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Attachment 1

Planning Standards for System Resource Plans – Part II

Long-Term Renewable Resource Planning Standards

Long-Term Renewable Resource Planning Standards

I Introduction

I.1 2010 Long-Term Procurement Plan Proceeding

The Commission opened the 2010 Long-Term Procurement Plan (LTPP) proceeding with an Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans (OIR) on May 6, 2010. In that OIR, the Commission stated its intent "to continue our efforts to ensure a reliable and cost-effective electricity supply in California through integration and refinement of a comprehensive set of procurement policies, practices and procedures underlying long-term procurement plans. This is the forum in which we shall consider the Commission's electric resource procurement policies and programs and how to implement them."[1]

The 2010 LTPP is expected to consider new generation needs within the 2010-2020 planning term. The OIR laid out three tracks for the proceeding:

> "(1) **Track I** will identify California Public Utilities Commission (CPUC)-jurisdictional needs for new resources to meet system or local resource adequacy and to consider authorization of IOU procurement to meet that need, including issues related to long-term renewables planning and need for replacement generation infrastructure to eliminate reliance on power plants using once-through- cooling (OTC).
>
> "(2) **Track II** will address the development and approval of individual IOU "bundled" procurement plans consistent with §454.5.
>
> "(3) **Track III** will consider rule and policy changes related to the procurement process which were not resolved in R.08-02-007…"[2]

As noted in the OIR, the need to integrate renewables is anticipated to be one of the "primary drivers for any need for new resources identified in this proceeding."[3] With this report, Energy Division staff presents a proposal within Track I of the proceeding, for a set of inputs, assumptions, methodologies, and resulting scenarios to guide long-term renewables planning within the 2010 LTPP.

I.2 Background

Since Decision (D.) 05-07-039, the Commission has stated its intent to integrate long-term planning for renewables into the LTPP proceeding. D.05-07-039 states: "We will address the long-term plans filed in this proceeding in a subsequent decision. After that decision, we intend to return long-term RPS planning to the long term procurement planning component of R.04-

[1] Rulemaking (R.) 10-05-006, at p. 2.
[2] *Id.*, at p. 9.
[3] *Id.*, at p. 12.

04-003 or its successor, as contemplated by [Pub. Util. Code] § 399.14(a)."[4] In the Scoping Memo for the 2006 LTPP, the Commission stated that "The 2006 LTPPs will identify the key planning decisions that the utilities need to make in the next few years in order to ensure the Commission's energy policy objectives are maintained and pursued in the future, including moving on a path to achieve the EAP [Energy Action Plan] II goal of 33% renewables by 2020".[5] The utilities were specifically directed to include in their plans "information about the extent to which the IOUs [Investor Owned Utilities] will exceed the existing legislative mandate of 20% renewables by 2010 and work towards the EAP policy goal of 33% by 2020."[6]

In response to the 2006 Long-Term Procurement Plans filed by the IOUs, and recognizing the growing support for increasing the existing 20% by 2010 Renewables Portfolio Standard (RPS) to a standard of 33% by 2020, the Commission directed "parties to work with ED staff to refine a methodology for resource planning and analysis that will allow [the IOUs] to adequately address the issue of a 33% renewables target by 2020 in subsequent LTPPs ….We expect these sections to be much more robust in subsequent LTPPs and expect that parties will work to make RETI [Renewable Energy Transmission Initiative] useful in this regard."[7] In response to this direction, Energy Division staff worked with parties to the 2008 LTPP proceeding, R.08-02-007, and other stakeholders to assess implementation of a 33% RPS, considering various resource portfolios with which the state might achieve such a target, as well as the associated timing, costs, and risks.

In June 2009, Energy Division staff released its *33% RPS Implementation Analysis Preliminary Results*[8] report. A December 9, 2009 ACR in the 2008 LTPP confirmed that the study had responded to the Commission's direction to develop a methodology for considering a 33% renewables target within long-term procurement planning; stated that it exemplified the sort of system-wide "Renewables and Transmission Study" that parties had generally supported in the 2008 LTPP proceeding; and anticipated that staff would "refine the 33% RPS Implementation Analysis assumptions and methodology in an updated study, as a direct input to the 2010 system planning proceeding."[9] On December 9-10, 2009, Energy Division staff held a workshop to review party comments on the *33% RPS Implementation Analysis Preliminary Results* report and to consider the refinements that should be incorporated into an updated analysis for the 2010 LTPP.

I.3 Preliminary Process and Relationship to other Considerations in LTPP

On May 28, 2010, a Ruling in R.10-05-006 transmitted two Energy Division staff proposals related to the Track I system plans – *Standardized Load and Resources Tables for System Resource Plans*, and *Planning Standards for System Resource Plans* (similar documents for the Track II bundled plans were also released). The scenarios presented in this report are discussed in the May 28 Planning Standards proposal:

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[4] D.05-07-039, at p. 29.
[5] September 25, 2006 ACR/Scoping Memo, at p. 18
[6] *Id*., at p. 20
[7] D. 07-12-052, at p. 256.
[8] Available here: http://www.cpuc.ca.gov/NR/rdonlyres/1865C207-FEB5-43CF-99EB-A212B78467F6/0/33PercentRPSImplementationAnalysisInterimReport.pdf
[9] Assigned Commissioner's Ruling in R.08-02-007, December 3, 2009, p. 3

> "The Energy Division shall propose a minimum set of renewable generation scenarios in its draft report due in June 2010. In addition to comments on staff's proposed renewable scenarios, the IOUs or any other party may propose other scenarios the Commission should consider to achieve the goals of this proceeding. The Assigned Commissioner will determine a reasonable minimum set of resource planning scenarios in the Scoping Memo, based on initial proposals and parties' comments. The required scenarios shall be consistent with the guiding principles set forth in Section II."[10]

This staff proposal presents four "RPS scenarios", containing specific portfolios of generation and transmission resources with which the state might achieve a 33% RPS. These RPS scenarios, however, are only one set of many inputs and assumptions discussed in the Planning Standards proposal as critical to the LTPP's determination of need for new system resources.

Some of the "non-RPS" inputs to the LTPP, such as assumptions about the retirement of once-through-cooled plants and demand response forecasts, have little or no impact on the makeup of the RPS scenarios. Others, however, including forecasts of load and of "load modifiers" such as customer-side distributed generation (DG) and combined heat and power (CHP), affect the amount of renewable generation assumed necessary under a 33% RPS, by affecting retail sales. The Planning Standards document proposes and solicits party comment on these inputs, and a separate, more detailed report specifically on energy efficiency assumptions will be released as "Resource Planning Assumptions – Part 3" and discussed at a workshop later in June.

Any set of RPS scenarios that the Commission adopts for planning purposes in the Scoping Memo for this proceeding will be updated to be consistent with the final demand-side assumptions – or the final range of demand-side assumptions – also adopted in the Scoping Memo. The present draft staff proposal uses one set of demand-side assumptions, which are detailed in the "Resource Gap Calculation" section below. *These assumptions, however, are outside the scope of this staff proposal*, and parties concerned about the impact of demand-side assumptions on RPS planning should submit comments on the *Planning Standards for System Resource Plans* and the forthcoming *Resource Planning Assumptions – Part 3* documents. Comments on the present staff proposal should focus solely on supply-side considerations associated with the RPS scenarios.

II Methodology

II.1 Terminology – Scenarios, Sensitivities, Cases, Portfolios

This staff proposal relies on the terminology for scenarios, cases, etc., proposed in Energy Division's May 28, 2010 *Planning Standards for System Resource Plans* – with the important exception noted in the next section. Specifically, for the terms relevant to this report:

[10] *Administrative Law Judge's Initial Ruling on Procurement Planning Standards and Setting Schedule for Comments and Workshops*, May 28, 2010, Attachment 2, at p. 6.

Scenario – A possible future state of the world encompassing assumptions about policy requirements, market realities and resource development choices.

Portfolio – A set of electric resources, both supply-side and demand-side, that provides electric service to all system ratepayers, under a given scenario.

Resource Plan – A filing before the Commission containing information and analysis on all portfolios developed and evaluated, including complete documentation of each portfolio's performance under required evaluation criteria. The filing also submits a utility-preferred portfolio to the Commission for consideration and possible adoption and the rationale for its selection over other portfolios evaluated.

Case – A set of input assumptions and parameters (e.g., gas price, or electricity demand) under a given scenario that drives the selection of a given portfolio of resources.

Base Case – A set of input assumptions and parameters that represent the expected or most likely values for each scenario. All required scenarios shall have the same Base Case assumptions, whereas supplemental scenarios may consider alternative Base Case assumptions.

Sensitivity Analysis – A test to measure the change in output variable (e.g., cost, resource need) due to a change in input assumptions and parameters. Sensitivity analysis is conducted by changing one or more input assumptions from the Base Case to an alternative value.

II.2 Statewide Approach

The one exception to this report's consistent use of these terms is that the "portfolios" presented in this report contain resources providing electric service to all ratepayers statewide, rather than to just the "system" ratepayers of one or all of the three large IOUs.

The need for a statewide approach to the development of the draft 33% RPS scenarios is due to the nature of renewable resources. The highest-quality renewable resources are clustered in distinct geographic areas, and they are often transmission-constrained. In order to assure that multiple utilities – whether investor-owned or publicly-owned – do not count on the same transmission-constrained resource to meet their long-term RPS targets, a statewide approach is warranted. Such an approach can also serve to identify priority resource areas to which utilities might consider developing transmission lines that would benefit ratepayers both inside and outside the system operated by the California Independent System Operator (ISO).

In order to be useful for the IOUs' system plans, the statewide scenarios presented in this report will need to be disaggregated, with resources "allocated" to each IOU for planning purposes. A possible approach to this allocation is offered in Section IV, below, under Next Steps.

II.3 33% Resource Gap Calculation

This report provides estimates under 4 different scenarios of renewable generation developed in every year between 2010 and 2020, the end of the 2020 LTPP planning horizon. In order to calculate the need, or "RPS resource gap" in each year, assumptions must first be made about three inputs: existing/baseline generation, load, and load-modifying demand-side resources.

II.3.1 Baseline generation

Energy Division's consultant, Energy and Environmental Economics, Inc. (E3) relied on the California Energy Commission's 2008 Net System Power Report[11] for California utilities' claims of renewable energy deliveries in 2008. Because the 2009 Net System Power Report for 2009 is not yet available, E3 added to the 2008 list those renewable resources that came online in 2009 according the CPUC's records, yielding a figure that represent the total existing renewable generation contracted to or located in California as of 2009.

In order to project the RPS need in 2020, E3 also had to make assumptions about the RPS generation facilities that would either retire or roll off their contracts over the next several years. A number of the projects now under contact to California utilities have short-term contracts that expire before 2020. In the case that these are in-state resources, E3 has assumed that the contracts would be renewed such that those resources would continue to contribute to the target through 2020; for out-of-state resources, E3 has assumed that no re-contracting occurs and that the local jurisdiction repossesses the RECs associated with these resources before 2020. E3 has assumed no facility retirements over the course of the study period.

II.3.2 Load forecast

This analysis relies on the forecast developed by the California Energy Commission as part of the 2009 Integrated Energy Policy Report process[12] for estimates of statewide retail energy demand 2010-2020. See Appendix A for more detail.

II.3.3 Load-modifying demand-side assumptions

As discussed above, the Commission is currently considering the appropriate planning assumptions related to demand-side resources to use for planning in the 2010 LTPP. The Commission may direct the utilities to model, for example, a range of energy efficiency assumptions in their resource plans. For purposes of these draft scenarios, however, staff assumed state achievement of:

1.) The mid-case incremental energy efficiency estimates presented by the Energy Commission in its *Incremental Impacts of Energy Policy Initiatives Relative to the* 2009 Integrated Energy Policy Report *Adopted Demand Forecast.*[13] Staff scaled up the Energy Commission's estimates for IOU savings in order to estimate statewide – not only IOU – savings, by applying an assumed IOU:non-IOU ratio of 75:25. This scaling was performed only on the savings estimated from "2020 Incremental Uncommitted Impacts", and not on the "IOU Program Decay Replacement" savings.

2.) The customer-side DG assumptions embedded in the 2009 IEPR forecast. Because the load forecast already assumes a large amount of customer-side DG,

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[11] Nyberg, Michael, 2009. *2008 Net System Power Report*. California Energy Commission. CEC-200-2009-010.
[12] Kavalec, Chris and Tom Gorin, 2009. *California Energy Demand 2010-2020, Adopted Forecast*. California Energy Commission. CEC-200-2009-012-CMF.
[13] Electricity and Natural Gas Committee. *Incremental Impacts of Energy Policy Initiatives Relative to the* 2009 Integrated Energy Policy Report *Adopted Demand Forecast*. CEC-200-2009-001-CTF.

staff assumed no additional installments of customer-side DG within the planning horizon.

3.) An additional installment of 4,000 MW of CHP by 2020, with 50% serving on-site load. This assumption, and year-by-year MW build-outs, was developed by Energy Commission staff, relying in part on ICF International's recent *Combined Heat and Power Market Assessment* for the Energy Commission, and on the Air Resources Board's (ARB's) Assembly Bill 32 Scoping Plan. Energy Division Staff translated the Energy Commission's capacity estimates into energy estimates, using the ARB's Scoping Plan's assumption of a 92.2% capacity factor.

See Appendix A for more detail.

II.4 Portfolio Development Approach and Proposed Scenarios

II.4.1 Guiding Principles for RPS Scenario Development

At the December 10-11, 2009 workshop, staff proposed, and parties generally agreed, that the following principle should guide development of new 33% RPS scenarios. These principles are reflected in the draft proposed methodology and scenarios:

<u>Guiding Principles for development of Inputs, Assumptions and Methodologies:</u>

1.) Assumptions should reflect the behavior of market participants, to the extent possible

2.) Methodology should be consistent with previous regulatory decisions, to the extent applicable

3.) Any proposal should explain the policy basis for the proposal

4.) Any proposal must include supporting documentation

<u>Guiding Principles for development of RPS Scenarios:</u>

5.) RPS scenarios should be reasonably feasible and reflect plausible procurement strategies with associated (conceptual) transmission.

6.) RPS scenarios should represent substantially unique procurement strategies resulting in material changes to corresponding (fossil) procurement needs and/or required (conceptual) transmission.

7.) The number of RPS scenarios should be limited to 3-5

Although not explicitly listed in the guiding principles, transparency was also a primary goal for staff, and the attempt to bring transparency to the planning process drove key decisions related to methodology, as described below.

II.4.2 Inclusion of a "Discounted Core" of Contracted Projects

One weakness of the June 2009 *33% RPS Implementation Analysis* was that, for all scenarios except the "33% Reference Case", insufficient consideration was given to the thousands of MW of projects with which California's utilities have signed contracts since the beginning of the RPS program, but which are not yet delivering energy. In effect, the

"High Wind", "High DG" and "High Out-of-State" cases in that analysis were built on the assumption that utilities could either step out of many of the contracts they had signed to pursue a different procurement strategy, or that those resources would fail to develop in accordance with the contract specifications. While it is not realistic to assume that all of the projects contracted to utilities will deliver as contracted, the IOU contracts nevertheless represent the best information available about the state's potential renewable resource portfolios over the next 10 years.

Staff addresses this issue in the draft proposal via the identification of a "discounted core" of resources intended to represent the most viable of the projects with which IOUs have signed contracts. These projects are held constant across all scenarios, assuming that these projects are reliable under several different futures.

Staff proposes the use of entirely public information as criteria for choosing the discounted core. Although the Commission has access to confidential information about project development and viability, use of such information – or of subjective judgments about project viability that could harm an individual project's ability to secure financing – in order to determine inclusion in the discounted core would preclude the public release of the specific portfolios of resources in each scenario. Given the widespread interest in long-term planning for renewables and staff's desire that the scenarios be fully vetted by parties, staff determined that the benefits of transparency in this case outweighed the potentially small gains in accuracy that might be gained by using confidential information.

The criteria that staff proposes be used to determine inclusion in the discounted core are:

1.) a project must have a **signed power purchase agreement** (PPA) either under review or already approved by the Commission as of June 1, 2010; and

2.) the project must have its **major permit** (Application for Certification if under the jurisdiction of the Energy Commission; Conditional Use Permit in most other cases) filed with and deemed data adequate by the appropriate agency, as of March 1, 2010.

Staff also considered the use of other public, objective information about developers' project development and ownership experience, and past demonstration of a technology at the scale proposed. Although staff does not propose to use these criteria, the functionality to test the use of these criteria on the makeup of the discounted core remains in the tool developed by E3, for parties to consider.

Staff proposes to also include in the discounted core the full MW potential that would be developed under the wholesale solar PV programs proposed and approved by the Commission for Southern California Edison (SCE) and Pacific Gas and Electric (PG&E), and the program proposed and under review by the Commission for San Diego Gas & Electric (SDG&E). If successful, these programs would lead to the development of 1,052 MW of rooftop and ground-mounted PV programs under 20 MW, over the next 5 years. Although the programs are relatively un-tested, staff finds it reasonable to assume the goals will be met, given the large solar PV potential identified for this analysis, and the

increasing number of bids in RPS solicitations from projects less than 20 MW, and the high level of commercial interest in the utility programs.

II.4.3 Zone-based Approach

The approach to portfolio development used for this report is an updated version of that used in the 2009 33% Implementation Analysis. The approach draws heavily on the resource identification, cost assessment, environmental ratings and Competitive Renewable Energy Zone (CREZ) identification done by the Renewable Energy Transmission Initiative (RETI).[14] Using an updated version of the 33% RPS Calculator developed for last year's analysis, E3 builds 33% RPS portfolios in three main steps:

Step 1: Identify resources geographically as located in one of 41 CREZs; as a "non-CREZ" resource that will deliver energy to California; or as an out-of-state "REC" resource assumed to deliver energy into the local out-of-state market (detail in Section II.6);

Step 2: Rank resources based on cost, timing, environmental concern, and commercial interest (detail in Section II.8);

Step 3: For each CREZ, select resources into bundles according to transmission constraints:

Increment 1: Generation that can fit on the existing transmission system;
Increment 2: Generation that can be accommodated by minor upgrades;
Increments 3-6: Generation that can be accommodated by the addition of new generic transmission lines of various sizes;

Step 4: Select from among non-CREZ resources, CREZ "bundles", and RECs enough resources to meet the 33% target (Section II.6)

One major change to last year's approach is in the treatment of transmission, as described in Step 2. This approach is explained in more detail in Section II.6.3, below.

II.4.4 Proposed Scenario Definitions

A key finding of last year's *Implementation Analysis* was that the scenarios developed for that study – High Wind, High DG, High Out-of-State Delivered and a Reference Case weighted towards contracts signed and under negotiation –varied in their achievement of policy goals often attributed to the RPS program.[15] From a high-level, for example, the High DG scenario may perform better on market transformation, while the High Wind case performs better on cost, but no one scenario performed well across all policy objectives.

For this updated analysis, staff proposes 33% scenarios that are in fact defined by the policy objectives against which they are expected to perform best:

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[14] Information about RETI is available on the RETI website, http://www.energy.ca.gov/reti/.
[15] California Public Utilities Commission, *33% RPS Implementation Analysis: Preliminary Results*, June 2009, at p. 10.

1.) Cost-constrained Scenario;
2.) Time-constrained Scenario;
3.) Environmentally-constrained Scenario; and
4.) a Trajectory Scenario weighted heavily towards commercial contracts, thus representing the IOUs' current contracting/procurement trajectory

In order to develop these scenarios, staff and its consultants developed metrics for zones and distributed projects related to that project or zone's estimated cost, estimated online date, estimated high-level environmental concern, and commercial interest/contracting status. The development of each of these metrics is discussed in more detail in the following sections.

Of course, there is tremendous uncertainty around the future of renewable generation and the performance of any of these scenarios against the stated policy objectives. If the Commission adopts this set of scenarios for planning purposes in the 2010 LTPP Scoping Memo, it might direct the development, over the course of the 2010 LTPP process, of a "balanced scenario" that attempts to balance achievement of multiple objectives, drawing from the 4 scenarios. The Commission may also find that a particular authorization for new non-RPS generation would accommodate several of the RPS scenarios listed above, obviating the need to develop a specific "balanced RPS scenario" for purposes of procurement authorization.

II.5 Resource Potential, Cost, and Performance

II.5.1 Overview of Resource Potential

The RPS model includes estimates of resource potential for renewables throughout the WECC based on four sources:

1.) **Commercial Projects Database:** The Commercial Projects Database includes data on potential projects currently under some phase of development by California utilities and draws from two sources: the CPUC Energy Division (ED) Database for IOU solicitations and resource plans for POUs in California. The ED Database includes all of the renewable resources with pending or approved contracts as well as projects that have been shortlisted by the IOUs. Details on the projects with pending or approved contracts are available to the public through the CPUC and are included explicitly in the RPS model. A subset of these projects is distinguished as the "Discounted Core," as described above.

The database also includes IOU shortlisted projects, which are confidential and cannot be included in the public model individually; therefore, the RPS model includes aggregate info on these contracts when there are at least 3 projects of the same technology type in a single CREZ. This process is necessary in order to preserve the confidentiality of projects that have not yet begun the permitting process. The RPS model has also incorporated information on planned Publicly-Owned Utility (POU) procurement based on data gathered from the Energy Commission. This data is similar in format and treatment in the model to the non-

Discounted Core ED Database projects. Most of the projects included in this set of data are small and are unlikely to require major transmission upgrades, but several POUs have expressed interest in the development of resources in CREZ that might require new transmission.

2.) **RETI Phase 2B Database**: This database includes assessments of renewable resources in California within CREZ as well as estimates of out-of-state potential developed as part of the Western Renewable Energy Zone (WREZ) Transmission Model. The resource potential quantified in the WREZ model is based on an assessment of high-quality remote resources that could be developed with new transmission and is not a comprehensive assessment of out-of-state potential. In addition to resource potential, RETI provides cost and performance metrics for each of the sites considered in its analysis.

3.) **E3 Greenhouse Gas (GHG) Calculator:** E3 has used data that it developed on renewable resource potential throughout the Western Electricity Coordinating Council (WECC) as part of the GHG Calculator, to supplement the RETI Phase 2B data on out-of-state resources. The resource potential estimates in the GHG Calculator were developed using a wide range of sources including National Renewable Energy Laboratory, the US Energy Information Administration, the Alberta Electric System Operator and the British Columbia Hydro and Power Authority. E3 data were used to develop "local" renewable resource builds for each zone (resources constructed to meet local RPS targets in each region), and to develop resource bundles available for export to California from Colorado, Montana, and the Canadian provinces of British Columbia and Alberta.

4.) **E3/Black & Veatch Estimates of Statewide DG Potential:** As part of the 2010 LTPP, E3 and another CPUC consultant, Black & Veatch, have worked together to assess the resource potential, performance, and cost of distributed solar photovoltaic (PV) resources in the state of California. These latest estimates are included as candidate resources to meet California's RPS target.

Resources in the model are divided into two categories: those available for delivery to California, which include all in-state resources and out-of-state resources that would require new transmission; and those only available as unbundled Renewable Energy Credit (REC) purchases, which include all out-of-state resources that could be developed without major new transmission investments. The model thus incorporates the functionality to build up a renewable portfolio with a combination of delivered resources and REC-only transactions.

II.5.2 Resource Cost and Performance

The RPS model assumes that new renewable resources are developed under PPAs between an independent power producer (IPP) and a credit-worthy utility. The utility's cost of developing a resource is the PPA price, which is a function of three types of assumptions: resource costs, resource performance, and financing characteristics. Using

a detailed pro-forma model, the RPS model calculates a levelized cost of energy (LCOE) for each resource, which is used as the PPA price in the model.

For each resource type, cost assumptions are derived based on an average of the site-specific costs included in the RETI Phase 2B Database, supplemented with data from the E3 Capital Cost Tool for resource types not included in RETI. These costs, which include capital costs, fixed and variable operations and maintenance (O&M), and fuel, serve as a generic set of assumptions for the costs of renewable resources in California. Site-specific information is preserved for the RETI and WREZ resources, while average costs are applied to the in-state resources from the ED and POU databases. For out-of-state resources, the model includes regional cost multipliers that are used to adjust resource costs appropriately based on local costs of labor, construction, and materials.

A similar methodology is applied to determine the capacity factor for each resource: site-specific information is used where available (RETI and WREZ resources), while a generic average of the RETI projects is used for projects that do not have specific performance characteristics (ED and POU databases). The capacity factors for the wind resources in the GHG Calculator are based on the resource class, which is used to make adjustments from the generic capacity factor for those resources.

Table 1.

Technology	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)	Heat Rate (Btu/kWh)	Capacity Factor	LCOE ($/MWh)
Biogas - Landfill	$ 2,750	$ 130	$ -	12,070	80%	$ 92
Biogas - Other	$ 5,500	$ 165	$ -	13,200	80%	$ 121
Biomass	$ 4,522	$ 72	$ 17	14,800	85%	$ 106
Geothermal	$ 6,379	$ -	$ 38	-	81%	$ 148
Hydro - Small	$ 3,300	$ 25	$ -	-	35%	$ 161
Solar Thermal	$ 5,300	$ 66	$ -	-	27%	$ 202
Wind	$ 2,371	$ 60	$ -	-	33%	$ 95

Based on these cost and performance assumptions, the RPS model calculates a levelized cost of electricity using a pro-forma tool included with the model. In addition to cost and performance, the levelized cost depends upon the tax credits available to and financing assumptions used for a specific resource, both of which vary by resource type. In order to capture real-world financing activity in new renewable development, E3 has adjusted the fractions of debt and equity in each project so that the debt-service coverage ratio of the project is at least 1.4. Subject to this constraint, the levelized cost of energy is calculated for each renewable technology considered in the model and is used as the representative generic PPA price for that technology.

II.6 Transmission and Geographic Classification

II.6.1 Overview

As described above, the RPS model selects from among hundreds of candidate resources to meet the 33% target. Resources are first identified geographically as being located

either in one of the 41 CREZs, as a "non-CREZ" resource that will deliver energy to California, or as an out-of-state "REC" resource that is assumed to deliver energy into the local out-of-state market.

II.6.2 Geographic Classification

Resources are classified into three geographic categories:

1.) CREZ resources;

2.) non-CREZ resources; and

3.) out-of-state RECs.

Non-CREZ resources are resources that are not in an identified CREZ, but are located in California or directly across the border and assumed to deliver energy directly to California. These resources generally require transmission upgrades. Where there is specific information regarding the transmission upgrade costs, this information is included in the total delivered cost. Non-CREZ resources for which no specific information is available are assigned a "neutral" transmission upgrade cost calculated as an average of the upgrade costs for CREZ resources.

REC resources are resources that are located distant from California and would be scheduled over the western transmission grid. These resources may or may not schedule their energy to California. For pricing purposes, the resources are assumed to sell energy and capacity services into the wholesale energy market closest to the project location (e.g., the Mid-Columbia or Palo Verde markets). RECs are priced at the "Net Cost" or "Green Premium" discussed below in Section II.8.1: the resource's LCOE plus transmission and integration services minus the revenues earned through sale of energy and capacity services into the local market. E3 has assumed that the costs of integration will be captured in any REC contract and uses a flat adder of $7.50 per MWh for intermittent resources. The following tables show the energy and capacity revenues for each REC resource type in each state in the WECC. These values include the cost of firm, point-to-point service from the resource location to the nearest market hub. More detail about REC resource assumptions is available in Appendix B.

Table 2.

REC Resource Energy Value by State and Resource Type ($/MWh)							
	Biogas	Biomass	Geothermal	Hydro - Small	Solar PV	Solar Thermal	Wind
Alberta	$ 59	$ 59	$ 59	$ 59	n/a	n/a	$ 60
Arizona	$ 55	$ 55	$ 55	$ 55	$ 60	$ 62	$ 52
British Columbia	$ 47	$ 47	$ 47	$ 46	n/a	n/a	$ 49
Colorado	$ 51	$ 51	$ 51	$ 51	$ 57	$ 58	$ 49
Idaho	$ 55	$ 55	$ 55	$ 55	n/a	n/a	$ 53
Montana	$ 49	$ 49	$ 49	$ 48	n/a	n/a	$ 50
New Mexico	$ 50	$ 50	$ 50	$ 50	$ 55	$ 56	$ 48
Nevada	$ 53	$ 53	$ 53	$ 52	$ 56	$ 56	$ 52
Oregon	$ 55	$ 55	$ 55	$ 54	n/a	n/a	$ 55
Utah	$ 47	$ 47	$ 47	$ 46	$ 49	$ 49	$ 45
Washington	$ 55	$ 55	$ 55	$ 54	n/a	n/a	$ 55
Wyoming	$ 47	$ 47	$ 47	$ 46	n/a	n/a	$ 48

Table 3.

REC Resource Capacity Value by State and Resource Type ($/MWh)							
	Biogas	Biomass	Geothermal	Hydro - Small	Solar PV	Solar Thermal	Wind
Alberta	$ 21	$ 20	$ 21	$ 32	n/a	n/a	$ -
Arizona	$ 20	$ 19	$ 20	$ 30	$ 36	$ 47	$ -
British Columbia	$ 21	$ 20	$ 21	$ 32	n/a	n/a	$ -
Colorado	$ 21	$ 20	$ 21	$ 31	$ 38	$ 52	$ -
Idaho	$ 21	$ 19	$ 21	$ 31	n/a	n/a	$ -
Montana	$ 20	$ 19	$ 20	$ 30	n/a	n/a	$ -
New Mexico	$ 20	$ 19	$ 20	$ 30	$ 36	$ 46	$ -
Nevada	$ 24	$ 22	$ 24	$ 35	$ 43	$ 59	$ -
Oregon	$ 24	$ 22	$ 24	$ 35	n/a	n/a	$ -
Utah	$ 20	$ 19	$ 20	$ 30	$ 36	$ 46	$ -
Washington	$ 23	$ 22	$ 23	$ 34	n/a	n/a	$ -
Wyoming	$ 19	$ 18	$ 19	$ 28	n/a	n/a	$ -

We understand that REC-only transactions are not currently compliant with RPS rules. Utilities' RPS transactions must be bundled (energy plus RECs) and if the facility is not interconnected within California, then the energy must be delivered to California pursuant to the provisions in the CEC's RPS Eligibility Guidebook.[16] However, since the current Guidebook allows the energy from the RPS-eligible facility to be remarketed in an out-of-state market before it is delivered to California, the assumptions used in this analysis are not inconsistent with current RPS rules. These assumptions may not reflect what would be allowed under future RPS policies and law, as the Commission is currently considering petitions for modification of a stayed Decision that would authorize REC-only transactions, define bundled versus REC-only transactions, and set limits on the amount and the cost of REC-only transactions that could be used for RPS compliance. In addition, the delivery requirements at the Energy Commission are subject to change and the California Legislature is considering eligibility and delivery rules for RPS resources in a 33% RPS bill.

CREZ resources were identified principally through the RETI process; however, the commercial projects represented in the ED database have also been assigned to CREZs or identified as a non-CREZ resource by the contracting IOU and CPUC staff, based on stated project location. Resources that are located in CREZs are first assessed based on transmission availability.

The model uses the following CREZs:
Table 4.

[16] http://www.energy.ca.gov/2007publications/CEC-300-2007-006/CEC-300-2007-006-ED3-CMF.PDF

Resource Zone Name	Description or Source
Alberta	GHG Calculator Zone
Arizona	Combination of RETI and GHG Calculator Zone
Baja	RETI Competitive Renewable Energy Zone (CREZ)
Barstow	RETI CREZ
British Columbia	RETI CREZ
Carrizo North	RETI CREZ
Carrizo South	RETI CREZ
Colorado	Combination of RETI and GHG Calculator Zone
Cuyama	RETI CREZ
Fairmont	RETI CREZ
Imperial East	RETI CREZ
Imperial North	RETI CREZ
Imperial South	RETI CREZ
Inyokern	RETI CREZ
Iron Mountain	RETI CREZ
Kramer	RETI CREZ
Lassen North	RETI CREZ
Lassen South	RETI CREZ
Montana	Combination of RETI and GHG Calculator Zone
Mountain Pass	RETI CREZ
Nevada C	RETI CREZ
Nevada N	RETI CREZ
New Mexico	RETI CREZ
NonCREZ	Resources of all types in the CPUC ED Database or POU Database that are assumed to come online without substantial transmission upgrades
Northwest	RETI CREZ
Owens Valley	RETI CREZ
Palm Springs	RETI CREZ
Pisgah	RETI CREZ
Riverside East	RETI CREZ
Round Mountain	RETI CREZ
San Bernardino - Baker	RETI CREZ
San Bernardino - Lucerne	RETI CREZ
San Diego North Central	RETI CREZ
San Diego South	RETI CREZ
Santa Barbara	RETI CREZ
Solano	RETI CREZ
Tehachapi	RETI CREZ
Twentynine Palms	RETI CREZ
Utah-Southern Idaho	RETI CREZ
Victorville	RETI CREZ
Westlands	RETI CREZ
Wyoming	RETI CREZ

II.6.3 Transmission sizing for CREZ resources

Resources from any one CREZ compete to fill transmission bundles from that zone, in the following increments:

Increment 1: Generation that can fit on the existing transmission system;

Increment 2: Generation that can be accommodated by minor upgrades;

Increments 3-4: Generation that can be accommodated by the addition of new generic transmission lines of various sizes[17];

Estimates of capacity on existing transmission system, and with minor upgrades

The previous 33% RPS Implementation Analysis assumed that the existing transmission system could not accommodate any new generation, and that new major new transmission lines would be needed to access any CREZs. While staff and parties agreed that this was a weakness, staff did not have the expertise to make any other informed assumption.

For purpose of this new analysis, the ISO has provided high-level estimates, based on the results of interconnection studies, of the amount of new renewable generation from certain CREZ that could be accommodated on the existing transmission system, as well as the amount of incremental generation that could be accommodated by new, relatively minor and inexpensive upgrades.

The ISO numbers are high-level estimates, they are not available for CREZ in which there are not a number of interconnection requests, and they are not in any way a guarantee. Nonetheless, this addition is a significant improvement – the estimates are based on the ISO's recent experience with interconnection studies for the extraordinarily large amount of generation now moving through the ISO's interconnection process, and they may allow for a more realistic assessment of the cost as well as the timing of generation from several CREZ.

The assessment from the ISO is available in Appendix D.

Addition of new generic transmission lines

The size and cost of new generic transmission lines depends on the CREZ. Transmission lines from CREZs are sized on a case-by-case basis based on the total potential for resources within the zone and the distance between the CREZ and load centers. Generally, high voltage (500kV) lines are used to link zones that have large resource potential or that are very far from California loads (e.g. out-of-state lines), while lower voltage lines are assumed for smaller CREZs close to loads. The cost of each line is a function primarily of its length and capacity; the main components are the cost of the line itself, new substation costs, and right-of-way costs. E3 uses generic estimate of each of these types of cost to assign a total capital cost to each potential transmission line considered in the model.

[17] The maximum total capacity added by new transmission from any CREZ to California is 3,000 MW.

II.6.4 Consideration of RETI Conceptual Transmission Plan

Another source of information that has become available since the release of the June 2009 *Implementation Analysis* is the RETI Phase 2A Conceptual Statewide Plan,[18] finalized in September 2009 with the active participation and support of dozens of stakeholders, including the Commission. The Phase 2A plan represents an important contribution to statewide planning, particularly in its introduction of an objective methodology for considering the value of particular groups of transmission lines for accessing renewable energy, and a process and methodology for considering environmental concerns early in the process of transmission planning.

Energy Division's consultant, Zaininger Engineering Company, Inc. (ZECO), estimated the amount of new capacity that could be accommodated by the transmission segments identified by RETI. This assessment is included in Appendix D to this report. To date, staff and E3 have not incorporated the RETI assessment directly into the 33% modeling effort. Because the RETI line segments are tied to more than one CREZ, and vice versa – each CREZ is potentially dependent on several line segments – direct consideration of these lines in the 33% model is challenging. However, direct incorporation of the RETI information and attention to specific line segments would allow for more detail on the cost, timing, and environmental aspects of this assessment. We look forward to party comments and suggestions on this challenge.

II.7 Zone Timing Assessment

The 2009 *Implementation Analysis* presented a first-of-its-kind attempt to estimate whether the state could actually develop the generation and transmission infrastructure estimated as necessary under the 33% Reference Case, under 3 different "states of the world". Not surprisingly, the analysis found that it would be very difficult to build 24,000 MW of new generation and 11 major new transmission lines by 2020, given existing permitting and planning processes, risks around deployment of new technology, concerns about environmental impacts, and other factors. That report stated that this finding might be justification for considering procurement strategies that offered less timing risk, due to a decreased dependence on new transmission or other factors.

Because the ARB has identified a 33% renewable energy target as a key strategy for reducing GHG emissions, timing is a critical consideration. For this updated analysis, staff proposes that generation and transmission development timing be an explicit input into scenario development, and presents a "Time-Constrained Scenario" that is weighted towards those resources estimated to be available earliest.

II.7.1 Timeline Tool

The Commission's consultant, Black & Veatch, developed an Excel-based timeline tool to automate the timing considerations and methodology developed by Aspen Environmental Group (Aspen) and CPUC staff for the *Implementation Analysis*.

[18] http://www.energy.ca.gov/2009publications/RETI-1000-2009-001/RETI-1000-2009-001-F-REV2.PDF

The assumptions populating the tool – estimates about the time required to develop various types of generation and transmission resources – have changed very little since last year's analysis, given their basis in historical experience and general party support for last year's assumptions. We are interested in party comment, however, on whether these assumptions should be changed due to recent efforts by the Energy Commission and the Bureau of Land Management, for example, to streamline generation permitting, and by the ISO to reform its annual Transmission Planning Process to more explicitly account for transmission needed for renewables. Because many of these new efforts are in their early stages, it is difficult as of this writing to estimate their effect.

II.7.2 Incorporating "Timing" into Scenario Development

The process for incorporating timing into scenario development involved three steps: estimating the availability of individual *generation* projects, combining those generation timelines with transmission timing to create *zone* timelines, and creating timelines for entire *scenarios*, once the zones for each scenario had been chose.

Generation Timing

Each candidate generation project or resource, whether a non-CREZ or CREZ resource, was assigned an online date, based on expected commercial online date (COD) per a contract, or an estimated based project size and type, assuming that development started on 7/1/2010, and that *transmission was available*. Those assumptions are detailed below:

Table 5.

Project Type		Development Length (months) *excluding transmission*	Estimated Commercial Online Date
Biogas/Biomass	< 50 MW	62	2015
	> 50 MW	72	2016
Geothermal	< 50 MW	46	2014
	> 50 MW	64	2015
Small Hydro		46	2014
Solar Thermal	< 50 MW	58	2015
	> 50 MW	68	2016
Solar PV	< 50 MW	32	2013
	> 50 MW	36	2013
Wind	< 50 MW	34	2013
	> 50 MW	50	2014
ED Database projects			
– Filed/approved by CPUC (public)			- Per public contract information
– Under negotiation (confidential)			- Per generic estimates above

Projects from the ED Database that are still under development, but for which the public expected commercial online dates have already passed, were all assigned an online date of 6/1/2013. This rough date, which is earlier than the dates assigned to most generic projects above, is meant to reflect the uncertainty associated with projects that have

already missed expected deadlines, but the likelihood that the projects have already undertaken significant development activities.[19]

The 0.5-20 MW solar PV resources identified by E3 and B&V were assigned a different development schedule than other PV resources. Because this market segment is relatively new and very few of these wholesale distributed generation (WDG) projects have been developed, it is difficult to estimate how many MW could be available in each year before 2020. However, for purposes of this analysis, staff assume that the utility PV programs approved by the Commission for Southern California Edison (SCE) and Pacific Gas and Electric (PG&E), and the program proposed by San Diego Gas & Electric (SDG&E) that is now undergoing Commission review, each meet their program targets of 500, 500, and 52 MW, respectively, within 5 years. For the other generic resources identified by E3 and B&V, staff assumed that the full potential identified by E3 and B&V could be available by 2020. For the 0.5-20 MW "easier to interconnect" projects, staff assumed a smooth build-out 2014-2020 that would allow the realization of the full identified potential by 2020. For the remote, "harder to interconnect" projects that might require more upgrades to the transmission or distribution system, staff assumed a build-out that begins in 2015 and then accelerates until that potential is fully built-out in 2020. The resulting timing assumptions are detailed below:

Table 6.

	0.5-2 MW Roof available/year		**0.5-2 MW Ground**		**2-5 MW Ground**		**5-20 MW Ground**		**20 MW Remote**		**CUMULATIVE TOTAL**		
Year	IOU Programs*	Generic**	IOU Pro.	Generic	IOU Pro.	Generic	IOU Pro.	Generic	IOU Pro.	Generic	**IOU Pro.**	**Generic**	**TOTAL**
2011	105						105				**210**	**0**	**210**
2012	105						105				**421**	**0**	**421**
2013	105						105				**631**	**0**	**631**
2014	105	330		6		32	105	146			**842**	**515**	**1,357**
2015	105	330		6		32	105	146		500	**1,052**	**1,530**	**2,582**
2016		436		6		32		251		750	**1,052**	**3,005**	**4,057**
2017		436		6		32		251		1,000	**1,052**	**4,731**	**5,783**
2018		436		6		32		251		1,500	**1,052**	**6,956**	**8,008**
2019		436		6		32		251		2,000	**1,052**	**9,682**	**10,734**
2020		436		6		32		251		3,417	**1,052**	**13,824**	**14,876**
TOTAL	**527**	**2,838**	**0**	**42**	**0**	**227**	**525**	**1,550**	**0**	**9,167**			
* IOU program assumptions, based on program specifics approved or under review by the Commission:													
SCE: 100 MW/yr; 10% is 10 MW ground; 90% is 1-2 MW rooftop													
PG&E: 100 MW/yr; 5% is .5-2 MW rooftop; 95% is 1-20 MW ground													
SDG&E: 10.4 MW/yr; all 1-2 MW roof													
** Generic numbers assume that all of the MW potential identified by E3 and B&V is available by 2020, less the MW already counted under IOU programs or in the ED database (2 projects subtracted from the 0.5-2 MW Ground category;													

[19] The timing assessment is another area in which, when dealing with ED Database projects, staff faced a tradeoff between the use of transparent, public information and confidential information or subjective assessments that might present more realistic estimates of individual projects' online dates. Section II.4.2 discusses this tradeoff. Here, again, staff proposes to rely on objective, public information.

23 projects subtracted from the 5-20 MW Ground category)

Transmission and Zone Timing

Following the generation timing assessment, each CREZ "transmission bundle"– incremental MW accommodated by the existing system; MW accommodated by minor upgrades; and MW accommodated by major new transmission lines – was assigned an online date, based on the expected development horizon of the required transmission.

The timeline tool allows users to assign to each CREZ transmission increment one of 9 different transmission schedules, and to choose a development start date:

Table 7.

Transmission Schedule Type	Transmission Planning by CAISO/ POU/ WECC (months)	Project Description Prep by Utility	CEQA/ NEPA Review by CPUC/POU / Feds	Final Review and Approval by CPUC/ POU/Feds	Final Design and Construction by Utilities	Total
Existing / Distributed	0	0	0	0	0	0
Typical	18	12	24	4	24	82
Typical - Short	12	6	12	3	18	51
Typical - Long	24	18	24	4	30	100
Long-Distance	24	18	24	6	30	102
Tehachapi 1-3	0	0	0	0	0	0
Tehachapi 4-11	0	0	0	0	24	24
Sunrise	0	0	0	0	24	24
Devers - CO River	0	0	0	0	30	30

CREZs and transmission increments were assigned schedules and start dates as detailed below, with few exceptions as justified by public details about specific projects:

Table 8.

CREZ and Transmission Increment	Transmission Schedule Type	Development Start Date
Non-CREZ	Existing/Distributed	6/1/2010
CREZ – accommodated by existing system	Existing/Distributed	"
CREZ – accommodated by minor upgrades	Typical-Short	"
CREZ – 230 kV line, in-state	Typical-Short	"
CREZ – 500 kV line, in-state	Typical or Typical-Long, depending on location	6/1/2010 for up to 4500 MW of capacity; every 2 years thereafter
Out-of-state Resource	Long-Distance	"

The output of the timeline tool for each transmission increment within each CREZ – a single date for each – becomes an input to the 33% Calculator. In the calculator, then,

CREZ projects and non-CREZ projects can be compared to each other according to their expected online dates, allowing the creation of a "Time-Constrained Scenario" that chooses resources based on their expected availability by year.

No Assumed Lag between Transmission Completion and Generation Availability

It is important to note a change in one key assumption from the *Implementation Analysis*. Given the long time horizon associated with much of the candidate transmission development and increased state efforts to signal the market as to the location of priority resource areas, staff assumed that generation would develop concurrent with transmission such that an entire zone of generation would be available to the market upon completion of an enabling transmission line.

This assumption may be reasonable, as it appears somewhat reflective of current activity in the market – many renewable energy developers are investing millions of dollars prior to final assurance from transmission permitting agencies. It differs from the *33% RPS Implementation Analysis*, however, which assumed that the majority of generation would secure financing and begin development in earnest only when regulatory approval of the needed transmission appeared likely, defined for that analysis as one year before final approval from all agencies. Staff welcomes party comment as to whether the proposed revision to this assumption is realistic and appropriate.

II.8 Resource Ranking and Selection Methodology

II.8.1 Resource Scoring Metrics

The model's resource ranking algorithm uses four scoring metrics to compare resources, including cost, environmental, commercial, and timing scores. Each score, which is evaluated on a scale between 0 and 100, represents a characteristic of a candidate resource that may be used to better understand that project's likelihood of development. These four scores serve as the basis for the ranking process used to select resources and build scenarios.

Economic Score

The cost score is based on the Modified RETI Economic Ranking cost, which captures the "Green Premium" associated with a specific renewable resource: the net cost to California ratepayers of procuring an additional MWh of that resource. This ranking cost is based on the levelized cost of energy; transmission, interconnection, and integration costs; and the market value of energy and capacity associated with that resource:

+ Levelized Cost of Energy (PPA Price)
+ Interconnection Cost
+ Integration Cost
+ Transmission Cost
- T&D Avoided Costs
- Energy Value
- Capacity Value

= Modified Economic Ranking Cost

Each component of the Modified Economic Ranking Cost captures a part of the cost (or benefit) to California ratepayers to develop a specific resource:

1.) **Levelized Cost of Energy** is the sum of all direct costs (capital, fixed and variable O&M, fuel) required to construct and operate a plant of the specified type. All costs are amortized over the plant's lifetime, resulting in an average cost of generating electricity from that particular plant.

2.) **Interconnection Costs** are any costs associated with interconnecting into the grid; these costs were obtained directly from RETI.

3.) **Integration Costs** apply generally only to intermittent resources (wind and solar PV) and capture the increased costs of dispatching conventional generators and procuring sufficient ancillary services in order to integrate these renewable resources into the grid. E3 assumed a flat integration cost adder of $7.50/MWh.

4.) **Transmission Costs** capture the cost of any transmission developments required to deliver energy from the point of generation to load. For resources delivered over existing transmission, this cost is zero; if resources are developed along with a transmission upgrade or a new line, the cost of that new line is allocated to each unit of generation to reflect cost of developing transmission along with the resources. The cost of each potential transmission line is calculated using E3's Transmission Cost Calculator, which includes costs of the line itself ($/mile), the right-of-way cost ($/mile), and substation costs.

5.) **T&D Avoided Costs** apply to a small set of resources, most often distributed renewables. The development of distributed renewable resources can result in the deferral of transmission and distribution network upgrades, which results in a net benefit to ratepayers.

6.) **Energy Value** is the average value in wholesale markets that a specific resource would receive for its generation over the course of the year. This adjustment captures the varying value of generation at different points of the day; resources that produce a large fraction of energy during peak periods (e.g. solar) have a higher energy value than resources that produce energy during off-peak periods (e.g. wind). Energy value is calculated for each resource based on the resource's production profile and wholesale market prices in California over the course of the year.

7.) **Capacity Value** is the value to ratepayers of avoided investments in conventional capacity resources in order to maintain resource adequacy. Each renewable resource provides a certain amount of capacity in peak periods (dependent on the type of generation); this capacity results in avoided construction of new conventional units to meet peak loads. The capacity value of a resource is a function of its availability during peak load hours and the carrying cost of a combustion turbine, which E3 uses as a proxy for the cost of capacity.

The ranking cost for each resource is translated to a cost score by assigning scores of 0 and 100 to the resources with the lowest and highest ranking costs, respectively, and

using linear interpolation between the two extremes to evaluate scores for each of the other resources.

Environmental Score

As with the Implementation Analysis, this update attempts to take into account environmental concerns with an infrastructure development as potentially massive as that required to achieve a 33% RPS. Ongoing efforts, including the Desert Renewable Energy Conservation Plan (DRECP) and the Bureau of Land Management's Solar Programmatic Environmental Impact Statement (PEIS) are examining these factors in a scientific and rigorous way, and will provide direction to developers in coming months and years. In the absence of results from those efforts, however, Aspen and staff propose to update the 2009 methodology as described in detail in Appendix E, relying in part on information gleaned from the environmental review of several renewable generation facilities now requesting certification by the Energy Commission.

The proposed methodology continues to rely heavily on RETI's environmental ratings. Among the most significant changes, however, is that environmental scores are now specific to each pairing of location and resource type, reflecting the fact that environmental concerns and potential impacts on factors such as air quality and sensitive species will vary with both the choice of technology and the site of development. While not in any way intended or adequate to reflect project-specific environmental assessments, this methodology attempts to capture some of the risk and uncertainty that environmental concerns introduce into the project development process.

Commercial Score

The commercial score is used to distinguish those projects currently under contract, negotiation or development by IOUs and POUs, from the generic resources included in the model: the former is assigned a commercial score of 0 (a "better" score, for purposes of ranking), while the latter is assigned a commercial score of 100. This scoring distinction is included to allow for scenario analysis of compliance portfolios that rely to differing extents upon the resources already in the permitting process.

Timing Score (Online Date)

As described in Section II.7, timing scores were developed by the Commission to distinguish between projects that can be brought online within a relatively short timeframe from those that are unlikely to be developed soon due to expected delays or extensions in the generation and transmission development process. Distributed resources and resources that can be delivered over existing transmission perform better on the timing assessment, relative to resources requiring major new transmission lines.

II.8.2 Resource Ranking and Selection Methodology

Resource ranking and selection is carried out differently for each scenario. The model first calculates the cost, commercial, environmental and timing scores as discussed above based on user-defined inputs. It then calculates a weighted-average project score for each resource based on user-defined weights that sum to 100%. For example, if the user

selects 25% for each of the four metrics, the model will score resources evenly across the four metrics. If the user selects 85% for cost and 5% for commercial, environmental and timing, the model will select a resource mix based heavily on the cost metric. The following table lists the weights used for each Scenario:

Table 9.

Scenario	Cost Weight	Commercial Weight	Environmental Weight	Timing Weight
Trajectory	20%	60%	20%	0%
Cost-Constrained	100%	0%	0%	0%
Environmentally-Constrained	0%	0%	100%	0%
Time-Constrained	0%	0%	0%	100%

As discussed above, CREZ resources are ranked and selected first to make use of any existing available transmission capacity from a zone. Remaining resources in the zone are selected in increments to fill transmission bundles.

In the ranking, projects from the Discounted Core are always ranked higher than all other commercial and theoretical projects. Once capacity has been allocated (either on existing or new transmission) to all of the Discounted Core projects in a zone, capacity is allocated to commercial and generic projects. On existing transmission, the remaining commercial projects compete with theoretical projects based on their score; on potential new lines, the remaining commercial projects are ranked above all the theoretical projects. Thus, commercial projects (particularly the Discounted Core) are much more likely to be assigned to lower-cost transmission bundles than are generic projects.

After all of the commercial projects have been included, generic projects are selected to fill any remaining capacity created by the assumed transmission upgrades. Aggregate scores for each of the 4 metrics are then calculated for each CREZ bundle, and the bundles then compete against non-CREZ resources and RECs for inclusion in each 33% scenario.

III Results

This section presents draft portfolios along with the portfolio ranking metrics resulting from the modeling process described above. Each subsection presents the results of one of the four cases: Trajectory, Environmentally-constrained, Cost-constrained, and Time-constrained. Each includes a summary table that presents the portfolio scores, a series of tables that summarize the resources selected in various ways, and a chart showing a truncated "supply stack"—resources selected indicated by type, ranked from best to worst scenario score, along with the best-scoring resources that are not selected.

The results show that, as expected, each scenario scores best on the criterion that defines the policy goal for that scenario, e.g., the cost-constrained case has the lowest cost, the environmentally-constrained case the lowest environmental impact, the time-constrained case has the lowest time score, and the trajectory case has the most commercial interest.

III.1 Trajectory Scenario

Trajectory Case	Score	Rank
Cost Score	19	2
Environmental Score	26	2
Commercial Interest Score	0	1
Timing Score	57	4
Total Net Cost	$ 3,070	2

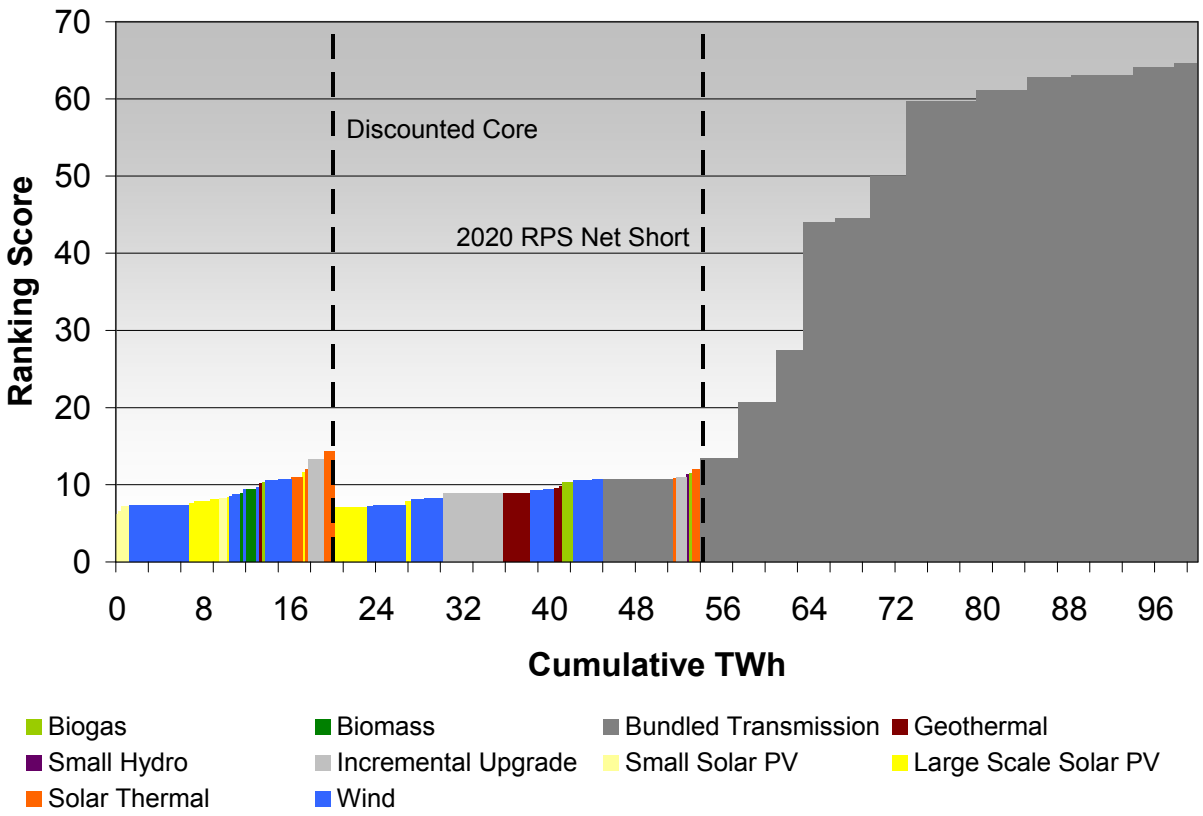
Delivery Type	GWh	MW
Existing Transmisssion	25,667	8,839
Minor Upgrades	7,786	2,025
New Corridors	6,606	1,593
Out-of-State RECs	14,201	5,201
Total	**54,259**	**17,659**

Project Status	GWh	MW
Discounted Core	22,395	8,494
Commercial Non-Core	31,753	9,114
Theoretical	112	51
Total	**54,259**	**17,659**

	All Resources (GWh)		
	In-State	Out-of-State	Total
Biogas	1,292	0	1,292
Biomass	938	250	1,188
Geothermal	10,564	864	11,428
Hydro	79	478	557
Large Scale Solar PV	7,897	864	8,760
Small Solar PV	2,027	0	2,027
Solar Thermal	4,232	935	5,167
Wind	13,029	10,810	23,839
Total	**40,059**	**14,201**	**54,259**
Out-of-State Share of 33% Target:		20%	

	All Resources (MW)		
	In-State	Out-of-State	Total
Biogas	184	0	184
Biomass	126	34	159
Geothermal	1,496	122	1,618
Hydro	26	156	182
Large Scale Solar PV	3,289	340	3,629
Small Solar PV	1,052	0	1,052
Solar Thermal	1,800	400	2,200
Wind	4,485	4,149	8,634
Total	**12,458**	**5,201**	**17,659**

	Resources Selected (GWh)	Commercial Interest Score (0-100)
Total (GWh and Average Score)	***54,259***	***0.21***
Arizona RECs	737	0.00
Riverside East	2,547	0.00
New Mexico RECs	238	0.00
Pisgah	218	0.00
Alberta RECs	2,422	0.00
Round Mountain	226	0.00
Palm Springs	222	0.00
NonCREZ	6,502	0.00
Nevada C RECs	1,415	0.00
Nevada N RECs	212	0.00
San Bernardino - Lucerne	170	0.00
Tehachapi	12,024	0.00
Distributed Solar - PG&E	970	0.00
Montana RECs	820	0.00
Imperial	11,903	0.00
Northwest RECs	5,742	0.00
Solano	878	0.00
Colorado RECs	1,301	0.00
Utah-Southern Idaho RECs	528	0.00
San Diego South	1,250	0.00
Distributed Solar - SCE	958	0.00
British Columbia RECs	442	0.00
Wyoming RECs	345	0.00
Distributed Solar - SDGE	99	0.00
Carrizo South	2,092	5.34



III.2 Environmentally-constrained Scenario

Environmental Case	Score	Rank
Cost Score	31	4
Environmental Score	18	1
Commercial Interest Score	56	3
Timing Score	52	3
Total Net Cost	$ 4,876	4

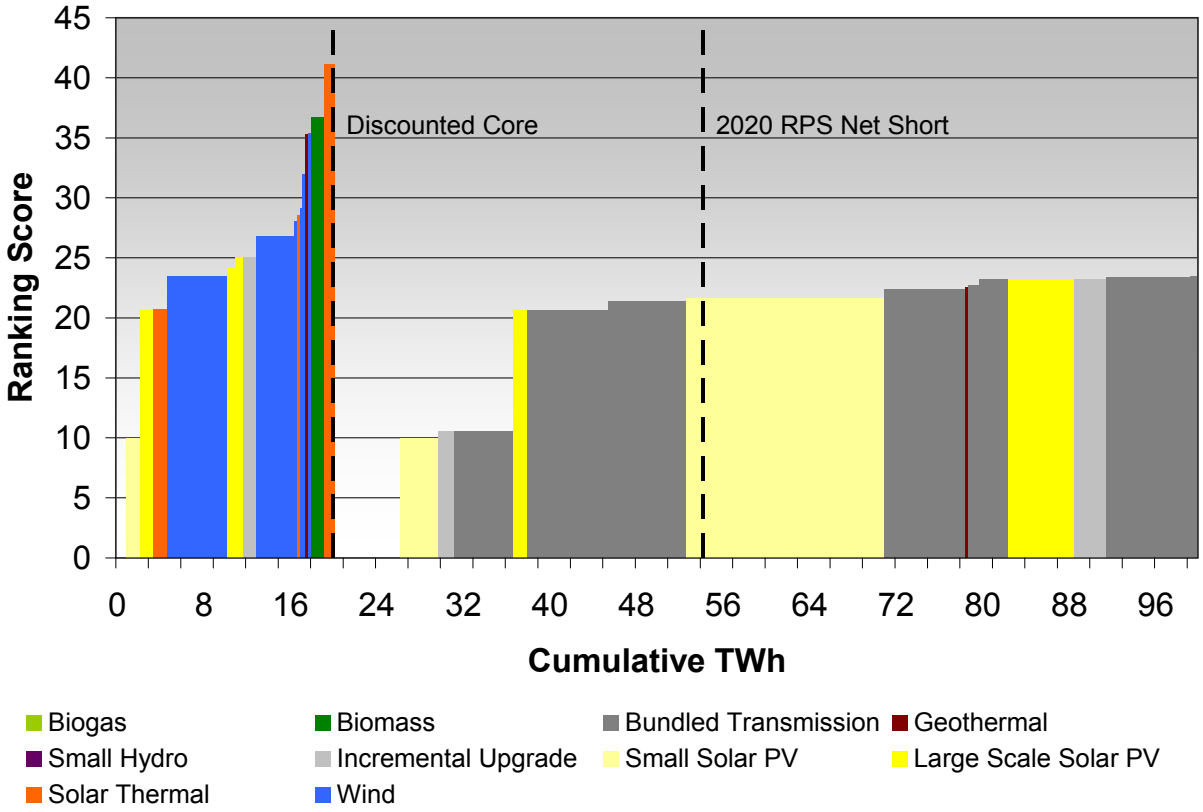
Delivery Type	GWh	MW
Existing Transmisssion	25,052	11,020
Minor Upgrades	3,046	1,400
New Corridors	20,296	8,666
Out-of-State RECs	5,865	2,256
Total	**54,259**	**23,342**

Delivery Type	GWh	MW
Existing Transmisssion	25,052	11,020
Minor Upgrades	3,046	1,400
New Corridors	20,296	8,666
Out-of-State RECs	5,865	2,256
Total	**54,259**	**23,342**

	All Resources (GWh)		
	In-State	Out-of-State	Total
Biogas	84	0	84
Biomass	938	238	1,176
Geothermal	0	212	212
Hydro	0	0	0
Large Scale Solar PV	22,701	864	23,564
Small Solar PV	13,112	0	13,112
Solar Thermal	5,474	935	6,409
Wind	6,085	3,616	9,701
Total	**48,394**	**5,865**	**54,259**
Out-of-State Share of 33% Target:		10%	

	All Resources (MW)		
	In-State	Out-of-State	Total
Biogas	12	0	12
Biomass	126	32	158
Geothermal	0	30	30
Hydro	0	0	0
Large Scale Solar PV	9,696	340	10,036
Small Solar PV	6,828	0	6,828
Solar Thermal	2,333	400	2,733
Wind	2,091	1,454	3,545
Total	**21,086**	**2,256**	**23,342**

	Resources Selected (GWh)	Environmental Score (0-100)
Total (GWh and Average Score)	***54,259***	***17.83***
Distributed Solar - Other	2,852	1.77
Distributed Solar - SDGE	785	3.62
Distributed Solar - SCE	4,596	4.54
Distributed Solar - PG&E	3,280	5.79
Westlands	7,163	10.53
Riverside East	11,192	20.65
Pisgah	7,260	21.22
Remote DG - SCE	348	21.62
Remote DG - Other	283	21.62
Remote DG - PG&E	929	21.62
Remote DG - SDGE	40	21.62
Tehachapi	5,516	23.46
Arizona RECs	737	24.10
Carrizo South	2,092	25.08
Alberta RECs	1,230	26.76
Northwest RECs	1,376	26.76
Montana RECs	820	26.76
Utah-Southern Idaho RECs	191	28.02
Palm Springs	222	29.14
San Bernardino - Lucerne	121	31.91
NonCREZ	1,333	33.71
San Diego South	156	34.08
Nevada N RECs	212	35.26
Round Mountain	226	35.37
New Mexico RECs	238	36.70
Nevada C RECs	1,062	40.79



III.3 Cost-constrained Scenario

Cost-Constrained Case	Score	Rank
Cost Score	16	1
Environmental Score	27	4
Commercial Interest Score	33	2
Timing Score	45	2
Total Net Cost	$ 2,515	1

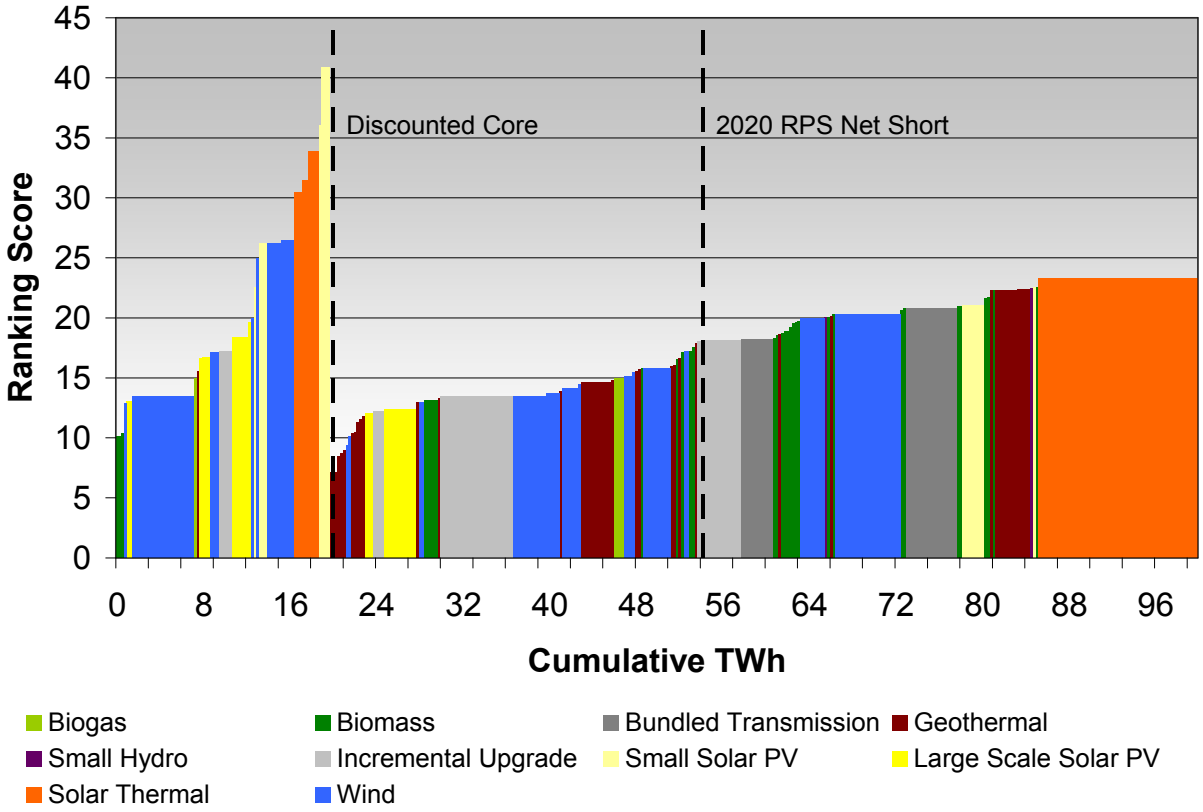
Project Status	GWh	MW
Discounted Core	21,213	8,073
Commercial Non-Core	15,153	4,529
Theoretical	17,894	3,503
Total	**54,259**	**16,105**

Delivery Type	GWh	MW
Existing Transmisssion	26,035	8,822
Minor Upgrades	9,282	2,083
New Corridors	0	0
Out-of-State RECs	18,942	5,200
Total	**54,259**	**16,105**

	All Resources (GWh)		
	In-State	Out-of-State	Total
Biogas	1,271	0	1,271
Biomass	938	2,812	3,750
Geothermal	8,617	5,022	13,639
Hydro	0	48	48
Large Scale Solar PV	7,454	864	8,317
Small Solar PV	2,027	0	2,027
Solar Thermal	2,202	935	3,137
Wind	12,808	9,262	22,070
Total	**35,317**	**18,942**	**54,259**
Out-of-State Share of 33% Target:		25%	

	All Resources (MW)		
	In-State	Out-of-State	Total
Biogas	181	0	181
Biomass	126	378	503
Geothermal	1,159	713	1,872
Hydro	0	16	16
Large Scale Solar PV	3,115	340	3,455
Small Solar PV	1,052	0	1,052
Solar Thermal	933	400	1,333
Wind	4,339	3,354	7,693
Total	**10,905**	**5,200**	**16,105**

	Resources Selected (GWh)	Average REC Cost ($/MWh)
Total (GWh and $Billions)	***54,259***	***$ 2,515***
Wyoming RECs	345	$ 27.29
New Mexico RECs	238	$ 29.27
Round Mountain	378	$ 31.45
Palm Springs	537	$ 33.46
British Columbia RECs	12	$ 35.12
Nevada N RECs	2,912	$ 35.33
Solano	995	$ 35.42
Tehachapi	12,216	$ 38.49
Imperial	6,733	$ 38.98
San Bernardino - Lucerne	785	$ 42.58
NonCREZ	5,557	$ 42.79
San Diego South	1,449	$ 43.16
Colorado RECs	3,705	$ 43.81
Carrizo South	2,092	$ 47.13
Arizona RECs	737	$ 48.61
Montana RECs	820	$ 49.73
Northwest RECs	5,543	$ 50.26
Nevada C RECs	2,873	$ 53.61
Utah-Southern Idaho RECs	528	$ 54.11
Riverside East	2,547	$ 73.69
Distributed Solar - PG&E	970	$ 75.59
Alberta RECs	1,230	$ 76.85
Distributed Solar - SCE	958	$ 102.41
Distributed Solar - SDGE	99	$ 113.67



III.4 Time-constrained Scenario

Time-Constrained Case	Score	Rank
Cost Score	20	3
Environmental Score	25	2
Commercial Interest Score	37	3
Timing Score	31	1
Total Net Cost	$ 3,084	3

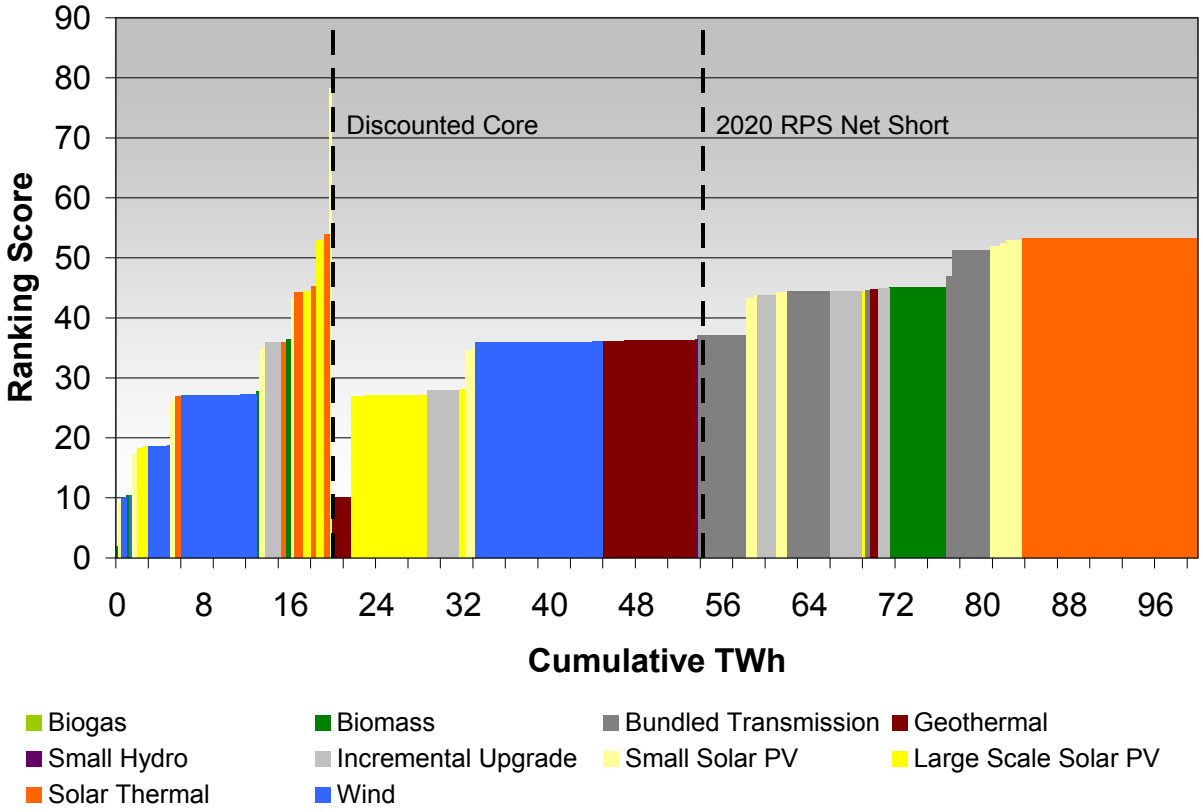
Delivery Type	GWh	MW
Existing Transmisssion	24,224	9,140
Minor Upgrades	4,338	1,725
New Corridors	0	0
Out-of-State RECs	25,697	9,079
Total	**54,259**	**19,944**

Project Status	GWh	MW
Discounted Core	21,103	8,035
Commercial Non-Core	13,192	4,572
Theoretical	19,964	7,336
Total	**54,259**	**19,944**

	All Resources (GWh)		
	In-State	Out-of-State	Total
Biogas	202	0	202
Biomass	938	238	1,176
Geothermal	2,048	3,363	5,412
Hydro	79	0	79
Large Scale Solar PV	13,515	864	14,378
Small Solar PV	3,076	0	3,076
Solar Thermal	2,202	935	3,137
Wind	6,502	20,297	26,799
Total	**28,562**	**25,697**	**54,259**
Out-of-State Share of 33% Target:		33%	

	All Resources (MW)		
	In-State	Out-of-State	Total
Biogas	29	0	29
Biomass	126	32	158
Geothermal	290	475	765
Hydro	26	0	26
Large Scale Solar PV	5,630	340	5,970
Small Solar PV	1,604	0	1,604
Solar Thermal	933	400	1,333
Wind	2,228	7,832	10,061
Total	**10,865**	**9,079**	**19,944**

Total (GWh and Average Score)	***54,259***	***30.86***
San Diego South	156	9.09
Round Mountain	226	9.09
NonCREZ	3,789	19.73
San Bernardino - Lucerne	710	22.62
Utah-Southern Idaho RECs	528	25.85
Palm Springs	537	27.03
Tehachapi	11,365	27.27
Imperial	2,945	28.15
Nevada N RECs	1,202	28.35
Montana RECs	1,923	28.61
Distributed Solar - PG&E	1,236	29.97
Alberta RECs	2,422	30.21
Distributed Solar - SDGE	173	31.16
Carrizo South	2,092	31.50
Distributed Solar - SCE	1,345	31.78
Northwest RECs	5,694	32.59
Riverside East	3,666	34.27
Wyoming RECs	345	36.36
New Mexico RECs	238	36.36
Colorado RECs	9,837	36.36
Distributed Solar - Other	322	36.37
Nevada C RECs	2,772	39.80
Arizona RECs	737	45.45



IV Next Steps

IV.1 Finalizing Demand-side Assumptions

As discussed in the Introduction, any set of RPS scenarios that the Commission adopts for planning purposes in the Scoping Memo for this proceeding will be updated to be consistent with the final set or range of demand-side assumptions adopted in the Scoping Memo. Changes in these demand-side assumptions could have an effect on the size and makeup of final RPS scenarios, separate from any changes to supply-side inputs and methodologies resulting from party comments on this staff proposal.

IV.2 IOU-Specific Allocations of RPS Portfolios

In order to provide direct input into the IOUs' 2010 Long-Term Procurement Plans, the scenarios in this report, or the updated versions of these scenarios, will need to be disaggregated, with resources "allocated" to each IOU for planning purposes. Staff proposes the following, relatively straightforward approach:

1.) Remove any POU resources from each portfolio;

2.) Allocate public ED database projects to the IOUs with which those projects have signed contracts (PUBLIC);

3.) Allocate confidential ED database projects to the IOUs with which those projects are negotiating contracts (CONFIDENTIAL);

4.) Allocate generic projects to load on a pro-rata basis for each resource type in each zone (PUBLIC);

5.) Aggregate each IOU's contracted, short-listed and generic project allocations to generate IOU-specific RPS portfolios (PUBLIC, provided the aggregation sufficiently masks the confidential data).

In practice, the allocation may not be entirely straightforward. The pro rata approach may result in commercially unlikely "project" configurations, for example, SDG&E has a particular commitment to procuring renewable energy from the Imperial Valley, and there may be other considerations. It will be important to keep in mind the overall purpose of this planning effort, which is not to *assign* particular renewable resources and obligations to any IOU, but to forecast reasonably foreseeable renewable generation development futures, for purposes of forecasting the need for new system generation within a reasonable range of error.

IV.3 Consideration of Integration Needs and Costs

The California ISO has been working for several months on a 33% RPS Operational Study that would estimate the need for resources and products such as generation ramping capability and regulation support, to manage the intermittency of the generation included in slightly updated versions of the *Implementation Analysis's* 33% RPS scenarios. Staff had hoped to have results from that study earlier this year, to update the integration cost assumptions used in this analysis. The study has been delayed, however, due to the complexity of the modeling and the questions it attempts to address.

Commission and ISO staffs are now consulting about the possibility that the model developed for that study could be introduced into the LTPP proceeding later this year and used, after vetting by parties, to estimate the integration needs and costs associated with the final RPS scenarios adopted in the Scoping Memo. Those results would then inform the Commission's consideration of the amount as well as the types of resources that might be authorized in the 2010 LTPP.

PG&E has developed its own tool for estimating the costs of integrating various portfolios of resources, called the Renewable Integration Model. Though not as analytically rigorous as the ISO's model, PG&E's tool is a simpler spreadsheet-based model that has the potential to be run with varied inputs by third parties. PG&E may also introduce this model into the LTPP proceeding, perhaps as a complement to the ISO's model.

Before formally considering either of the models above as an input to the 2010 LTPP, the Commission would provide parties with ample opportunity to vet the models, approaches, and possible application in the proceeding. Staff simply wanted to inform parties of the current status of this issue, given questions that have been raised.

IV.4 Consideration of Scenario Transmission Needs, and Coordination of Planning and Permitting

On May 13, 2010, the Commission signed a Memorandum of Understanding (MOU) with the California ISO, agreeing to certain aspects of the ISO's proposed Revised Transmission

Planning Process.[20] The MOU also committed to increased collaboration on resource and transmission planning and, as a direct result, transmission permitting. Specifically, the MOU included the following points:

> "2. In Phase 2 of the 2010-2011 cycle of the ISO transmission planning process, the ISO will consider and incorporate into its plan scenarios from the CPUC Long Term Procurement Plan process, to the maximum extent practical given the goal of identifying needed renewable access elements of the Phase 2 plan by December 2010. The CPUC will provide notice that Phase 2 of ISO transmission planning process will consider and incorporate these scenarios, and the subsequent CPUC siting/permitting process will then give substantial weight to project applications that are consistent with the ISO's final Phase 2 plan.
>
> "3. The CPUC and the ISO will review the results of the California Transmission Planning Group modeling phases and evaluate their implications for the transmission needs of the CPUC's Long Term Procurement Plan renewable resource scenarios. The ISO will subsequently seek, within the time and human resource constraints of Phase 2 of the transmission planning process, to provide the CPUC and other stakeholders with a formal assessment of the transmission planning needs within the ISO balancing authority area for the Long Term Procurement Plan renewable resource scenarios.
>
> "4. CPUC and ISO will determine a process for subsequent cycles of the ISO transmission planning process, by which the ISO will formally assess scenarios provided by the CPUC. Provided the CPUC meets parameters agreed to by both parties with regards to the number, timing, and format of the scenarios, the ISO will provide CPUC and other stakeholders with a formal assessment of the transmission planning needs within the ISO balancing authority area for the CPUC-provided renewable resource scenarios."

ISO and Commission staff will work in coming months to implement this MOU as it relates to the draft and final RPS scenarios. As highlighted by last year's *Implementation Analysis,* close coordination between resource planning, transmission planning, and transmission permitting is critical to achieving California's ambitious renewable energy goals.

[20] http://www.caiso.com/2799/2799bf542ee60.pdf

Appendix A

Load Forecast and Demand-Side Assumptions

A1: 2009 Integrated Energy Policy Report Demand Forecast

A2: Assumptions about Load-Modifying Demand-Side Resources

A1: 2009 Integrated Energy Policy Report Demand Forecast

The demand forecast used for this analysis can be found in Table 1.1c of the Energy Commission's California energy Demand 2010-2020, available here: http://www.energy.ca.gov/2009publications/CEC-200-2009-012/CEC-200-2009-012-CMF.PDF. To calculate RSP-obligated sales, E3 used "Total Statewide Retail Deliveries excluding pumping load", minus forecasted sales from small load-serving entities. Any load-serving entity with 2020 retail sales qualifies as a small LSE and is exempt from compliance with the RES; the LSEs that E3 included in that category are shown below:

Load Serving Entity	2020 Retail Sales (GWh)
City of Shasta Lake	193
City of Banning	184
Bear Valley Electric Service	176
Plumas-Sierra Rural Electric Cooperation	172
Truckee-Donner Public Utility District	163
Lassen Municipal Utility District	153
City of Lompoc	151
Boulder City/Parker Davis	137
City of Ukiah	133
Trinity Public Utility District	99
Surprise Valley Electrification Corporation	92
City of Healdsburg	76
City of Rancho Cucamonga	67
Moreno Valley Utilities	65
Anza Electric Cooperative, Inc.	62
City of Needles	58
Port of Oakland	54
City of Cerritos	48
City of Gridley	42
Victorville Municipal	32
Calaveras Public Power Agency	30
Tuolumne County Public Power Agency	29
City of Biggs	20
Port of Stockton	14
Valley Electric Association, Inc.	7
Mountain Utilities	4
Total	**2,260**

A2: Assumptions about Load-Modifying Demand-Side Resources

The assumptions described in Section II.3.3, above, result in the following reductions to the demand forecast referenced above:

Load Decrement (GWh)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
EE Decay replacement	169	313	488	693	913	1,093	1,254	1,391	1,504	1,598	1,684	1,769	1,861
EE Uncommitted - IOU	0	0	0	0	0	1,644	2,888	4,089	5,640	7,490	9,350	10,909	12,226
EE Uncommitted - Non-IOU	0	0	0	0	0	411	722	1,022	1,410	1,873	2,338	2,727	3,057
Incremental DG	0	0	0	0	0	0	0	0	0	0	0	0	0
CHP	0	382	765	1,147	1,529	1,911	2,294	3,278	4,262	5,246	6,230	7,214	8,198
Total	**169**	**695**	**1,253**	**1,840**	**2,442**	**5,059**	**7,158**	**9,780**	**12,816**	**16,206**	**19,602**	**22,619**	**25,342**

Appendix B

RPS Generation Resource Assumptions

B1: RPS Baseline: Existing Generation and Retirement Assumptions

B2: Planned Procurement by Publicly-Owned Utilities

B3: Energy Division Database

B4: Statewide Solar PV Resource Assessment

B5: Renewable Energy Transmission Initiative Phase 2B List of Resources

B6: Out-of-State Renewable Energy Credit Supply Estimates

B1: RPS Baseline – Existing Generation and Retirement Assumptions

	Energy (GWh)	Source
Total In-State Renewable Generation, 2008	28,804	*2008 Net System Power Report* (p.5)
Utilities Claims for Out-of-State Renewable Generation, 2008 (Northwest)	1,728	*2008 Net System Power Report* (p.A-2)
Utilities Claims for Out-of-State Renewable Generation, 2008 (Southwest)	740	*2008 Net System Power Report* (p.A-2)
Total Existing Renewable Generation, 2008	***31,272***	
New In-State Resources Online in 2009	992	ED Database
New Out-of-State Resources Online in 2009 with Long-Term Contracts	350	ED Database
Total Existing Renewable Generation, 2009	***32,613***	

B2: POU Data

Data on planned procurement of renewables has been gathered for a number of the larger POUs in California. This data was obtained from the California Energy Commission and gives POU renewable resource plans for 2010 and 2018; the data has been adjusted in order to incorporate it in to the RPS model, which uses 2008 and 2020 as its starting and ending points. The table below shows an overview of the distribution of POU planned procurement incremental to 2008 levels by resource type.

	In-State		Out-of-State	
	MW	GWh	MW	GWh
Biogas	145	1,013	-	-
Biomass	-	-	2	12
Geothermal	550	3,884	42	299
Hydro - Small	-	-	156	478
Solar Thermal	358	836	-	-
Solar PV	-	-	-	-
Wind	504	1,455	648	1,871
Total	***1,557***	***7,188***	***848***	***2,660***

B3: Energy Division Database

The Energy Division (ED) Database tracks the IOU solicitations for renewables and includes both CREZ and non-CREZ resources. The database includes both public projects that are in advanced stages of permitting and confidential shortlisted projects. A public list of the RPS contracts approved and under review by the Commission is available here: http://www.cpuc.ca.gov/NR/rdonlyres/A02EAAD2-7C72-4C3D-B4E5-92DEC4237672/0/RPS_Project_Status_Table_2010_June.XLS. The tables below show an overview of the distribution of the resources included in the RPS model from the ED Database.

CREZ	MW	GWh
Tehachapi	4,174	11,239
Northwest	1,805	4,137
Pisgah	1,700	3,974
NonCREZ	841	3,831
Imperial South	1,074	3,042
Riverside East	1,042	2,547
Alberta	886	2,422
Carrizo South	849	1,980
Mountain Pass	710	1,720
Nevada C	500	1,415
Colorado	420	1,301
San Diego South	415	1,293
Montana	300	820
Imperial North	109	770
Fairmont	296	752
Arizona	290	737
Solano	240	704
Kramer	250	584
Inyokern	242	566
Distributed Solar - PG&E	244	468
Distributed Solar - SCE	140	290
Round Mountain	86	281
New Mexico	32	238
Santa Barbara	83	238
Palm Springs	77	222
Nevada N	30	212
Imperial East	30	212
Utah-Southern Idaho	90	191
San Bernardino - Lucerne	49	170
Total	**17,003**	**46,357**

	Signed - Approved		Signed - Pending Approval		In Negotiations		*Total Projects Included in RES Calculator*	
	MW	GWh	MW	GWh	MW	GWh	*MW*	*GWh*
Biogas	21	144	19	135	-	-	***40***	***279***
Biomass	89	659	77	573	-	-	***166***	***1,232***
Geothermal	219	1,547	290	2,048	-	-	***509***	***3,595***
Hydro	-	-	26	79	-	-	***26***	***79***
Large Scale Solar PV	1,138	2,724	1,421	3,591	1,596	3,722	***4,155***	***10,037***
Small Solar PV	7	14	268	536	109	209	***384***	***758***
Solar Thermal	1,615	3,775	2,434	5,689	-	-	***4,049***	***9,464***
Wind	2,950	8,034	814	2,249	3,910	10,629	***7,675***	***20,911***
Total	***6,039***	***16,896***	***5,349***	***14,900***	***5,615***	***14,560***	***17,003***	***46,357***

B4: Statewide Solar PV Resource Assessment

The assessment of the solar PV resource potential was adjusted from the original 33% RPS Implementation Analysis approach. PV potential estimates were identified as 'Easy-to-connect' and 'Harder-to-connect' and were further broken down into 4 size categories (0.5 – 2 MW rooftop, 0.5 – 2 MW ground-mounted, 2 – 5 MW ground mounted, and 5 – 20 MW ground mounted) and 4 locations across California (Desert, Central Valley, North Coast, South Coast). The proprietary utility substation data and the large rooftop potential data from satellite imagery were screened for 'easy' interconnection, participation, and penetration. Existing PV programs including the California Solar Initiative (CSI), Self-Generation Incentive Program (SGIP) and other utility PV programs were accounted for. The table below shows the results of the solar PV resource assessment:

Hard-to-Interconnect	Easy-to-Interconnect				TOTAL
Ground Mounted (>30% of peak load)	Ground Mounted (<30% of peak load)	Large Rooftop	Small Rooftop	Easy-to-Interconnect Total	
9167	1728	3241	977	**5947**	**15113**

The solar PV assessment performed by E3 and Black & Veatch is available here, in PowerPoint form: http://www.cpuc.ca.gov/NR/rdonlyres/A0CBE958-E2C4-4AC7-9D56-3AB4D14D723D/0/BVE3PVAssessment.ppt.

B5: RETI Phase 2B list of resources

The list of RETI resources, costs, and other detail is available on the RETI website, http://www.energy.ca.gov/reti/documents/phase2B/CREZ_name_and_number.xls.

B6: Out-of-State REC Supply

The RPS model assumes that a subset of the out-of-state candidate resources is available to California for use as REC-only transactions. The potential out-of-state supply of RECs is constrained by several criteria. It is unlikely that any resource that would require significant new transmission would be developed for RECs alone. For this reason, the highest quality wind resources in each zone—which are generally also the most remote—are excluded from the potential supply of RECs. These remote, high-quality wind resources are available for development for delivery to California if a new transmission line from that zone to California is selected in the ranking process.

The supply of potential REC resources—especially wind—is further limited by the physical operating constraints of the grid. There is a limit to the amount of wind that an area can easily integrate before it begins to have major effects on market operations and integration costs increase substantially. As that limit is approached, it would become increasingly difficult to find a buyer for the energy produced, and the economics of a REC deal as the "green premium" as calculated in the model would no longer apply. E3 has roughly estimated this limit in each out-of-state resource zone by analyzing 2020 production simulations to determine the point at which wind would begin to displace baseload generators instead of intermediate gas generators; this gives a good approximation of the point at which market operations would shift dramatically. The capacity of wind resources that can be developed for REC only deals

for California is capped in each zone at half of the zone's limit reduced by existing installed capacity; these limits are shown in the table below. With these two constraints on supply, the final set of resources that is available as RECs for California is scored using the same methodology as candidate delivered resources. The REC resources then compete against transmission bundles and non-CREZ resources for selection in California's renewable portfolio.[21]

[21] See the discussion in Section II.6.2 on the relationship of these assumptions to current policy.

Appendix C

RPS Generation Cost Assumptions

C1: Project Characteristics and Cost Calculator spreadsheet
C2: E3 Capital Cost Tool
C3: PV Cost Calculator

For each renewable resource type included in the RPS model, E3 has developed cost and performance assumptions using data from several sources. E3's general approach in modeling is to use any site-specific public cost and performance information where it is available and to apply generic estimates to resources without site-specific data. The table below shows the source of the generic assumptions for each resource in the model.

Resource Type	Description or Source
Biogas	E3 Capital Cost Tool
Biomass	RETI Project Characteristics and Cost Calculator
Geothermal	RETI Project Characteristics and Cost Calculator
Hydro	E3 Capital Cost Tool
Large Scale Solar PV - Thin Film	PV Cost Calculator
Large Scale Solar PV - Tracking	PV Cost Calculator
Small Scale Solar PV	PV Cost Calculator
Solar Thermal	RETI Project Characteristics and Cost Calculator
Wind	RETI Project Characteristics and Cost Calculator

C1: Project Characteristics and Cost Calculator spreadsheet

RETI maintains the Project Characteristics and Cost Calculator spreadsheet[22], a detailed database with site-specific data on resource potential, cost, and performance in California and similar data for the out-of-state zones in the WECC based on data developed as part of the WREZ transmission modeling efforts. E3 has incorporated each of these individual resources, along with site-specific information on costs (capital, fixed and variable O&M, gen-tie, fuel) and performance (heat rate, capacity factor, on-peak availability) into the RPS model. In addition, E3 uses the Project Characteristics and Cost Calculator to develop generic assumptions for the renewable technologies included in the RPS model that do not have site-specific information from RETI. E3's generic cost and performance assumptions, below, are based on averages of the data in the RETI spreadsheet.

Technology	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)	Heat Rate (Btu/kWh)	Capacity Factor	LCOE ($/MWh)
Biogas - Landfill	$ 2,750	$ 130	$ -	12,070	80%	$ 92
Biogas - Other	$ 5,500	$ 165	$ -	13,200	80%	$ 121
Biomass	$ 4,522	$ 72	$ 17	14,800	85%	$ 106
Geothermal	$ 6,379	$ -	$ 38	-	81%	$ 148
Hydro - Small	$ 3,300	$ 25	$ -	-	35%	$ 161
Solar Thermal	$ 5,300	$ 66	$ -	-	27%	$ 202
Wind	$ 2,371	$ 60	$ -	-	33%	$ 95

[22] The RETI Project Characteristics and Cost Calculator can be found here: http://www.energy.ca.gov/reti/documents/phase2B/CREZ_name_and_number.xls

C2: E3 Capital Cost Tool

The E3 Capital Cost Tool was developed in collaboration with WECC's Transmission Expansion Planning Policy Committee (TEPPC) in order to facilitate further analysis of TEPPC's studies of WECC-wide transmission development. The tool contains generic assumptions for a wide range of resources; E3 consulted a large number of sources in the development of these estimates. The tool is used to inform the RPS model's assumptions for resources that are not included in the scope of the RETI analysis; for these resource types, cost and performance information was taken directly from the E3 Capital Cost Tool. The RPS Model also uses the regional multipliers developed in the tool in order to translate generic costs for the WECC into region-specific costs, which vary based on local costs of labor, materials, and construction.

The E3 Capital Cost Tool is available for public download via TEPPC: http://www.wecc.biz/committees/BOD/TEPPC/Shared%20Documents/E3%20Capital%20Cost%20Tool/E3_TEPPC_ProForma_2010-01-17.xls.

C3: PV Cost Calculator

The PV cost calculator tool was developed to accurately calculate the levelized cost of solar PV projects. The financial modeling behind the tool includes features to balance complexity with applicability for a broad range of projects. The PV cost and performance assumptions were developed as a joint effort by E3 and Black and Veatch.

The assumptions and key results of the cost calculator are detailed here: http://www.cpuc.ca.gov/NR/rdonlyres/A0CBE958-E2C4-4AC7-9D56-3AB4D14D723D/0/BVE3PVAssessment.ppt.

The cost calculator is available here: http://www.cpuc.ca.gov/NR/rdonlyres/A52A5A3E-F737-49E1-A4D5-E81ED68F3E41/0/FinalPVProForma.xls.

Appendix D

Transmission Assumptions

D1: California ISO assessment of capacity on existing transmission system, and with minor upgrades

D2: ZECO assessment of capacity over segments of RETI Phase 2A conceptual plan

IV.5 *General Assumptions*

The potential MW capacity of each CREZ is listed in Table 2-2 on Page 2-36 of the RETI 2A report. Looking at Table 2-2, the potential 2A CREZ MW capacity totals more than 77,000 MW. Note, only a fraction of this CREZ capacity will be required to deliver the renewable energy requirement for 2020.

Transmission expansion requirements to deliver the CREZ energy to the California utility customers in the RETI 2A report are broken into three groups - several local transmission collector line segment groups to reliably inject the power from the associated local CREZs into the transmission foundation group, transmission foundation group line segment additions to reliably deliver the renewable power between northern and southern California load centers, and delivery group line segment additions to deliver the power within the northern and southern California load centers. Table 3-5 in the RETI 2A report presents the transmission collector line segment groups developed as part of the RETI 2A study and associated CREZ accessed by the transmission collector groups. Line segments developed for each transmission collector group as well as the foundation and delivery groups are listed on Page F-55 in Appendix F, the line segments are described in Appendix G, the line segment costs and mileage are listed in Appendix H, new substations and network upgrades are listed in Appendix I and CREZ injection points and new substations used for the RETI 2A study are listed in Appendix J. Transmission cost assumptions used in the RETI 2A study for the line segment costs in Appendix H were obtained from Jan Strack of San Diego Gas & Electric Co. Some of these assumptions listed in Table 1 have been used to develop the incremental transmission line segment cost estimates in this work. All new 230 kV line segments are

assumed to be double circuit construction as in the RETI 2A study. Line termination costs are assumed to be an adder of 25% to the line segment cost as assumed in the RETI 2A study.

IV.6 *Table 1 - Transmission cost assumptions from RETI 2A Study*

Line Segment Description	Line Cost $1000/mi
Cost of 230 kV double circuit towers with one circuit	2000
Cost of second 230 kV circuit on double circuit 230 kV towers	500
Cost of 230 kV double circuit towers with two circuits	2500
Cost of 500 kV single circuit construction	2600
Cost of 500 kV double circuit towers with one circuit	4500
Cost of second 500 kV circuit on double circuit 500 kV towers	500
Cost of 500 kV double circuit towers with two circuits	5000
Adder for "Line Termination" costs	25%

The MW capacity of the transmission line segments employed in the RETI 2A study was not included in the RETI 2A report. The typical range of existing 230 kV transmission line ratings is from 200 - 800 MW[23]. For this high level estimate, existing 230 kV lines will be assumed to have a 500 MW rating per circuit. New and uprated 230 kV lines will be assumed to have a higher line rating of 1000 MW per circuit, which is compatible with the capacity assigned for a potential new 230 kV line included for the Carrizo area upgrades described in Appendix G of the RETI 2A report. The typical range of existing 500 kV transmission line ratings in the above referenced EPRI synthetic utility system report is from 1200 - 2500 MW. Both new and existing 500 kV line capacity is assumed to be 2000 MW per circuit, which is compatible with the ratings of existing 500 kV lines. The philosophy of this high level, first cut allowable local CREZ estimate is to consider the above assumed transmission ratings for the new transmission collector line segment additions for each line segment along with the assumed ratings of other existing local transmission facilities in the vicinity, when estimating how much power can reliably be injected into the foundation transmission facilities. The simplified transmission reliability considerations are that there must be enough transmission capacity remaining to transmit the power from the local CREZ to the foundation transmission lines with any one of the new or existing single circuit lines out of service. For double circuit lines on the same structures, there must be enough transmission capacity remaining to transmit the power from the local CREZ to the foundation lines with both circuits out of service. Foundation

[23] Table 4-19, page 4-44, *Synthetic Electric utility Systems for Evaluating Advanced Technologies*, EPRI EM-285, Final Report, February 1977.

and delivery line segments are assumed to be adequate to deliver the power from the transmission lines to the California load centers in this task. These transmission reliability assumptions used for this simplified high level estimate of allowable local CREZ are compatible with the category B single contingency (N-1) criteria and category C credible double contingency (N-2) criteria presented in the NERC/WECC Planning Standards[24] commonly used in WECC detailed bulk power system planning assessments.

The following caveats should be considered when interpreting the accuracy level of the results of this work. The high level estimates of allowable CREZ are based on inspection of the RETI 2A report and maps showing collector line segments added for each of the collector groups along with other existing local transmission corridors. This high level inspection also included review of associated existing transmission facilities shown on a pre 9/11 WSCC one line diagram[25] to identify characteristics of existing transmission facilities in the transmission corridors. No power flow, transient or post transient analyses commonly employed in transmission planning assessments have been performed for this high level estimates.

[24] Table 1, page 24, *Western Electricity Coordinating Council NERC/WECC Planning Standards*, Revised April 10, 2003.

[25] *Western Systems Coordinating Council Map of Principal Transmission Lines*, January 1, 2000.

IV.7 *Carrizo*

Table 2 presents the resulting high level estimates of allowable local CREZ MW capacity for the Carrizo Collector Group first assuming the line segments developed in the RETI 2A report, then adding additional transmission facilities to estimate the next incremental increase in allowable local CREZ MW. Reconductoring the Midway - Carrizo 230 kV lines will provide the first 1100 MW as described in Appendix G of the RETI 2A report. Reconductoring the Morro Bay - Gates 230 kV lines will provide the next 1000 MW resulting in a total local allowable local CREZ of about 2100 MW, as also described in Appendix G of the RETI 2A report. Mileage and cost assumptions for these line segment upgrades from the RETI 2A report are also included.

Adding a new 230 kV line from Carrizo to Gates is expected to increase the allowable local CREZ MW capacity another 1000 MW, resulting in a total local allowable local CREZ of about 3100 MW. This line segment addition is also described in Appendix G of the RETI 2A report. Note adding this new approximately 70 mi. line segment to allow the next 1000 MW of local CREZ is expected to cost significantly more than the reconductoring of the existing line segments.

IV.8 *Individual CREZ and transmission considerations*

Reconductoring the Midway - Carrizo 230 kV lines is expected to provide adequate transmission capacity for a total of 1100 MW local CREZ installed at Carrizo South and Cuyama . Adding a new 230 kV line from Carrizo to Gates is expected to increase the allowable local CREZ MW capacity another 1000 MW to 2100 MW.

Reconductoring the Morro Bay - Gates 230 kV lines is expected to provide adequate transmission capacity for 1000 MW local CREZ installed at Carrizo North.

IV.9 *Table 2 – Carrizo Collector Group*

IV.10 *CREZ Accessed: Carrizo North, Carrizo South, Cuyama*

Line Segment	Mileage	Cost $Millions	Allowable CREZ MW
MIDW_CARZ_1	46	31.05	1100
GATE_MBAY_1	70	47.25	1000
Totals RETI 2A	116	78.30	2100
Incremental mi Cost and CREZ	70	175.00	1000
New Totals	186	253.30	3100

IV.11 *North*

Table 3 presents the resulting high level estimates of allowable local CREZ MW capacity for the North Collector Group first assuming the line segments developed in the RETI 2A report, then adding additional transmission facilities to estimate the next incremental increase in allowable local CREZ MW. Building a 500 kV line from Collinsville – Tracy, a +/- 500 kV HVDC line from NE Oregon – Collinsville, and a Selkirk, BC - NE Oregon double circuit 500 kV line kV line will provide a total local allowable local CREZ of about 3000 MW. This assumes that there are adequate transmission facilities in the Northern portion of WECC to supply the 3000 MW for a credible N-2 outage in the DC or double circuit portion of the RETI 2A line segments. Mileage and cost assumptions for these line segments show that delivering these CREZ more than 1200 mi. will be costly. If there is serious consideration about delivering a significant amount of these Northern CREZ to California, a detailed transmission study will be required to determine how much the other existing northern WECC transmission facilities can transmit for a credible N-2 outage of these proposed RETI line segments.

Building a second set of line segments, another 500 kV line from Collinsville – Tracy, another +/- 500 kV HVDC line from NE Oregon – Collinsville, and a second Selkirk, BC - NE Oregon double circuit 500 kV line kV line will increase total local allowable local CREZ to about 6000 MW, assuming existing northern WECC transmission facilities can supply 3000 MW for a credible N-2 outage. If northern WECC transmission facilities cannot supply 3000 MW for a credible N-2 outage of the RETI 2A lines, the second set of transmission line segments will firm up the Northern collector lines and allow about 3000 MW of local CREZ during a credible N-2 event on one of the sets of line segments.

IV.12 *Individual CREZ and transmission considerations*

Building a 500 kV line from Collinsville – Tracy, a +/- 500 kV HVDC line from NE Oregon – Collinsville, and a Selkirk, BC - NE Oregon double circuit 500 kV line kV line is expected to provide for a total allowable local CREZ of about 3000 MW for CREZ installed in British Columbia and Oregon assuming there are adequate transmission facilities in Northwest WECC. If all the 3000 MW of CREZ are located in Oregon, the Selkirk, BC - NE Oregon double circuit 500 kV line kV line is not required.

The +/- 500 kV HVDC line from NE Oregon – Collinsville is shown going right by the Round Mountain A and B CREZ. Thus, the Round Mountain A and B CREZ are included in both the North and Northeast transmission collector groups. However, my cursory investigation indicates that the Round Mountain A and B CREZ should not be included in the North collector group, because of expected high costs to connect the CREZ in the middle of the DC line.

Instead the Round Mountain A and B CREZ can be connected to the Northeast transmission collector group or be connected to existing transmission facilities without adding any of the North collector group transmission lines. There are two existing 500 kV lines and the Round Mountain substation in the vicinity of the Round Mountain CREZ which could be used to interconnect these CREZ. For example, the Round Mountain A and B CREZ could be connected to the Round Mountain substation. See the Northeast collector group discussion for potential mileage and cost estimates for the

Round Mountain trunk-lines. These assumptions would be similar to connect to the ZETA1 subatation, which is about a mile away from the Round Mountain substation .

IV.13 *Table 3 – North Collector Group*

IV.14 *CREZ Accessed: British Columbia, Oregon, Round Mountain*

Line Segment	Mileage	Cost $Millions	Allowable CREZ MW
COLL_TRCY2_1	40	130.00	
NEO_COLL_1	640	2080.00	
SELK_NEO_1	270	843.75	
SELK_NEO_2	270	843.75	
Totals RETI 2A	1220	3897.50	3000
Incremental mi Cost and CREZ	1220	3897.50	3000
New Totals	2440	7795.00	6000

IV.15

IV.16 *Northeast*

Table 4 presents the resulting high level estimates of allowable local CREZ MW capacity for the Northeast Collector Group first assuming the line segments developed in the RETI 2A report, then adding additional transmission facilities to estimate the next incremental increase in allowable local CREZ MW. The RETI 2A line segments consist of a single circuit 500 kV line from Olinda - Dillard Rd, a single circuit 500 kV line from Zeta1 – Olinda, a short 500 kV connection from Zeta1 - Round Mountain. Adding these 500 kV lines is expected to result in a total local allowable local CREZ of about 2000 MW. These lines are part of the TANC project, which is no longer actively being pursued I believe. Adding a second set of these line segments, another single circuit 500 kV line from Olinda - Dillard Rd, another single circuit 500 kV line from Zeta1 – Olinda, and another short 500 kV connection from Zeta1 - Round Mountain Sub is expected to increase the allowable local CREZ MW capacity another 2000 MW, resulting in a total local allowable local CREZ of about 4000 MW.

IV.17 *Individual CREZ and transmission considerations*

The key issue for this transmission collector group is how to transmit the power from the local CREZ to the ZETA1 substation.
Round Mountain A CREZ could be connected to the ZETA1 substation with a single circuit 230 kV approximately 50 mi. long trunk-line costing about $125 million.
Round Mountain B CREZ could be connected to the ZETA1 substation with a single circuit 230 kV approximately 10 mi. long trunk-line costing about $25 million.
On Page G-75 of the RETI 2A report, Lassen North and South CREZ are shown connected to the ZETA1 substation with two 80-100 mi. 500 kV collector lines costing up to about $650 million to maintain N-1 reliability. This transmission would also apply to other CREZ in northern Nevada.

IV.18 *Table 4 – Northeast Collector Group*

IV.19 *CREZ Accessed: Round Mountain A&B, Lassen N&S, N Nevada*

Line Segment	Mileage	Cost $Millions	Allowable CREZ MW
OLND_DILL_1	183	594.75	
ZETA1_OLND_1	42	136.50	
ZETA1_RDMT_1	1	3.25	
Totals RETI 2A	226	734.50	2000
Incremental mi Cost and CREZ	226	734.50	2000

New Totals	452	1469.00	4000

IV.20 *Inyo*

Table 5 presents the resulting high level estimates of allowable local CREZ MW capacity for the Inyo Collector Group first assuming the line segments developed in the RETI 2A report, then adding additional transmission facilities to estimate the next incremental increase in allowable local CREZ MW. The RETI 2A line segments consist of a building a 230 kV line using 500 kV construction from Control - Lone Pine, building a 230 kV line using 500 kV construction from Inyokern – Kramer, and building a 230 kV line using 500 kV construction from Lone Pine - Inyokern. Adding these 230 kV lines is expected to result in a total local allowable local CREZ of about 500 MW, assuming that the parallel existing 230 kV is limiting with an outage of these new lines.
Adding a second set of single circuit 500 kV line segments from Control - Lone Pine, Inyokern - Kramer, Lone Pine - Inyokern, and operating both sets of lines at 500 kV is expected to increase the allowable local CREZ MW capacity to 2000 MW, an incremental increase of 1500 MW.

IV.21 *Individual CREZ and transmission considerations*

The transmission collector line segments proceed in series southward from Control to Lone Pine to Inyokern to Kramer. Although the new 230 kV line segments will have a rating of about 1000 MW when operated at 230 kV, total local CREZ is limited to 500 MW due to the line capacity of an existing parallel 230 kV line. Since the collector line segments are constructed using 500 kV construction, the plan should be to construct additional 500 kV transmission collector segments to access more than 500 MW of local CREZ. If a second set of 500 kV line segments are built and the two sets of line segments are operated at 500 kV in parallel, the above local CREZ totals will increase to about 2000 MW.
Kramer is near the foundation transmission system and Kramer CREZ can be accessed through the foundation system as well as the Inyo collector group. Several thousand MW of Kramer CREZ can be connected directly to the foundation transmission system without connecting to the transmission collector system.
Accessing Inyokern CREZ requires building the Inyokern – Kramer line segment. Assuming only the Inyokern – Kramer line segment is built as described in the RETI 2A report, the collector system can reliably inject a total of about 500 MW of Inyokern CREZ and any Kramer CREZ connected to the Inyo collector group into the foundation system. If a second set of 500 kV line segments are built from Inyokern – Kramer and the two sets of line segments are operated at 500 kV in parallel, the total local CREZ at Inyokern will increase to about 2000 MW, or 1500 MW, with an additional 500 MW total CREZ at Owens Valley and Central Nevada.
Accessing the Owens Valley CREZ requires building the Inyokern – Kramer line segment and the Lone Pine – Inyokern line segment. Assuming the Inyokern – Kramer line segment and the Lone Pine – Inyokern line segment are built, the collector system can reliably inject a total of about 500 MW of Owens Valley CREZ, Inyokern CREZ and any Kramer CREZ connected to the Inyo collector group into the foundation system. If a second set of 500 kV line segments are built from Lone Pine - Inyokern – Kramer and the two sets of line segments are operated at 500 kV in parallel, the total local CREZ at

Inyokern and Owens Valley will increase to about 2000 MW, or 1500 MW, with an additional 500 MW total CREZ in Central Nevada.
Accessing the Central Nevada CREZ requires building the Inyokern – Kramer line segment, the Lone Pine – Inyokern line segment, and the Control – Lone Pine line segment. Assuming the Inyokern – Kramer line segment, the Lone Pine – Inyokern line segment, and the Control – Lone Pine line segment are built, the collector system can reliably inject a total of about 500 MW of Central Nevada CREZ, Owens Valley CREZ, Inyokern CREZ and any Kramer CREZ connected to the Inyo collector group into the foundation system. If a second set of 500 kV line segments are built from Control - Lone Pine - Inyokern – Kramer and the two sets of line segments are operated at 500 kV in parallel, the total local CREZ at Inyokern, Owens Valley and Central Nevada will increase to about 2000 MW.
Note this transmission expansion from Control – Lone Pine – Inyokern – Kramer could temporarily transmit approximately 1000 MW of CREZ while operating at 230 kV. However, it would not maintain N-1 transmission system reliability.

IV.22 *Table 5 – Inyo Collector Group*

IV.23 *CREZ Accessed: Central Nevada, Inyokern, Owens Valley, Kramer*

Line Segment	Mileage	Cost $Millions	Allowable CREZ MW
CONT_LPIN_1	45	202.50	
INYK_KRAM_1	66	214.50	
LPIN_INYK_1	53	238.50	
Totals RETI 2A	164	655.50	500
Incremental mi Cost and CREZ	164	533.00	1500
New Totals	328	1188.50	2000

IV.24 *MtPass*

Table 6 presents the resulting high level estimates of allowable local CREZ MW capacity for the MtPass Collector Group first assuming the line segments developed in the RETI 2A report, then adding additional transmission facilities to estimate the next incremental increase in allowable local CREZ MW. The RETI 2A line segments consist of a building a 500 kV line from Baker - Barstow, building a 500 kV line from Barstow - Lugo, building a 500 kV line from Mountain Pass – Baker and building a 500 kV line from Mountain Pass - Eldorado. Adding these 500 kV lines is expected to result in a total local allowable local CREZ of about 2000 MW.

Adding a second set of single circuit 500 kV line segments from Baker - Barstow, Barstow - Lugo, Baker - Mountain Pass and Mountain Pass – Eldorado is expected to increase the allowable local CREZ MW capacity another 2000 MW, resulting in a total local allowable local CREZ of about 4000 MW.

IV.25 *Individual CREZ and transmission considerations*

The 500 kV line segments result in a 500 kV path from Eldorado – Mt. Pass – Baker – Barstow – Lugo. Eldorado is a large substation with two existing 500 kV lines heading to the LA area and two other 500 kV lines heading elsewhere in WECC. Lugo is part of the foundation group. With any collector line segment out of service it is expected that 2000 MW can be delivered into the foundation system either through Lugo or via the 500 kV lines out of Eldorado.

The Victorville CREZ is located near the foundation transmission system and is its power expected to be injected directly into the foundation network rather than through the collector lines.

Mt. Pass, Baker and Barstow CREZ are expected to be accessed by the Mt. Pass collector group transmission lines. This high level assessment indicates that a total of about 2000 MW at these three CREZ locations can be reliably injected into the foundation lines. If a second set of collector lines is installed, the total allowable CREZ can be increased to about 4000 MW.

Considering the CREZ individually, Mt. Pass is about 150 mi. from Lugo. 2000 MW of Mt. Pass CREZ could be probably be reliably injected into Eldorado substation with two 32 mi. 500 kV line segments costing about $248 Million, and delivered to the foundation system via the existing 500 kV transmission system.

Barstow is about 50 mi. from Lugo. 2000 MW of Barstow CREZ could be reliably delivered to Lugo with two 51 mi. 500 kV line segments from Lugo – Barstow costing about $574 million.

Baker is about 100 mi. from Lugo. 2000 MW of Barstow plus Baker CREZ could be reliably delivered to Lugo with two 51 mi. 500 kV line segments from Lugo – Barstow and two 50 mi. 500 kV line segments from Barstow – Baker costing about $962 million. Note this alternative is more expensive than building the transmission line segments from Lugo – Barstow – Baker – Mt. pass – Eldorado in shown in Table 6.

IV.26 *Table 6 – MtPass Collector Group*

IV.27 *CREZ Accessed: Mountain Pass, Baker, Barstow, Victorville*

Line Segment	Mileage	Cost $Millions	Allowable CREZ MW
BAKR1_BARS1_1	50	193.75	
BARS1_LUGO_1	51	286.88	
MTPS1_BAKR1_1	50	193.75	
MTPS1_ELDO_1	32	124.00	
Totals RETI 2A	183	798.38	2000
Incremental mi Cost and CREZ	183	594.75	2000
New Totals	366	1393.13	4000

IV.28

IV.29 *BarrenRidge*

Table 7 presents the resulting high level estimates of allowable local CREZ MW capacity for the BarrenRidge Collector Group first assuming the line segments developed in the RETI 2A report, then adding additional transmission facilities to estimate the next incremental increase in allowable local CREZ MW. The RETI 2A line segments consist of upgrading the existing Owens Gorge - Rindaldi 230 kV line from Barren Ridge switching station to Haskel Canyon switching station, building double circuit 230 kV line #2 from Barren Ridge switching station to Haskel Canyon switching station, adding 230 kV #2 line from Castaic power plant - Haskel Canyon on open side of towers, and upgrading the existing Owens Gorge - Rindaldi 230 kV line from Haskel Canyon switching station to Rinaldi. Upgrading and adding these 230 kV lines is expected to result in a total local allowable local CREZ of about 2000 MW.

Adding additional single circuit 230 kV lines from Barren Ridge switching station to Haskel Canyon switching station, from Castaic power plant - Haskel Canyon, and from Haskel Canyon to Rindaldi is expected to increase the allowable local CREZ MW capacity another 1000 MW, resulting in a total local allowable local CREZ of about 3000 MW.

IV.30 *Individual CREZ and transmission considerations*

First further review of the RETI 2A report, Page G-61 indicates that the allowable CREZ in Table 7 should be increased from 2000 MW to 2200 MW.

This transmission collector group provides a path to deliver approximately 2200 MW of Tehachapi and Kramer CREZ to the LADWP system as described in the RETI 2A report. The additional transmission expansion is expected to increase the allowable CREZ another 1000 MW to 3200 MW.

IV.31 *Table 7 – BarrenRidge Collector Group*

IV.32 *CREZ Accessed: Kramer, Tehachapi*

Line Segment	Mileage	Cost $Millions	Allowable CREZ MW
BRNR_HASC_1	60	40.50	
BRNR_HASC_2	60	150.00	
CAST_HASC_2	12	7.50	
HASC_RNLD_1	15	10.13	
Totals RETI 2A	147	208.13	2200
Incremental mi Cost and CREZ	87	217.50	1000
New Totals	234	425.63	3200

IV.33 *IronMt*

Table 8 presents the resulting high level estimates of allowable local CREZ MW capacity for the IronMt Collector Group first assuming the line segments developed in the RETI 2A report, then adding additional transmission facilities to estimate the next incremental increase in allowable local CREZ MW. The RETI 2A line segments consist of rebuilding double circuit 500 kV line circuits #1 and #2 from Iron Mountain - Junction over existing 230 kV to assess Iron Mountain CREZ, rebuilding a 500 kV line from Junction - Camino over existing 230 kV to access Needles CREZ, and building a double circuit 500 kV line circuit #1 and #2 from Jontry Junction – Pisgah. Unfortunately uprating and adding all these 500 kV lines is expected to only result in a total allowable local CREZ of about 500 MW at Iron Mountain and possibly 1000 MW at Needles, while meeting transmission reliability criteria discussed above. Problems associated with reliably delivering larger amounts of power from potential Iron Mountain CREZ are discussed in the RETI 2A report on page 3-71. Note, there is enough capacity in the double circuit 500 kV line to deliver about 4000 MW of CREZ into the foundation transmission system with both circuits in service, without meeting the credible N-2 outage criteria.
If the current problems can be resolved, Adding another double circuit 500 kV line from Iron Mountain – Jontry Junction - Pisgah, could deliver up to 4000 MW from Iron Mountain or 1000 MW at Needles with 3000 MW at Iron Mountain, while maintaining a credible N-2 reliability criteria.

IV.34 *Individual CREZ and transmission considerations*

The individual CREZ and transmission considerations associated with Iron Mountain and Needles CREZ are discussed above.

IV.35 *Table 8 – IronMt Collector Group*

IV.36 *CREZ Accessed: Iron Mountain, Pisgah, Needles*

Line Segment	Mileage	Cost $Millions	Allowable CREZ MW
IRMT_SCEJ_1	39	134.06	
IRMT_SCEJ_2	39	134.06	
SCEJ_CAMI_1	10	38.75	
SCEJ_PISG_1	84	262.50	
SCEJ_PISG_2	84	262.50	
Totals RETI 2A	256	831.88	500
Incremental mi Cost and CREZ	123	768.75	3500
New Totals	379	1600.63	4000

IV.37 *Riverside*

Table 9 presents the resulting high level estimates of allowable local CREZ MW capacity for the Riverside Collector Group first assuming the line segments developed in the RETI 2A report, then adding additional transmission facilities to estimate the next incremental increase in allowable local CREZ MW. The RETI 2A line segments consist of building two 500 kV lines from Desert Center - Devers, and building a 500 kV line from Midpoint – Desert Center. Adding these 500 kV lines is expected to result in a total local allowable local CREZ of about 4000 MW.

Adding another single circuit 500 kV line from Midpoint – Desert Center, and from Desert Center - Devers is expected to increase the allowable local CREZ MW capacity another 2000 MW, resulting in a total local allowable local CREZ of about 6000 MW, with up to 4000 MW of the CREZ connected at Midpoint.

IV.38 *Individual CREZ and transmission considerations*

The above allowable CREZ limits apply to Riverside East CREZ.

The Palm Springs CREZ appears to be located near Devers substation, and the CREZ power should be able to be injected directly into the foundation transmission system using a 10 mi. 230 kV trunk-line costing about $25 million.

IV.39 *Table 9 – Riverside Collector Group*

IV.40 *CREZ Accessed: Riverside East, Palm Springs*

Line Segment	Mileage	Cost $Millions	Allowable CREZ MW
DESC_DEVR_1	40	125.00	
DESC_DEVR_2	40	125.00	
MIDP_DESC_1	70	227.50	
Totals RETI 2A	150	477.50	4000
Incremental mi Cost and CREZ	110	357.50	2000
New Totals	260	835.00	6000

IV.41 *LEAPS*

Table 10 presents the resulting high level estimates of allowable local CREZ MW capacity for the LEAPS Collector Group first assuming the line segments developed in the RETI 2A report, then adding additional transmission facilities to estimate the next incremental increase in allowable local CREZ MW. The RETI 2A line segments consist of reconductoring the double circuit Talega - Escondido 230 kV #1 line from Escondido - Camp Pendleton, adding a second #2 circuit to the towers, reconductoring the double circuit Talega - Escondido 230 kV #1 line from Talega - Camp Pendleton, and adding a second #2 circuit to the towers, and building a 500 kV Talega to Escondido to the Valley - Serrano line. Reconductoring the 230 kV lines and adding the 500 kV line is expected to result in a total local allowable local CREZ of about 2000 MW.
Adding another single circuit 500 kV line from Talega to Escondido to the Valley - Serrano line is expected to increase the allowable local CREZ MW capacity another 2000 MW, resulting in a total local allowable local CREZ of about 4000 MW.

IV.42 *Individual CREZ and transmission considerations*

Table B-1 in the RETI 2A report indicates that the total local developable North Central San Diego CREZ is 281 MW. The above cursory examination of the transmission segments proposed in the RETI 2A report indicates that the proposed collector segments provide for about 2000 MW of allowable local CREZ. In my opinion the existing 230 kV transmission may be adequate to inject a large portion of the developable North Central San Diego CREZ power directly into the San Diego transmission system.

IV.43 *Table 10 – LEAPS Collector Group*

IV.44 *CREZ Accessed: San Diego North Central*

Line Segment	Mileage	Cost $Millions	Allowable CREZ MW
CMPL_ECND_1	37	24.98	
CMPL_ECND_2	37	23.13	
CMPL_TALG_1	10	6.75	
CMPL_TALG_2	10	6.25	
LELK_CMPL_1	31	100.75	
Totals RETI 2A	125	161.85	2000
Incremental mi Cost and CREZ	31	100.75	2000
New Totals	156	262.60	4000

IV.45 *Tehachapi*

Table 11 presents the resulting high level estimates of allowable local CREZ MW capacity for the Tehachapi Collector Group first assuming the line segments developed in the RETI 2A report, then adding additional transmission facilities to estimate the next incremental increase in allowable local CREZ MW. The RETI 2A line segments consist of upgrading the existing line #1 from Antelope - Vincent from 220 kV to 500 kV, upgrading the existing line #2 from Antelope - Vincent from 220 kV to 500 kV on separate right of way, upgrading existing 220 kV line from Chino – Mira Loma to double circuit 220 kV lines #1 and #2, adding 220 kV circuit to the open side of existing 500 kV creating Chino - Mira Loma 220 kV line #3 (using 500 kV construction), adding 220 kV Gould – Eagle Rock 220 kV line using existing towers, rebuilding a portion of the Eagle Rock - Pardee 220 kV line creating the Mesa - Vincent #2 220 kV line, building the Rio Hondo - Vincent #2 220 kV line, changing the Windhub - Antelope line operating voltage from 220 kV to 500 kV, building the Whirlwind - Windhub 500 kV line, and building the Whirlwind - Antelope 500 kV line. Upgrading the above 220 kV lines and adding the 500 kV lines creates a lot of transmission capacity. The total local allowable CREZ capacity is difficult to estimate without performing load flow analysis. However, all these upgrades and additions are expected to result in a total local allowable local CREZ of at least 4000 MW.

Adding another single circuit 500 kV line, say from Windhub – Whirlwind - Vincent is expected to increase the allowable local CREZ MW capacity another 2000 MW, resulting in a total local allowable local CREZ of about 6000 MW.

IV.46 *Individual CREZ and transmission considerations*

Table B-1 in the RETI 2A report indicates that the total local developable Tehachapi CREZ is more than 10,000 MW and Fairmont CREZ is more than 3500 MW. It appears that the following list of Tehachapi collector group transmission line segments in Table 11 were developed based on a relatively extensive transmission assessment by the RETI group. If more than 6000 MW local CREZ is planned, I suggest we contact the appropriate transmission planners to develop a more accurate estimate of the allowable local CREZ associated with the transmission facilities added in the RETI report.

IV.47 *Table 11 – Tehachapi Collector Group*

IV.48 *CREZ Accessed: Tehachapi, Fairmont*

Line Segment	Mileage	Cost $Millions	Allowable CREZ MW
ANTE_VINC_1	21	16.28	
ANTE_VINC_2	18	68.20	
CHNO_MIRA_1	7	24.06	
CHNO_MIRA_2	7	15.31	
CHNO_MIRA_3	7	15.31	
GULD_EGLR_1	9	3.53	
MESA_VINC_2	36	126.00	
RIOH_VINC_2	32	124.39	
WHUB_ANTE_1	26	16.64	
WHUB_WRLW_1	17	54.60	
WRLW_ANTE_1	16	50.70	
WRLW_VINC_1	33	10.79	
Totals RETI 2A	228	525.81	4000
Incremental mi Cost and CREZ	50	162.50	2000
New Totals	278	688.31	6000

IV.49 *Imperial*

Table 12 presents the resulting high level estimates of allowable local CREZ MW capacity for the Imperial Collector Group first assuming the line segments developed in the RETI 2A report, then adding additional transmission facilities to estimate the next incremental increase in allowable local CREZ MW. The RETI 2A line segments consist of rebuilding the existing 161 kV Line to double circuit 230 kV line #1 from Avenue 58 - Coachella Valley, rebuilding the existing 161 kV line to double circuit 230 kV line #1 from Avenue 58 – Bannister, adding a second circuit to double circuit 230 kV line creating Bannister - Coachella Valley line #1, building the 500 kV Bannister - Devers #1 line, adding the second circuit to double circuit 230 kV creating the Bannister - El Centro line #1, building 230 kV Bannister - Geo #1 line, building 230 kV Bannister - Geo #2 line, building 230 kV Coachella Valley - Devers II line #1, building 230 kV Coachella Valley - Devers II line #2 , upgrading 230 kV Coachella Valley - Mirage line #1, upgrading 230 kV Coachella Valley - Mirage line #2, adding a short 500 kV line connection between Devers – Devers II, rebuilding existing 161 kV to double circuit 230 kV line #1 from Dixieland – Bannister, rebuilding existing 161 kV to double circuit 230 kV line #1 from El Centro – Highline, adding second circuit to double circuit 230 kV creating El Centro - Highline line #2, building El Centro - Imperial ValleyII 230 kV line #2, building the 500 kV Bannister - Imperial Valley line#1, replacing the existing 500/230 kV 600 MVA Imperial Valley transformer with a new 1120 MVA transformer, adding a third 500/230 kV 1120 MVA Imperial Valley transformer, building Midway - Geo double circuit 230 kV lines #1 and #2, upgrading existing Mirage - Devers 230 kV line #1, and upgrading existing Mirage - Devers 230 kV line #2. I believe the transmission capability of all these upgrades and additions has been studied pretty thoroughly, as can be seen in the RETI 2A report. As stated in Appendix G, page G-57 of the RETI 2A report, 3200 MW of local CREZ capacity can be delivered at to LADWP and SCE at Devers/Mirage and 1800 MW of local CREZ can be delivered to SDGE at Imperial Valley, resulting in a total allowable local CREZ of 5000 MW.
Adding another single circuit 500 kV line 500 kV line from Imperial Valley - Bannister – Devers is expected to increase the allowable local CREZ MW capacity delivered to LADWP and SCE at Devers/Mirage another 2000 MW, to about 5200 MW, and increasing the total allowable local CREZ to 7000 MW.

IV.50 *Individual CREZ and transmission considerations*

This collector group has been thoroughly studied in determining the allowable local CREZ. If more than 7000 MW local CREZ is planned, I suggest we contact the appropriate transmission planners to discuss additional transmission facilities to add.

IV.51 *Table 12 – Imperial Collector Group*

IV.52 *CREZ Accessed: Imperial North A&B, Imperial South, Imperial East, Baha*

Line Segment	Mileage	Cost $Millions	Allowable CREZ MW
AV58_CHCV_1	18	32.81	
BANN_AV58_1	61	107.41	
BANN_CHCV_1	56	140.22	
BANN_DEVR_1	91	296.40	
BANN_ELCN_1	28	51.56	
BANN_GEO_1	16	25.00	
BANN_GEO_2	16	25.00	
CHCV_DVR2_1	35	54.69	
CHCV_DVR2_2	35	54.69	
CHCV_MIRG_1	20	13.50	
CHCV_MIRG_2	20	13.50	
DEVR_DVR2_1	0	0.98	
DIXL_BANN_1	43	51.56	
ELCN_HILN_1	19	35.63	
ELCN_HILN_2	19	35.63	
ELCN_IMPV2_2	18	33.75	
IMPV_BANN_1	51	165.75	
IMPV_XFMR_2	0	51.25	
IMPV_XFMR_3	0	51.25	
MIDW_GEO_1	16	25.00	
MIDW_GEO_2	16	25.00	
MIRG_DEVR_1	15	10.13	
MIRG_DEVR_2	15	10.13	
Totals RETI 2A	608	1310.81	5000
Incremental mi Cost and CREZ	142	462.15	2000
New Totals	750	1772.96	7000

D3: E3 additions of generic 500kV transmission lines

E3's analysis includes a look at the relative values of fixed capacity transmission lines from the various zones. The size of the transmission lines from each zone are chosen to

reflect the total resource availability in that zone, up to a maximum of 3,000 MW consisting of two single-circuit 500 kV lines or one dual-circuit 500 kV line. The lines are assumed to originate at the center of the resource clusters in each zone[26] and terminate at the closer of the Tesla (near Tracy, CA) or Victorville substations, whichever. These two substations were chosen because they represent transmission hubs in close proximity to major California load centers.

With the exception of the line from British Columbia, which E3 models as a hybrid alternating current (AC) and direct current (DC) line, E3 assumes all lines to be AC lines. The cost of these lines is estimated using a generic line costing model that accounts for both equipment (substations, towers, conductors, etc.) and right-of-way acquisition.[27] The following table details the cost and size of the transmission line that E3 assumes from each zone, as well as the losses associated with those lines.

[26] For example, the Wyoming line originates in eastern rather than central Wyoming due to the fact that most wind resources are located in the eastern part of the state.
[27] This transmission costing model was the same as that used for the GHG Calculator. It can be found at http://www.ethree.com/GHG/Transmission_Line_Cost_2007-11-16.xls

CREZ Name	Assumed Line Capacity (MW)	Transmission Line Distance (miles)	Transmission Configuration	Total Cost ($MM 2008)	Incremental Losses	Levelized Cost, $/yr
Alberta	3,000	1,498	500 kV Double Circuit AC Line	$ 7,998	17.2%	$ 997
Arizona-Southern Nevada	1,500	403	500 kV Single Circuit AC Line	$ 2,044	4.6%	$ 255
Baja	1,500	211	500 kV Single Circuit AC Line	$ 1,425	2.4%	$ 178
Barstow	1,500	97	500 kV Single Circuit AC Line	$ 889	1.1%	$ 111
British Columbia	3,000	1,166	500 kV Double Circuit AC Line and 3000 MW DC Line	$ 5,100	13.4%	$ 636
Carrizo North	1,500	174	500 kV Single Circuit AC Line	$ 1,127	2.0%	$ 140
Carrizo South	1,500	237	500 kV Single Circuit AC Line	$ 1,478	2.7%	$ 184
Colorado	3,000	936	500 kV Double Circuit AC Line	$ 5,250	10.8%	$ 654
Cuyama	500	249	230 kV Single Circuit AC Line	$ 1,094	0.5%	$ 136
Distributed Solar	n/a	n/a	n/a	$ -	0.0%	$ -
Fairmont	1,500	13	500 kV Single Circuit AC Line	$ 549	0.2%	$ 68
Imperial East	1,500	224	500 kV Single Circuit AC Line	$ 1,472	2.6%	$ 183
Imperial North	1,500	151	500 kV Single Circuit AC Line	$ 1,085	1.7%	$ 135
Imperial South	1,500	181	500 kV Single Circuit AC Line	$ 1,199	2.1%	$ 149
Inyokern	1,500	118	500 kV Single Circuit AC Line	$ 948	1.4%	$ 118
Iron Mountain	1,500	170	500 kV Single Circuit AC Line	$ 1,120	2.0%	$ 140
Kramer	1,500	82	500 kV Single Circuit AC Line	$ 823	0.9%	$ 103
Lassen North	1,500	266	500 kV Single Circuit AC Line	$ 1,642	3.1%	$ 205
Lassen South	1,500	344	500 kV Single Circuit AC Line	$ 1,940	4.0%	$ 242
Montana	3,000	1,105	500 kV Double Circuit AC Line	$ 6,090	12.7%	$ 759
Mountain Pass	1,500	194	500 kV Single Circuit AC Line	$ 1,287	2.2%	$ 160
Nevada C	1,500	215	500 kV Single Circuit AC Line	$ 1,345	2.5%	$ 168
Nevada N	500	790	230 kV Double Circuit Line	$ 1,232	0.9%	$ 154
New Mexico	3,000	237	500 kV Double Circuit AC Line	$ 4,522	9.1%	$ 564
NonCREZ	All NonCREZ resources are assigned a generic $68/kW-yr Transmission Adder					
Northwest	1,500	738	500 kV Single Circuit AC Line	$ 3,270	8.5%	$ 408
Owens Valley	1,500	188	500 kV Single Circuit AC Line	$ 1,211	2.2%	$ 151
Palm Springs	1,000	73	500 kV Single Circuit AC Line	$ 668	0.3%	$ 83
Pisgah	1,500	111	500 kV Single Circuit AC Line	$ 908	1.3%	$ 113
Remote DG	n/a	n/a	n/a	$ -	0.0%	$ -
Riverside East	1,500	169	500 kV Single Circuit AC Line	$ 1,143	1.9%	$ 166
Round Mountain	500	191	230 kV Single Circuit AC Line	$ 879	0.4%	$ 110
San Bernardino - Baker	1,500	125	500 kV Single Circuit AC Line	$ 1,002	1.4%	$ 125
San Bernardino - Lucerne	1,500	64	500 kV Single Circuit AC Line	$ 732	0.7%	$ 91
San Diego North Central	500	45	230 kV Single Circuit AC Line	$ 585	0.1%	$ 73
San Diego South	1,000	205	230 kV Double Circuit AC Line	$ 1,118	0.9%	$ 139
Santa Barbara	500	280	230 kV Single Circuit AC Line	$ 1,153	0.6%	$ 144
Solano	1,000	20	230 kV Double Circuit AC Line	$ 538	0.1%	$ 67
Tehachapi	3,000	80	500 kV Double Circuit AC Line	$ 1,252	0.9%	$ 156
Twentynine Palms	1,000	112	230 kV Double Circuit AC Line	$ 766	0.5%	$ 95
Utah-Southern Idaho	1,500	676	500 kV Single Circuit AC Line	$ 2,925	7.8%	$ 365
Victorville	1,500	43	500 kV Single Circuit AC Line	$ 674	0.5%	$ 84
Westlands	1,500	149	500 kV Single Circuit AC Line	$ 1,058	1.7%	$ 153
Wyoming	3,000	1,030	500 kV Double Circuit AC Line	$ 5,796	11.8%	$ 722

D4: Transmission cost assumptions – Project Specific

The CAISO provided E3 with assumptions about the existing capacity on the transmission system that could be used to deliver renewable resources from the various CREZs. The data provided included estimates of the existing capacity without any incremental upgrades and identified those areas in which relatively minor transmission upgrades could provide spare capacity on the system. For those projects, CAISO provided a rough estimate of the total cost of the upgrade. The following table shows the zones for which CAISO identified either existing transmission capacity or spare capacity with minor upgrades, and the cost estimates for the minor upgrades.

CREZ #	CREZ Name	Existing Tx Capacity (MW)	Capacity with Minor Upgrades (MW)	Description of minor transmission upgrades	Cost of minor upgrade ($)
18	Carrizo South	300	900	Reconductoring from Carrizo Interconnection Points to Midway and possibly from Morro Bay to Templeton	$100 M
30	Imperial South	0	1125	install third Imperial Valley 500/230kV bank	$50 M
32	Palm Springs	1000	1000		
43	Pisgah	0	275	SPS	$40 M
36	Riverside East	1500	1500		
3	Round Mountain	100	100		
44	San Bernardino - Lucerne	261	261		
27	San Diego South	400	761	connect Boulevard substation to new 500/230 kV substation between Imperial Valley and Miguel substations	$60 M
8	Solano	0	300	Reconductorings South of Contra Costa	$100 M
52	Tehachapi	4500	5825	2nd and 3rd AA banks at Whirlwind	$100 M
	Westlands	0	800	Reconductor Borden-Gregg 230 kV line	$50 M

D5: Distribution System Benefits/Upgrade Penalties for Wholesale Distributed Solar Resources

E3 has modeled four different types of wholesale distributed solar PV generation for this effort. These different types of solar resource are either given a credit for the benefits that they provide to the distribution system (small installations serving load downstream of the substation) or assessed a penalty for system upgrades that they might trigger (larger installations that violate Rule 21[28]).

The size of the benefit for the smaller installations was determined by where they interconnect to the system. Remote DG installations that are not compliant with Rule 21 are assessed a generic $68/kW-yr system upgrade penalty. The following table shows the different benefits/penalties by interconnection point and the types of distributed resources to which they correspond.

[28] Rule 21 governs the amount of downstream distributed generation that can be connected to a given substation. More information on Rule 21 can be found at the California Energy Commission website: http://www.energy.ca.gov/distgen/interconnection/california_requirements.html.

Interconnection Point	Upgrade Penalty (Distribution System Benefit), $/kW-yr.	Applicable Solar PV Technologies
Meter	($45)	Large Rooftop (0-2 MW)
Feeder	($45)	Small Ground (0-2 MW)
Dist. Bank	($45)	
Transmission Substation	($10)	Mid Ground (2-5 MW), Large Ground (5-20 MW)
Remote DG	$68	Large Ground (5-20 MW), Not Rule 21 Compliant

Appendix E

Environmental Scoring

Environmental Scoring for 33% RPS Scenarios

This white paper describes work conducted by Aspen Environmental Group (Aspen) in support of the ongoing effort by CPUC to identify various 33% RPS Scenarios. Aspen's tasks were to help CPUC update the methodology for environmental ranking of renewable resources and to assign scores to generation resources so environmentally-ranked scenarios (portfolios) could be developed. Aspen is under contract to provide RPS Technical Support to the California Institute for Energy and Environment (CIEE) through direction from the CPUC Energy Division. The CPUC 33% RPS Implementation Analysis team will use the scores to create environmentally-constrained scenarios of new renewable generating resources to fill the RPS need and for use in the Long-Term Procurement Planning (LTPP) process.

1. Introduction

1.1 Purpose

Aspen Environmental Group shows a way of scoring individual renewable energy projects based on the relative environmental ranking of its location [using the Renewable Energy Transmission Initiative (RETI) Competitive Renewable Energy Zone (CREZ)] and the technology of the resource. Aspen also provides comparable scores for projects that are out-of-state or do not fall within a CREZ.

The CPUC Energy Division is forecasting scenarios of new renewable generation development to comply with the mandate for 33% renewable electricity by 2020. In separate work for the LTPP, a range of development scenarios for 2020, including those that are environmentally-constrained, will be made up of specific selected projects. This white paper describes how each project can be given an environmental score. Each environmental score is a composite of the environmental ranking of the applicable CREZ, which characterizes location, and the weighting of the environmental criteria according to how relevant various concerns would be to the technology.

1.2 Reliance on Renewable Energy Transmission Initiative

RETI EWG Environmental Criteria. The Renewable Energy Transmission Initiative includes an Environmental Working Group (EWG) that developed eight environmental criteria for measuring the level of environmental concern associated with developing renewable generation in various Competitive Renewable Energy Zones (CREZs). The eight criteria originally defined as part of RETI Phase 1B are documented in the RETI Phase 1B report of January 2009.

Identification of Resources. New generating resources to fill the RPS need come from the RETI Phase 2B Supporting Documents and the confidential CPUC Energy Division database. Given the variety of resources and the different levels of available information on possible projects, this white paper identifies a way of discerning which projects would have the least environmental concern based on the ranking of each project's CREZ and the technology proposed.

- **Projects Identified by RETI:** Scores were assigned to projects identified by RETI Phase 2B Supporting Documents (1,222 projects),[29] which do not include distributed solar photovoltaic (PV) projects.

[29] The RETI Phase 2B Supporting documents include the list of 1,222 projects with the following description (available at: http://www.energy.ca.gov/reti/documents/index.html, accessed June 2, 2010): "Hypothetical proxy projects have been located based on relative resource potential and other constraints in a general area; pre-

Revisiting RETI Environmental Criteria. This white paper shows how our environmental scoring departs from CREZ Environmental Ranking of the RETI process in several ways. Our work:

1) revises some of the RETI environmental criteria based on new and additional publicly-available data;

2) reflects our recent experiences in active cases subject to current environmental review;

3) weighs the level of concern of separate environmental criteria by renewable technology; and

4) results in scores for projects, rather than area rankings, in a range of 0 to approximately 100, with 0 representing the projects with the lowest level of environmental concern and scores approaching 100 indicating the highest level of environmental concern.

By assigning a weight to the different criteria, depending on how relevant each environmental concern would be to a given technology, scores can be assigned to each renewable project. The results of ranking resources in California are then extrapolated to score renewable projects outside of California, where data on project location and environmental attributes are scarce. Projects are drawn from the RETI list and projects within the Energy Division database.

The remainder of this paper explains the goals and methodology used to arrive at the environmental scores, the environmental weight assigned to each criterion for each renewable technology, and the method for scoring out of state renewable technologies.

2. Goals in Deriving an Environmental Score

Aspen's primary goal is to score resources on a clear range for side-by-side comparison, and a scale of 0 to approximately 100 is used for a readily understandable system. A total of eight environmental criteria (or environmental concerns) were considered for each location and renewable resource, using a mix of existing RETI data and additional publicly-available data. For each geographic location, each criterion was given a score of between 0 and 10, 0 representing the least environmental concern and 10 the greatest. The eight environmental criteria were then assigned a weight for each renewable technology (again ranging between 0 and 10) based on the relevance of each environmental concern to successful development of the technology. The renewable technology with the greatest combined potential environmental concern across the eight criteria, including over-weighting some criteria, results in a total environmental score ranging from 0 to approximately 100, where lower scores indicates the least environmental concern.

Another goal was to arrange the scoring system so projects from the RETI and CPUC Energy Division (ED) project databases could be treated with the same methodology. The location of each project determines whether it is within or near a ranked CREZ. If it is within or near a ranked CREZ, the project is given a score appropriate for that technology in that CREZ. When a project falls far beyond a CREZ boundary or out-of-state, then it is treated as a Non-CREZ or out-of-state resource, as needed. The environmental score is then only a function of the project's location and technology.

identified projects have been located based on known commercial interest in a general area. Locations of actual projects may vary significantly from locations shown in the [RETI] GIS files."

3. Environmental Criteria

This section details the eight environmental criteria representing the level of environmental concern for each renewable resource. The environmental criteria originate from RETI EWG scores and are modified by Aspen to reflect experience gathered through our participation in the environmental review process of some currently-proposed projects.

3.1 RETI EWG Environmental Assessment of CREZs

The RETI EWG determined how environmental considerations should be factored into CREZ development and ranking. The EWG's work was finalized in the January 2009 Phase 1B Report as a 46-page appendix addressing "Environmental Assessment of CREZs."

The RETI EWG assessment illustrated the relative merits of each zone. The RETI EWG scores are not intended for use in evaluating individual projects, and the EWG makes no recommendations for the level of environmental concern for resources outside of defined CREZs (Non-CREZ), outside a scored sub-CREZ (portions of CREZs with differing economic profiles), or areas outside of California (out-of-state). RETI EWG Phase 2B results included updates limited to environmental ranking of certain CREZs, rather than all CREZs, and Phase 2B also provided one alternate set of CREZ rankings to address a lack of consensus on how the footprint of wind projects should be defined (May, 2010).

The RETI EWG scores apply uniformly across each CREZ and do not discern which types of projects within a ranked CREZ might have a lower or higher level of environmental concern.

3.2 Environmental Criteria Retained

The ranking criteria originally developed as part of RETI EWG Phase 1B address important environmental concerns, some of which were used directly in our Environmental Scoring. The following criteria were carried forward as part of our Environmental Scoring, modified only to reflect a 0 to 10 scale instead of 0 to 5 as used by RETI:

- **Transmission Footprint**: This criterion includes the amount of land needed for new transmission rights-of-way (ROW) as a useful measure of the expected impact on the environment.
- **Significant Species**: State and federal policies identify species of wildlife that are of significant concern. This criterion gives preference to CREZs in which fewer significant species are known to occur. This criterion in particular should continue to be updated based on new information that is continuously uploaded in the California Natural Diversity Database.
- **Wildlife Corridors**: Biologists have recognized the importance of the integrity of wildlife corridors that enable animals to move as needed from one habitat to another. Although corridors are not well understood and existing data is preliminary, the EWG included corridor data to give preference to those CREZs that minimize conflicts with wildlife corridors.
- **Important Bird Areas**: Potential impacts of energy development on avian species are of significant environmental concern. Areas designated as Important Bird Areas (IBA) by the National Audubon Society are areas designated as vital to bird species, including common and game species as well as rare species.

The EWG factors that were not used in our scoring are the "Energy Development Footprint", "Sensitive Areas in CREZs", and "Sensitive Areas in CREZ Buffer Areas", as discussed in Section 3.3.

The RETI Phase 1B Final Report includes more information on economic and environmental rankings of the CREZs and descriptions of the resources within each CREZ.

Additional environmental concerns, including aesthetics (visual impact), Native American concerns (cultural resources), and some land use conflicts (regarding forest use), are neither represented in the existing RETI data nor the criteria in this white paper. However, these concerns could be addressed by the environmental scores in future updates of this work as criteria and data become available.

3.3 Environmental Criteria Updated or Added

Our Environmental Scoring takes into account additional and updated environmental factors, building on the criteria of the RETI EWG rankings. RETI EWG criteria for "Sensitive Areas in CREZs" and "Sensitive Areas in CREZ Buffer Areas" were not carried forward because our experience indicates that development in sensitive areas (as they were defined by the RETI EWG) is generally not feasible, and the presence of sensitive areas near a renewable zone is not generally a limiting concern for successful development of the zone. In addition to the RETI EWG criteria that were incorporated unchanged (see Section 3.2), we revised the RETI EWG "Energy Development Footprint" score and added criteria to address high desert ecosystems, regional air quality, and development opportunities on degraded lands, including brown-field and other EPA-tracked sites.

Energy Development Footprint

The RETI EWG "Energy Development Footprint" criterion considered the land needed for renewable energy collection and generation as a useful measure of potential environmental concern. We revised this criterion to focus on whether the energy development footprint would be likely to align with land that may be already degraded or mechanically disturbed.

The relative size of the "Energy Development Footprint" is a useful indicator of environmental concern, especially in locations with little history of disturbed land. However, the RETI EWG analysis of this factor resulted in a larger (worse) score for a CREZ that has a greater energy development footprint, even if that CREZ is entirely degraded or mechanically disturbed, such as is the case with the Westlands CREZ. Our analysis accounts for the mechanically disturbed land within a CREZ by finding the percentage of the CREZ located on active farmland by:[30]

- Calculating the acreage of active, mechanically disturbed farmland in each CREZ using the California Department of Conservation Important Farmland Maps database and the CREZ shapefiles;
- Calculating the percentage of the total CREZ area that was considered mechanically disturbed farmland; and
- Ranking the CREZs to identify those with the greatest fraction of mechanically disturbed land within the adjusted CREZ area.

Our experience has illustrated that active grazing lands, while also agriculture lands, tend to foster sensitive biological resources, and a number of renewable projects currently under consideration are finding large numbers of species of concern located on actively grazed land. For this reason, only mechanically disturbed farmland, non-grazing land, was included in our calculation. Regions with

[30] Conflict between renewable energy siting and the use of farmland has been raised by numerous members of the public and public agencies. Nonetheless, mechanically disturbed farmland in a CREZ illustrates an opportunity that exists in the CREZs to target non-productive agriculture land for renewable energy development.

essentially no mechanically disturbed farmland were assigned highest (worse) scores, and regions with abundant mechanically disturbed farmland per renewable development footprint were assigned lowest (best) scores.

High Desert Ecosystems

We are directly involved with reviewing various proposals for renewable projects that would be located in the California Mojave and Sonoran Deserts. These environmental reviews reveal valuable biological resources especially in the portions of the desert at higher elevations. Because of the great sensitivity of biological resources at higher elevations, a 2,500 foot contour line was used to calculate the percentage of land within CREZs located in the California Desert that fell into high desert and the percentage of land within the CREZ that was located in the low desert. The CREZs were then ranked based on the portion of their land that was located in high desert.

Regional Air Quality

Previous work by RETI considers the economic influence that regional air quality has on renewable projects (primarily biomass), but no environmental criteria previously identified air quality as a potential environmental concern for renewable development throughout the State. Regional air quality conditions are considered here in part as a proxy for environmental justice and public health concerns because most of California's population resides in polluted air basins. We determined the CREZs that are located in air basins with designations of federal PM2.5 nonattainment, federal PM10 nonattainment, and State-level ozone nonattainment. CREZs with one or more pollutants in nonattainment were assigned higher (worse) scores.

EPA Tracked Degraded Lands

We sought to capture the results of work completed in February 2010 by U.S. EPA and the National Renewable Energy Laboratory (NREL) regarding renewable energy development opportunities on "degraded" lands. The U.S. EPA and NREL published a tool, including shapefiles, that tracks EPA and state-tracked degraded sites and maps these based on their appropriateness for renewable development.[31] This shapefile was used to calculate the acreage of tracked degraded land considered appropriate for renewable development inside of each CREZ and within 10 miles of each CREZ boundary. A 10-mile buffer was used because a majority of the renewable energy applications currently under environmental review in California include a distance of 10 miles or less from transmission as one of the project objectives.

We calculated the percentage of degraded land inside or within 10 miles of each CREZ compared to the total renewable project area that would be needed to develop each CREZ. For degraded lands currently in use, such as is the case for active military lands, ten percent of the degraded lands were included for the calculation. CREZs with excess or the most degraded land available as a ratio of the anticipated renewable project area received the lowest (best) scores, and CREZs with little or no degraded land available were assigned higher (worse) scores.

[31] See http://www.epa.gov/renewableenergyland/ for further tools compiled by the EPA for siting renewable energy on potentially contaminated land and mine sites.

3.4 Relative Ranking Results

Table 1 shows how each of the RETI CREZs rank according to the eight criteria defined in this white paper.

Table 1. Relative Ranking of CREZ by Environmental Criteria

CREZ Name	Mechanically Disturbed	ROW (Transmission Footprint)	High Desert	Air Quality	Significant Species	Wildlife Corridors	Important Bird Areas	EPA Tracked Degraded
Barstow	9.9	2.8	5.0	6.7	0.5	1.7	0.5	9.8
Carrizo North	7.7	4.1	0.0	3.3	1.4	0.6	0.0	9.9
Carrizo South	10.0	1.7	0.0	3.3	0.7	0.7	0.8	10.0
Cuyama	10.0	1.9	0.0	3.3	3.5	0.0	0.0	10.0
Fairmont	9.1	2.3	7.4	3.3	0.7	0.8	0.9	9.7
Imperial East	10.0	2.6	0.0	6.7	1.3	0.7	0.1	9.8
Imperial North-A	5.5	1.8	0.0	6.7	0.5	0.4	2.4	10.0
Imperial North-B	7.6	3.8	0.0	10.0	1.2	0.6	4.6	9.3
Imperial South	7.0	2.1	0.0	10.0	0.5	0.8	2.7	9.9
Inyokern	9.9	1.8	6.6	3.3	0.6	0.5	0.0	10.0
Iron Mountain	10.0	1.6	0.3	6.7	0.2	0.0	0.0	10.0
Kramer	10.0	1.6	7.7	3.3	0.2	0.6	0.4	2.5
Lassen North	10.0	8.6	0.0	0.0	1.3	1.2	0.0	10.0
Lassen South	10.0	4.3	0.0	0.0	4.4	10.0	7.5	0.0
Mountain Pass	10.0	2.1	7.4	6.7	1.1	0.0	1.0	9.4
Owens Valley	10.0	1.1	0.0	6.7	0.3	2.3	0.2	10.0
Palm Springs	9.3	3.4	0.1	10.0	5.2	0.0	1.8	4.3
Pisgah	10.0	0.1	0.0	6.7	0.5	0.0	0.0	10.0
Riverside East	9.6	0.7	0.0	3.3	0.2	0.0	0.0	9.9
Round Mountain-A	10.0	1.3	0.0	0.0	1.2	0.0	0.0	10.0
Round Mountain-B	10.0	4.7	0.0	3.3	4.8	3.4	0.0	10.0
San Bernardino - Baker	10.0	1.2	0.0	6.7	0.3	1.1	0.0	10.0
San Bernardino - Lucerne	9.9	4.5	10.0	6.7	1.1	1.1	0.0	9.6
San Diego North Central	9.6	10.0	4.3	3.3	10.0	2.5	10.0	9.4
San Diego South	10.0	1.5	2.2	3.3	2.9	2.5	0.0	9.9
Santa Barbara	9.8	2.3	0.0	3.3	4.4	3.9	0.0	0.0
Solano	10.0	0.9	0.0	6.7	1.8	1.3	8.5	0.0
Tehachapi	9.6	1.4	0.0	3.3	0.2	0.9	0.5	9.9
Twentynine Palms	10.0	1.4	0.5	6.7	0.6	0.7	0.0	9.9
Victorville	10.0	2.7	10.0	6.7	0.7	0.4	0.1	8.8
Westlands	0.2	0.2	0.0	6.7	0.3	0.4	0.0	8.9

3.5 Scoring Out of State Resources

Out of state resources that are adjacent to the California border and have similar environmental characteristics as their neighboring CREZs were given a score that reflects the average score of the neighboring California CREZs. This groups the out of state resources with those that would have similar ecology as neighboring California.

For instance, the Baja California CREZ falls within the La Rumorosa mountain chain which is an extension of the Peninsular Ranges of eastern San Diego. As such it has a similar habitat and similar special status species as one would find in eastern San Diego. Efforts such as the *Las Californias Binational Conservation Initiative* recognize the shared landscape between these two border regions and the many shared resources. Likewise, the CREZs located in the Sonoran Desert of eastern Imperial County share numerous ecological characteristics with the adjacent Sonoran Desert in western Arizona. For these reasons, the Baja California, Arizona, and Nevada zones were given the average of the neighboring California CREZ scores.

Oregon and other out of state renewable resources were given a median environmental score reflecting the median of all CREZs. This was done in an attempt to retain a relatively neutral ranking for renewable resources outside California. To capture the unknown environmental concerns associated with the most-distant resources, a minor penalty for long-distance transmission was also included for all out of state resources except those from Baja and Arizona, where new transmission right-of-way would be less likely. As stated above, the amount of land needed for new ROW is a useful measure of the expected impact on the environment.

4. Weighting of Environmental Criteria

This section outlines our approach for considering how each environmental criterion is relevant to the successful development of a given renewable technology. Each renewable technology with greater combined potential environmental concerns across the eight criteria was given higher (worse) weights, where lower weights indicate less least environmental concern.

4.1 Relative Environmental Concerns of Technologies

The environmental criteria relate to different renewable energy technologies in different ways. Assigning the environmental criteria a weighting factor for each technology allows identification of the resources that would pose the least environmental concern for a given location. Having established environmental criteria scores for CREZs, we considered how each technology might be related to each environmental criterion. We developed a weighting system to highlight the relative concern of each technology for each issue. For example, when developing a biomass or biogas facility, air quality nonattainment is usually an issue of high concern. Likewise the issues of special status wildlife and plant species are of greater concern for utility-scale solar which occupies vast amounts of land.

Table 2 shows the relative weighting of the criteria that we selected for each technology.

Table 2. Relative Weight of Environmental Criteria by Technology

Technology	Mechanically Disturbed	ROW (Transmission Footprint)	High Desert	Air Quality	Significant Species	Corridors	Important Bird Areas	EPA Tracked Degraded	Total Weight
Biomass / Biogas	1.0	1.0	0.0	2.5	1.5	0.0	0.5	1.0	7.5
Geothermal	1.0	1.0	0.5	1.0	1.0	1.0	0.5	1.0	7.0
Solar PV	1.0	1.0	1.5	0.0	2.0	1.5	1.0	1.0	9.0
Solar Thermal	1.0	1.0	1.5	0.0	2.5	2.0	1.0	1.0	10.0
Wind	1.0	1.0	0.5	0.0	1.5	1.0	2.5	1.0	8.5
Rural PV (DG)	1.0	0.5	0.5	0.0	1.0	0.0	0.5	1.0	4.5
Urban Ground PV	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.5	1.0
Urban Roof PV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

4.2 Discussion of Weighting the Criteria by Technology

Biomass and Biogas. The primary environmental concern for most biomass and biogas generation is air quality. Although biomass and biogas project do not require large land resources as compared to other renewable technologies, the presence of significant species is a concern because of the large number of daily truck trips that may be required for biomass fuel gathering and delivery. Adding truck traffic can disproportionately increase impacts to animal species when compared to technologies that generate electricity without heavily increasing road use.

Geothermal. The relative environmental concerns for geothermal generation are basically neutral with proportionately less concern for high desert ecosystems, which could be avoided by strategic placement of geothermal project elements like wells and piping, and less concern for important bird areas that would not tend to obstruct geothermal development.

Solar Photovoltaic (PV). Relatively high levels of environmental concern occur for utility-scale solar PV development, especially due to large project footprints and likely impacts to high desert, significant species, and habitat corridors. Solar PV projects are generally more configurable than solar thermal projects, meaning that significant species and habitat corridors may be less of a concern for PV than they are for solar thermal.

Solar Thermal. Relatively high levels of environmental concern occur for utility-scale solar thermal development, especially for significant species and corridors because of the comparative inflexibility in siting that this technology seems to have.

Wind. The primary environmental concern for developing wind resources is avian mortality. Accordingly, important bird areas are of greater concern than other environmental criteria.

Photovoltaic Distributed Generation (DG). Rural solar photovoltaic (PV) that would occur at the scale of distributed generation (DG) (on the order of 20 MW or less) depends somewhat on the environmental criteria but less so than utility scale solar. While there is a greater flexibility to site a rural distributed generation photovoltaic project than a larger utility scale project, there is still the possibility of causing environmental concern.

Urban PV Distributed Generation. Urban solar PV developed on a DG scale would be likely to avoid most of the environmental concerns discussed in this report. Urban ground-mounted PV would have some concern for areas where a lack of available disturbed or degraded lands could obstruct ground-level development. Rooftop PV could essentially avoid all of the identified concerns.

5. Results

5.1 Environmental Rankings and Scores

Each RETI CREZ was analyzed according to the eight environmental criteria (Section 3). The results for each environmental criterion were then weighted to calculate an individual score for each technology in each CREZ, as shown in Table 3.

Table 3. Environmental Scores for Each CREZ and Technology

CREZ	Biomass	Geothermal	Solar Photovoltaic	Solar Thermal	Wind
Arizona	36.16	27.84	23.07	23.46	22.65
Baja	45.68	41.57	51.71	56.19	51.51
Barstow	40.30	34.21	34.22	35.32	28.87
Carrizo North	32.14	27.06	25.47	26.51	24.44
Carrizo South	31.55	26.89	25.08	25.81	25.63
Cuyama	35.54	28.77	28.98	30.75	27.21
Fairmont	30.94	30.05	35.69	36.45	28.95
Imperial East	41.12	31.16	26.20	27.18	25.43
Imperial North-A	35.94	26.14	21.37	21.81	24.54
Imperial North-B	49.89	34.83	28.63	29.52	34.68
Imperial South	46.17	31.74	24.05	24.73	27.48
Inyokern	30.87	29.36	33.39	33.92	26.31
Iron Mountain	38.49	28.56	22.38	22.47	21.98
Kramer	22.85	22.18	27.21	27.58	19.72
Lassen North	30.50	31.09	32.97	34.22	31.72
Lassen South	24.72	32.50	45.68	52.89	49.70
Mountain Pass	40.33	33.48	35.80	36.35	29.40
Nevada	36.85	37.36	43.15	46.15	41.94
NonCREZ	35.94	29.56	26.88	27.58	26.31
Out-of-State (Other)	45.94	39.56	36.88	37.58	36.31
Oregon	45.94	39.56	36.88	37.58	36.31
Owens Valley	38.28	30.47	25.39	26.71	24.38
Palm Springs	50.55	33.03	29.21	31.81	29.14
Pisgah	37.46	27.24	21.09	21.33	20.81
Riverside East	28.88	23.79	20.64	20.73	20.55
Round Mountain-A	23.12	22.52	23.72	24.32	23.12
Round Mountain-B	40.26	36.29	39.51	43.65	35.37
San Bernardino - Baker	38.32	29.30	23.48	24.19	22.78

Table 3. Environmental Scores for Each CREZ and Technology

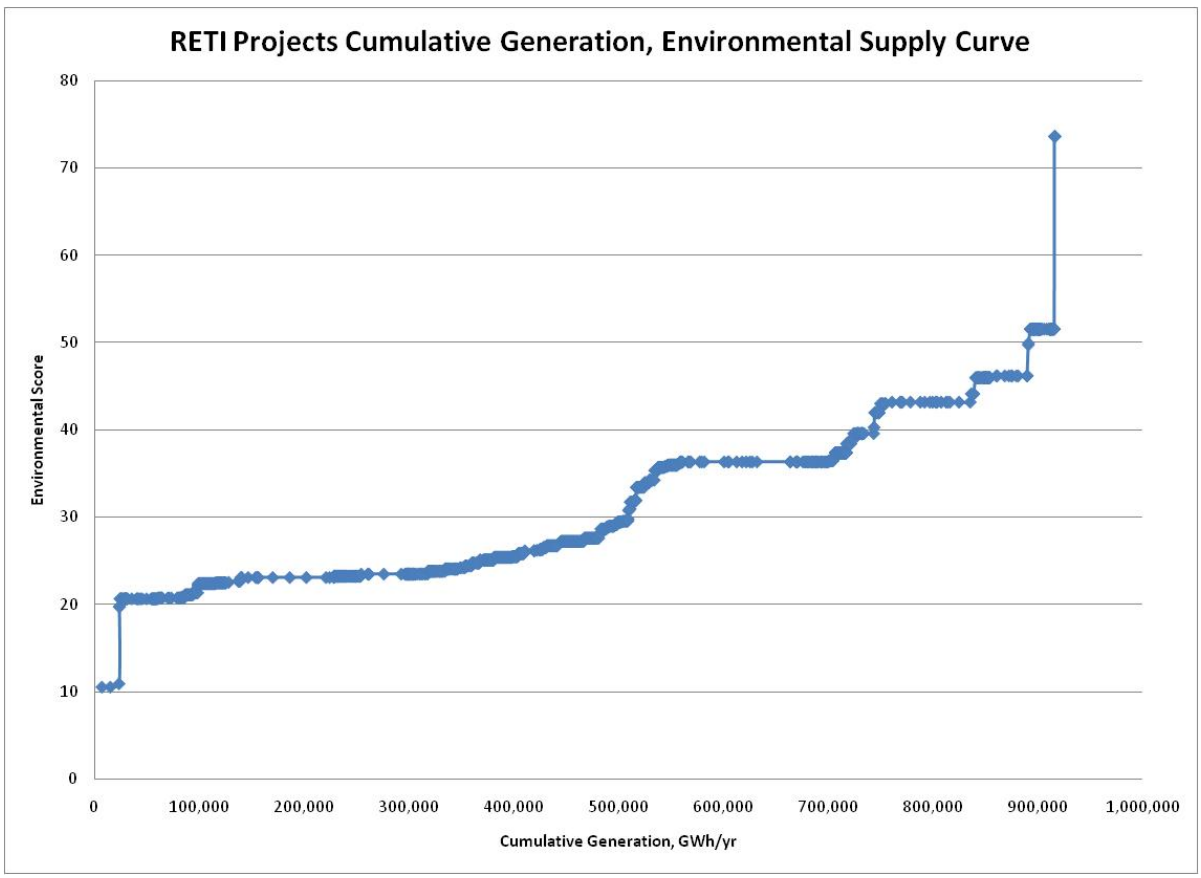
CREZ	Biomass	Geothermal	Solar Photovoltaic	Solar Thermal	Wind
San Bernardino - Lucerne	42.37	37.98	42.98	44.10	31.91
San Diego North Central	57.28	51.89	69.11	75.34	73.56
San Diego South	34.08	31.24	34.32	37.05	29.46
Santa Barbara	27.09	23.83	26.88	31.06	22.70
Solano	34.58	24.95	25.03	26.59	36.29
Tehachapi	29.78	25.60	23.22	23.79	23.46
Twentynine Palms	38.89	29.56	24.39	25.07	23.20
Victorville	39.17	34.17	38.39	38.90	28.02
Westlands	26.37	16.65	10.53	10.91	10.14

5.2 Environmental Supply Curve

The "environmental supply curve" shows the cumulative annual energy in gigawatt-hours per year (GWh/yr) that could be provided by renewable projects in relation to the environmental scores.

The environmental scores from this white paper (Table 2) were assigned to each of the projects identified by RETI Phase 2B Supporting Documents (1,222 projects), representing up to 916,000 GWh/yr potential generation, and the results are shown in Figure 1.

Figure 1. Environmental Scoring Results for RETI Projects



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Appendix F

Timing Assessment

F1: Generation timing assumptions

F2: Transmission timing assumptions

F1: Generation Timing Assumptions

The table below summarizes the timing assumptions used to develop the summary development timelines presented in Section II.7 of this report.

Technology	Size	Permitting Jurisdiction	Development Duration (months)			
			Preparation	Permitting / Environmental Review	Construction	Total
Biogas/Biomass						
	<50 MW	City/County/Federal	12	14	36	**62**
	≥ 50 MW	State/Federal	12	24	36	**72**
Geothermal						
	<50 MW	City/County/Federal	12	14	20	**46**
	≥ 50 MW	State/Federal	12	24	28	**64**
Small Hydro						
		City/County/Federal	12	14	20	**46**
Solar Thermal						
	<50 MW	City/County/Federal	12	14	32	**58**
	≥ 50 MW	State/Federal	12	24	32	**68**
Solar PV - ground mounted, ≥ 20 MW						
	<50 MW	City/County/Federal	12	10	10	**32**
	≥ 50 MW	City/County/Federal	12	12	12	**36**
Wind						
	<50 MW	City/County/Federal	12	10	12	**34**
	≥ 50 MW	City/County/Federal	12	20	18	**50**

F2: Transmission Timing Assumptions

As described in Section II.7, each transmission "bundle" from each CREZ was assigned to one of the following transmission schedules:

Transmission Schedule Type	Transmission Planning by CAISO/ POU/ WECC (months)	Project Description Prep by Utility	CEQA/ NEPA Review by CPUC/POU/ Feds	Final Review and Approval by CPUC/ POU/Feds	Final Design and Construction by Utilities	Total
Existing / Distributed	0	0	0	0	0	0
Typical	18	12	24	4	24	82
Typical - Short	12	6	12	3	18	51
Typical - Long	24	18	24	4	30	100
Long-Distance	24	18	24	6	30	102
Tehachapi 1-3	0	0	0	0	0	0
Tehachapi 4-11	0	0	0	0	24	24
Sunrise	0	0	0	0	24	24
Devers - CO River	0	0	0	0	30	30

In general, zones were assigned to schedules as follows:

CREZ and Transmission Increment	Transmission Schedule Type	Development Start Date
Non-CREZ	Existing/Distributed	6/1/2010
CREZ – accommodated by existing system	Existing/Distributed	“
CREZ – accommodated by minor upgrades	Typical-Short	“
CREZ – 230 kV line, in-state	Typical-Short	“
CREZ – 500 kV line, in-state	Typical or Typical-Long, depending on location	6/1/2010 for up to 4500 MW of capacity; every 2 years thereafter
Out-of-state Resource	Long-Distance	“

The table below lists CREZ transmission bundles more specifically, by the size of the incremental bundle, the assumed transmission schedule, and the assumed development start time.

For the modeling effort, E3 assumed that each zone was available at the beginning of the year following whatever date resulted from the combination of the assigned start date and transmission schedule.

Transmission Zone	Line Capacity (MW)	Schedule Type	Start Date
Existing		Existing / Distributed	1-Jun-2010
Alberta		Long-Distance	1-Jun-2010
Arizona-Southern Nevada			
Arizona-Southern Nevada - 1	1500	Long-Distance	1-Jun-2010
Arizona-Southern Nevada - 2	1500	Long-Distance	1-Jun-2010
Arizona-Southern Nevada - 3	1500	Long-Distance	1-Jun-2010
Arizona-Southern Nevada - 4	1500	Long-Distance	1-Jun-2010
Baja			
Baja - 1	1500	Typical - Short	1-Jun-2009
Baja - 2	1500	Typical - Short	1-Jun-2010
Baja - 3	1500	Typical - Short	1-Jun-2010
Baja - 4	1500	Typical - Short	1-Jun-2010
Barstow			
Barstow - 1	1500	Typical	1-Jun-2010
Barstow - 2	1500	Typical	1-Jun-2010
British Columbia			
British Columbia - 1	3000	Long-Distance	1-Jun-2009
British Columbia - 2	3000	Long-Distance	1-Jun-2012
British Columbia - 3	3000	Long-Distance	1-Jun-2014
British Columbia - 4	3000	Long-Distance	1-Jun-2016
Carrizo North			
Carrizo North - 1	1500	Typical	1-Jun-2010
Carrizo South			
Carrizo South - existing/approved	300	Existing / Distributed	1-Jun-2010

Carrizo South - minor new	600	Typical - Short	1-Jun-2009
Carrizo South - 1	1500	Typical	1-Jun-2010
Colorado			
Colorado - 1	3000	Long-Distance	1-Jun-2010
Colorado - 2	3000	Long-Distance	1-Jun-2012
Colorado - 3	3000	Long-Distance	1-Jun-2014
Colorado - 4	3000	Long-Distance	1-Jun-2016
Cuyama			
Cuyama - 1	500	Typical - Short	1-Jun-2010
Fairmont			
Fairmont - 1	1500	Typical	1-Jun-2010
Fairmont - 2	1500	Typical	1-Jun-2010
Imperial East			
Imperial East - 1	1500	Typical	1-Jun-2010
Imperial North			
Imperial North - 1	1500	Typical	1-Jun-2010
Imperial North - 2	1500	Typical	1-Jun-2010
Imperial South			
Imperial South - minor new	1125	Sunrise	1-Jun-2010
Imperial South - 1	1500	Typical	1-Jun-2010
Imperial South - 2	1500	Typical	1-Jun-2010
Inyokern			
Inyokern - 1	1500	Typical - Long	1-Jun-2010
Inyokern - 2	1500	Typical - Long	1-Jun-2010
Iron Mountain			
Iron Mountain - 1	1500	Typical - Long	1-Jun-2010
Iron Mountain - 2	1500	Typical - Long	1-Jun-2010
Iron Mountain - 3	1500	Typical - Long	1-Jun-2010
Kramer			
Kramer - minor new	62	Existing / Distributed	1-Jun-2010
Kramer - 1	1500	Typical - Long	1-Jun-2010
Kramer - 2	1500	Typical - Long	1-Jun-2010
Kramer - 3	1500	Typical - Long	1-Jun-2010
Kramer - 4	1500	Typical - Long	1-Jun-2012
Lassen North			
Lassen North - 1	1500	Typical - Long	1-Jun-2010
Lassen South			
Lassen South - 1	1500	Typical - Long	1-Jun-2010
Montana			
Montana - 1	3000	Long-Distance	1-Jun-2010
Montana - 2	3000	Long-Distance	1-Jun-2012
Montana - 3	3000	Long-Distance	1-Jun-2014
Montana - 4	3000	Long-Distance	1-Jun-2016
Mountain Pass			
Mountain Pass - 1	1500	Typical	1-Jun-2010
Nevada N			
Nevada N - 1	500	Typical - Long	1-Jun-2010
Nevada N - 2	500	Typical - Long	1-Jun-2010
Nevada N - 3	500	Typical - Long	1-Jun-2010
Nevada N - 4	500	Typical - Long	1-Jun-2010
Nevada C			
Nevada C - 1	1500	Typical - Long	1-Jun-2010
Nevada C - 2	1500	Typical - Long	1-Jun-2010
Nevada C - 3	1500	Typical - Long	1-Jun-2010
Nevada C - 4	1500	Typical - Long	1-Jun-2012

New Mexico			
New Mexico - 1	3000	Long-Distance	1-Jun-2010
New Mexico - 2	3000	Long-Distance	1-Jun-2012
New Mexico - 3	3000	Long-Distance	1-Jun-2014
New Mexico - 4	3000	Long-Distance	1-Jun-2016
NonCREZ		Existing / Distributed	1-Jun-2010
Northwest			
Northwest - 1	1500	Long-Distance	1-Jun-2010
Northwest - 2	1500	Long-Distance	1-Jun-2010
Northwest - 3	1500	Long-Distance	1-Jun-2010
Northwest - 4	1500	Long-Distance	1-Jun-2012
Owens Valley			
Owens Valley - 1	1500	Typical - Long	1-Jun-2010
Owens Valley - 2	1500	Typical - Long	1-Jun-2010
Owens Valley - 3	1500	Typical - Long	1-Jun-2010
Palm Springs			
Palm Springs - existing/approved	1000	Existing / Distributed	1-Jun-2010
Pisgah			
Pisgah - minor new	275	Typical - Short	1-Jun-2010
Pisgah - 1	1500	Typical	1-Jun-2010
Pisgah - 2	1500	Typical	1-Jun-2010
Pisgah - 3	1500	Typical	1-Jun-2010
Remote DG		Existing / Distributed	1-Jun-2010
Reno Area/Dixie Valley			
Reno Area/Dixie Valley - 1		Typical - Long	1-Jun-2010
Reno Area/Dixie Valley - 2		Typical - Long	1-Jun-2010
Reno Area/Dixie Valley - 3		Typical - Long	1-Jun-2010
Reno Area/Dixie Valley - 4		Typical - Long	1-Jun-2010
Riverside East			
Riverside East - existing/approved	1500	Devers - Colorado River	1-Jun-2010
Riverside East - 1	3000	Typical	1-Jun-2010
Riverside East - 2	3000	Typical	1-Jun-2012
Riverside East - 3	3000	Typical	1-Jun-2014
Round Mountain			
Round Mountain - existing/approved	100	Existing / Distributed	1-Jun-2010
Round Mountain - 1	500	Typical - Short	1-Jun-2010
San Bernardino - Baker			
San Bernardino - Baker - 1	1500	Typical	1-Jun-2010
San Bernardino - Baker - 2	1500	Typical	1-Jun-2010
San Bernardino - Lucerne			
San Bernardino - Lucerne - existing/approved	261	Existing / Distributed	1-Jun-2010
San Bernardino - Lucerne - 1	1500	Typical	1-Jun-2010
San Diego North Central			
San Diego North Central - 1	500	Typical - Short	1-Jun-2010
San Diego South			
San Diego South - existing/approved	400	Existing / Distributed	1-Jun-2010
San Diego South - minor new	361	Typical - Short	1-Jun-2010
Santa Barbara			
Santa Barbara - 1	500	Typical - Short	1-Jun-2010
Solano			
Solano - minor new	300	Typical - Short	1-Jun-2010
Solano - 1	1000	Typical - Short	1-Jun-2010
Tehachapi			

Tehachapi - existing/approved	4500	Tehachapi 4-11	1-Jun-2010
Tehachapi - minor new	1325	Typical - Short	1-Jun-2010
Tehachapi - 1	3000	Typical	1-Jun-2012
Tehachapi - 2	3000	Typical	1-Jun-2014
Twentynine Palms			
Twentynine Palms - 1	1000	Typical	1-Jun-2010
Twentynine Palms - 2	1000	Typical	1-Jun-2010
Utah-Southern Idaho			
Utah-Southern Idaho - 1	1500	Long-Distance	1-Jun-2010
Utah-Southern Idaho - 2	1500	Long-Distance	1-Jun-2010
Utah-Southern Idaho - 3	1500	Long-Distance	1-Jun-2010
Utah-Southern Idaho - 4	1500	Long-Distance	1-Jun-2012
Victorville			
Victorville - 1	1500	Typical	1-Jun-2010
Westlands			
Westlands - minor new	800	Typical - Short	1-Jun-2010
Westlands - 1	1500	Typical	1-Jun-2010
Westlands - 2	1500	Typical	1-Jun-2010
Wyoming			
Wyoming - 1	3000	Long-Distance	1-Jun-2010
Wyoming - 2	3000	Long-Distance	1-Jun-2012
Wyoming - 3	3000	Long-Distance	1-Jun-2014
Wyoming - 4	3000	Long-Distance	1-Jun-2016

(END OF ATTACHMENT 1)