPG 2020 Study Plan

Draft

January 29, 2010

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1 Executive Summary

The CTPG will complete the executive summary section prior to the final draft version.

2 Phase 2 Study Plan Overview

2.1 Objectives

The CTPG is committed to developing a California state-wide transmission plan to meet, by year 2020, the state's 33% renewable portfolio standard (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.

2.2 Scope

In addition to using elements of the Renewable Energy Transmission Initiative (RETI) conceptual transmission plan, the CTPG will develop a state-wide transmission plan using multiple renewable resource portfolios and generation re-dispatch scenarios from stakeholders to determine the transmission system improvements that are needed to support the state's 33% Renewable Portfolio Standard (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 to the respective entities responsible for each particular proposed transmission improvement to conduct a robust alternative analysis utilizing their own analysis assumptions and mitigation policies and practices similar to the analysis planned by the CAISO in its Renewable Energy Transmission Planning Process (RETPP).

The identification of transmission system improvements that may be required by an expected change in generation resources or the grid configuration starts with snapshot analysis of grid performance under forecasted 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". 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 high 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.

For Phase 1 the CTPG developed 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
- Case C: 2020 Normal Weather (50-50) development case
- Case L: 2020 Light Load (study is in-progress)

The Phase 2 analysis will focus on developing and assessing additional scenarios and assumptions through which a state wide transmission plan can be defined. It is important to note that while this analysis will focus on scenarios, the case assumptions used in the Phase 1 analysis can appropriately be applied in the Phase 2 analysis. As such, the Phase 1 base cases will be used as "seed" cases to develop all cases needed to complete the Phase 2 analysis. By testing a range of possible resource scenarios, in each phase across these same cases, the most accurate statewide transmission plan will be developed. As part of this process some adjustments are anticipated between phases. For Phase 2 the following adjustments are to be implemented:

- Remove the Green Path North project. LADWP has stated that this project will not be pursued.

- Relocate SCE wind resources at Barren Ridge to Windhub.

Cases A and B includes those transmission additions that are in the WECC 2019 Heavy Summer seed case as well as certain transmission elements that will mitigate reliability criteria violations that are identified assuming the interconnection of new renewable resources. Case C is intended to develop the first set of needed transmission elements to accommodate the interconnection of a controlled set of renewable resources under in a normal summer case. This set of transmission elements will facilitate the evaluation of the more stressed cases. Case L will assess the transmission needs that are required to mitigate reliability criteria violations that are identified with the addition of new renewable resources assuming light loads, such as winter evenings. The heavy and light load scenarios will capture a fairly broad range of renewable generation output patterns. This range includes high solar output coupled with low wind output and vice versa.

Case A incorporates forecasted Northern California adverse summer weather peak loads (90/10) for year 2020. Case A1 assumes that major upgrades are built including Midpoint-Devers-Valley, Tehachapi Segments 1-11, the Haskell Canyon upgrades, upgrades in the Owens Valley, and new substations and six network transmission lines in the southern Nevada-Los Angeles area corridor Case A2 assesses how much additional transmission is needed during a northern California 1-in-10 year peak to mitigate identified reliability criteria violations assuming 33% RPS goals are met but without stressing path flows. Case A2 may identify certain Category C reliability criteria violations and 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 operational measures (See Section 3.1

Reliability Criteria for discussion). It is important to note that Case A does not assess deliverability needs or off-peak conditions.

Case B incorporates forecast Southern California adverse summer weather peak loads (90/10) for year 2020. Case B1 assumes that major RETI upgrades are built including Midpoint-Devers-Valley, Tehachapi Segments 1-11, the Haskell Canyon upgrades, upgrades in the Owens Valley, and new substations and six network transmission lines in the southern Nevada-Los Angeles area corridor. Case B2 will assess the transmission improvements that are needed to mitigate reliability criteria violations that are identified for a southern California 1-in-10 year peak assuming 33% RPS goals are met but without stressing path flows. Case B2 also may identify certain Category C reliability criteria violations and 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 that Case B does not assess deliverability needs or off-peak conditions.

Case C represents a normal weather summer peak (50/50) for year 2020. Case C1 assumes that major RETI upgrades are built including Midpoint-Devers-Valley, Tehachapi Segments 1-11, the Haskell Canyon upgrades, upgrades in the Owens Valley, and new substations in the southern Nevada-Los Angeles corridor looped into existing transmission lines owned by LADWP and SCE. Case C2 is designed to assess the capability of the existing grid , including the upgrades included in Case C1 under normal peak load conditions to accommodate increased levels of renewable resource development without violating Category A and B reliability criteria. Case C2 may identifies certain Category C reliability criteria violations and further study will be 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 that case C does not assess deliverability needs or off-peak or highly stressed conditions. The grid capability determined in this development case is important as it provides a reference for additional cases and not an overall system assessment

The Studies Cases were 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 meet reliability criteria

Step 1: Add Renewable Projects

- Model renewable projects at 0 MW output
- Modify grid to provide CREZ connections
- Perform detailed contingency analysis to meet reliability criteria
- Add required projects from RETI conceptual transmission plan

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 needs that will mitigate identified reliability criteria violations

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.

2.3 Grid configuration

Like Phase 1, Phase 2 studies will be performed using 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.

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	Green Path North	

Upgrades with Key Regulatory Approvals and Environmental Permits	Upgrades without Key Regulatory Approvals and Environmental Permits	Upgrades Removed	
	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.		

3 General Guidelines and Criteria

CTPG conducted contingency-based power flow analysis for the cases described in the previous section. The General Electric Positive Sequence Load Flow program (GE-PSLF) was 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. However, the CTPG will not perform an alternative analysis for mitigating the need for a new or upgraded transmission line with protection control systems.. 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. Therefore, the CTPG will provide wire recommendations only.

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 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 (see further discussion in Section 9.1). This alternative analysis will be completed by the entity responsible for each particular proposed transmission improvement utilizing its own analysis assumptions.

These criteria provide a framework from which computer simulation studies were performed to model forecasted system conditions and evaluate the system performance. The following standards were 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 Specific Local Planning Criteria

3.2 Power Flow Contingency Analysis Guidelines

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

3.3 Transient Stability Analysis Guidelines

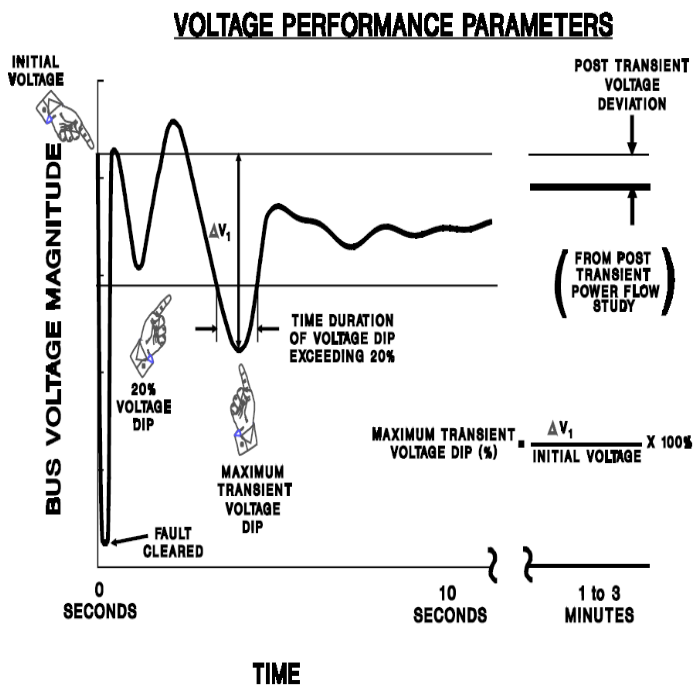
Transient stability studies were performed to establish stability transfer limits and ensure system stability following a critical fault on the system and to facilitate the development of the dynamic voltage support requirements, if required.

- Machine Representation

  - For the stability analysis, resources consistent with the time period studied were dispatched to meet the load requirements in the base cases. Representation of turbine generators was consistent with available turbine generator data. The base case power system stabilizers that are normally in-service within the WECC system were modeled for the Heavy Summer operating period studied. For new generator technologies that do not yet have specific representations, the study group made reasonable assumptions and selected the closest existing generator representation.
- Load Representation
  - Studies were 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 were simulated.
- Fault Clearing Time
  - Faults on the transmission lines being evaluated were cleared in accordance with guidelines provided by the facility owners.
- Under frequency Load-Shedding Simulated
  - The frequency was 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 was reviewed and updated as necessary.
- Series Capacitors
  - Series capacitor modeling during transient conditions is indicated by the attached switching sequences.
- Unit Tripping
  - Unit tripping of other utility generation and pumping loads on under-frequency were 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 were 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 were performed to ensure the WECC Voltage Stability Criteria was 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 were 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) were considered as appropriate.
- Shunt capacitors (132 MVAR) at Adelanto and Marketplace were 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 were modeled according to the SCE Centralized Grid Capacitor Control to be provided by SCE.
- All automatic switching was allowed if the switching action could be completed within the post-transient study time frame.

4 Input Assumptions

This section describes the 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, members of CTPG (that are responsible for supplying most of California's retail loads) provided the CTPG study team with their planned renewable resource additions to meet the 33% RPS planning target, known as the "net short" renewable requirement.[1] 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 miscellaneous renewable resource additions, clarify other differences in assumptions, and define updated net short estimates that will be applied to the renewable resource portfolios modeled in Phase 2. This updated approach has the effect of slightly reducing the renewable energy needed to meet RPS targets.

[1] As shown in Table 1, 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 1.

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. Table 1 compares CTPG's Phase 1 study estimated renewable energy production and net short with the 2009 RETI Phase 2A calculation and the 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.

Table 1: 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 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.[2] Table 2 provides the data from this forecast for each area for the 1-in-2 and 1-in-10 year peak demand forecasts for year 2020.

Table 2: Year 2020 Peak Demand based on CEC 2009 forecast

Area	PEAK DEMAND (MW)	
	1-in-2-year	1-in-10-year
SDG&E	5,157	5,673
LADWP	6,912	7,501
IID	1,256	1,354
SCE	26,875	29,240

[2] Available at http://www.energy.ca.gov/2009publications/CEC-200-2009-012/CEC-200-2009-012-SF-REV.PDF

Area	PEAK DEMAND (MW)	
	1-in-2-year	1-in-10-year
PG&E	24,626	26,423
SMUD	5,196	5,679
TID	776	829
Total	**69,099**	**74,975**

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, referred to as scenarios 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 RETI's Phase 2A conceptual transmission plan.[3] These procurement plans -- which to a significant degree are based on signed Power Purchase Agreements (PPAs) -- suggest

[3] 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 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.

that the actual quantities, mix and location of renewable resource additions may be significantly different than what was developed by RETI.[4] The procurement plans are also different from the renewable generation in the generation interconnection queues of the CTPG members and the California ISO that are proposed for study in Phase 2.

RETI developed its estimates based on economically feasible renewable development potential, not on 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 further commercially-based renewable portfolio, as reflected in generation interconnection queues.

Generation Interconnection Queue-based Portfolio

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).[5] As such, the ISO and many municipal utilities apply interconnection procedures based upon these requirements, as well as subsequent modifications to facilitate the interconnection process.[6]

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[4] Not all entities serving retail loads in California that are subject to California's renewable resource goals supplied renewable procurement plans to CTPG. **Error! Reference source not found.** lists those load serving entities that supplied renewable procurement plans to CTPG, and those that did not.

[5] 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

[6]. 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 Phase 2 commercial interest approach will utilize the renewable generation and the associated transmission in the CAISO queue, as long as 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).

Phase 2 will also add the proposed renewable generation projects and associated transmission that are in a similar status for the remainder of the planning entities in the state. Since these entities, have varying project approval processes, the CTPG will use this Phase 2 Draft Study Plan to obtain a recommendation on what the appropriate criteria that should be used for determining what projects should be aggregated with the CAISO queue projects.

If the aggregate of the CAISO queue projects and the other state planning agency projects plus assumed renewable imports exceed the 33% RPS requirement, the CAISO queue projects will be scaled proportionally so that the aggregate with the other state planning agency proposed projects will equal 33%. If the aggregate does not equal 33%, the CTPG will select projects from the CAISO queue or from the other state planning entities to be added to the scenario that are closest to the agreed upon criteria to reach the 33% RPS.

Table 3: 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)**	**Reqeusted Capacity in Non-CAISO queues**	**Identified Annual Renewable Energy Production (GWh)**
British Columbia	0	0	340	1849	0	TBD	TBD
Washington	963	2594	0	0	0	TBD	TBD
Montana	413	1111	N/A	N/A	0	TBD	TBD
Idaho	130	350	N/A	N/A	0	TBD	TBD
Oregon	1637	4408	392	3062	0	TBD	TBD

the Transition Cluster and any projects received in subsequent clusters will be evaluated through a standard annual process.

	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)**	**Reqeusted Capacity in Non-CAISO queues**	**Identified Annual Renewable Energy Production (GWh)**
Round Mountain-A	0	0	101	710	0	TBD	TBD
Round Mountain-B	78	319	49	196	102	TBD	TBD
Lassen North	873	2262	387	999	0	TBD	TBD
Lassen South	0	0	108	292	0	TBD	TBD
Nevada N	0	0	115	822	0	TBD	TBD
Nevada C	239	1886	352	2624	253	TBD	TBD
Nevada S	217	502	N/A	N/A	530	TBD	TBD
Owens Valley	0	0	370	954	0	TBD	TBD
Inyokern	242	467	642	1669	295	TBD	TBD
Kramer	344	988	1693	4370	250	TBD	TBD
Mountain Pass	768	1777	438	1145	714	TBD	TBD
San Bernardino – Baker	825	1870	969	2299	0	TBD	TBD
Barstow	850	1985	617	1546	0	TBD	TBD
Pisgah	3248	7763	673	1658	850	TBD	TBD
San Bernardino – Lucerne	174	560	800	2150	0	TBD	TBD
Twenty-nine Palms	0	0	477	1219	0	TBD	TBD
Victorville	0	0	432	1128	0	TBD	TBD
Tehachapi	3868	10189	5514	15716	4398	TBD	TBD
Fairmont	345	862	929	2734	0	TBD	TBD
Needles	0	0	122	313	0	TBD	TBD
Iron Mountain	0	0	1297	3065	0	TBD	TBD
Arizona	333	740	0	0	0	TBD	TBD
Riverside East	1562	3471	2785	6725	2750	TBD	TBD
Palm Springs	147	500	203	685	167	TBD	TBD
Imperial North-A	352	2775	1370	10626	0	TBD	TBD
Imperial North-B	*386*	*1843*	483	1190	0	TBD	TBD
Imperial South	*466*	*1091*	981	2420	825	TBD	TBD

	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)**	**Reqeusted Capacity in Non-CAISO queues**	**Identified Annual Renewable Energy Production (GWh)**
Imperial East	15	43	429	1045	290	TBD	TBD
Baja-B (Santa Catarina)	0	0	2632	8931	0	TBD	TBD
Baja-A (La Rumorosa)	0	0	2368	8035	0	TBD	TBD
San Diego South	0	0	179	508	1481	TBD	TBD
San Diego North Central	0	0	74	195	0	TBD	TBD
San Diego	23	171	N/A	N/A	99	TBD	TBD
Humboldt	11	82	N/A	N/A	64	TBD	TBD
Solano	408	1248	236	756	944	TBD	TBD
Cuyama	0	0	211	471	0	TBD	TBD
Carrizo North	0	0	422	896	882	TBD	TBD
Carrizo South	1545	3429	1024	2197	240	TBD	TBD
Santa Barbara	92	249	114	312	160	TBD	TBD
Total	**20553**	**55535**	**30327**	***95536***	15294	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.

RETI-Based 33% RPS Portfolios

CTPG has committed to work with RETI to evaluate additional renewable generation portfolios 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 some RETI scenarios will be available for Phase 2, although the data may be provided shortly after the study analysis begins. Depending on the when the necessary data is received will determine if the scenarios can be completed in Phase 2 or proceed in Phase 3.

The background to the scenario is as follows. Based upon meetings with RETI, the CTPG's has the following understanding of the proposed RETI scenarios. In 2009, the CPUC created 4 alternative renewable portfolios for its jurisdictional entities under a 33% RPS, initially for purposes of conducting implementation analysis.[7] 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 resources that is considered to have a high likelihood of implementation and that is thus included as a subset of all of the resource portfolios being modeled. Reasonable distributions of additional higher risk resources would then be added to this "discounted core" to achieve several 33% RPS scenarios.

Out of State Renewable Generation

The modeling of out of state renewables was an explicit concern of stakeholders. If it is assumed that load serving entities will replace some of their existing fossil out of state contracts with new renewable contracts, or that renewable energy will displace fossil energy in system import transactions.

Phase 2 will analyze two Out of State resource scenarios as proposed. They are a Northwest and a Southwest scenario which would address most in-state transmission needs to access out-of-state resources.

The objective of the Northwest resource scenario would be to assess the California transmission needs if the renewable resource mix for California was changed such that the renewable resources modeled in or being delivered into Northern California were to change from the 18% of total renewable resources that was assumed in the CTPG Phase 1 studies to about 25% of total renewables. In these studies the "pre-project" COI flows should be at approximately 4,800 MW and the Northern California hydro levels should be at about 60% of installed capacity. 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 delivered to Malin/Captain Jack
- Northeastern California – 1,000 MW, 60% wind and 40% solar, (located in Lassen County)[8] assumed to be interconnected with the COI facilities at Round Mountain and/or Olinda
- Northern Nevada – 1,000 MW, 60% wind and 40% geothermal,[9] assumed to be interconnected with the COI facilities at Round Mountain and/or Olinda

For the Northwest resource scenario, in state resources would be decremented as follows:

[7] 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

[8] 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

[9] Based on projects located in northern Nevada in the NV Energy interconnection queue as of January 12, 2010

- San Bernardino-Baker – 825 MW of solar
- Barstow – 850 MW of solar
- Pisgah – 1,725 MW of solar
- Kramer – 100 MW of solar

The objective of the Southwest resource scenario would be to assess the California transmission needs if the renewable resource mix for California was changed such that the renewable resources modeled in or being delivered into Southern California from the southwest were to change from the 2% of total renewable resources that was assumed in the CTPG Phase 1 studies to about 5% of total renewable. In general the suggested amounts of additional renewables to be modeled in the proposed case are as follows:

- Arizona – 750 MW of solar delivered through the Riverside East CREZSouthern Nevada – 750 MW of solar delivered through the Mountain Pass CREZ

For the Southwest resource scenario, in state resources would be decremented as follows:

- Pisgah – 1,500 MW of solar

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.

5 Generation Dispatch

(Note to reviewers: *We will have mitigation measures after Phase 2 as well; it is true they may get revised later*).

5.1 Fossil Fuel Generation Re-Dispatch

Renewable generation is ramped up requiring an equal amount of fossil fuel generation to be turned down. 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 among themselves to remain in the market. The least efficient fossil fuel units will be the most likely to be shut down by 2020. Phase 1 studies used heat rate as the basis for reduction priority with high heat rate units backing down first.

Some fossil fuel generation because of their location may provide local capacity benefits which may override economic considerations. Renewable integration during real time operations may also require more fossil fuel generation to remain on line to address intermittency issues (see discussion of operational issues in Section 9.1). Fossil fuel generation developed as peakers may also remain in the generation fleet though they typically have higher heat rates. 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 locations of the renewable generation and the corresponding decremented fossil fueled generation are the more significant factors in determining where reliability criteria violations are likely to occur and the transmission needs 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. 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.[10]

Phase 1 cases only considered a reduction priority based on heat rate. Phase 2 will also consider a reduction priority based on fuel type & technology. Phase 2 will primarily utilize the heat rate method to reduce fossil generation with select scenarios also employing the fuel type and technology method to gauge the sensitivity of this particular method in changing transmission needs. 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. Table 4 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 4: 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

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

Internal (In California)			
Name	**Unit**	**Nameplate (MW)**	**FL H.R. (mmBtu/MWh)**
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 reduce is 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. Nuclear and hydro units are not decremented in the summer peak cases.

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 the "Heat Rate" based back-down case but not for the "Fuel Type & Technology" based back-down case because there are no coal plants in California. but Phase 3 may investigate other sensitivity conditions for the "Heat Rate" based back-down scenario like 50/50 and 90/10 for selected cases.

6 Methodology comparison to RETI

The CTPG team is considering whether the purpose of this section is thoroughly addressed in the respective sections. Amendments will be made as necessary in the final draft version.