RETI

Coordinating Committee

Renewable Energy Transmission Initiative Phase 1A

DRAFT REPORT

MARCH 2008
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RETI Stakeholder Steering Committee

Renewable Energy Transmission Initiative Phase 1A

DRAFT REPORT
B&V Project Number 149148.0010

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1.0 Executive Summary

Black & Veatch is pleased to provide this report on the Renewable Energy Transmission Initiative Phase 1A activities to the Stakeholder Steering Committee. The purpose of this report is to describe the methodology, assumptions and resource information to be used in Phase 1B of the California Renewable Energy Transmission Initiative project.

1.1 Background and Objective

California was among the first states to enact a renewable portfolio standard and currently has one of the most aggressive portfolio requirements in the country. California has adopted an RPS requiring that 20 percent of electric energy be generated from renewable resources by 2010 (2013 with flexible compliance).[1] The Governor and the state's Energy Action Plan have endorsed a further goal of 33 percent renewables by 2020, in part, as a strategy for meeting the greenhouse gas emission reduction requirements of AB 32.[2] Meeting these RPS goals will require a substantial amount of new transmission development, as most large-scale renewable resources are located in remote areas rather than near the state's major load centers. The Renewable Energy Transmission Initiative (RETI) is a statewide initiative designed to identify and quantify the renewable resources that can provide cost-effective energy to meet the RPS requirements, and also to identify the transmission investments necessary to ensure delivery of that energy to California consumers.

RETI brings together renewable transmission and generation stakeholders in a process to identify, plan, and establish a rigorous analytical basis for regulatory approvals of the next major transmission projects needed to access renewable resources in California and adjacent areas. RETI is divided into three discrete phases. Phase 1 is designed to provide a project level screening and ranking of potential renewable resource zones and to broadly identify transmission requirements to access these zones. Phase 2 will examine generation and transmission in more detail and will develop conceptual transmission plans to the highest-ranking zones. Phase 3 is intended to support transmission owners in developing detailed plans of service for commercially viable

[1] SB 1078 established an RPS of 20% by 2017. The Energy Action Plan, adopted by the Commission and the California Energy Commission (CEC) in May 2003, accelerated the completion date to 2010. SB 107, passed in 2006, codified that policy.

[2] Assembly Bill 32, Ch. 488, Stats. 2006. Executive Order S-3-05, signed by the Governor on June 1, 2005, establishes greenhouse gas emission reduction goals for California and identifies acceleration of the renewable energy goals to 33% of energy sales by 2020 as one strategy to meet those goals. See "Strategies Underway in California That Reduce Greenhouse Gas Emissions" at http://www.climatechange.ca.gov/climate_action_team/factsheets/2005-06_GHG_STRATEGIES_FS.PDF

transmission projects and to establish the basis for regulatory approvals of specific transmission projects. Phase 1 has been sub-divided into two tasks, with Phase 1A defining the resource assessment methodology, detailing study assumptions, and identifying resources to be considered in the project-level analysis (this report). Phase 1B will utilize this methodology to aggregate the identified renewable energy resources into Competitive Renewable Energy Zones (or "CREZ").

1.2 Stakeholder Collaboration

RETI is a multi-stakeholder collaborative process involving a broad range of participants, including utilities, generators, regulatory agencies, public interest and environmental groups. A collaborative process is crucial to developing consensus support for specific plans for renewable energy and related transmission development. The RETI organization includes two permanent Committees, and creates ad hoc Committees as necessary. For instance, the Stakeholder Steering Committee developed a Phase 1A Working Group to advise Black & Veatch on the development of methodologies and assumptions in Phase 1A.

1.3 RETI Study Area

The objectives of RETI are to identify renewable resources in California and adjoining areas that can deliver energy to California to meet its RPS requirements, and to identify the transmission necessary to deliver this energy. The RETI study region, depicted in Figure 1-1, includes California, Arizona, Nevada, Oregon, Washington, British Columbia, and the northern part of Baja California.

Figure 1-1. RETI Region of Study.

1.4 Methodology

Black & Veatch has developed a bottom-up approach to achieving the RETI objectives. Phase 1 of RETI involves the identification and thorough assessment of the renewable resources available to California, including the costs to develop the resources and deliver the renewable energy. To the extent possible and practical, this work incorporates the great body of work that has already been performed to assess renewable energy development potential in California. This analysis brings together many previously disparate pieces of information. For example, renewable energy potential assessments are combined with information from the utility Transmission Ranking Cost

Reports to identify potentially opportune renewable energy projects. Similarly, a recent study conducted by AWS Truewind for the California Energy Commission's Intermittency Analysis Project will be used as a first screen for identification of 100+ potential wind projects. Adding to this body of information, Black & Veatch incorporates its knowledge of resource technologies, costs and performance to update and augment available information. Finally, Black & Veatch will work to ensure consistency in assumptions and approach so that all resources are evaluated against common metrics without bias. Throughout this process stakeholders will be engaged to provide input on assumptions, methodologies and results.

Many of the potential renewable resources in the RETI study area are located in common areas and would be attached to the transmission system at a common interconnection point. These aggregations of resource are called Competitive Renewable Energy Zones (CREZs). CREZs are ranked by their cost-effectiveness based on their developable potential, taking into account environmental concerns, the quality of the resources, the cost to develop those resources, and the cost of transmission needed to deliver those resources to load centers.

Figure 1-2 gives a graphical overview of the RETI Phase I methodology. Key aspects of this methodology are discussed in more detail below.

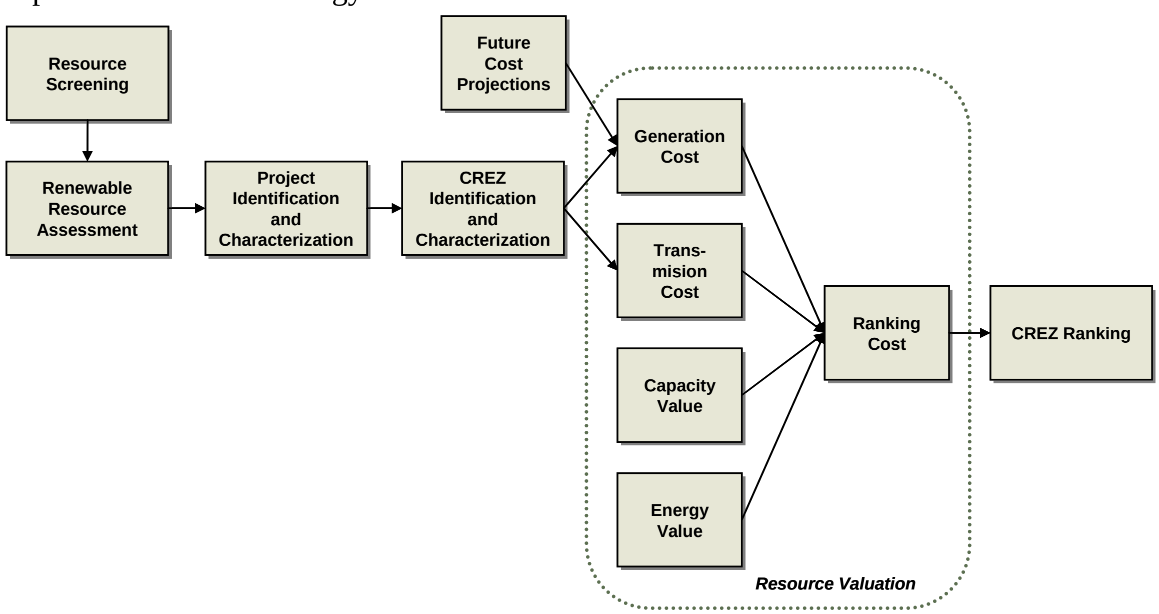


Figure 1-2. Overview of RETI Phase I Methodology.

Resource Assessment and Project Identification - RETI will assess the potential for the development of renewable technologies in the study area. After a high-level screening in Phase 1A, a more detailed resource assessment will be performed to identify potential projects. Projects will be characterized based on the cost and performance assumptions for each technology. To the extent possible, RETI will use information about actual projects in this analysis. Where those projects are not sufficient to exploit the identified resource, RETI will use generic information to develop additional hypothetical, but realistic, projects.

Resource Valuation – The economics of identified projects will be evaluated using the resource valuation methodology. This methodology allows disparate technologies and projects to be considered on a consistent basis. Resource valuation takes into account the busbar cost of generation as well as the transmission cost. RETI will not include transmission integration costs. The methodology then subtracts the energy and capacity value of the project, based on the generation profile. RETI will develop supply curves consisting of the many projects identified in the assessment. This will be used to compare projects in an economically rational fashion.

CREZ Identification and Characterization – Renewable resources will be aggregated into CREZs based on their transmission requirements, economics, and resource characteristics. CREZs may then be ranked to determine the priority for transmission development. The methodology used to design and rank CREZs includes such factors as cost, the ability of the CREZ to contribute to meeting the RPS requirements, resource development timeframe and environmental impacts.

Transmission Development – RETI will identify transmission availability, criteria for transmission additions, and estimate the costs of new transmission. RETI will use public information, such as the California utilities' Transmission Cost Ranking Report (TRCR) data and proposed transmission line information as a basis for developing transmission costs, where possible. Where public information is not available, RETI will use transmission cost information developed by Black & Veatch.

1.5 Assumptions

The RETI analysis incorporates a wide variety of assumptions including renewable demand and current generation and transmission system information, resource operating and cost assumptions, and economic assumptions. RETI Phase 1 assumptions were developed over the course of several meetings with the Phase 1A Working Group.

A key assumption was developing the "base case" or the group of generating and transmission resources the RETI process includes as the starting point for the analysis. For generation resources, this includes:

- Operating renewable generation resources;
- Renewable projects currently under construction; and

- Renewable projects in pre-construction that have all three of the following: a contract for energy sales, all major siting and construction permits and a transmission interconnection agreement.

For transmission resources, the base case includes:

- Existing transmission
- Transmission projects under construction
- Transmission projects approved by the transmission control operator

Black & Veatch has developed representative cost and performance assumptions all the major renewable energy resource types. These will be used as a general starting point for developing site-specific project characteristics in Phase 1B. These typical technology assumptions are shown in Table 1-1, with the levelized cost of generation shown in Figure 1-3. It is important to note that the levelized cost of generation is only one component of the resource valuation process. The others include transmission cost, energy value, and capacity value.

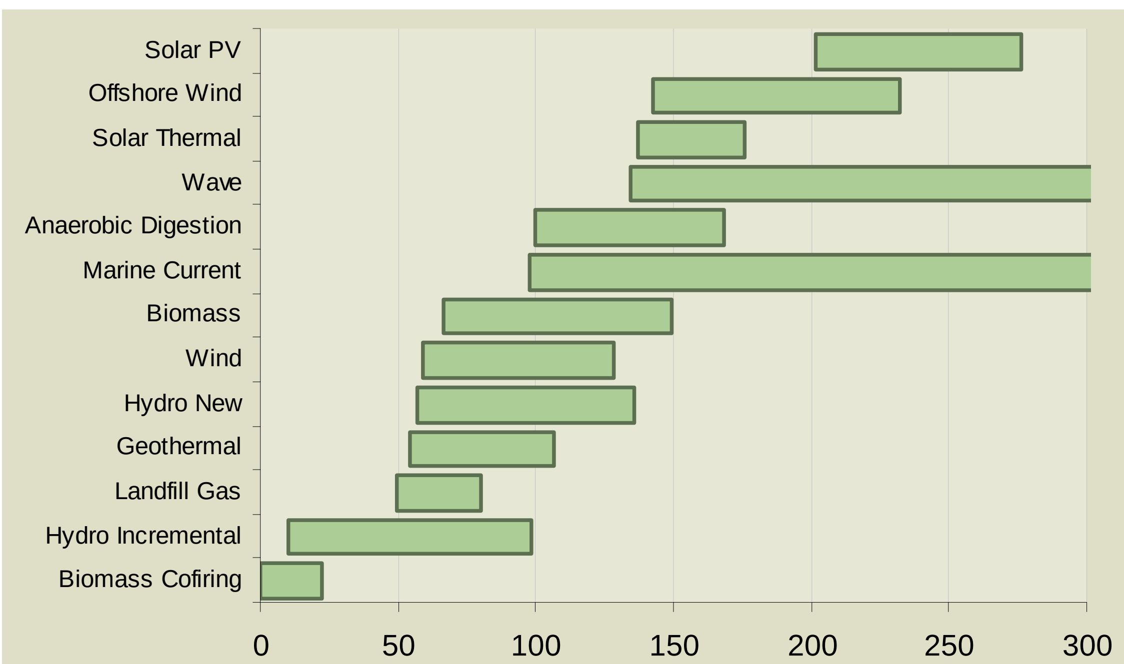


Figure 1-3. Typical Levelized Cost of Generation ($/MWh).

Table 1-1. Renewable Technologies Performance and Cost Summary.

	Net Plant Capacity, MW	Net Plant Heat Rate, Btu/kWh	Capacity Factor	Capital Cost, $/kW	Fixed O&M, $/kW-yr	Variable O&M, $/MWh	Fuel Cost, $/MBtu	Levelized Cost, $/MWh
Solid Biomass	35	14500	80	3000 to 5000	83	11	0 to 3	67 to 150
Cofired Biomass	35	10000	85	300 to 500	5 to 15		-0.5 to 1	-1 to 22
An. Digestion	0.15	13000	80	4000 to 6000		17	1 to 3	100 to 168
Landfill Gas	5	13500	80	1200 to 2000		17	1 to 2	50 to 80
Solar Thermal	200		26-29	3600 to 4200	66			137 to 176
Solar Photovoltaic	20		25-30	6500 to 7500	35			201 to 276
New Hydroelectric	<50		40 to 60	2500 to 4000	5 to 25	5 to 6		57 to 136
Inc. Hydroelectric	1 to 600		40 to 60	600 to 3000	5 to 25	3.5 to 6		10 to 98
Wind	100		25 to 40	1900 to 2400	50			59 to 128
Offshore Wind	200		35 to 45	5000 to 6000	75-100			142 to 232
Geothermal	30		70 to 90	3000 to 5000		25 to 30		54 to 107
Marine Current	100		25 to 45	2200 to 4725	90 to 255			97 to 410
Wave	100		25 to 45	2800 to 5200	150 to 270	11		135 to 445

Notes:
Levelized Cost includes applicable incentives, subsidies, etc.

1.6 Resource and Technology Recommendations

A comprehensive resource and technology review was conducted to assess the technical potential for various types of renewables (e.g. solar, wind, biomass) in the RETI study region. Resource and technology evaluation were conducted for the ten resource types listed in Table 4-1. The table also shows the technical potential for each resource across the RETI study region.

Table 1-2. Renewable Energy Technical Potential in RETI Study Region (MW).

	AZ	Baja	BC	CA	NV	OR	WA	Total
Biomass	180	N/A	2,560	4,160	42	425	1,615	8,982
Anaer. Dig.	8-18	N/A	60	85-293	0	10-13	18-203	181-587
Landfill Gas	10	N/A	22	139	6	23	17	217
Solar Thermal	316,628	N/A	0	443,799	172,181	0	0	932,608
Solar PV	N/A	N/A	N/A	*17 million*	N/A	N/A	N/A	*17 million*
Hydro	0	0	162	231	0	66	244	703
Wind	2,553	1,800	4,790	21,099	6,178	7,226	9,544	53,190
Geothermal	50	80	610	2,375	1,488	380	50	5,033
Wave	0	N/A	760	8,166	0	3,523	2,850	15,299
Marine Current			1,436	86		N/A	36	2,114

Sources: see individual report sections

Notes:

The estimates of technical potential are based on the following constraints, described in the Resource Screening section of the report.

- Solar Thermal Class 1 and higher resources, slope < 1 percent
- Solar PV Only California resources
- Hydro Projects >10 MW and <30 MW
- Wind Class 4 and higher resources
- Wave Primary sites, rated capacity

Based on the resource and technology assessments performed, Black & Veatch has developed a set of recommendations as to the resources that should be considered in Phase 1B. The determination of whether to include a resource and technology in Phase 1B was based on several factors including: likely ability of the resource to contribute to California RPS requirements due total resource potential, ability to cost-effectively deliver the resource to the California grid, and technology maturity. Based on these assessments, resources with limited potential to provide energy to California are eliminated from further review in Phase 1B. While there may be discrete resources in these regions that might provide energy to California, there are not sufficient resources in these areas to merit exploring potential new transmission to access these resources.

Each resource is discussed in more detail below.

Biomass - resources were identified in all states and regions, with California and the Pacific Northwest having substantial biomass resource potential. Based on the potential to meaningfully contribute to California's requirements RETI recommends that biomass resources in California, Oregon, Washington and British Columbia are considered further in the Phase 1B analysis.

Anaerobic Digestion - resources were identified in most areas, though the quantity was limited. Due to the small size and distributed nature of these resources, Black & Veatch does not recommend including anaerobic digestion resources in the Phase 1B analysis.

Landfill Gas – There is limited resource potential for landfill gas to meet the RPS requirements. Similar to anaerobic digestion, due to the small size and distributed nature of these resources, Black & Veatch does not recommend including these resources in the Phase 1B analysis.

Solar Thermal – The solar thermal resource is limited to the Southwest U.S. The resource assessment revealed substantial quantities of developable solar thermal resource. Black & Veatch recommends that solar thermal in California, southern Nevada and western Arizona be included in the Phase 1B analysis.

Solar Photovoltaic – Solar photovoltaic (PV) is unique among renewable technologies, as it can be located almost anywhere, and scaled to virtually any size. RETI Phase 1A identified a virtually unlimited amount of PV potential. For Phase 1B, Black & Veatch recommends incorporating only solar PV located in California as there is sufficient high-quality resource within in California to meet almost any level of demand.

Hydro – the Phase 1A analysis determined there is several hundred MW of potential small-scale (10-30 MW) hydro generation available in California, Oregon, Washington and British Columbia. The sites identified are those with the fewest environmental concerns. This is potential cost-effective and reliable generation that can provide substantial amounts of energy. Black & Veatch recommends that the small hydro resources identified between 10-30 MW be included in the Phase 1B analysis.

Wind – Wind resources were identified in all areas, though the quality of the resource differs widely. Based on the wind quality and accessibility, Black & Veatch recommends that wind be included from all regions except Arizona and northern Nevada.

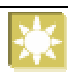
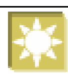
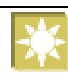
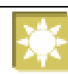
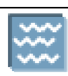
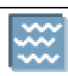
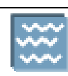
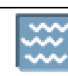
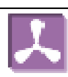
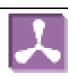
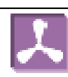
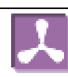
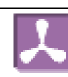
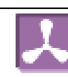
Geothermal - the Phase 1A analysis determined there is substantial geothermal development potential in California, Oregon, Nevada and British Columbia, with limited amounts elsewhere. Like hydro, geothermal has the potential to provide substantial amounts of energy. Black & Veatch recommends that geothermal located in California, Oregon, Nevada and British Columbia should be included in the Phase 1B analysis.

Wave and Marine Current – These technologies offer substantial technical potential but are unlikely to achieve a commercial level of development sufficient to contribute to California's RPS goals within the planning horizon. Black & Veatch recommends that these technologies not be brought into the Phase 1B analysis, but should be monitored for potential future inclusion in the RETI analysis.

The only Baja, Mexico area resource recommended for inclusion in Phase 1B analysis is wind. There is limited information regarding the resource potential in Mexico, but it is unlikely there will be significant renewable development for export, as there are no financial incentives for renewable energy development in Mexico and there is limited transmission between Mexico and California.

Table 1-3 identifies resources that are recommended for consideration in Phase 1B.

Table 1-3. Resource Recommendations for Phase 1B.

	CA	OR	WA	NV	AZ	Baja California, MX	British Columbia, CA
Solid Biomass							
Solar Photovoltaic							
Solar Thermal				 (south)	 (west)		
Small Hydro							
Onshore Wind				 (south)		 (north)	
Geothermal							

1.7 Phase 1B Scope of Work

Phase 1B of RETI is designed to implement the methodology developed in Phase 1A, as described in this document. The proposed DRAFT Scope of Work for Phase 1B is included as Appendix A to this report.

2.0 Introduction

The California Renewable Energy Transmission Initiative (RETI) is intended to bring together all stakeholders in renewable transmission and generation to participate in a process to identify, plan, and establish a rigorous analytical basis to inform planning and permitting for the next major transmission projects needed to access renewable resources in California and adjacent areas. The goal of RETI is to identify and quantify the renewable resources that may provide cost effective energy to meet the California Renewable Portfolio Standard (RPS) and then identify the transmission requirements to access and deliver these resources to the California electric grid.

The overall RETI project is divided into three discrete phases. Phase 1 is designed to provide an initial identification and ranking of potential renewable resource zones and to broadly identify transmission requirements to access these zones. Black & Veatch has been retained to conduct the Phase 1 analysis on behalf of the RETI Stakeholder Steering Committee (SSC). Phase 2 will examine generation and transmission in more detail and will develop conceptual transmission plans to the highest-ranking zones. Phase 3 is intended to support transmission owners in developing detailed plans of service for commercially viable transmission projects and to establish the basis for regulatory approvals of specific transmission projects.

Phase 1 has been sub-divided into 2 tasks, with Phase 1A defining the study methodology, detailing study assumptions, and identifying resources to be considered in the analysis. Phase 1B will utilize this methodology to aggregate the identified renewable energy resources into Competitive Renewable Energy Zones (or “CREZ”). A CREZ is defined as a group of renewable projects that are electrically associated that, when combined, have improved economics over individual resources.

Black & Veatch is pleased to provide to the SSC this report on RETI Phase 1A activities. This report is designed to describe to the RETI SSC the methodology, assumptions and resource information to be used in Phase 1B of the project.

2.1 Background

California has adopted a Renewable Portfolio Standard (RPS) requiring that 20 percent of electric energy be generated from renewable resources by 2010 (2013 with flexible compliance),[3] and may soon require that investor-owned utilities meet 33 percent of their needs with renewables by 2020 in order to meet the green house gas emission

[3] SB 1078 established an RPS of 20% by 2017. The Energy Action Plan, adopted by the Commission and the California Energy Commission (CEC) in May 2003, accelerated the completion date to 2010. SB 107, passed in 2006, codified that policy.

reduction requirements of AB 32.[4] Meeting these RPS goals will require a substantial amount of new transmission development, as most renewable resource areas are located in remote areas rather than near the state's major load centers. Without proactive transmission planning guided by an economic analysis of developable potential, it is difficult to know which resource areas are the most economically viable, which areas should be priorities for development, and the scale of required transmission. Transmission is costly and difficult to permit, and it has a longer development horizon than most renewable generation development. Furthermore, transmission investments typically require large expenditures at the outset of the renewable development cycle. Foresight is required in the planning of transmission development for the purpose of exploiting renewable resources. If economically inefficient resources are targeted for development, then California may burden ratepayers with "stranded costs" to connect transmission to sub-par resources. Further, if a piecemeal approach is taken to develop transmission to individual resources, than the opportunity to develop a cost efficient, all-inclusive integrated transmission plan may be lost.

The Renewable Energy Transmission Initiative (RETI) is a statewide initiative designed to identify the transmission investments necessary for California to achieve its renewable energy goals in the most cost-effective and environmentally sensitive manner possible. RETI is intended to inform and support California renewable policy-making, regulatory activities, and planning processes. It supports, rather than supplants, existing processes, including:

- California Independent System Operator's (CAISO) interconnection reform efforts and transmission planning process, including any modifications to that planning process resulting from compliance with Order No. 890 of the Federal Energy Regulatory Commission
- California Energy Commission (CEC) energy policy development, transmission corridor designation, and power plant siting to help facilitate and coordinate the planning and permitting of renewable generation and minimize duplication of efforts
- California Public Utility Commission (CPUC) renewable resource and transmission proposal proceedings

[4] Assembly Bill 32, Ch. 488, Stats. 2006. Executive Order S-3-05, signed by the Governor on June 1, 2005, establishes greenhouse gas emission reduction goals for California and identifies acceleration of the renewable energy goals to 33% of energy sales by 2020 as one strategy to meet those goals. See "Strategies Underway in California That Reduce
Greenhouse Gas Emissions" at http://www.climatechange.ca.gov/climate_action_team/factsheets/2005-06_GHG_STRATEGIES_FS.PDF

- Publicly-owned utility resource and transmission planning processes

Additional background information on the RETI process including frequently asked questions is available on the CEC web page at www.energy.ca.gov/reti.

2.2 RETI Organization

RETI is a multi-stakeholder collaborative process involving a broad range of participants, including utilities, generators, regulatory agencies, federal land use management agencies, and public interest and environmental groups. A collaborative process is crucial to developing consensus support for specific plans for renewable energy and related transmission development. The RETI organization includes three permanent Committees/Groups, and creates ad hoc Work Groups as necessary. For instance, the Stakeholder Steering Committee developed the Phase 1A Working Group to advise Black & Veatch on the development of methodologies and assumptions in Phase 1A.

2.2.1 Coordinating Committee

The RETI effort is supervised by a Coordinating Committee comprised of California entities responsible for ensuring the implementation of the state's renewable energy policies and development of electric infrastructure, including:

- California Public Utilities Commission
- California Energy Commission
- California Independent System Operator
- Three Publicly-Owned Utility Organizations - (SCPPA, SMUD, and NCPA)

2.2.2 Stakeholder Steering Committee

The RETI Stakeholder Steering Committee (SSC) was established to support and guide the work of RETI on behalf of all stakeholders. The SSC has approximately 30 members, representing a wide range of interests including transmission owners, load serving entities, renewable generation developers, environmental groups, state and federal permitting agencies and others that will be impacted by the development of renewable resource and transmission in California.

A kickoff presentation for the Black & Veatch Phase 1A scope of work was made to the SSC on January 22, 2008. A progress report was provided to the SSC on February 27, and a presentation of the Phase 1A report was made to the SSC on March 19.

2.2.3 Plenary Stakeholder Group

The RETI Plenary Stakeholder Group (PSG) includes all participants and interested parties, and is assembled once every 2-3 months to review RETI progress and to provide input and advice to the SSC and its Working Groups. The PSG is tasked with reviewing the work of the SSC to ensure its views are represented. A kickoff presentation for the Black & Veatch Phase 1A scope of work was made to the PSG on January 22, 2008. A presentation of the Phase 1A report was made on March 26.

2.2.4 Phase 1A Working Group

The RETI SSC established an ad hoc 11-member Phase 1A Working Group to work with Black & Veatch on the RETI methodology and assumptions discussed in this report. Meeting weekly, the Phase 1A Working Group has provided valuable input into the process. Presentation materials for these meetings are available on the RETI website. The Phase 1A Working Group input and recommendations are reflected in the methodology and assumptions detailed in this report. The members of the Phase 1A Working Group included:

- Gary Allen – Southern California Edison
- Rainer Aringhoff - Solar
- Joe Bertotti – Regional Council of Rural Counties
- Linda Brown – San Diego Gas & Electric
- Mike DeAngelis, Sacramento Municipal Utility District
- Anne Gillette - CPUC
- Steven Kelly – Independent Energy Producers
- Clare Laufenberg – CEC
- John McCaull – Geothermal Developers
- Greg Morris – Biomass Developers
- Dariush Shirmohammadi – Wind Developers

The valuable contributions of these volunteers are greatly appreciated.

2.3 Objective

The overarching objective of RETI is to provide information to policymakers and stakeholders on the transmission requirements to access cost-effective renewable resources. This study takes the broadest possible perspective, attempting to integrate many different sources into a single study to develop a clear picture of a California renewable development pathway. The existing knowledge base creates a very strong foundation for this process.

RETI Phase 1 involves a thorough assessment of the renewable resources in California and adjoining regions, resulting in the identification of those areas, called Competitive Renewable Energy Zones (CREZs), which have the potential to offer California the most cost-effective renewable energy development. Phase 1 also estimates the transmission costs associated with delivering these resources to the electric grid and California energy consumers. CREZs are then ranked by their cost-effectiveness and environmental attributes, based on the renewable resource supply curves and the transmission costs to access each CREZ.

2.4 Approach

Black & Veatch has developed a bottom-up approach to achieving RETI's Phase 1 objectives. Black & Veatch's work involves the identification and thorough assessment of the renewable resources available to California and neighboring areas, including an assessment of the costs to develop those resources and deliver the energy to load centers.

To the extent possible and practical, this work incorporates the great body of work that has already been performed to assess renewable energy development potential in the RETI region of study. This analysis brings together many previously disparate pieces of information. For example, renewable energy potential assessments are combined with information from the utility Transmission Ranking Cost Reports to identify potentially opportune renewable energy projects. Additionally, recent work by AWS Truewind for the CEC's Intermittency Analysis Project is used as a first screen for identification of 100+ potential wind projects. Adding to this body of information, Black & Veatch incorporates its knowledge of resource technologies, costs and performance to update and augment available information. Finally, Black & Veatch will work to ensure consistency in assumptions and approach so that all resources are evaluated against common metrics without bias.

2.5 RETI Study Region

RETI assesses resources in California and adjoining areas that can deliver renewable energy to California cost-effectively. As shown in Figure 2-1, the RETI study region includes California, Arizona, Nevada, Oregon, Washington, British Columbia, and the northern part of Baja California. Other initiatives are currently underway to review renewable resources outside of this region.

Figure 2-1. RETI Study Region.

2.6 Report Organization

The purpose of this Phase 1A report is to detail the assumptions and methodology Black & Veatch will use in Phase 1B of the RETI analysis. This report also presents a general overview of renewable energy technologies under consideration and concludes with a high-level screening of renewable resource opportunities in the RETI region of study. Following this Introduction, this report is organized into the following sections:

- **Section 3 –Methodology**
- **Section 4 –Assumptions**
- **Section 5 – Technology Characterization**
- **Section 6 – Resource Screening**
- **Section 7 – Phase 1B Scope of Work**

3.0 Methodology

RETI Phase 1 involves a thorough assessment of the renewable resources in California and adjoining regions, resulting in the identification of those areas, called Competitive Renewable Energy Zones (CREZs), which hold the greatest potential for cost-effective renewable development. CREZs are ranked by their cost-effectiveness based on developable potential. CREZ ranking takes into account high level environmental concerns, the quality of the resources in the CREZ, the cost to develop those resources, and the preliminary, high level estimates of the cost to develop the transmission needed to deliver those resources to load centers. RETI Phase 2 will develop conceptual transmission plans for those CREZs identified as priorities in Phase 1, and include a more detailed examination of the cost effectiveness of resource procurement and transmission development for a particular CREZ as compared to other projects or resources.

This section describes the methodologies that Black & Veatch will use in the Phase 1 analysis. The section begins with a general overview of the key steps in the methodology. The remaining sections examine these steps in greater detail.

3.1 RETI Phase 1 Methodology Overview

The RETI methodology is not a single algorithm; rather it is a series of analytical processes and steps that will culminate in the development of CREZs. Figure 3-1 provides a high-level overview of the RETI methodology.

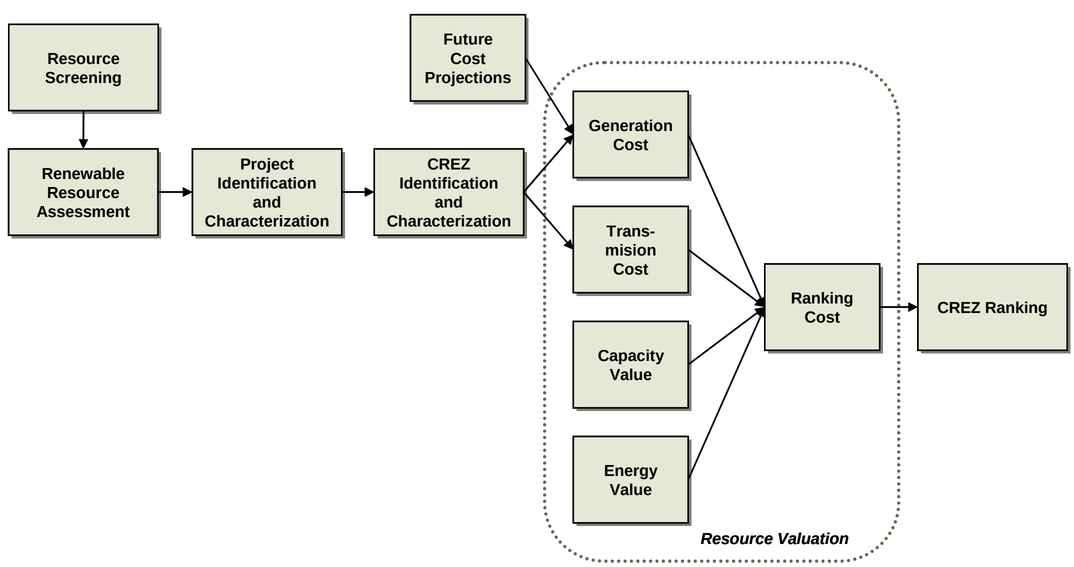


Figure 3-1. Overview of RETI Phase 1 Methodology.

The major steps in the Phase 1 methodology are briefly introduced below and then described further in the remainder of this section.

- **Base Case Definition –** Fundamental to the RETI analysis is the characterization of existing generation and transmission resources. California's RPS has existed for several years, and many projects and initiatives to develop renewables are underway. RETI will consider this existing development and use it as a starting point.
- **Resource Assessment and Project Identification –** RETI will assess the potential for the development of renewable technologies in the study area. After a high-level screening in Phase 1A, a more detailed resource assessment will be performed to identify potential projects. To the extent possible, RETI will use information about actual projects in this analysis. Where those projects are not sufficient to exploit the identified resource, RETI will use generic information to develop additional hypothetical, but realistic, projects.
- **Transmission Interconnection and Development –** Meeting California's ambitious renewable policy goals will require the construction of new transmission infrastructure to deliver energy from cost-efficient resource areas to the electric grid. RETI has developed a methodology to identify transmission availability, criteria for transmission additions, and a process for developing and allocating high-level cost estimates.
- **Technology Characterization –** RETI has developed characterizations for the different resource technologies considered in the analysis. These "generic" characterizations are necessary in order to estimate costs of projects if that information is unavailable. This information will also be used when Black & Veatch develops "generic" projects to meet resource potential.
- **Environmental Considerations –** Many potential renewable resources are located in remote and undeveloped areas, and developing these resources and the transmission required to access them will have environmental impacts. This section will identify how RETI Phase 1 will factor environmental considerations into its analysis.
- **Resource Valuation –** A relative economic evaluation for individual projects will be developed based on a methodology that considers project costs and value. This allows disparate projects to be considered on a consistent basis, and is one of the factors used in the CREZ analysis.
- **Future Cost and Performance –** Some renewable technologies are still emerging resources while others are at a more advanced stage of technical and

commercial development. Phase I of the analysis will consider the level of technical development for resources and project performance and possible cost changes in the future as technology develops.

- **Supply Curve Development –** RETI will develop a supply curve consisting of the many projects identified in the assessment. This will be used to compare projects in an economically rational fashion.
- **CREZ Identification and Characterization** - Black & Veatch has developed a methodology to rank the potential renewable resources and aggregate these into CREZ.

3.2 Base Case Definition

Crucial to the RETI process is developing an accurate projection of the additional renewable resources that will be required to meet California's 33 percent renewable goal by 2020. California has been implementing its RPS program for several years, and utilities are actively procuring renewable energy from new and existing generators to meet these requirements. Many of the newly contracted resources are located in areas requiring substantial transmission development and they will be unable to deliver their expected (and contracted) energy without this transmission. Additionally, increasing costs for power project development and technical problems with commercializing some renewable technologies may impact the ability of some executed contracts to deliver energy. The RETI base case must balance between respecting the commercial contracts for new renewable resources that have been executed and recognizing the reality that some portion of these contracts may never be fulfilled. If RETI overestimates the amount of renewable generation required, it may result in an overbuilding of the transmission system, leading to stranded costs. On the other hand, if RETI assumes more resources will be constructed than will likely happen, it will underestimate California's future resource and transmission needs.

Similarly, an accurate characterization of the transmission system is required. The current western transmission system is highly utilized, and RETI must make assumptions regarding current and future transmission availability to assess the cost and practicality of adding resources at different points on the transmission grid.

In developing its base case, RETI assumes that all existing renewable generating resources remain in operation at their current capacity through 2020. The base case also assumes that highly probable renewable resources and transmission additions will be constructed. These assumptions are detailed below.

3.2.1 Renewable Generation Projects

The RETI base case includes existing renewable resources and those projects with a high probability of coming on-line on schedule. Identifying which resources are "high probability" is problematic, however, as there are a variety of metrics that could potentially be used to identify these resources. Criteria such as economic viability of the project (is there a Power Purchase Agreement at a high enough price to allow the project to be financed?), level of project development (does the developer control the proposed site?), access to transmission (can the project reasonably interconnect to existing transmission?), and technical feasibility all must be considered. Projects included in the base case will be assumed to exist throughout the study period and will not be studied for their economic feasibility.

Projects not included in the base case will be considered as "potential" resources. These projects will be reviewed, potentially grouped with other resources into cost-effective CREZs, and then ranked by their economic viability.

Black & Veatch consulted with the RETI Phase 1A Working Group to develop criteria for determining base case resources, which discussed this issue at length. While there was not complete consensus on which renewable generation resources to include in the base case, the majority of the Working Group endorsed a proposal that the base case include the following renewable generation resources:

- Operating renewable generation resources;
- Renewable projects currently under construction; and
- Renewable projects in pre-construction that have all three of the following: a contract for energy sales, all major siting and construction permits and a transmission interconnection agreement.

Below is a discussion of these and other renewable resource categories that were considered for the base case.

Operating Renewable Resources

California currently has approximately 6,500 MW of operating RPS-eligible renewable resources. While many of these resources have contracts that will expire within the planning horizon, or that may change or expand within the horizon, RETI anticipates these resources will continue to operate at their current level of output. Any additions to these resources will be considered as new incremental capacity. It is clear that operating resources should be included in the base case.

Existing non-hydro renewable resources are shown in Figure 3-2 and Table 3-1. There are nearly 11,000 MW of non-hydro renewable resources operating in the RETI region of study. Wind and geothermal are the dominant resources, with over 8,000 MW between the two. Biomass has nearly 2,000 MW, with solar, landfill gas, and anaerobic digestion completing the picture. It should be noted that this number represents nameplate capacity and does not reflect the different capacity factors of the resources.

These resources are simply defined by location, not by power purchaser. For example, some of the renewable resources in Oregon and Washington are serving load in California. Further, some of the California resources export power to out-of-state purchasers.

Table 3-1. Operating Non-Hydro Renewable Energy Capacity in the RETI Region (Nameplate MW).

	Anaer. Digest.	Landfill Gas	Biomass / MSW	Geo-thermal	Solar	Wind	Grand Total
Arizona		5			12		17
Baja California				720			720
British Columbia		9	537				546
California	75	252	810	2,634	420	2,356	6,546
Nevada			1	291	82		374
Oregon	3	11	280			883	1,177
Washington	4	13	341		1	1,166	1,525
Grand Total	82	290	1,969	3,645	514	4,405	10,905

Source: Black & Veatch query of Ventyx Energy Velocity database, March 11, 2008.

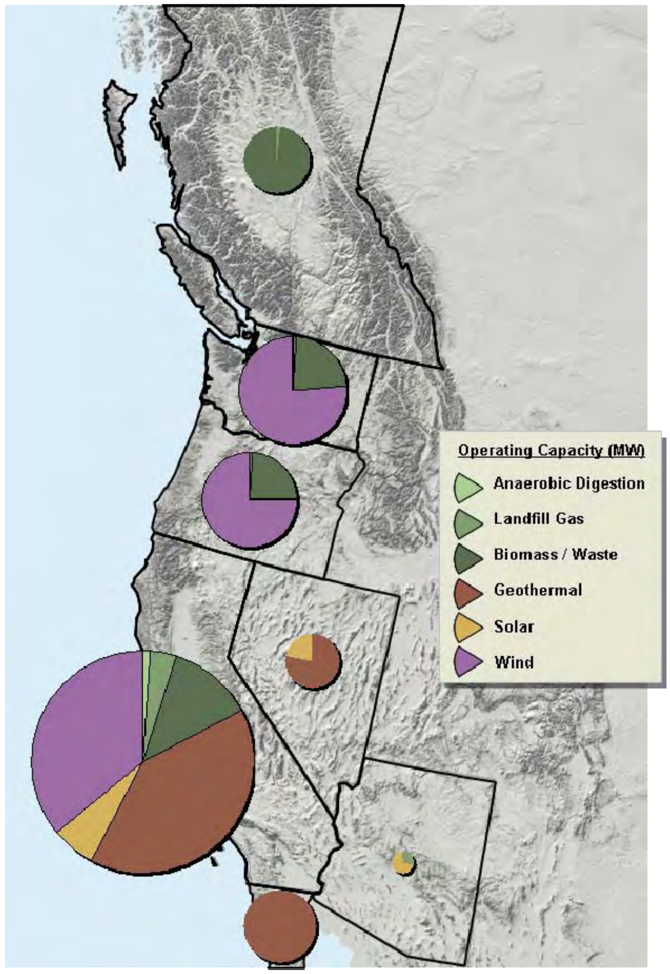


Figure 3-2. Operating Renewable Energy Capacity in the RETI Region of Study.

Renewable Generation under Construction

Generation that is under construction has a very high probability of coming on line and is included in the base case. As shown in Table 3-2, as of March 14, 2008 there were 316 MW of renewable energy projects under construction in California.

Table 3-2. Renewable Energy Projects Under Construction in California.

Plant Name	Owner	Technology	Capacity, MW
Kittyhawk	Envirepel Energy Inc	Biomass	2.2
Brawley Geothermal	Ormat Technologies Inc	Geothermal	50
Heber Geothermal	Heber Geothermal Co	Geothermal	10
Chiquita Canyon Landfill	Ameresco Inc	Landfill Gas	8
Keller Canyon Landfill	Ameresco Inc	Landfill Gas	3.8
Ox Mountain Landfill	Ameresco Inc	Landfill Gas	11.4
Alite Wind Farm	Allco Wind Energy	Wind	24
Dillon Wind	PPM Energy Inc	Wind	45
Pine Tree Wind	LADWP	Wind	120

Source: Black & Veatch query of Ventyx Energy Velocity database, March 13, 2008.

Renewable Generation with Approved and Pending PPAs

California public and investor-owned utilities have aggressively procured renewable resources in the past several years, executing contracts for over 4,000 MW from existing generators and proposed new resources since the enactment of the RPS requirement[5]. Whether to assume executed contracts as "existing" resources for base case purposes raises a number of issues. Utilities are depending on these contracts for RPS compliance, and acquisition of an executed contract requires a substantial amount of project development time and energy. Further, an executed contract indicates the resource may have commercial viability. That said, historically, not all executed contracts will result in on-line generation, and recent experience indicates many projects with PPAs are likely to be delayed, if not cancelled. Technical problems, inability to secure construction permits, and changing economics are just a few of the reasons why resources with a contract may not become operational.

In modeling projects with PPAs, RETI will make the following assumptions:

- A project will be included in the RETI base case only if it also has secured major siting and construction permits and an interconnection agreement. All other resources will be considered as "potential" resources, albeit with near-term on-line dates.
- The on-line date for the resources may be modified to reflect current expectations of delivery. RETI will use on-line dates for projects furnished by

[5] Renewables Portfolio Standard Quarterly Report, CPUC, January, 2008. http://www.cpuc.ca.gov/NR/rdonlyres/F710CD37-3053-439C-B2A4-07CCB5D8B287/0/RPS_Rpt_to_Legislature_January_2008.DOC

investor-owned utilities (IOUs) to the CPUC in March 2008 (as publicly available). For publicly-owned utilities, RETI will contact these entities to establish current expected on-line dates for their projects.

- Resources that have a range of capacity in the PPA contract will be modeled at the lowest quantity of capacity specified. The additional capacity will be considered as a separate project.

Utility-owned projects will be assessed under the same standards as other privately-owned projects.

Table 3-3. California IOU Proposed Projects with PPAs.

Technology	Minimum Contract MW		
	Approved	Pending Approval	Total
Biomass [a]	94	2	96
Geothermal [b]	245	170	415
Ocean	-	2	2
Small Hydro	1	-	1
Solar Thermal	1,452	177	1,629
Solar Photovoltaic	7	9	16
Wind [c]	525	2,022	2,547
Grand Total	2,324	2,381	4,705

Source: CPUC contract database.

This list includes facilities to be constructed or restarted/repowered. It does not include online facilities. All facilities are in California unless noted below.

Notes:

[a] One project (20 MW) is located in Oregon

[b] Two projects (160 MW) in Oregon, one project (30 MW) in Nevada

[c] One project (200 MW) is located in Northern Baja, Mexico.

Short-listed and MOU Resources

The contract process for resources is long, and California utilities are constantly procuring additional future renewable generation. California IOUs have been issuing annual RPS solicitations for several years and are expected to continue this practice. From these solicitations, utilities develop a “short-list” of resources they will pursue contracts with, though there is no certainty that executed contracts will be developed for each of these resources. Similarly, utilities have signed “Memorandum of Understanding” (or MOU) agreements with developers to participate in the development of renewable facilities, with the expectation these agreements will lead to contracts or ownership of resources in the future.

For purposes of Phase 1, RETI will consider these projects as “potential” resources, rather than included in the base case. Without a contract for the sale of energy, it is more unlikely these resources will be developed, and as noted above there is no certainty that a contract will result from a short-listed resource.

Proposed Resources without Utility Contracts

Many renewable developers have proposed generation projects without having a contract for the entire project output. Some of these resources may be short-listed in utility solicitations or may have an MOU for development, but no contract. The resources are at various level of development – some are purely theoretical and have no site, while others may be pursuing permits for construction and waiting in the CAISO queue. For purposes of Phase 1, RETI will consider these projects as “potential” resources, rather than included in the base case.

California Independent System Operator (CAISO) Queue Resources

As of January 25, 2008, the California ISO has received applications for transmission interconnection for over 42,000 MW of renewable generation. While this is meaningful evidence of renewable developer interest in California, an interconnection application at the CAISO provides little information regarding the degree of project development or project viability. Currently, anyone can submit an interconnection application to the CAISO by posting the $10,000 application fee and designating the interconnection point, the technology and potential size of the generation unit, among other items. The CAISO has embarked on an application reform process to make the process more stringent to ensure that only projects with a high probability of development submit applications and/or remain in the queue.

Confidentiality limits the amount and detail of information on interconnection applications available to RETI. The CAISO makes public general project location, interconnection point, potential MW, resource type, and on-line date, but does not provide more specific information to assess the viability of a project. Without access to additional information, it is not possible to determine, of the 42,000 MW, which resources are contracted, short-listed, or simply proposed. For this reason, RETI will use the information available in the queue as an indication of commercial interest in a general area, requiring further investigation in Phase 1B.

Table 3-4 shows the active ISO queue applications by technology. Figure 3-3 shows the applications on a map of California. Location of projects is shown as the point of interconnection, not the actual project location.

Table 3-4. California ISO Interconnection Queue.

Technology	MW of Active Projects
Biomass	102
Geothermal	297
Small Hydro	0
Solar Thermal	15,567
Solar Photovoltaic	7,052
Wind	19,070
Grand Total	**42,087**

Source: California ISO Queue (public version), accessed January 25, 2008.

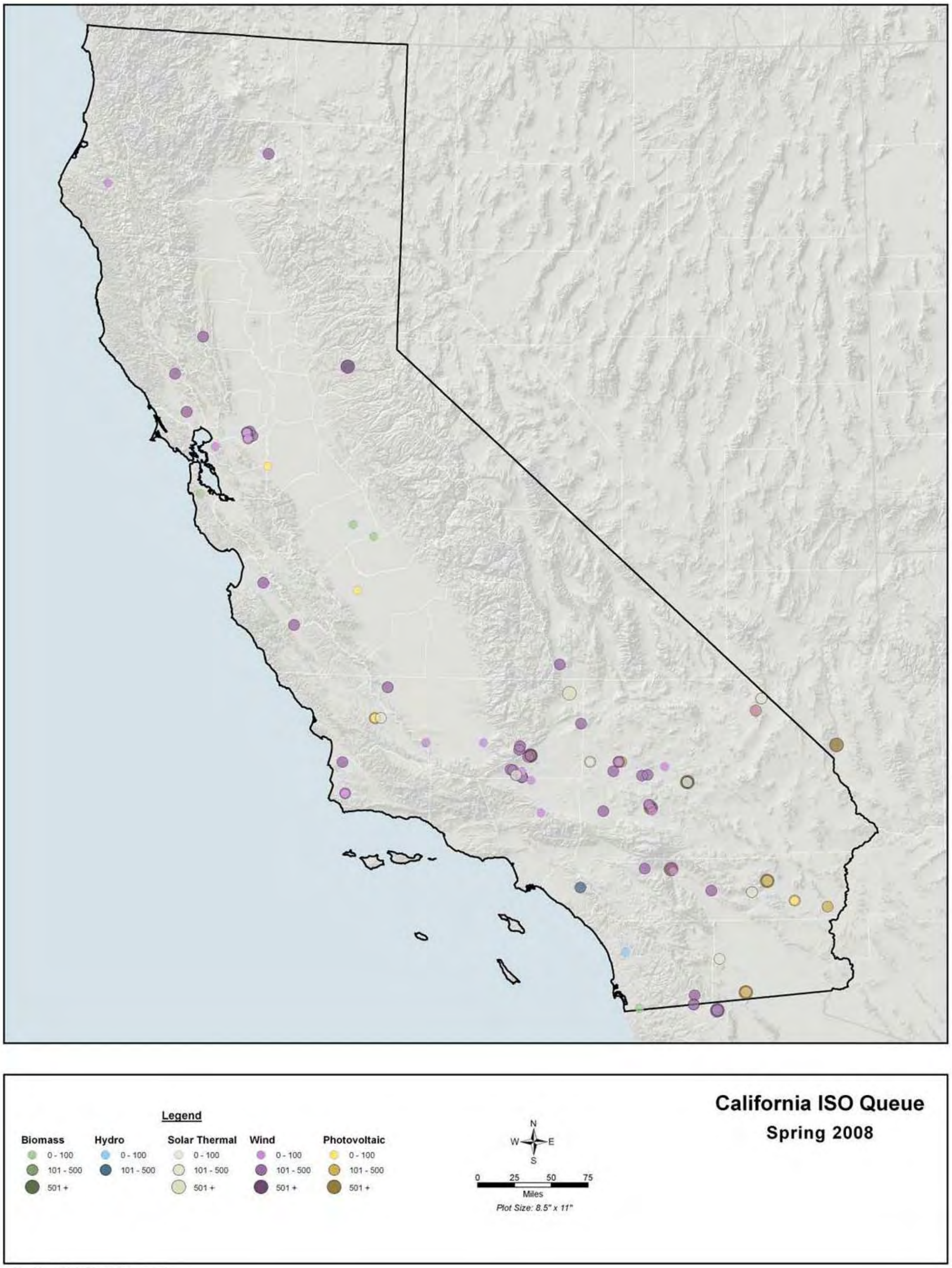


Figure 3-3. General Renewable Locations in CAISO Queue (data:CEC, CAISO).

Bureau of Land Management (BLM) Land Applications

The California Desert District of the BLM has received hundreds of applications for developing solar and wind projects on BLM land. The applications total 66,000 MW on 1,800 square miles of land, far more capacity than is required to meet California's RPS requirement. As with queue resources, these applications reflect commercial interest in particular areas or technologies and will be addressed as such in the Phase 1 assessment.

Figure 3-4. BLM California Desert District (source: BLM).

Table 3-5. BLM Applications.

	Acres	MW
Solar Thermal	550,000	45,000
Solar Photovoltaic	130,000	11,500
Wind	480,000	9,700*
Total	1,160,000	66,200

Source: http://www.blm.gov/ca/st/en/fo/cdd/alternative_energy.html
Notes:
* This is assuming 50 acres per MW – most of these applications were for measurement Rights of Way that did not specify MW.
This does not include applications that were rejected.

3.2.2 Transmission Resources

The RETI Phase 1 base case will include the entire California high-voltage transmission system (defined as 230 kV and above), including both CAISO-controlled and publicly-owned utility transmission facilities. The base case will also include lower-voltage transmission facilities required to access renewable resources, as well as that portion of the western U.S. high voltage transmission that may be required to allow California to import renewable resources from other states and areas. In Phase 1 the transmission analysis will be an economic rather than technical. Phase 1 will identify the cost of interconnecting California resources to the grid and the cost of importing non-California renewable resource energy to California.

Transmission Additions in the Base Case

There are several transmission lines that have been proposed to increase transfer capability for new renewable generation in California and throughout the Western Interconnection. In California, some of these lines are within the CAISO control area, while others are proposed to be owned and operated by POUs. Outside of California there are several interstate transmission lines proposed for construction in the Western Interconnection to facilitate delivery of additional energy to California and the Southwestern U.S.

Consistent with the treatment of proposed renewable generation resources, the base case will include only high probability transmission additions. Determining which additions this should include is problematic, as the transmission planning, siting, approval, and construction process can easily span a decade from initiation to completion.

Black & Veatch consulted with the RETI Phase 1A Working Group to develop criteria for determining base case resources. The Working Group discussed this issue at length. While there was not complete consensus on additions to include, the final proposal made was that the base case include existing transmission, projects under construction and projects approved by the transmission control operator. Table 3-6 identifies transmission projects to be included in the CAISO control area. Black & Veatch will work with the POUs to determine if additional proposed transmission resources controlled by these entities should be included in the base case.

Table 3-6. New Transmission Included in the RETI Base Case

Line Name	Primary Owner	Location	In-Service Year
Tehachapi 1-3	SCE	Tehachapi	2009
Tehachapi 4-11	SCE	Tehachapi	2013
Sunrise Powerlink	SDG&E	Imperial Valley	2012
Devers – Palo Verde 2	SCE	LA Basin – Arizona	2012

3.3 Resource Assessment and Project Identification

RETI is assessing all renewable resources that will likely be employed to deliver renewable energy to California through 2020. This includes a range of technologies that are technically mature and commercially available, such as wind and solar photovoltaic, and emerging technologies such as marine current and wave technologies. The resource assessment is designed to determine which resources are appropriate for inclusion in the analysis, project the resource availability in terms of size, and assess the relative competitiveness of the resources for each region in the analysis. Resources under consideration for this study include:

- Biomass
- Biogas
- Solar
- Hydroelectric
- Wind
- Geothermal
- Marine current
- Wave

This section describes the approach to resource assessment, screening, and project identification.

Resource Assessment and Data Sources

RETI builds on the large and excellent foundation of existing studies and analyses from the CEC, the National Renewable Energy Laboratory (NREL), industry groups, universities, utilities, and other sources. Section 6 of this report identifies the data sources used for each renewable energy resource.

Many analyses have been performed on renewables in California and it is not the objective of RETI to simply duplicate or update past analyses. What differentiates RETI from the previous analyses is the broad view that RETI takes. RETI provides a detailed analysis of resource potential in the western North America., and with a much larger geographic perspective than previous work. This provides for consistent technical and economic assessment of resources and transmission using common assumptions and methodology, which hereto for has not been available to policy-makers, generators, utilities or others interested in renewable resource development. This provides RETI with the necessary information to identify and select the most cost effective CREZs.

RETI will incorporate and expand upon the existing body of work to develop current characterizations of renewable resources and identify projects relevant to California today. Existing data sources contain a wealth of information and data, but it is important to recognize the limitations of previous analyses. Much of the information available in the public domain is now out-of-date. Costs have been increasing rapidly for a variety of factors. According to the Power Capital Costs Index developed by IHS Inc. and Cambridge Energy Research Associates, the cost of new power plant construction has increased 19 percent in the most recent 6 months, 27 percent over the past year, and 130 percent since 2000.[6]

The RETI work will also be additive in other respects:

- Many studies have just focused on the technical potential of renewables, while disregarding economic constraints to develop that potential. Other studies have focused either on a single resource (such as wind), on a single area (such as the Imperial Valley), or very specific issues (such as the intermittency of renewables). Finally, some important projects (such as the CEC's Strategic Value Analysis) do not consider potentially valuable resources, such as small hydro and wave energy. No single study has yet answered the question: "of all available resources through 2020, what renewables should be developed first, and where?"
- Most analyses assume a single fixed cost and performance per technology type (class 3 wind, flash geothermal, biomass, etc.). However, even within a resource category, there are wide variations in renewable projects that impact the cost of generation from any given project. The use of supply curves allows representation of the varying cost of renewables (see discussion near the end of this section, Supply Curve Development). Such models may demonstrate that renewable resources can have shallow supply curves, with the "lowest hanging fruit" developed first and more expensive resources developed later. Use of supply curves is particularly important for California given the relatively high 33 percent RPS target. For example, to assume that all wind in the state has a capital cost of $1900/kW would likely underestimate actual costs for more remote and difficult to construction sites.
- Past work has generally not defined project-specific resources and costs. The resolution of many past estimates has at best been county-level or regional data (e.g., there is a total potential of 3500 MW of wind in Kern County). RETI will identify actual developable projects on a site-by-site basis. Project specific performance and costs will be estimated. This is approach is necessary to develop meaningful supply curves and ultimately CREZs that reflect actual developable potential and realistic costs.

[6] Power Engineering, "Power plant construction costs rise 27 percent", February 24, 2008.

Resource Screening

RETI includes consideration of resources, projects, and potential CREZs. Broadly, "resource" means renewable resource, such as solar, wind, biomass, etc. Projects are the individual proposed developments to use the resource. A "project" is an identified (or generic) development that has a specific capacity and location. A CREZ, described in detail in the CREZ Identification and Characterization section below, is a aggregation of projects that have cost economies by being combined. The relationship of the resource, project and CREZ is shown in Figure 3-5.

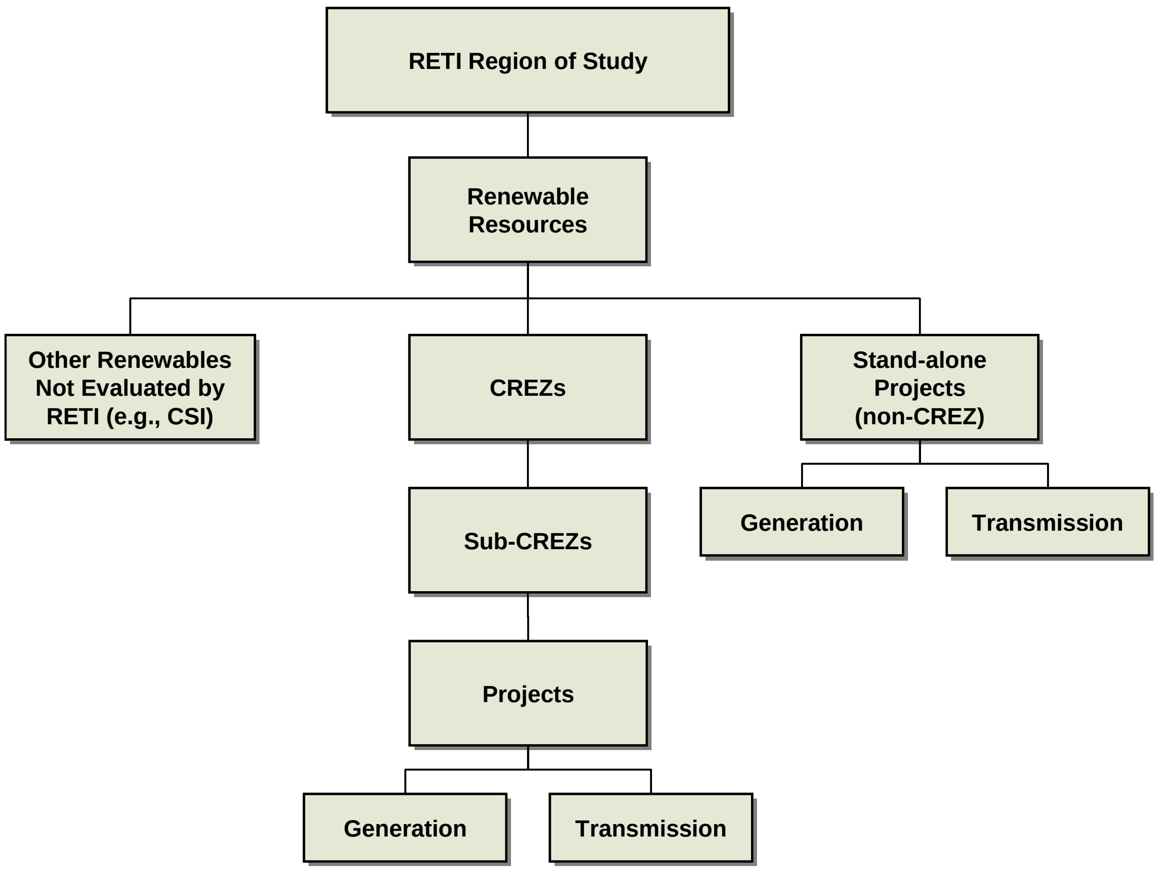


Figure 3-5. RETI Structure.

RETI starts with definition of the study region. This has been established to be California, Arizona, Nevada, Oregon, Washington, British Columbia, and the northern part of Baja California. Within this region there are numerous potential renewable resources that may be commercially viable. This Phase 1A report performs a high-level assessment and screening of those resources and regions. The objective of the high-level resource assessment is to identify the most promising renewable energy sources to meet

California's RPS. This screening allows Phase 1B of RETI to focus its energy on higher priority opportunities. Several criteria are considered in the resource screening:

- Technical viability
- Commercial availability by 2020
- Economically competitive over the study timeframe
- Resource has significant potential to meet California RPS

As the focus of RETI is on the transmission requirements for renewable generation, RETI is not directly evaluating projects, opportunities, or customer-sited generation and distribution-level resource additions (<10 MW). RETI will include utility and CEC forecasts of these resources if available. This in no way makes a determination on the viability of these resources, and the RETI process accounts for the potential economic development of these resources to meet renewable goals.

As a result of the initial screening process in Phase 1A resources are placed into one of several categories:

- Resources sufficiently concentrated to enable economic consideration of large-scale, shared transmission for these areas. These resource areas are often comprised of several potential projects with associated transmission. CREZs and sub-CREZs will be identified that group projects in various combinations. This process is discussed further in the CREZ Identification and Characterization section of this report. It is expected that this will constitute most of the resources and projects.
- Resources that are isolated and which support the development of stand-alone projects. These projects are of sufficient scale to be considered in Phase 1B, but there are no additional regional resources that justify forming a CREZ.
- Resources not evaluated in Phase 1B. These resources generally have limited potential to meet California RPS, are smaller projects (<10 MW) that do not require transmission, or rely on technologies which are not fully commercial. An example is landfill gas, which has relatively limited potential and is typically less than 10 MW per project site. The aggregate generation potential of these resources is accounted for, but they are not directly considered as potential projects.

Section 6 of this report summarizes the resource screening carried out for Phase 1A. The resource assessment also serves the important role of providing fundamental data to identify and characterize renewable energy projects, as described further in the next section.

Project Identification and Characterization

Whether they are stand-alone or grouped as part of CREZs, Phase 1B includes identification of specific projects including proposed and generic projects. When available, information on specific proposed projects will be used to the extent possible. If there appears to be resource potential for development in an area that is greater than the quantity of proposed defined projects, "generic" projects will be identified. Project characteristics will be estimated by Black & Veatch for each project including:

- Location
- Net plant output
- Capital costs
- Interconnection point
- Generation interconnection costs ("gen-tie")
- Fixed operation and maintenance
- Variable operation and maintenance
- Heat rate (if applicable)
- Fuel costs (if applicable)
- Incentives
- Capacity factor
- Generation profile

Development Time-frame

Projects are assigned to one of three development time-frames:

- **Near-term: now to 2012.** These represent projects which can come online in time to meet the 2013 RPS target (assuming flexible compliance). It is expected that most of these projects are already under active development and are publicly known (for example, projects with approved PPAs). For projects with PPAs, the latest stated target on-line date will be used to establish the development time-frame.
- **Mid-term: 2013-2016.** These represent projects which will require more time to come on-line due to limited development thus far or timing of new transmission.
- **Long-term: 2017-2020.** These projects likely require significant new transmission with long planning lead times. This may also include some new projects which are expected to have longer than typical development and permitting periods (for example, new hydro).

3.4 Technology Characterization

Assessing generation technology alternatives involves the identification of generic technologies whose technical and cost characteristics cause them to be worthwhile candidates for inclusion in portfolio plans. The objective of the technology characterization is to assess the various renewable energy technologies suitable for application in California and neighboring regions. This information is used in combination with resource data discussed in the previous section to screen resource options for more detailed assessment in Phase 1B. Further, the generic technology assumptions identified in Phase 1A are used as a basis for developing project specific assumptions for Phase 1B.

In some cases different types of technologies can be used to harness a renewable resource. For example, combustion, gasification, and anaerobic digestion are all potential technology options to extract energy from biomass. The technologies evaluated in Phase 1B of RETI are:

- Solid biomass
  - Direct fired
  - Cofiring
- Biogas
  - Anaerobic digestion
  - Landfill gas
- Solar
  - Solar thermal electric
  - Solar photovoltaic
- Hydroelectric
- Wind
  - On-shore
  - Off-shore
- Geothermal
- Ocean
  - Marine current
  - Wave

Section 5 of this report provides an overview of these technologies and provides typical cost and performance assumptions for each technology.

3.5 Environmental Considerations

Many of the renewable resources in the RETI study area are located in remote, environmentally sensitive areas. Phase 1 includes a "fatal flaw" environmental screening, with environmental impacts considered when evaluating generation and transmission resources. This environmental screening will focus on ensuring that resources and transmission are not located on protected or sensitive lands. Water and land impacts will also be assessed and, where possible, quantified. RETI will provide general environmental information for the siting of transmission and generation projects. This information is expected to be informative but not definitive -- any transmission or generation project that seeks to begin actual construction will still undergo, as part of existing permitting process, more targeted and thorough environmental impact review.

3.5.1 Environmental Screening of Resource Areas

Areas designated to be environmentally sensitive, such as federally designated wilderness and National Parks, were excluded from the resource assessment performed in Phase 1A. The full list of these exclusion zones was developed by NREL and is discussed in more detail in Section 6. By screening these areas from the Phase 1A analysis, their associated resources are considered undevelopable and are not included in RETI's initial resource assessment.

In Phase 1B, RETI will identify and assess potential resources in more detail. For this phase, a more comprehensive exclusion list will be developed that will include sensitive habitat areas, state parks, and other environmentally sensitive areas. RETI will form an environmental working group to develop these detailed screening criteria. The working group will take into account existing work from the CEC as well as input from a wide variety of environmental groups and other stakeholders.

While RETI aims to provide valuable information about the environmental impact and feasibility of renewable generation and transmission within the study area, it will not perform an official state or federal environmental impact assessment. The RETI analysis produces outputs that may be used in such processes, but individual transmission and generation projects will still need to follow established environmental processes.

3.5.2 Environmental Metrics

RETI Phase 1 will provide important information regarding the impacts of the renewable development modeled in the analysis, including estimates of:

- General location of generation projects, and proximity to sensitive areas, habitats, etc.
- Land use for generation and transmission projects.

- Water use by generation projects
- Air emissions of generation projects

By producing estimates of these metrics, RETI will assist in understanding the cumulative environmental impact from the renewable development necessary to meet California's RPS requirements.

3.5.3 CREZ Environmental Ranking

In addition to the economic metrics that rank CREZs, RETI plans to include environmental factors in the ranking criteria. Such criteria for rating the environmental attributes of CREZs will be developed with input from the environmental working group. The criteria might take into account such factors as miles of new right of way required, impacts to sensitive habitats, water use, and other issues.

3.6 Transmission Methodology

A key component of RETI is the identification and cost assessment of new transmission facilities required to interconnect renewable resources to the transmission grid. Most of California's renewable-rich resource areas are location-constrained and will require some level of transmission investment, in addition to facility interconnections, to deliver significant amounts of energy to the grid.

RETI Phase 1 will identify high-level transmission requirements for connecting projects to the California grid. This is a screening-level assessment to identify high-level transmission needs, projected development time-frame (i.e. near, mid, long-term), and approximate costs. The primary purpose for this is to develop transmission timing and costs for the project screening process. For example, the resource assessment may indicate that a wind project in a given location is economically viable today, but if the transmission required to get this energy cannot be developed until 2015, the resource will not be considered for development in RETI until 2015. In Phase 2, RETI will develop more detailed transmission designs and specific costs for individual projects and CREZs.

In developing transmission assumptions, including available transfer capacity and cost information, RETI will use existing publicly available information to the extent possible.

3.6.1 Interconnection Points - Available Transfer Capability and Cost

Each resource and CREZ will be linked to an existing interconnection point on the California high-voltage transmission grid. The determination of which point the CREZ will be associated with will depend on the physical location of the resources and electrical relationship of resources. (i.e. two resources tapping into the same transmission line but located 40 miles apart may be included in the same CREZ). Non-California resources will be assumed to connect to the grid at the nearest CAISO delivery point.

Transmission costs for individual projects will depend on several factors, including: the CREZ grid interconnection point; available transfer capability at the interconnection point; the amount of proposed generation in the CREZ; and the cost of transmission development in the CREZ (CREZ development is further discussed in Section 3.10). The allocation of transmission costs to individual projects is on a dollar-per-megawatt ($/MW) basis for all expected new generation located in the CREZ.

The transmission availability and cost assumptions for resource interconnects to disparate transmission points is discussed below and summarized on Table 3-7.

California IOU Interconnection Points

Transmission availability and cost estimates are available for California transmission interconnection points owned by California IOUs. As part of the RPS procurement process, California IOUs are required to provide estimates of the Available Transfer Capacity (ATC) for grid interconnection points on their respective systems, as well as the estimated network upgrade costs to increase the ATC at these points. This information is included in utility Transmission Ranking Cost Reports (TRCR).[7]

California Non-CAISO Interconnection Points

POUs do not make their ATC publicly available. To develop transmission availability for non-CAISO transmission, RETI will seek comparable data for POU interconnection points in California, but outside of the CAISO control area.

Non-California Interconnection Points

RETI anticipates that there will be a substantial quantity of renewable resources identified outside of California. To deliver energy to California, generators must interconnect to the local utility and transmit the power to the CAISO control area.

[7] The latest version of the TRCRs at the time of this writing included:
"Pacific Gas and Electric Company 2008 Solicitation Protocol", February 29, 2008. http://www.pge.com/includes/docs/pdfs/b2b/wholesaleelectricsuppliersolicitation/2008protocolagreementRev022908.pdf; "SCE Conceptual Transmission Requirements and Costs for Integrating Renewable Resources", September 6, 2007., http://www.sce.com/nrc/rfp/2008_RPS_Appendix_D_SCE_TRCR.pdf,; "Transmission Cost Ranking Report of San Diego Gas & Electric Company (U 902E) for Renewable Portfolio Standard Procurement", September 10, 2007, http://www.sdge.com/regulatory/tariff/svc%20TRCR%20Filing.pdf .

There is currently limited interstate transmission capacity available to import energy into California, though several proposed high-voltage transmission facilities that would increase energy transfer capacity to California are currently being studied by the Western Energy Coordinating Council (WECC). For Phase 1, RETI will assume that all non-California renewable generation will require new high voltage transmission to send energy to California. The cost of the transmission will be based on the cost of a new 500 kV transmission link from the generating facility to the California grid interconnection point, assigned on a pro-rata basis.

Table 3-7. Transmission

Transmission Category	Methodology	Transmission Cost
California resources interconnecting to CAISO on existing/upgraded transmission lines	Resources will be added to existing transmission network up to the maximum level identified in the TRCR for that point. Resources in excess of the max. identified MW at a given location will be assumed to require new transmission.	Utility TRCR for network upgrades based on project interconnection point up to max. MW seeking interconnection. Resources above that level will be assumed to require pro-rata transmission on a new transmission line.
California resources interconnecting w/ POU	To be determined – Phase 1B activity	To be determined – Phase 1B activity
Non-California Resources interconnecting w/CAISO	All non-California resources assumed to be connected to new high-voltage transmission. Simplifying assumption that all new transmission will be 500-kV	Pro-rata allocation of 500-kV cost, based on $/MW-mile from project to California delivery point.
California resources interconnecting to CAISO using new transmission lines	New California lines will be constructed to the level or resource identified within the development timeframe.	Based on level of proposed resource in the CREZ in the timeframe

3.6.2 Transmission Cost Additions

RETI Phase 1 will include estimated costs for transmission additions that may be required to connect discrete projects and CREZs to the grid. This will approximate the cost of transmission facilities required to meet the project or CREZ requirement, and include new transmission, substations and ancillary facilities required to support the new transmission. Only generation to be developed within the time-horizon (i.e. near, mid, or long-term) will be considered when sizing a transmission line.

3.6.3 Transmission Costs

The Phase 1 transmission costs will be a proxy for costs associated with transmission and energy delivery, including capital costs and operating costs, as set forth below:

- Network and transmission infrastructure costs – For purposes of the Phase 1 economic valuation, the cost of new transmission facilities will be allocated pro-rata to all new generation projects based on the capacity of the project.
- Wheeling charges (transmission access charges for CAISO resources) - This includes the variable cost of transmitting power charged by the control area operator.
- Facility interconnection (or "gen-tie") costs - These are not considered as part of the transmission cost in RETI. The gen-tie cost is unique to each generating facility and is considered as a capital cost for the individual project and treated as such in the RETI analysis.
- Firm Transmission Rights (FTRs) and Congestion Revenue Rights (CRRs) - Many generators have FTRs, which allow them access to the CAISO transmission system. In addition, the CAISO offers CRRs, a financial tool to hedge against CAISO generation curtailments. RETI recognizes there is value to FTRs and CRRs, but it is impossible at this time to determine the value of these for any given transmission line. Consequently, RETI Phase 1 will make no assumptions regarding FTRs or CRRs.
- Integration Costs – Discussed in more detail in Section 3.7 the interconnection of intermittent and as-available resources will likely impact the operation of the transmission system and result in higher costs for transmission. RETI Phase1 makes no assumption regarding these costs.

3.7 Resource Valuation

For RETI to assess and rank projects for the supply curve development, it must first develop a method to measure the economics of resources on a consistent basis. Renewable technologies all have different characteristics, with different cost requirements and energy delivery patterns. Resource valuation is a way to measure different renewable resources on a comparable basis.

Black & Veatch has developed a valuation process designed to provide a single ranking value to a resource. This process is intended to identify those resources with the combination of lowest cost and highest value. Individual project ranking values will be used to develop supply curves of renewable resources, and the project values will be one of the criteria used to develop and rank CREZs.

Black & Veatch's valuation approach is similar to the bid evaluation process many utilities use when procuring renewable resources. The process is summarized in Table 3-8 with the components discussed below.

Table 3-8. Resource Valuation.

Ranking Cost = Cost – Value	
Costs: Generation Costs + Transmission Cost + Integration Costs	**Value:** Energy Value + Capacity Value

The resource valuation methodology was presented to and discussed by the Phase 1A Working Group. For determination of capacity value, the Working Group suggested that determination of resource availability be based on average generation during summer months rather than average availability in all months. This change was incorporated into the resource valuation methodology.

3.7.1 Generation Cost

The cost of generation is calculated as a levelized cost of energy ("LCOE") at the point at which the project will interconnect to the existing transmission system. The LCOE for a project is the total life-cycle cost of generating electricity at the facility normalized by the total generation from the facility and is calculated in terms of dollars per megawatt hour ($/MWh). LCOE provides a consistent basis for comparing the economics of disparate projects across all technologies and ownership.

For each project, a pro forma financial analysis is conducted to determine the life-cycle cost. This pro forma model uses input assumptions for key project variables to determine expected revenues, costs, and year-by-year after-tax cash flow over the project life. The pro forma model used in RETI is consistent with that used by the CEC in its

Cost of Generation model. It is also very similar to the model used by the CPUC to calculate the Market Price Referent (MPR), with the necessary modifications to make the calculations appropriate for renewable resources, including the modeling of tax incentives, accelerated depreciation, and other incentives.

The analysis includes appropriate assumptions for each project. Some assumptions are tailored to be technology specific, such as financing terms and appropriate tax incentives. Other assumptions such as capacity factor and capital cost may depend on geography and the available natural resource. These will be assessed on a project-specific basis in Phase 1B. Facility-specific costs included in the generation costs are:

- Capital costs
- Generation interconnection costs ("gen-tie")
- Fixed operation and maintenance
- Variable operation and maintenance
- Heat rate (if applicable)
- Fuel costs (if applicable)
- Incentives
- Net plant output
- Capacity factor
- Economic life

General economic, financing and incentive assumptions common for technology classes are discussed in Section 4, while technology-specific performance and cost assumptions are discussed in Section 5.

3.7.2 Transmission Cost

Similar to generation costs, transmission costs in the Phase 1 analysis will be calculated as the levelized cost of transmission ("LCOT"). This includes the cost of any transmission network infrastructure upgrades required to interconnect with the grid, and also all wheeling charges (transmission access charge for CAISO) to deliver the energy. The cost of connecting the generating project to the grid (or "gen-tie" cost) is part of the facility costs and will be included in the generation cost of the project. The LCOT for a project is the total cost of transmission upgrades normalized by the total generation from the facility and is calculated in terms of ($/MWh). Wheeling costs are be added to the network costs.

Transmission assumptions will vary by project, depending on the location, interconnection point, and transmission upgrades required to provide transmission access to the facility. For instance, a project located in Washington and selling into the California market will pay wheeling costs from its point of interconnection to the CAISO, and will also pay the CAISO transmission access fee.

3.7.3 Integration Cost

The integration cost of a project is the indirect operational cost to the transmission system to accommodate the generation from the project into the grid. The addition of substantial amounts of intermittent and as-available renewable resources will result in substantial generation swings on the transmission system, and the grid operator must accommodate these swings by ensuring there is sufficient regulation service, modifications to current daily ramps, additional reserve capacity and voltage support. Additional integration costs will include wear-and-tear on resources if they are required to repeatedly cycle to adjust for the intermittent resource output. The CAISO released an Integration of Renewable Resources analysis in November 2007 and determined that to add an additional 4,100 MW of wind resources in the Tehachapi area would require additional regulation service and adjustments to current ramping practices.[8]

While there is anecdotal evidence that large scale integration of renewable resources will result in additional system costs, these costs have not been quantified to date for California. It is expected that the costs will be relatively small compared to the generation and transmission components of the cost analysis. RETI will not use an integration cost in Phase 1, though Black & Veatch recommends that this issue be reconsidered in the RETI Phase 2 and subsequent analyses.

3.7.4 Capacity Value

The capacity value of a generating resource is based on its ability to provide dependable and reliable capacity during peak periods when the system requires reliable resources for stable operation. Resources that can provide firm capacity will have a higher capacity value than resources that cannot. In California capacity value is assessed by the resource adequacy value. Current resource adequacy practice considers the average resource capacity factor during the 12:00 p.m. – 6:00 p.m. period year-round. However, based on guidance from the Phase 1A Working Group, RETI will limit this to determination of capacity factor during the summer months (June-September). For the purposes of RETI, this average summer peak capacity factor is known as the “capacity credit.”

[8] California Independent System Operator, “Integration of Renewable Resources”, available at: http://www.caiso.com/1ca5/1ca5a7a026270.pdf, November 29, 2007.

The baseline value of capacity is the cost of the next most likely addition of low-cost capacity, defined as the fixed carrying costs of a simple cycle gas turbine generator. This includes the capital costs, fixed operations and maintenance costs, and other fixed charges associated with the gas turbine generator capacity, expressed as a dollar per kilowatt per year ($/kW-year). The capacity value does not include variable costs, such as fuel purchases.

This baseline capacity value is adjusted for each project based on its capacity credit. Resources that are more “firm” receive a higher capacity credit. As discussed previously, the capacity credit is the average capacity factor for a project during the period from 12:00 p.m. – 6:00 p.m. during summer months. For new projects, this is derived from the projected 24 hour by 12 month generation profile for the resource. When projects are near currently operating generation, the CAISO’s net qualifying capacity (NQC) values can be used to help determine an appropriate capacity credit.[9] For example, for new wind resources in the Southern California Edison territory, the capacity credit would be 23 percent. For simplification, the comparative capacity credit for the baseline gas turbine generator is assumed to be 100 percent.

There are other methods to calculate the capacity credit, such as the effective load carrying capability (ELCC), that might be more accurate. However, basing the capacity credit on the current resource adequacy approach is relatively straightforward from an analytical perspective and also consistent with current regulatory practice.

The example Table 3-9 shows the capacity value calculation for three hypothetical projects based on a hypothetical baseline capacity value of $100/kW-year and hypothetical capacity factors. This example is included for illustrative purposes only. The capacity value in dollars per kilowatt-year is calculated by multiplying the capacity credit by the baseline capacity value. Kilowatt-years are then converted to megawatt-hours using the project’s annual capacity factor. The formula for calculating capacity value ($/MWh) is:

Capacity Value ($/MWh) =
(Capacity Credit) x (Baseline Capacity Value) / 8760 hr / (Capacity Factor)

[9] CAISO, “NQC, Local Area Data and TAC Wind Factor Data for Compliance Year 2008 – Final” available at: http://www.caiso.com/1833/1833e95e5f760.xls, accessed March 11, 2008.

Table 3-9. Example Capacity Value Calculation.

	Wind	Solar	Biomass / Geothermal
Capacity Credit (CF in summer 12-6)	25%	90%	100%
Baseline Capacity Value ($/kW-yr)	$100	$100	$100
Capacity Value ($/kW-yr)	$25	$90	$100
Annual Capacity Factor	35%	35%	90%
Capacity Value ($/MWh)	$8.15	$29.35	$12.68

Note: Hypothetical example, for conceptual illustration only.

The baseline capacity value is the levelized fixed costs of a simple cycle gas turbine generator, owned by a merchant generator. This value is sourced from the CEC Cost of Generation report. The determination is outlined below in Table 3-10.

Table 3-10. Baseline Capacity Value ($2007)

Levelized Fixed Costs of a Simple Cycle Gas Turbine Generator ($/kW-yr)	
Capital & Financing - Construction	$137
Insurance	$8
Ad Valorem Costs	$7
Fixed O&M	$13
Corporate Taxes (w/Credits)	$39
Total Fixed Costs	$204

Source: CEC Comparative Cost of California Central Station Electricity Generation Technologies, CEC-200-2007-011-SF, December 2007.

3.7.5 Energy Value

The energy value of a resource assesses the value of its hourly output to the energy markets. Resources that produce more power during high-price, peak demand periods will have a higher energy value than resources that provide power primarily during low demand periods.

The value of the energy generated by a project is based on a market price forecast developed using a production cost model. In Phase 1B RETI will use a price forecast developed by an independent entity using their assumptions rather than assumptions developed by RETI. Black & Veatch believes this bifurcation of tasks is appropriate to avoid any appearance that RETI assumptions will "drive" the analysis towards a particular set of resources or technology.

The production cost model is anticipated to include 15 zones (identified in Table 3-11, below) and will produce prices for each zone. Energy generated by projects located within these zones will be valued at the price forecast in the zone. The price periods to be used include the WECC traded periods: off-peak, on-peak, and super-peak. Generation profiles for each renewable resource are used to value the output during these time periods.

Table 3-11. Energy Value Price Zones.

N. California (NP15)	Imperial I.D.	N. Nevada
C. California (ZP26)	Imperial V. -NG	S. Nevada
SCE	CA/OR Border (COB)	Palo Verde
LADWP	Pacific Northwest	Arizona
SDG&E	British Columbia	N. Baja (Mex.)

The hypothetical example in Table 3-12 illustrates the energy value calculation for three projects located in the same price zone. For this simple example, only two time periods are shown, day and night. The average energy value is the weighted average of the energy value of every megawatt-hour of energy generated. The formula for calculation of energy value is:

Energy Value ($/MWh) =
Σ [(Energy Value in Time Period) x (Energy Output in Time Period)] / Total Energy Output

Table 3-12. Example Energy Value Calculation.

	Wind	Solar	Biomass / Geothermal
Marginal Energy Value Forecast ($/MWh)			
Day	$85	$85	$85
Night	$50	$50	$50
Average Production per Period (MWh/yr)			
Day	1,000	3,000	1,500
Night	2,000	0	1,500
Total	3,000	3,000	3,000
Annual Value of Energy ($/yr)			
Day	$85,000	$255,000	$127,500
Night	$100,000	$0	$75,000
Total	$185,000	$255,000	$202,500
Average Energy Value ($/MWh)	$61.67	$85.00	$67.50
Note: Hypothetical example, for conceptual illustration only.			

3.7.6 Ranking Cost

The generation cost, transmission cost, integration cost, capacity value, and energy value are combined in a single cost metric that represents the overall economic merit of a given project or CREZ. This is known as the ranking cost. The ranking cost is calculated using the following formula:

Ranking Costs =
Generation Cost + Transmission Cost + Integration Costs - Energy Value - Capacity Value

The ranking cost represents the costs of a renewable energy resource above (or below) its energy and capacity value. A lower ranking cost (including negative values), is indicative of a more cost-effective renewable energy project.

3.8 Future Cost and Performance Projections

Despite recent cost increases driven by commodity price, high demand and a decline in the value of the U.S. dollar, development costs for renewable energy technologies have generally improved significantly over the past 30 years. These trends may continue in the future as new concepts are introduced, tested in pilot and demonstration programs, and then accepted in the marketplace.

The technologies under consideration for this study include:

- Solid biomass
- Anaerobic digestion
- Landfill gas
- Solar thermal
- Solar photovoltaics
- Hydroelectric
- Wind (onshore and offshore)
- Geothermal
- Marine current
- Wave

Each of the technologies considered for RETI has some potential for technology improvement prior to 2020, the last year for new project installations in the RETI study period. However, certain technologies are considered more established than others with respect to their technology development. For example, hydro is generally considered a very mature technology, while wave energy is still in its relative infancy. Of the technologies under investigation, marine and solar have the largest potential for cost improvements.

The marine energy technologies (offshore wind, wave, and marine current) have significant potential for cost reductions over the next decade. However, there are currently no commercial installations for any of these technologies in North America. While it is hoped that these technologies will become commercially viable during the RETI study period, it is premature to begin the process of large-scale transmission planning at this juncture for these technologies. For this reason, consideration of marine technologies is excluded from Phase 1B, and cost improvements for marine technologies have not been forecasted. As these promising technologies develop, it is recommended that future RETI analyses revisit this assumption.

Costs for solar technologies may also decrease in the future, although this is uncertain and difficult to predict accurately. Driven by strong demand, large investments are currently being made in solar R&D and manufacturing. However, as with some other renewable technologies, high demand may lead to higher market prices for solar equipment and services. Market signals indicate that solar is economic today. Several new large-scale solar projects have been recently announced as the result of competitive utility solicitations. This indicates that large-scale solar can be competitive with other renewable technologies at current costs. Without solid evidence justifying cost declines in the future, Black & Veatch recommends that the base RETI assumptions use current solar costs. This assumption may be "tested" in an alternate scenario to see the effects of improved solar costs on recommended CREZs.

The other technologies listed above are considered relatively mature. While there may be significant improvements in the technologies, without strong evidence to the contrary, it is difficult to predict that any one technology will substantially outperform the other technology options with regard to cost improvements. All the technologies are expected to exhibit the same relative improvement.

In summary, a simplifying approach is recommended: all technologies that will be assessed in Phase 1 will be based on current 2008 technology and costs, with no relative improvements in these values among technologies.

Finally, it should be noted that RETI is expected to be a continuing process. This allows for these assumptions to be reviewed regularly and adjusted to reflect changes in technology cost and performance as they occur.

3.9 Supply Curve Development

Supply curves are used in economic analysis to determine the quantity of a product that is available for a particular price (e.g., the amount of renewable energy that can be generated within a utility system for under \$100/MWh). Typically, the more supply is needed, the higher the price. For renewable energy, supply curves are constructed by plotting the amount of generation (GWh/yr) added by each resource against its corresponding cost metric. As an example, see Figure 3-6. This figure is from a 2007 report by Black & Veatch on renewable energy resources in Arizona. In this case, generation (GWh/yr) is on the x-axis and levelized cost of energy (\$/MWh) is shown on the y-axis. This supply curve is for the year 2020 and does not include incentives, such as tax credits. The supply curve shows that there are only a few projects that would be able to supply power for under \$100/MWh by 2020. However, there is a large pool of solar resources at a cost of about \$200/MWh.

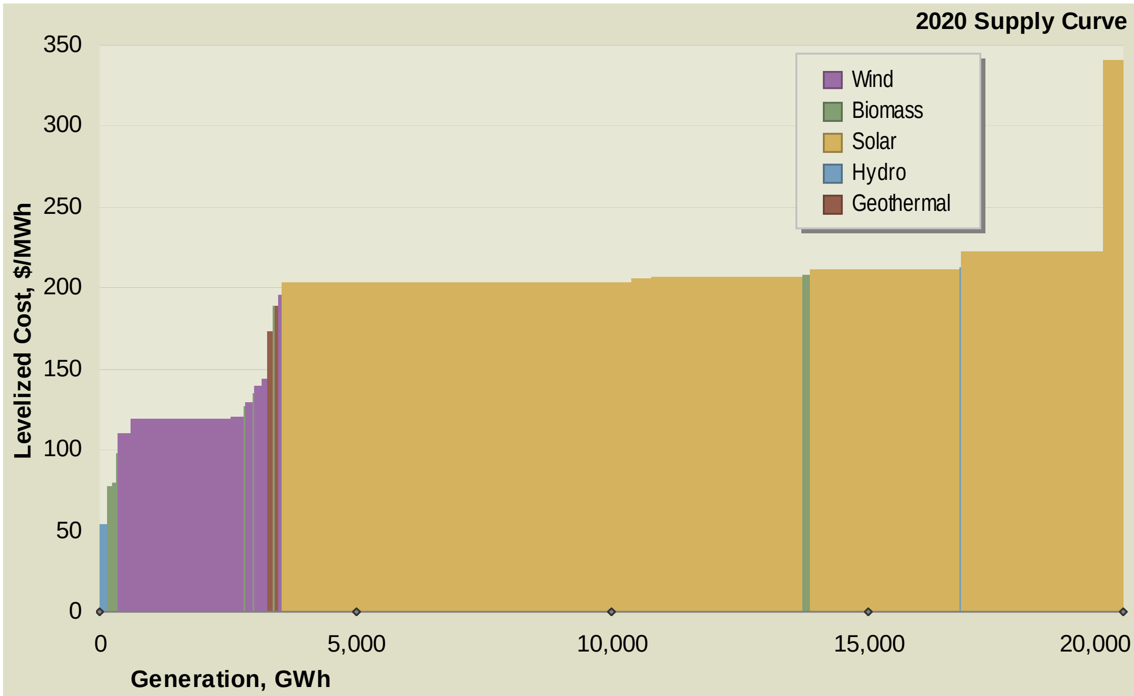


Figure 3-6. Example Supply Curve from Assessment of Arizona Renewable Resource.

Every "step" on the graph represents an individual project color-coded by its technology type. The curve compares the quantities and costs for the renewable resources and shows which products can be built at the lowest cost (resources towards the left side).

For this study, the smallest element of a supply curve will be a specific project. These projects can be grouped into sub-CREZs, CREZs, or larger clusters, depending on the situation. The supply curve is simply a method of visualizing data. Supply curves can be constructed to analyze many data sets and can be used to summarize all of the projects in a resource area, timeframe, state/province, transmission line, etc.

In the case of Figure 3-6, the levelized cost of generation is used as the cost metric. Other cost metrics can be used. For example, Figure 3-7 shows a supply curve derived from PG&E's 2007 transmission ranking cost report for the 230 kV Gregg substation. This chart shows the transmission upgrade costs required for incremental capacity additions at the substation. While generation and transmission costs are useful metrics for visualization and comparison, it is anticipated that supply curves used for ranking alternatives for RETI will be based on the ranking cost, as defined in the Resource Valuation section of this report.

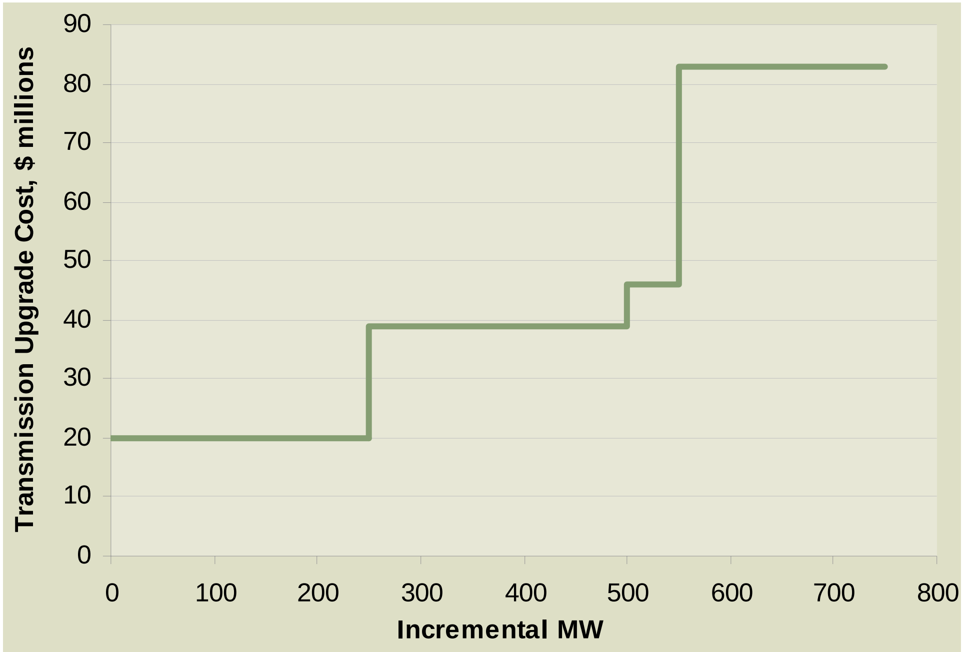


Figure 3-7. Example Transmission Supply Curve from PG&E 2007 TRCR (Gregg 230 kV).

As described earlier, the RETI analysis will be split into three distinct time periods: near-term (through 2012), mid-term (2013 to 2016) and long-term (2017 to 2020). Because a supply curve is composed of individual potential projects, different timeframes have different supply curves. Due to the time required for resource procurement, engineering, regulatory approval, transmission development, and construction, many projects are not feasibly available for energy production for several years. Of the many potential projects in California and neighboring regions, only a select few could be available over the next few years. However, by 2020, the majority of potential projects could be available. The further out the time horizon, the “longer” the supply curves become, representing a large pool of available generation.

As time proceeds, the lower cost renewable energy resources are most likely to be developed first, while higher price resources would likely be developed in future years. However, it is important to note that supply curves will change for each time period for a variety of factors, including:

- The least-cost projects are assumed to be developed first and can no longer be considered as part of the supply curves for new generation
- Minimum project development timelines constrain project development (e.g., not all wind resources could be developed in 2012)

- Improvements in technology over time
- Timing of development of proposed transmission projects enabling development of new resources
- Expiration of tax credits and other incentives

Supply curves are an idealized representation of the cost and quantity of generation resources. By their nature, they show discrete quantities of renewables theoretically available at specific costs. As with all estimates of future renewable supply and cost, they will not be 100 percent accurate. Further, there are numerous other factors to consider in addition to economics when making resource decisions. The above notwithstanding, supply curves will be an important presentation tool in Phase 1B of RETI in order to provide a basis for comparison across CREZs.

3.10 CREZ Identification and Characterization

A Competitive Renewable Energy Zone is defined as an aggregation of renewable projects that, when combined, have improved economics. A CREZ must have the following attributes:

- Multiple renewable generating projects that share a common transmission interconnection point;
- Projects with similar development time frames; and
- When combined, have improved economics over individual projects.

The purpose for developing CREZs is to identify efficiencies in transmission development that will allow for lowest-cost and most beneficial development of renewable resources.

Not all renewable projects identified will be assigned to a CREZ. An individual project will not be designated a CREZ, even if it is transmission constrained, since no cost-efficiencies would result. Further, projects which do not benefit economically from being grouped with other projects will not be forced into a CREZ. Whether an individual resource is included in a CREZ is no measure of project worthiness, as all projects will still be evaluated in the resource evaluation process, will be assigned a ranking score, and will be included in the resource supply curves and ranking process. The inclusion of non-CREZ projects in this evaluation process ensures that all renewable energy options in California are counted to meet the RPS, whether they are stand-alone 30 MW biomass projects or 2000 MW clusters of wind.

CREZ development is a multi-step process that considers the resource area and project identification, location, timing and economics. In addition to CREZs, there is also need to consider projects and sub-CREZs as elements of CREZs. The relationship of these is highlighted in Figure 3-8, discussed in Section 3.3. The remainder of this section explores CREZ identification and characterization in more detail.

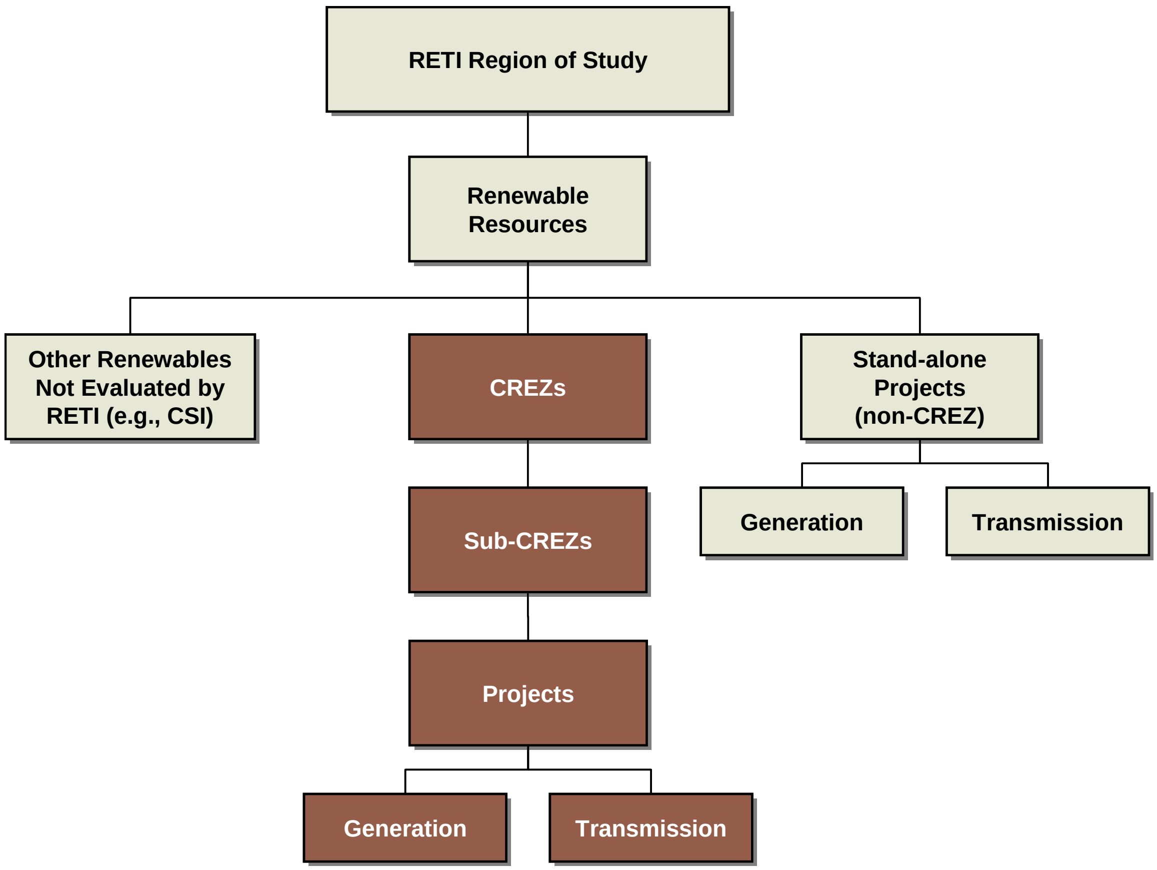


Figure 3-8. RETI Structure.

3.10.1 Resource Area Identification

The first step in CREZ development is resource identification. Resource areas are identified according to the results of the resource assessments discussed earlier in this section and may include multiple resource technologies available in different time frames. Figure 3-9 presents a conceptual resource area based on the renewable assessments.

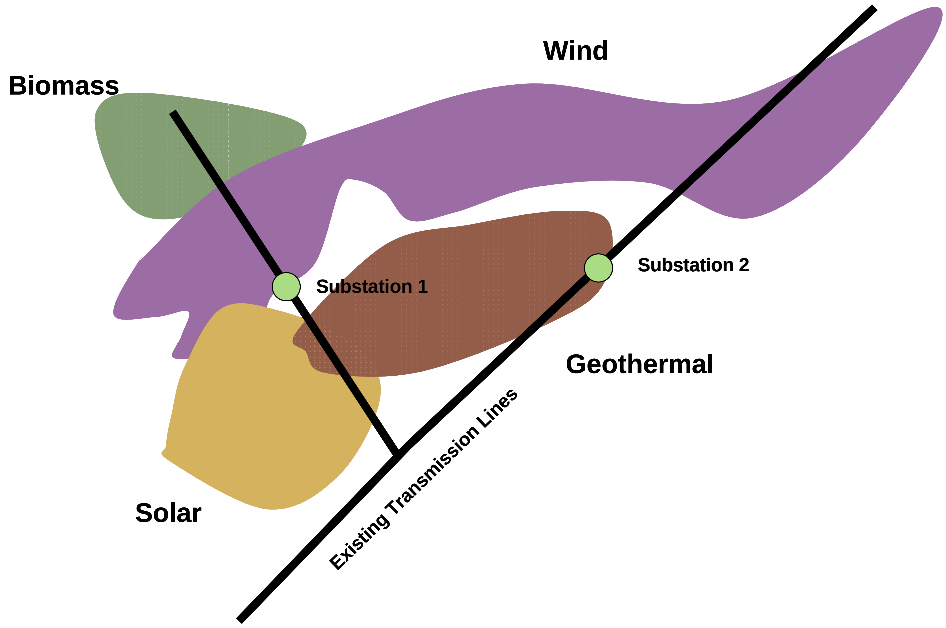


Figure 3-9. Example Renewable Resource Area.

Once the resource area has been identified and quantified, individual projects are identified within the resource area, including proposed and generic projects. If the resource assessments identify more potential in the area than is being proposed by developers, "generic" projects will be added that make use of the available resource capability in the resource area. The specific resource characteristics assumed for these generic projects are detailed in Section 5. If developers are now proposing more projects for an area than the resource assessments suggest are reasonably developable, RETI will prioritize the proposed projects based on the level of individual project development and expected energy delivery date. For example, a project demonstrating advanced development, such as an executed PPA for the sale of energy from the facility, will have priority over a project without an executed PPA. Illustrative project identification is depicted in Figure 3-10.

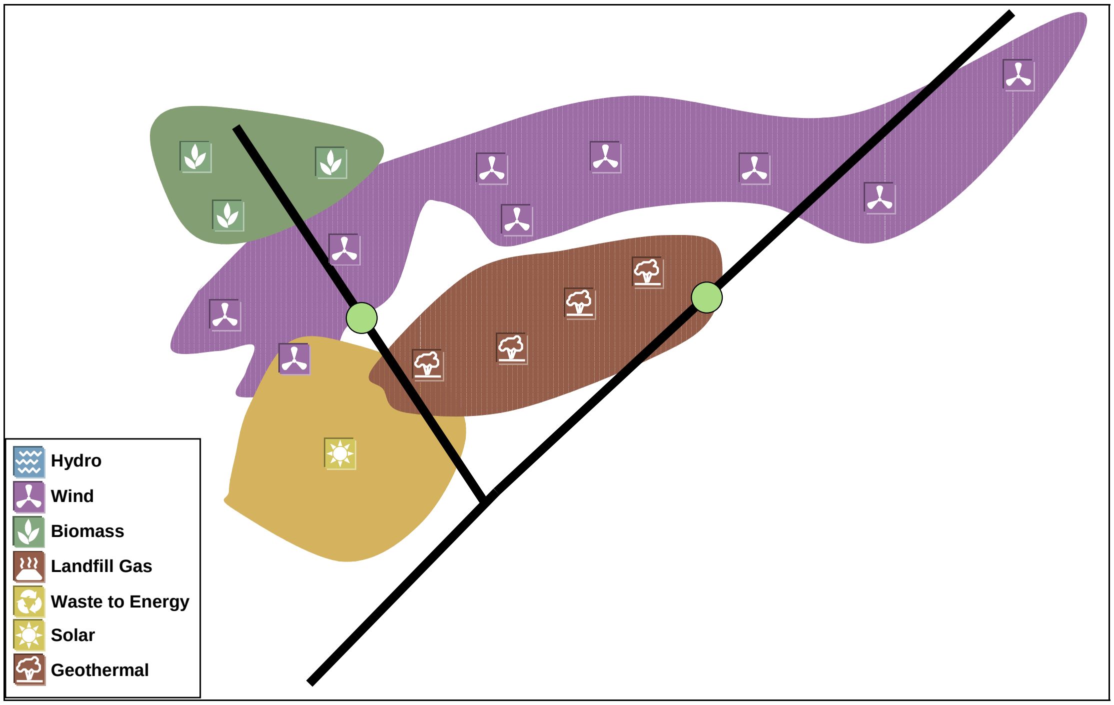


Figure 3-10. Example Project Identification.

3.10.2 CREZ Identification

To develop CREZs, projects are first grouped together based on their grid interconnection point. Figure 3-11 illustrates resources aggregated into two CREZs based on each project's physical proximity to grid interconnection points. Note that each CREZ contains multiple projects from different types of resources.

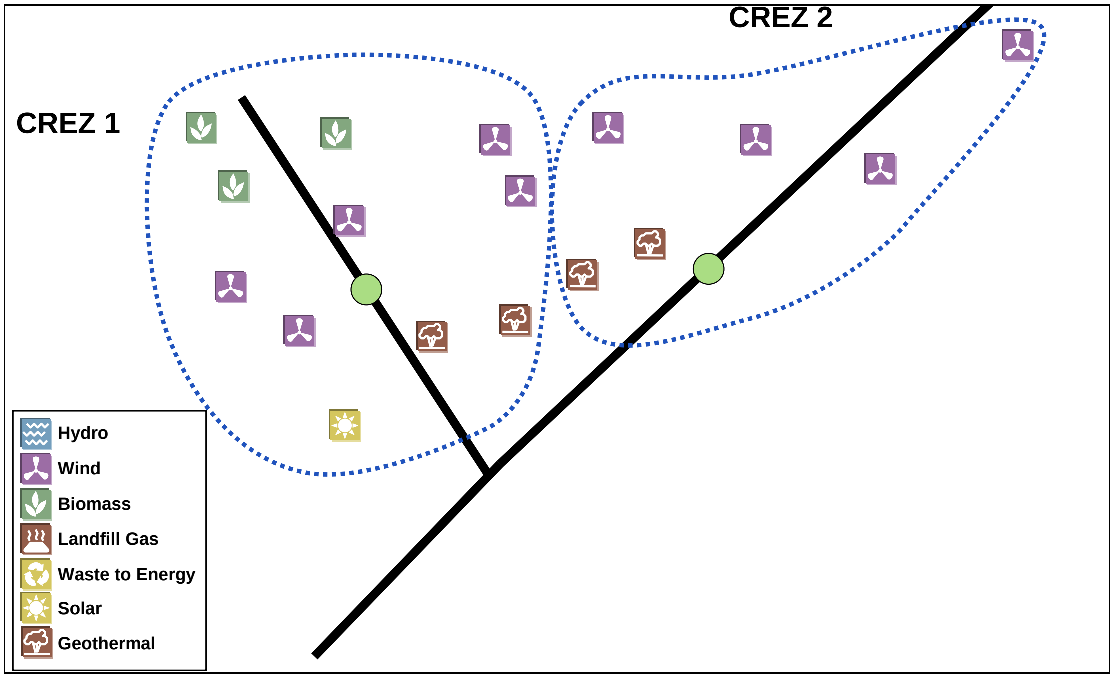


Figure 3-11. CREZ Identification.

Once a preliminary CREZ has been identified, additional analysis needs to be performed to subdivide the projects in that CREZ by common timeframe and economics. Sub-CREZs are defined to accomplish this. A sub-CREZ is comprised of one or more projects.

Development Timeframe

In the example above, CREZ 1 includes eleven projects, with the hypothetical characteristics listed in Table 3-13.

Table 3-13. Example Projects in Hypothetical CREZ 1.

Technology	Capacity (MW)	On-line date	Time Horizon
Wind	100	2010	Near-term
Wind	100	2012	Near-term
Wind	100	2015	Mid-term
Wind	100	2016	Mid-term
Wind	100	2018	Long-term
Solar Thermal	100	2019	Long-term
Biomass	100	2010	Near-term
Biomass	100	2011	Near-term
Biomass	100	2011	Near-term
Geothermal	100	2012	Near-term
Geothermal	100	2014	Mid-term

Based on the development time horizon of the projects in this example, three sub-CREZs are identified: near-term, mid-term and long-term. This is depicted on Figure 3-12 through Figure 3-14.

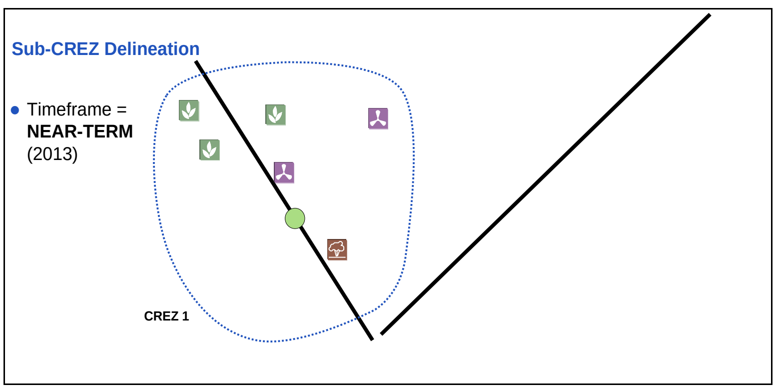


Figure 3-12. Near-Term sub-CREZ.

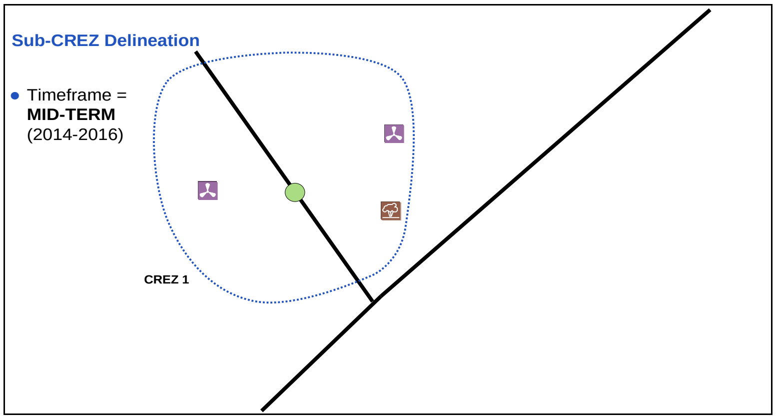


Figure 3-13. Mid-Term sub-CREZ.

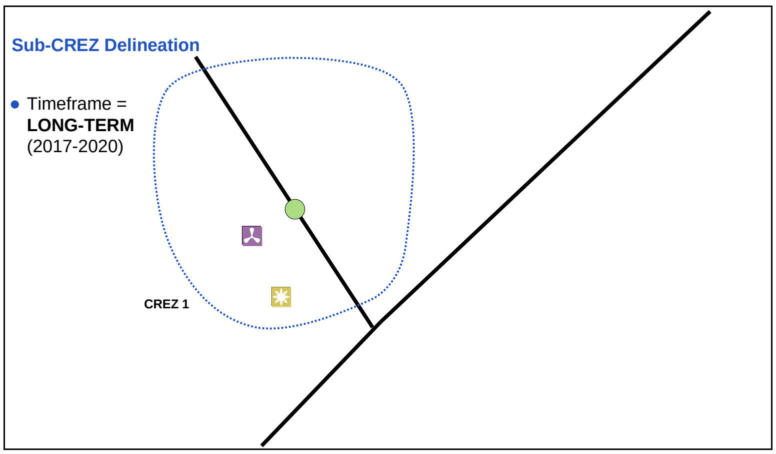


Figure 3-14. Long-Term sub-CREZ.

Economics

A fundamental criterion for a CREZ or sub-CREZ is that it must have improved economics over individual projects included in the CREZ. If adding a project to a CREZ (or sub-CREZ) worsens the economics for either the project added or the projects that are already in the CREZ, the project will not be included in the CREZ.

In the following example, two wind projects have similar economics. The ranking cost of sub-CREZ A is equal to $15/MWh and sub-CREZ B is equal to $21/MWh (ranking cost is discussed previously in the Resource Valuation discussion). In this example, if both generators were to separately connect to the grid, each generator will have to pay a $25 million interconnection cost, as depicted in Figure 3-15. In a combined sub-CREZ C, however, the two projects could share $30 million total cost for the interconnection, rather than $25 million for both independent interconnections. The aggregate ranking cost of this sub-CREZ C ($14/MWh) is less than either A or B. This is depicted on Figure 3-16. Conversely, if grouping the projects raised the cost, then the projects would be left separate and not evaluated as sub-CREZ C.

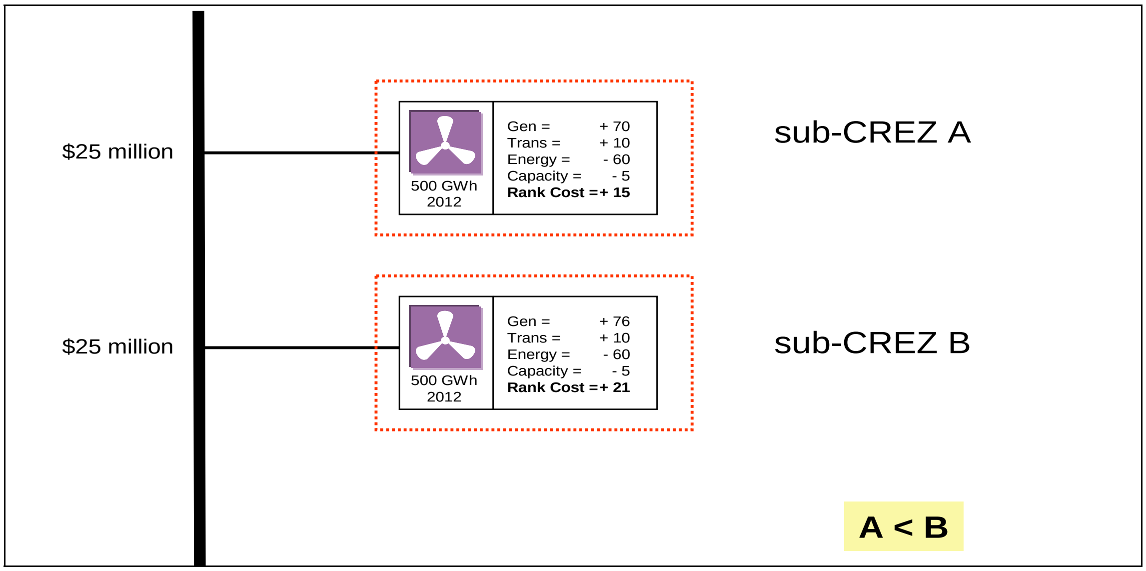


Figure 3-15. Individual Project Economics.

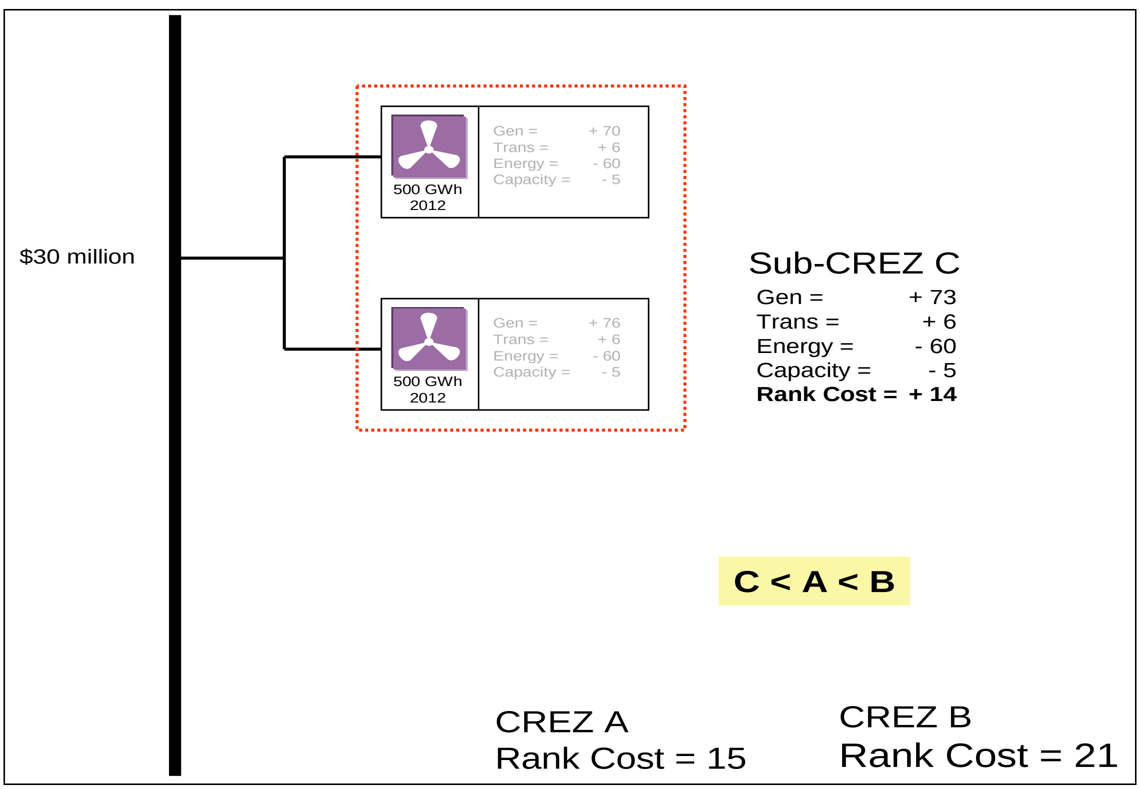


Figure 3-16. CREZ Project Economics.

3.10.3 CREZ Characterization and Ranking

Technical and economic characteristics of CREZs reflect the projects that comprise that CREZ. With the exception of transmission cost (discussed earlier in the Transmission Methodology section), the economic characteristics of a CREZ (or sub-CREZ) will simply be the sum or weighted average of the constituent project characteristics. These economic characteristics include:

- Capacity (MW)
- Generation (GWh/yr)
- Capacity factor
- Development timeframe
- Capital cost
- Operating and maintenance costs
- Fuel costs (if applicable)
- Resource valuation (generation, transmission, energy, capacity)
- Ranking cost

Each CREZ will then be assigned an economic ranking cost, analogous to the ranking cost assigned to each project as discussed in Section 3.7.6, and the CREZs will be ranked in comparison to each other and to any individual, stand-alone projects..

4.0 General Study Assumptions

This section documents the RETI Phase 1 general assumptions. This includes a discussion of the economic assumptions that apply to all new renewable projects, the financial incentives available for projects, the RPS requirements to be met, and future cost and performance projections. The numerous assumptions for renewable technologies are discussed in Section 5.

RETI Phase 1 assumptions were discussed by the Phase 1A Working Group in several meetings. The Phase 1A Working Group was generally supportive of the assumptions and recommended several modeling enhancements that will be incorporated into the study.

4.1 Economic Assumptions

Generation cost for each project is the levelized cost of energy over the life of a project. This cost is calculated by means of a pro forma financial model that characterizes the economic performance given project-specific characteristics and common assumptions about project ownership and financing for each technology type.

4.1.1 Ownership Structure

Both utilities and non-utilities can own renewable energy projects. Project ownership structure has an impact on project financing assumptions and available renewable energy incentives. For the purposes of modeling, RETI assumes that non-utility independent power producers (IPPs) own all projects, with some special exceptions.

With the notable exception of hydroelectric facilities, renewable energy projects have typically been owned by industrial and independent power producers (IPPs) with excess power sold to utilities through long-term power purchase agreements (PPAs). At the end of 2007, out of a total of about 32,000 MW of non-hydro renewable capacity installed in the US, only about 3,800 MW was owned by utilities (roughly 10 percent).[10] In California, the utility-owned fraction is even smaller. This historical dominance of IPP ownership stems from the rules of the Public Utilities Regulatory Policy Act of 1978 and the standard offer contracts of the 1980s. An additional consideration is that the lucrative 30 percent investment tax credit for solar is not generally available to utility owners.

[10] Source: Black & Veatch query of Ventyx Energy Velocity database, January 21, 2008.

For the purpose of creating a consistent and simple financial model, projects assessed in RETI Phase 1 are assumed to be owned by an IPP with a long term power purchase agreement in place. This is an appropriate structure for all of the utility-scale technologies within the scope of this project. Alternative project structures are being refined that have potential to lower the costs of renewable energy projects. However, for the purposes of identifying the relative value of CREZs, ownership structure is not a determining factor.

Private ownership may not be an appropriate assumption for a few projects which are more likely to be publicly owned. One such example would be upgrading an existing publicly-owned hydroelectric project. For these rare exceptions, adjustments will be made to the financing assumptions to reflect the financing structure of a publicly-owned project.

The Phase 1A Working Group reviewed this assumption and agreed that it was appropriate for the study. The Phase 1A Working Group recommended, however, that the model include a toggle to allow project ownership to be modified to understand the financial impacts of project ownership. This feature will be included in the model.

4.1.2 Financing Assumptions

Black & Veatch generated assumptions for the details of project financing based on the CEC's cost of generation report[11] and its own experience with project financing conventions in renewable energy. Table 4-1 outlines assumptions for each technology.

[11] California Energy Commission, "Comparative Costs of California Central Station Electricity Generation Technologies, Final Staff Report," Publication # CEC-200-2007-011-SF, available at: http://www.energy.ca.gov/2007publications/CEC-200-2007-011/CEC-200-2007-011-SF.PDF, December 6, 2007

Table 4-1. Financing Assumptions.

Technology	Economic Life	Debt: Equity	Debt Term	Interest Rate	Equity Cost	Tax Life
Anaerobic Digester	20	60/40	15	7.5%	15%	15
Landfill Gas	20	60/40	15	7.5%	15%	15
Solid Biomass	20	60/40	15	7.5%	15%	7
Geothermal	20	60/40	15	7.5%	15%	5
Small Hydro	30	60/40	15	7.5%	15%	20
Solar Photovoltaic	20	60/40	15	7.5%	15%	5
Solar Thermal	20	60/40	15	7.5%	15%	5
Wind	20	60/40	15	7.5%	15%	5
Marine Current	20	60/40	15	7.5%	15%	20
Wave	20	60/40	15	7.5%	15%	20

The economic life is the useful life of the project from the developer's perspective. The twenty year assumption for most technologies is a common term for a power purchase agreement. This is consistent with the assumed ownership structure. Hydroelectric power facilities generally have a longer life, and their economic life is extended.

The financing assumptions are the same for all technologies. It is a representative structure for the financing of renewable energy projects: 60 percent debt financed over 15 years at a rate of 7.5 percent and 40 percent equity at a cost of 15 percent. This results in a weighted average cost of capital of 10.5 percent. The debt to equity ratio is consistent with that used in the CEC's cost of generation model, as is the cost of equity. The debt term and rate are appropriate with the 20 year economic life and prevailing interest rates. The cost of equity is an approximation of the return on investment that a renewable energy project investor would require, taking into account the rate of return that an investor could receive on a comparable investment. It is understood that the cost of equity varies between technologies and projects based on the perceived risk and innumerable other factors. In the absence of a generally accepted set of assumptions, however, Black & Veatch does not see adequate justification for assuming differences. It is not feasible to attempt to forecast the perceived relative risk between technologies over the 13 year horizon of the RETI analysis.

The tax life is the depreciation schedule for project assets. Tax incentives permit accelerated depreciation for most renewable projects as described further in the next section.

There are several additional assumptions that are made to support the economic analysis:

- Combined federal and state income tax rate: 40 percent
- Discount rate: 10.5 percent
- General inflation: 2.5 percent

4.2 Renewable Energy Financial Incentives

A number of financial incentives are available for the installation and operation of renewable energy technologies. These incentives can substantially influence profitability and can make the difference between a non-viable and a viable project. The following discussion provides a brief list of existing incentives that are available to new renewable energy facilities. It should be noted that the intent of this section is to provide general information on available incentives; Black & Veatch cannot provide tax advice concerning the implications of specific incentive programs.

4.2.1 U.S. Federal Government Tax-Related

The predominant federal incentive for renewable energy has been offered through the U.S. tax code in the form of tax deductions, tax credits, or accelerated depreciation. An advantage of this form of incentive is that it is defined in the tax code and is not subject to annual congressional appropriations or other limited budget pools (such as grants and loans). Tax-related incentives include:

- Section 45 Production Tax Credit (PTC)
- Section 48 Investment Tax Credit (ITC)
- Accelerated depreciation

The Section 45 PTC is available to private entities subject to taxation for the production of electricity from various renewable energy technologies. The income tax credit amounts to 1.5 cents/kWh (subject to annual inflation adjustment and equal to 2.0 cents/kWh in 2008) of electricity generated by wind, solar, geothermal, and closed-loop biomass. The credit is equal to 0.75 cents/kWh (inflation adjusted, equal to 1.0 cents/kWh in 2008) for all other renewable energy technologies. A problem with the credit is the ever-present threat of expiration, which promotes boom and bust building patterns. Currently projects must be online by the end of 2008 to qualify for this credit (and the ITC). Assumptions about the future form and longevity of incentives are presented at the end of this section.

Major provisions of the Section 45 PTC are presented in Table 4-2.

Table 4-2. Major Production Tax Credit Provisions.

Resource	Eligible In-service Dates	Credit Size*	Special Considerations
Wind	12/31/93 - 12/31/08	**Full**	None
Biomass			
Closed-Loop	12/31/92 - 12/31/08	**Full**	Crops grown specifically for energy
Closed-Loop Cofiring	12/31/92 - 12/31/08	**Full**	Only specific coal power plants; based on % of biomass heat input
Open-Loop	Before 12/31/08	Half	Does not include cofiring
Livestock Waste	Before 12/31/08	Half	>150 kW.
Poultry Waste	10/22/04 - 12/31/03	**Full**	Incorporated with "livestock waste" with the American Jobs Creation Act of 2004
Geothermal	12/31/99 - 12/31/08	**Full**	Cannot also take investment tax credit
Solar	10/22/04 - 12/31/08	**Full**	Cannot also take investment tax credit; eligibility expired Dec. 31, 2005
Small Irrigation Hydro	10/22/04 - 12/31/08	Half	No dams or impoundments; 150 kW-5 MW
Incremental Hydro	10/22/04 - 12/31/08	Half	Increased generation from existing sites
Landfill Gas	8/8/05 - 12/31/08	Half	Cannot also take Sec. 29 tax credit
Municipal Solid Waste	10/22/04 - 12/31/08	Half	Includes new units added at existing plants

Source: Black & Veatch research.

Notes:

* All PTCs are inflation-adjusted and equaled $20/MWh ("Full") or $10/MWh ("Half") in 2007.

The Section 48 ITC effectively offsets a portion of the initial capital investment in a project. The Energy Policy Act of 2005 modified the ITC to include additional resources and to increase the credit amount. Currently, investor owned utilities are not eligible to receive the ITC. The ITC provisions are now:

- Solar – Eligible solar equipment includes solar electric and solar thermal systems. The credit amount for solar is 30 percent for projects that come online prior to December 31, 2008; otherwise, it is 10 percent.
- Geothermal – Geothermal includes equipment used to produce, distribute, or use energy derived from a geothermal deposit. The credit amount is 10 percent, but it cannot be taken in conjunction with the PTC.

The language of the PTC extension does not allow claiming of both the PTC and the ITC. Project developers must choose one or the other. For capital-intensive solar projects, the ITC is typically more attractive. For geothermal projects, the PTC is more attractive. The ITC also interacts with accelerated depreciation, as discussed further below.

Section 168 of the Internal Revenue Code contains a Modified Accelerated Cost Recovery System (MACRS) through which certain investments can be recovered through accelerated depreciation deductions. There is no expiration date for the program. Under this program, certain power plant equipment may qualify for 5-year, 200 percent (i.e., double) declining-balance depreciation, while other equipment may also receive less favorable depreciation treatment. Renewable energy property that will receive MACRS includes solar (5-year), wind (5-year), geothermal (5-year) and biomass (7-year).

The accelerated depreciation law also specifies that the depreciable basis is reduced by the value of any cash incentives received by the project, and by half of any federal investment tax credits (e.g., the ITC). This provision has the effect of lowering the depreciable basis to 95 percent for projects that receive the 10 percent ITC (and 85 percent for projects that take the 30 percent ITC).

4.2.2 U.S. Federal Non Tax-Related

Government-owned utilities and other tax-exempt entities are not able to directly take advantage of tax incentives. Tax-exempt entities, however, do enjoy a number of other benefits when financing and operating capital investments. The most obvious benefit is freedom from federal and state income tax liability. Depending on project location and local laws, payment of property taxes may also be reduced or eliminated. These entities are also able to issue tax-exempt debt, which carries lower interest rates than comparable corporate debt. As discussed previously, the default ownership assumption for RETI is IPP ownership, so these considerations will only be taken into account for specific publicly-owned projects that are identified.

The federal government has established two other primary incentive programs for non-taxable entities. These are the Renewable Energy Production Incentive (REPI) and Clean Renewable Energy Bonds (CREBs). Neither program is intended for privately-owned projects, and both rely on limited congressional appropriations. For these reasons, RETI assumes that no project will benefit from these programs.

4.2.3 U.S. State Financial Incentives

All U.S. states within the RETI study area have incentives for renewable energy projects. Black & Veatch reviewed the incentives and concluded that none would have a substantive effect on the analysis. Therefore, for the sake of simplicity, the Phase 1 assessment does not include state incentives.

4.2.4 British Columbia Incentives

British Columbia has an accelerated depreciation program and tax breaks for renewable energy. In addition, the province recently announced that a feed-in tariff is currently in development.

The central government has also recently established the EcoENERGY for Renewable Power program. This program will provide an incentive of 1 cent (CND) per kWh for up to 10 years for eligible low-impact, renewable electricity projects constructed from April 1, 2007 to March 31, 2011.

While the incentives available to renewable energy projects in British Columbia are not the same as those available to U.S. projects, the net effects are similar. For simplicity, the Phase 1 assessment models projects in British Columbia with the same incentive assumptions as projects located in the U.S.

4.2.5 Baja California, Mexico

Mexico has no noteworthy financial incentives for renewable energy development. The Phase 1 assessment models projects in Baja California without the benefit of the U.S. Federal tax credits.

4.2.6 Future Term and Nature of Incentives

The future of financial incentives is a source of uncertainly in the RETI analysis. Currently, the eligibility period for the PTC and 30 percent ITC expire at the end of 2008. Both of these incentives have a substantial impact on the cost of generation from renewables. Black & Veatch discussed this issue extensively with the Phase 1A Working Group. There is little basis on which to forecast future incentives. However, it was widely accepted that incentives will, in general and in some form, be available to renewable energy projects over the term of this study. The decision of the working group was to assume that existing financial incentives extend in their current form through the RETI study period. The model will allow the ability to "toggle" specific incentives to see the sensitivity of the results to this assumption.

4.3 Renewable Energy Demand

The RETI Phase 1B analysis forecasts the demand for renewable energy in California in order to determine the quantity of new generation that must be built. Demand is a function of California load growth, assumptions about the state's RPS, and treatment of existing resources.

California was among the first states to enact a renewable portfolio standard and currently has one of the most aggressive portfolio requirements in the country. California has adopted an RPS requiring that 20 percent of electric energy be generated from renewable resources by 2010 (2013 with flexible compliance).[12] The Governor and the state's Energy Action Plan have endorsed a further goal of 33 percent renewables by

[12] SB 1078 established an RPS of 20% by 2017. The Energy Action Plan, adopted by the Commission and the California Energy Commission (CEC) in May 2003, accelerated the completion date to 2010. SB 107, passed in 2006, codified that policy.

2020, in part, as a possible strategy for meeting the greenhouse gas emission reduction requirements of AB 32.[13] The RETI analysis assumes the 33 percent standard.

The Phase 1A Working Group reviewed the Phase 1 renewable demand assumptions and agreed that these were appropriate. It was noted that publicly owned utilities are not subject to the same RPS requirements as investor owned utilities. However, most have developed similar renewable goals, and it was agreed that the state's requirements for investor owned utilities were an appropriate proxy for all load-serving entities.

The Phase 1A Working Group also discussed whether the California Solar Initiative's (CSI) projected 3,000 MW of solar photovoltaics should be considered as a resource that will count towards the state's 33 percent renewable goal. The Working Group decided that it was likely that half of the CSI energy would somehow be used by load serving entities for RPS compliance. This will add approximately 0.7 percent renewables to the California system in 2016. RETI Phase 1 will model this energy as a renewable project.

4.3.1 California Load Growth

To project future renewable requirements RETI is using the CEC statewide load forecast prepared as part of the 2007 Integrated Energy Policy Report (2007 IEPR). The IEPR load forecast extends through 2018. To forecast loads for years 2019 and 2020 RETI inflated the 2018 statewide total electric load by 1.3 percent per year. The 1.3 percent value is the average annual growth rate in the CEC forecast.[14]

4.3.2 RPS Assumptions

RETI considers three RPS target points for generation in the analysis. The near term target is the 20 percent requirement, which RETI assumes, with flexible compliance, is met in 2013. The ultimate target is the 33 percent standard in 2020. Additionally, an intermediate goal has been set in 2016, which lies on a straight-line interpolation.

[13] Assembly Bill 32, Ch. 488, Stats. 2006. Executive Order S-3-05, signed by the Governor on June 1, 2005, establishes greenhouse gas emission reduction goals for California and identifies acceleration of the renewable energy goals to 33% of energy sales by 2020 as one strategy to meet those goals. See "Strategies Underway in California That Reduce Greenhouse Gas Emissions" at http://www.climatechange.ca.gov/climate_action_team/factsheets/2005-06_GHG_STRATEGIES_FS.PDF

[14] California Energy Commission, "California Energy Demand 2008 - 2018: Staff Revised Forecast, FINAL Staff Forecast, 2nd Edition", Publication # CEC-200-2007-015-SF2, November 27, 2007.

Table 4-3. RPS Requirements

Year	CA Load (GWh)	RPS Requirement (%)	RPS Requirement (GWh)
2013	319,757	20%	63,951
2016	331,081	26%	84,662
2020	346,997	33%	114,509

4.3.3 Existing Resources

Approximately 11 percent of California's total electric energy requirements are currently satisfied with RPS-eligible generation. Investor-owned utilities serve a somewhat higher percentage of load with renewable energy, but this is tempered by lower quantities by publicly owned utilities. Table 4-4 provides a breakdown of the existing renewable capacity by resource type.

Generation from existing renewable resources is assumed to stay constant during the RETI study period.

Table 4-4. Existing RPS-Eligible Resources.

Resource	Energy Delivery (GWh)	Percent of California Energy
Small Hydro	6,236	2.1%
Geothermal	13,708	4.7%
Biomass	6,285	2.1%
Wind	5,370	1.8%
Solar	616	0.2%
Total	32,215	10.9%

Source: CEC 2006 Gross System Electricity Production

4.3.4 RETI Net Short

California currently has approximately 6,500 MW of operating renewable resources, providing for approximately 11 percent of California's energy needs. To provide for 33 percent renewables by 2020, California requires approximately 20,000 MW of new renewable capacity (assuming 50 percent capacity factor).

The RETI net short is the generation target to be met with resources identified in this project. The net short takes into account RPS demand as well as base case resources and small renewables not directly considered by RETI. To develop the RETI net short, existing and high probability renewables will be netted from the demand (base case resources discussed in Section 3), as will RETI assumptions regarding California Solar Initiative (CSI) resource and other small renewable resources (discussed in Section 3 in detail).

RETI Net Short (GWh) =
(California Energy Demand) x (Annual RPS Requirement) – (Operating Resources – Under Construction and pre-constriction resource - CSI – Other small renewables)

5.0 Technology Assumptions

This section discusses the renewable energy technologies considered by the RETI analysis. Each discussion includes a description of the technology and an outline of the cost and performance assumptions used to model it in the analysis. The objective of this section is to characterize the various renewable energy technologies suitable for application in California and neighboring areas. The information contained in this section will be used as a starting point for project characterization in Phase 1B.

Technologies to harness renewable energy are diverse and include wind, solar, biomass, biogas, geothermal, hydroelectric, and ocean energy. Steady advances in equipment and operating experience spurred by government incentives have lead to many mature renewable technologies. The technical feasibility and cost of energy from nearly every form of renewable energy have improved since the early 1980s. However, in most countries the renewable fraction of total electricity generation remains small. This is true despite a huge resource base that has potential to provide many multiples of current electricity demand. Nevertheless, the field is rapidly expanding from the niche markets of the past to making meaningful contributions to the world's electricity supply.

The technologies evaluated in Phase 1A of RETI are:

- Solid biomass
  - Direct fired
  - Cofiring
- Biogas
  - Anaerobic digestion
  - Landfill gas
- Solar
  - Solar thermal electric
  - Solar photovoltaic
- Hydroelectric
- Wind
  - On-shore
  - Off-shore
- Geothermal
- Ocean
  - Marine current
  - Wave

Generally, each technology is described with respect to its principles of operation, applications, resource characteristics, cost and performance, and environmental impacts. The alternatives have been presented with a typical range for performance and cost, and the generic data provided should not be considered definitive estimates. A more detailed treatment of cost for promising technologies (including supply curves) will be perfomed in Phase 1B for specific project opportunities. The performance and costs are based on a representative size and installation in the Western US. Estimates are based on Black & Veatch project experience, vendor inquiries, and a literature review. In addition, an overall levelized cost range for the general technology type is provided. This levelized cost of energy accounts for capital cost (including direct and indirect costs), fuel, operations, maintenance, and other costs over the typical life expectancy of the unit. (See further description below.) A range of levelized costs is typically provided. In such cases, the low end of the levelized cost is based on the higher capacity factors and the lower capital and O&M costs. This approach is simple from a calculation perspective; however it must be noted that the low end of the costs represents and ideal "best case scenario", which is likely difficult to achieve in practice. The high end of the levelized cost is based on the lower capacity factors and the higher capital and O&M costs. Applicable financial incentives have been included in the levelized cost calculations, as indicated for each technology. These incentives are generally described in Section 4.

Calculating the levelized cost of generation allows various technologies to be compared on an economic basis. However, it is important to note that busbar costs may not always be comparable between all options. For example, it is not appropriate to directly compare the levelized cost of an intermittent wind plant with dispatchable output from a peaking plant. This is because the economic value of the peaking plant is higher than the time variant output from the wind plant. Additionally, transmission costs have not been included in the generalized levelized cost of generation. All of these additional factors will be considered in the resource valuation in Phase 1B

It should be noted that the characteristics provided in this section are general, and have been developed for the purposes of providing high-level screening information to identify the most promising technologies.

Although a few of the technologies are not commercially viable at this time, cost and performance data were assembled as available to provide a complete screening-level resource planning evaluation.

5.1 Solid Biomass

Biomass is any material of recent biological origin; the most common form is wood. Solid biomass power generation options include direct-fired biomass and cofired biomass. This study focuses on biomass combustion options for the utilization of solid biomass fuels. Biomass gasification options were excluded from this study, as direct combustion processes are employed for nearly all of the world's biomass power facilities. Gasification technologies are not yet economically competitive with direct combustion options. In addition, advanced biomass gasification concepts such as Biomass Integrated Gasification Combined Cycle (BIGCC) and plasma arc gasification, which respectively offer advantages over conventional combustion technologies of increased efficiency and ability to handle problematic waste materials, have not yet been technically demonstrated at commercial scales.

Direct-fired biomass and cofired biomass options are described in the following subsections.

5.1.1 Direct-Fired Biomass

According to the US Department of Energy, there is about 35,000 MW of installed biomass combustion capacity worldwide. Combined heat and power applications in the pulp and paper industry comprise the majority of this capacity.

Operating Principles

Direct biomass combustion power plants in operation today use the same steam Rankine cycle that was introduced commercially 100 years ago. In many respects, biomass power plants are similar to coal plants. When burning biomass, pressurized steam is produced in a boiler and then expanded through a turbine to produce electricity. Prior to its combustion in the boiler, the biomass fuel may require processing to improve its physical and chemical properties. Furnaces used in biomass combustion include spreader stoker fired, suspension fired, fluidized bed, cyclone, and pile burners. Advanced technologies, such as integrated biomass gasification combined cycle (IGCC), Plasma Gasification and biomass pyrolysis, are currently under development.

Applications

Although wood is the most common biomass fuel, other biomass fuels include agricultural residues such as bagasse (sugar cane residues), dried manure and sewage sludge, black liquor from pulp mills, and dedicated fuel crops such as fast growing grasses and eucalyptus.

Biomass plants usually have a capacity of less than 50 MW because of the dispersed nature of the feedstock and the large quantities of fuel required. As a result of the smaller scale of the plants and lower heating values of the fuels, biomass plants are commonly less efficient than modern fossil fuel plants. In addition to being less efficient, biomass is generally more expensive than conventional fossil fuels on a $/MBtu basis because of added transportation costs. These factors usually limit the use of direct-fired biomass technology to inexpensive or waste biomass sources.

Resource Availability

To be economically feasible, dedicated biomass plants are located either at the source of a fuel supply (such as at a sawmill) or within 50 miles of numerous suppliers (up to 200 miles for a very high quantity, low cost supplier). Wood and wood waste are the primary biomass resources and are typically concentrated in areas of high forest-product industry activity. In rural areas, agricultural production can often yield significant fuel resources that can be collected and burned in biomass plants. These agricultural resources include bagasse, corn stover, rice hulls, wheat straw, and other residues. Energy crops, such as switchgrass and short rotation woody crops, have also been identified as potential biomass sources. In urban areas, biomass is typically composed of wood wastes such as construction debris, pallets, yard and tree trimmings, and railroad ties. Locally grown and collected biomass fuels are relatively labor intensive and can provide substantial employment benefits to rural economies. In general, the availability of sufficient quantities of biomass is less of a feasibility concern than the high costs associated with transportation and delivery of the fuel.

Based on recent biomass resource assessments that Black & Veatch is familiar with, the expected cost of clean wood residues can vary as much as 100 percent depending on the type of residue, quantity, and hauling distance.

Cost and Performance Characteristics

Table 5-1 presents the typical characteristics of a 35 MW stoker boiler biomass plant with Rankine cycle using wood as fuel. Capital costs for standalone biomass plants can range significantly, depending on land costs, construction labor costs, and the availability of existing transmission. Areas with high costs for land and construction labor and without existing transmission will approach the upper end of the capital cost range presented in Table 5-1. For standalone biomass plants, two fuel costs scenarios were evaluated: (1) a relatively lower cost ($1.00/MBtu) scenario which would be based primarily on urban wood waste sources in the major metropolitan areas, and (2) a moderate cost ($2.50/MBtu) scenario which would be more representative of a project using forest thinnings and forestry residues. Actual fuel cost could vary significantly from the values characterized here based on local supply and demand, and transportation distance. For example, Black & Veatch has previously estimated costs for biomass resources at greater than $3/MBtu in some parts of the western United States. In these cases, transport distances were up to 200 miles. Another possible biomass fuel is dedicated energy crops, which are grown specifically to provide feedstock for biomass plants. However, experience with energy crops is very limited, and costs for these fuels would likely approach $4.00/MBtu or greater. For these reasons, electricity costs for energy crops are not provided.

Table 5-1. Direct-Fired Biomass Combustion Technology Characteristics.

Performance	
Typical Duty Cycle	Baseload
Net Plant Capacity (MW)	35
Net Plant Heat Rate (HHV, Btu/kWh)	14,500
Capacity Factor (percent)	80
Economics	
Total Project Cost ($/kW)	3,000 to 5,000
Fixed O&M ($/kW-yr)	83
Variable O&M ($/MWh)	11
Fuel Cost ($/MBtu)	0 to 3
Levelized Cost of Energy ($/MWh)	67 to 150
Applicable Incentives	Open loop: $10/MWh PTC, 7-yr MACRS Closed loop: $20/MWh PTC, 7-yr MACRS
Technology Status	
Commercial Status	Commercial
Installed US Capacity (MW)	7,000

Environmental Impacts

Biomass power projects must maintain a careful balance to ensure long-term sustainability with minimal environmental impact. Most biomass projects target utilization of biomass waste material for energy production, saving valuable landfill space. Biomass projects that burn forestry or agricultural products must ensure that fuel harvesting and collection practices are both sustainable and do not adversely affect the environment. On the positive side, biomass projects that collect forest thinnings to reduce the risk of forest fires are increasingly seen as a way to restore a positive balance to forest ecosystems while avoiding catastrophic and polluting uncontrolled forest fires.

Unlike fossil fuels, biomass is viewed as a carbon-neutral power generation fuel. While carbon dioxide (CO_2) is emitted during biomass combustion, a nearly equal amount of carbon dioxide is absorbed from the atmosphere during the biomass growth phase. Further, biomass fuels contain little sulfur compared to coal and therefore produce less sulfur dioxide (SO_2). Finally, unlike coal, biomass fuels typically contain only trace amounts of toxic metals, such as cadmium, and lead. However, biomass combustion still must include technologies to control emissions of nitrogen oxides (NO_x), particulate matter (PM), and carbon monoxide (CO) to maintain Best Available Control Technology (BACT) standards.

5.1.2 Biomass Cofiring

One of the most economical methods to burn biomass is to cofire it with coal in existing plants. Cofired projects are usually implemented by retrofitting a biomass fuel feed system to an existing coal plant, although greenfield facilities can also be designed to accept a variety of fuels.

As discussed in the previous section, a major challenge to biomass power is that the dispersed nature of the feedstock and high transportation costs generally preclude plants larger than 50 MW. By comparison, coal power plants rely on the same fundamental power conversion technology but can have much higher unit capacities, exceeding 1,000 MW. As a result of this larger capacity, modern coal plants are able to obtain higher efficiency at lower cost. Through cofiring, biomass benefits from this higher efficiency through a more competitive cost than a stand-alone, direct-fired biomass plant.

Applications

There are several methods of biomass cofiring that can be used to produce energy on a commercial scale. Provided that they were initially designed with some fuel flexibility, stoker and fluidized bed boilers generally require minimal modifications to accept biomass. For these types of boilers, simply mixing the fuel into the coal pile may be sufficient to cofire biomass.

Figure 5-1. Coal and Wood Mix.

Cyclone boilers and pulverized coal (PC) boilers (the most common in the utility industry) require smaller fuel sizes than stokers and fluidized beds and may necessitate processing of the biomass before combustion. There are two basic approaches to cofiring in this case: co-feeding the biomass through the coal processing equipment or separately processing and then injecting the biomass in the boiler. The first approach blends the fuels and feed them together to the coal processing equipment (crushers, pulverizers, etc.). In a cyclone boiler, up to 10 percent of the coal heat input can be replaced with biomass using this method. Pulverizers in a PC boiler are not designed to process relatively low density biomass, and fuel replacement is generally limited to around 2 or 3 percent if the fuels are mixed. The second approach (separate biomass processing and injection) allows higher cofiring percentages (10 to 15 percent) in a PC unit but costs more than processing a fuel blend.

Even at these limited cofiring rates, plant owners and operators have raised numerous concerns about the negative effects of cofiring on plant operations. These include the following:

- Reduced plant capacity.
- Reduced boiler efficiency.
- Ash contamination decreasing the quality of coal ash.
- Increased O&M costs.
- Minimal NOx reduction potential (usually proportional to biomass heat input).
- Boiler fouling/slagging because of the high alkali in biomass ash (more of a concern with fast growing biomass, such as energy crops).

- Potentially negative effects on SCR air pollution control equipment (catalyst poisoning).
- Reopening existing air permits.

These concerns have hampered the widespread adoption of biomass cofiring by electric utilities in the United States. However, these concerns can often be addressed through proper system design, fuel selection, and limits on the amount of cofiring.

Coal and biomass cofiring can also be considered in the design of new power plants. Designing the plant to accept a diverse fuel mix allows the boiler to incorporate biomass fuel, ensuring high efficiency with low O&M impacts. Fluidized bed technology is often the preferred boiler technology for cofiring since it has inherent fuel flexibility. There are many fluidized bed units around the world that burn a wide variety of fuels, including biomass. An example is a 240 MW circulating fluidized bed (CFB) in Finland, which burns a mixture of wood, peat, and lignite. This unit is capable of burning various fuels, ranging from 100 percent biomass to 100 percent coal.

Resource Availability

For viability, the candidate coal plant should be located within 100 miles of suitable biomass resources. The United States has a larger installed biomass power capacity than any other county in the world. The United States-based biomass power plants provide 7,000 MW of capacity to the national power grid. Coal power generation accounted for 2 trillion kWh in 2005, which comprised 49.7 percent of the total generation in the United States. Conversion of as little as 5 percent of this generation to biomass cofiring would increase electricity production from biomass by nearly 400 percent. Again, biomass cofiring does not produce new capacity. It changes the source of generation from coal to biomass.

Cost and Performance Characteristics

Table 5-2 presents the typical characteristics for a biomass and coal cofired plant. The characteristics are based on cofiring 35 MW of biomass (separate injection) in a 400 MW pulverized coal power project. Except for fuel, the characteristics are provided on an incremental basis (changes that would be expected compared to the coal plant). The primary capital cost for the project would be related to the biomass material handling system. As with direct fired biomass, biomass fuel cost is assumed to range from \$1.00/MBtu for urban wood residues to \$2.50/MBtu for forestry residues. To calculate the incremental fuel cost, coal has been assumed at a base cost of \$1.50/MBtu. The incremental biomass cost is then -\$0.50/MBtu to \$1.00/MBtu. Thus on the low-end, the biomass fuel cost is actually assumed to be \$0.50/MBtu less expensive than coal.

Analysis of the range of incremental levelized costs presented in Table 5-2 indicates that the costs to cofire biomass with coal would be relatively small. The analysis shows that the cost ranges from negligible (due to fuel possibly being cheaper than the coal it displaces) up to \$22 per MWh.

Capital costs range from \$300 to \$500. The difference between a high and a low value in this range depends on the magnitude of material handling and fuel processing equipment is required.

Table 5-2. Cofired Biomass Technology Characteristics.

Performance	
Typical Duty Cycle	Typically baseload, depends on host
Net Plant Capacity (MW)	35
Net Plant Heat Rate (Btu/kWh)	Increase 0.5 to 1.5 percent
Capacity Factor (percent)	Unchanged
Economics (Incremental Costs in 2007\$)	
Total Project Cost (\$/$kW_{biomass}$)	300 to 500
Fixed O&M (\$/$kW_{biomass}$-yr)	5 to 15
Variable O&M (\$/$MWh_{biomass}$)	Included with fixed
Fuel Cost (\$ incremental to coal price)	-0.5 to 1
Levelized Cost (\$/$MWh_{biomass}$)	-1 to 22
Applicable Incentives	None
Technology Status	
Commercial Status	Established, not fully commercial

Environmental Impacts

As with direct-fired biomass plants, the biomass fuel supply must be collected in a sustainable manner. Assuming this is the case, cofiring biomass in a coal plant generally has overall positive environmental effects. The clean biomass fuel typically reduces emissions of SO_2, CO_2, NO_x, and heavy metals such as mercury. Further, compared to other renewable resources, biomass co-firing directly offsets fossil fuel use. It may also provide an alternative to landfilling wastes, particularly wood wastes.

5.2 Anaerobic Digestion

Anaerobic digestion is a natural process that occurs when bacteria decompose organic materials in the absence of oxygen. The byproduct of this decomposition is generally composed of 50 to 80 percent methane. The most common applications of anaerobic digestion use industrial wastewater, animal manure, or human sewage as feedstock. According to Bioenergy News, the publication of the Bioenergy Association of New Zealand, Inc., the projection of total installed capacity of anaerobic digestion will grow from 185 MW in 2004 to 575 MW in 2013. The projection is that 203 MW will be installed in Western Europe, 68 MW in North America, and 46 MW in Australia.[15]

5.2.1 Applications

Anaerobic digestion is commonly used in municipal wastewater treatment as a first-stage treatment process for sewage sludge. Increasingly stringent agricultural manure and sewage treatment management regulations are the primary drivers for the heightened interest in anaerobic digestion technologies. Use of anaerobic digestion technologies in wastewater treatment applications results in a smaller quantity of biosolids residue compared to aerobic (digestion in the presence of oxygen) technologies Waste water treatment plants commonly use the biogas for process heating requirements. Power production from digestion facilities is typically a secondary consideration.

The Los Angeles Department of Water and Power has announced a new agreement to purchase power from a proposed 40 MW anaerobic digestion facility that will process 3,000 tons per day of municipal green waste, such as landscape trimmings and food waste to produce biogas for power production. The proposed facility would be the largest of its kind in the world. There are various other high-solids digestion systems installed worldwide, primarily in Europe and Japan.

Biogas produced by anaerobic digestion can be used for power generation, direct heat applications, and absorption chilling. Reciprocating engines are the most common power conversion device, although demonstrations with microturbines and fuel cells have been successful.

5.2.2 Resource Availability

For manure digestion on farms, the resource is readily accessible, and only minor modifications to existing manure management techniques are required to produce biogas suitable for power generation. In some cases, economies of scale may be realized by transporting manure from multiple farms to a central digestion facility. For central plant digestion of manure from several sources, the availability and proximity of a large number of livestock operations is necessary to provide sufficient manure feed rate to the facility. However, the larger size of regional facilities does not necessarily guarantee better economics, because of higher manure transportation costs. For anaerobic digestion of municipal sewage wastes, the resource is readily available at the wastewater treatment plant.

5.2.3 Cost and Performance Characteristics

Table 5-3 presents the typical characteristics of farm-scale dairy manure anaerobic digestion systems utilizing reciprocating engine technology. Costs for anaerobic digestion systems are very site specific. Variations in capital costs are due primarily to (1) the feedstock (substrate) being digested, and (2) the technology selected (e.g., lagoon, plug flow, or complete mix). Capacity factors range as result of the complexity of the system and availability of the feedstock. A photo of a dairy manure digester is shown on Figure 5-2.

Table 5-3. Farm-Scale Anaerobic Digestion Technology Characteristics.

Performance	
Typical Duty Cycle	Baseload
Net Plant Capacity (MW)	0.150
Capacity Factor (percent)	80
Net Plant Heat Rate (Btu/kWh)	13,000
Economics (2007$)	
Total Project Cost ($/kW)	4,000 to 6,000
Variable O&M ($/MWh)	17
Fuel Cost ($/MBtu)	1 to 3
Levelized Cost ($/MWh)	100 to 168
Applicable Incentives	$10/MWh PTC (>150 kW only)
Technology Status	
Commercial Status	Commercial
Installed Worldwide Capacity (MW)	185

[15] The World Biomass Report, *Bioenergy News*, December 2004, http://www.bioenergy.org.nz.

Figure 5-2. 135 kW Dairy Manure Digester.

5.2.4 Environmental Impacts

Anaerobic digesters have multiple positive environmental impacts: they reduce pathogens in the waste stream; they eliminate odor problems; they reduce methane emissions relative to atmospheric decomposition of manure, which are a significant contributor to greenhouse gas emissions; and they can help prevent nutrient overloading in the soil resulting from manure spreading.

5.3 Landfill Gas

LFG is produced by the decomposition of the organic portion of waste stored in landfills. LFG typically has methane content in the range of 45 to 55 percent and is considered an environmental risk. There is increased political and public pressure to reduce air and ground water pollution and to reduce the risk of explosion associated with LFG. From a generation perspective, LFG is a valuable resource that can be burned as fuel by reciprocating engines, small gas turbines, or other devices (Figure 5-3). LFG energy recovery is currently regarded as one of the more mature and successful waste-to-energy technologies. There are more than 600 LFG energy recovery systems installed in 20 countries.

Figure 5-3. Reciprocating Engine Used to Generate Power from LFG.

5.3.1 Applications

LFG can be used to generate electricity and process heat, or can be upgraded for pipeline sales. Power production from an LFG facility is typically less than 10 MW. There are several types of commercial power generation technologies that can be easily modified to burn LFG. Internal combustion engines are by far the most common generating technology choice. About 75 percent of the landfills that generate electricity use internal combustion engines. Depending on the scale of the gas collection facility, it may be feasible to generate power via a combustion turbine or a boiler and steam turbine. LFG co-firing in larger utility boilers is also in use; nearly 35 percent of all landfill gas projects in the U.S. are co-fired. Testing with microturbines and fuel cells is also under way, although these technologies do not appear to be economically viable for power generation.

5.3.2 Resource Availability

Gas production at a landfill is primarily dependent on the depth and age of waste in place and the amount of precipitation received by the landfill. In general, LFG recovery may be economically feasible at sites that have more than 1 million tons of waste in place, more than 30 acres available for gas recovery, a waste depth greater than 40 feet, and at least 25 inches of annual precipitation.

The economic life of an LFG resource is limited. After waste deliveries to a landfill cease and the landfill is capped, LFG production will decline, typically following a first order decay.

5.3.3 Cost and Performance Characteristics

The economics of installing an LFG energy facility depend heavily on the characteristics of the candidate landfill. The payback period of an LFG energy facility at a landfill that has an existing gas collection system can be as short as 2 to 5 years, especially if environmental credits are available. However, the cost of installing a new gas collection system at a landfill can prohibit installing an LFG facility. Table 5-4 presents cost and performance estimates for typical LFG projects using reciprocating engines. The low end of the capital cost range represents larger facilities employing combustion turbine technologies and minimal gas cleanup requirements, while the high end of the capital cost range represents sites with small generation capacities, employing reciprocating engines and significant gas cleanup equipment to remove siloxanes and acid gases. Facilities with multiple engines or turbines, minimal gas cleanup equipment and reliable delivery of LFG from well field tend to have higher capacity factors than those of facilities with a single engine or turbine, complex gas cleanup systems and sporadic delivery of LFG from the well field.

Table 5-4. Landfill Gas Technology Characteristics.

Performance	
Typical Duty Cycle	Baseload
Net Plant Capacity (MW)	5
Heat Rate (Btu/kWh)	13,500
Capacity Factor (percent)	80
Economics (2007$)	
Total Project Cost ($/kW)	1,200 to 2,000
Variable O&M ($/MWh)	17
Fuel Cost ($/MBtu)	1 to 2*
Levelized Cost ($/MWh)	50 to 80
Applicable Incentives	$10/MWh PTC
Technology Status	
Commercial Status	Commercial
Installed US Capacity (MW)	1,100

Notes:

* Fuel cost is variable. The low end of this range is unlikely unless an existing gas purchase contract is in place, or responsibility for the gas collection system is assumed.

5.3.4 Environmental Impacts

Combustion of LFG releases pollutants similar to those released by many other fuels, but the combustion of LFG is generally perceived as environmentally beneficial. Since LFG is principally composed of methane, if it is not combusted, LFG is released into the atmosphere as a greenhouse gas. As a greenhouse gas, methane is 23 times more harmful than CO_2. Collecting the gas and converting the methane to CO_2 through combustion greatly reduces the potency of LFG as a source of greenhouse gas emissions.

5.4 Solar Thermal

The performance, commercial readiness, cost, reliability, and technical risk of solar thermal electric technologies are characterized in this section. The technologies discussed include:

- Parabolic trough
- Parabolic dish
- Power tower
- Compact Linear Fresnel Reflector (CLFR)

Concentrating solar thermal power plants (CSP) produce electric power by converting the sun's energy into high temperature heat using various mirror or lens configurations. For solar thermal electric systems (trough, dish-Stirling, and power tower), the heat is transferred to a turbine or engine for power generation. Thermal plants consist of two major subsystems: a collector system that collects solar energy and converts it to heat, and a power block that converts heat energy to electricity.

All CSP systems make use of the direct normal insolation (DNI) component of solar radiation, that is, the radiation that comes directly from the sun. Global radiation, which is reflected radiation, is present on sunny and cloudy days but is unusable by CSP systems. Since all CSP systems use DNI and concentration of DNI allows a solar system to achieve a high working fluid temperature, there is a need for the collector systems to track the sun. Parabolic trough and CLFR systems use single-axis trackers to focus radiation onto a linear receiver, while dish-Stirling and power tower CSP systems use two-axis trackers.

Trough, power tower and CLFR systems collect heat to drive central turbine-generators making them best suited for relatively large plants—50 MW or larger. Trough, tower and CLFR plants, with their large central turbine generators and balance of plant equipment, have a cost advantage of economy of scale—that is, cost per kW goes down with increased size. Dish systems are modular in nature, with single units producing power in the range of 10 kW to 35 kW making them ideal for distributed or remote generation applications. Dish systems can also be sited as large plants by aggregating many units. Dish systems have the potential advantage of mass production of individual units, similar to the mass production of automobiles

Trough and tower systems have the potential advantage over dish systems in that an amount of dispatchability can be designed into the system with thermal storage or the use of hybrid fossil fuel. Storage for CLFR systems, while being explored in concept, has not been developed. Dispatchability allows the solar plant to generate electricity during short duration cloudy periods or to generate electricity into the evening after sunset. This gives the plant potential to receive capacity credit, and provides the ability to more closely match the utility peak load profile. At this time, dish-Stirling systems have not been configured to provide hybrid fossil capability.

5.4.1 Parabolic Trough Systems

Parabolic trough solar thermal systems have been the dominant solar thermal technology installed to date. Parabolic trough systems concentrate DNI using single axis tracking, parabolic curved, trough-shaped reflectors onto a receiver pipe or heat collection element (HCE) located at the focal line of the parabolic surface. A high temperature heat transfer fluid (HTF) picks up the thermal energy in the HCE. Heat in the HCE is then used to make steam in the steam generator. The steam drives a conventional steam-Rankine power cycle to generate electricity. Figure 5-4 shows trough collectors. A collector field contains many parallel rows of troughs connected in series. Rows are typically placed on a north-south axis, allowing the single-axis troughs to track the sun from east to west during the day.

Figure 5-4. Kramer Junction Trough Plant (NREL).

The largest collection of parabolic systems in the world is the Solar Energy Generating Systems (SEGS) I through IX plants in the Mohave Desert in southern California. The SEGS plants were built in the 1985 to 1991 time frame. The Kramer Junction site has five 30 MW systems. The largest of the SEGS plants, SEGS IX, located at Harper Lake, is 80 MW. All of the SEGS plants are "hybrids," using fossil fuel to supplement the solar output during periods of low solar radiation. Each plant is allowed to generate 25 percent of its energy annually using fossil fuel.

There are several commercial parabolic trough projects in the planning or active project development stage. Solargenix, (now Acciona) completed Nevada Solar One, a 64 MW tplant outside of Las Vegas, in June 2007. There are five 50 MW plants under construction in Spain. Three of these, the Andasol plants, will include 7 hours of thermal storage. Abengoa is constructing two others (Solnova 1 and 3) without storage. Other projects in various stages of planning include integrated solar combined cycle system (ISCCS) in southern California, India, Egypt, Morocco, Mexico, and Algeria. In addition, there are plans for a series of SEGS type plants in Israel.

Parabolic trough systems are considered commercially available. The primary developers of this technology include Acciona, Solel Solar Systems, Solar Millennium and Solucar (Abengoa). Suppliers of components for trough systems include reflector supplier Flabeg and receiver suppliers Schott Glass and Solel Solar Systems. Other major glass companies have expressed interest in entering the trough mirror market. The currently planned technology, for thermal storage, is the molten salt two-tank system. This provides a feasible storage capacity of up to 12 hours and is considered to have a low-to-moderate associated technology risk.

5.4.2 Parabolic Dish-Engine Systems

A solar parabolic dish-engine system comprises a solar concentrator (or “parabolic dish”) and the power conversion unit (PCU). The concentrator consists of mirror facets which combine to form a parabolic dish. The dish redirects DNI to a receiver mounted on a boom at the dish’s focal point. The system uses a two-axis tracker such that it points at the sun continuously.

A parabolic dish-engine system using a Stirling engine is shown in Figure 5-5. The PCU includes the thermal receiver and the engine-generator. In the solar receiver, radiant solar energy is converted to heat in a closed hydrogen loop, driving the Stirling engine-generator. Because the PCUs are air cooled, water cooling is not required. This is important because water cooling is necessary for the large, central power blocks associated with trough and power tower technologies. Thermal storage is not currently considered to be a viable option for dish-Stirling systems.

Figure 5-5. Dish-Stirling System (NREL)..

Relatively level land is preferable for construction and maintenance ease; however, siting requirements on slope are likely less stringent than those for trough and tower systems.

Individual dish-Stirling units range in size from 10 to 25 kW. Because they can operate independent of power grids, they can be used for remote applications as well as grid connected applications. With their high efficiency and modular construction, the cost of dish-engine systems is expected to be competitive in distributed markets. Stirling Engine Systems (SES), the principal dish-Stirling developer in the United States, projects that the cost of dishes will decrease dramatically with hundreds of MWs of central station, grid connected deployment.

At the present time, there are no operating commercial dish-Stirling power plants. A six dish test deployment at Sandia National Laboratories (SNL) in Albuquerque, New Mexico, was completed in 2005. This development is under a joint agreement between SES and SNL. In 2005, Southern California Edison publicly announced the completion of negotiations on a 20 year power purchase agreement with SES for between 500 to 850 MW of capacity (producing 1,182 to 2,010 GWh/year) of dish Stirling units. Also in 2005, SES announced a contract with San Diego Gas & Electric to provide between 300 and 900 MW of solar power using the dish technology. If successful, this large deployment of dish Stirling systems is expected to drastically reduce capital and O&M costs and result in increased system reliability.

Other planned deployments of dish-engine systems include contracted deployments of a 25 kW demonstration dish by SES at Eskom in South Africa and a 10 kW Schlaich Bergermann und Partner (SBP) dish providing power to the grid in Spain. Proposed or planned deployments include a 10 kW SBP dish in France and a 10 kW SBP dish in Italy. Abengoa also plans 80 kW of dish Stirling at their Sanlucar facility. A new entrant, Infinia, recently commissioned their first demonstration unit a 5 kW system using a free-piston Stirling engine.

5.4.3 Power Tower Systems

A power tower uses thousands of sun-tracking mirrors called heliostats to redirect DNI to a receiver at the top of a tower. The receiver at the top of the tower either generates steam directly, or heats a molten nitrate salt HTF to generate steam. The steam is used in a conventional turbine generator to produce electricity. Molten nitrate salt has superior heat transfer and energy storage capabilities, but is more expensive and difficult to work with. Systems with air as the working fluid in the receiver or power system have also been explored in international research and development programs. Commercial power tower plants can be sized to produce anywhere from 50 to 200 MW of electricity.

Figure 5-6 is a photograph of the 10 MW Solucar PS 10 plant in Spain, a direct steam generation system.

Figure 5-6. Solucar PS 10 Tower (Solucar).

An advantage of power tower plants is that molten salt can be heated to 1,050°F, with steam generation at 1,000°F, which is utility-standard main steam temperature. This results in slightly higher cycle efficiency than is achievable with the lower temperature (about 700°F) steam produced in a trough system. Furthermore, power towers have the advantage that the molten salt is used both as the HTF and as the storage medium, unlike the trough system which uses high temperature oil as the HTF, and requires oil-to-salt and salt-back-to-oil heat exchange for thermal storage. The result is that storage is less costly and more efficient for power towers than for troughs.

A 10 MW power tower plant, Solar One, located near Barstow, California, operated from 1982 to 1988 and produced over 38 million kilowatt-hours (kWh) of electricity. Solar One generated steam directly in the receiver. To implement improved heat transfer and thermal storage, the plant was retrofitted (and renamed Solar Two). Solar Two operated from 1998 to 1999. Although Solar Two successfully demonstrated efficient collection of solar energy and dispatch of electricity, including the ability to routinely produce electricity during cloudy weather and at night, the plant encountered various technical issues. Solutions to these issues have been identified; however, successful demonstration of certain improvements is required prior to commercial financing of a large-scale plant.

In addition to Solar One and Solar Two, experimental and prototype systems have operated in Spain, France, and Israel. Solucar Energia, S.A., an Abengoa company, recently announced the completion of an 11 MW solar power tower near Seville, Spain. Called PS 10, the power plant is the first tower-based solar power system to generate electricity commercially. PS 10 uses a water-steam receiver. Solucar has plans for a 20 MW plant, which also uses a water-steam receiver. In addition, ESKOM, the largest utility in South Africa, is considering a 100 MW molten-salt plant. The primary developer of molten salt technology for power towers is Solar Reserve, a joint venture between United Technologies Corporation and US Renewables.

Two US companies, eSolar and Brightsource, are pursuing “distributed power tower” concepts. These use smaller heliostats and smaller towers, and use several towers to provide steam for a single turbine. Both of these companies are still in the technology development stage, with no working demonstration plant.

5.4.4 Compact Lens Fresnel Reflector (CLFR)

The compact linear Fresnel reflector (CLFR) is a solar thermal technology in which rows of mirrors reflect solar radiation on a linear receiver located on towers above the mirror field. Ausra is developing a CLFR technology, and recently opened a Las Vegas manufacturing facility. Liddell 1, Ausra’s first generation CLFR system, is shown in Figure 5-7. That system is located at the Macquarie Liddell Power Station near Singleton, New South Wales, Australia. Liddell 2 is under construction at the same site. Liddell 2 will supply steam to the Liddell Power Station for feedwater heating. Ausra recently announced a 177 MW PPA with Pacific Gas & Electric (PG&E) to be constructed in the Carrizo plains area of San Luis Obispo County.

Figure 5-7. Liddell Phase 1 CLFR Demonstration System..

In the CLFR, collector mirrors rotate on the linear axis parallel to the receiver, following the sun's movement throughout the day. The CLFR is similar to the more commercially mature solar parabolic trough systems in that it uses one-axis tracking to focus solar radiation on a linear receiver. However, the CLFR has major difference from the trough system. These include several advantages:

- The CLFR optics are less stringent than optics of a trough. This allows a less expensive collector/receiver system.
- The CLFR receiver does not move, such that no flexible hoses or ball joints are required as in a trough system.
- The CLFR is more compact in terms of land use. A CLFR may have a ground cover ratio (GCR), which is the ratio of mirror area to land area, of about 70 percent versus a GCR of about 30 percent for a trough.

Disadvantages of the CLFR compared to the trough include the following:

- The CLFR is less mature in technical and commercial development.
- Trough cost and performance are fairly well known, whereas CLFR cost and performance are unproven.
- The saturated steam generated by the CLFR is relatively low temperature and being saturated, rather than superheated, results in less efficient power generation.
- The overall CLFR solar to steam efficiency is substantially lower than trough.

5.4.5 Environmental Impacts

Solar thermal projects are large installations that require significant amounts of land, anywhere from 7 to 10 acres per MW. Solar thermal systems do not have air emissions of criteria pollutants, such as carbon dioxide, sulfur dioxide, or particulates. Wet cooled plants will use significant amounts of water, but RETI has assumed that plants built in California will be dry cooled. Some water is required for mirror (or heliostat) washing. Land would be cleared and fenced for installations, which could restrict wildlife movement. There would be significant disturbance during the construction phase of the project.

5.4.6 Cost and Performance Characteristics

While there are several solar thermal technologies being actively promoted, the only commercial technology is parabolic trough. In addition, much of the commercial development interest appears to be for trough technology. Trough systems make up 84 percent of the BLM's California Desert District solar thermal applications, far more than dish or tower. Parabolic trough systems will therefore be used as a proxy for all solar thermal technologies, considering that the costs and performance for trough are better understood than for other technologies. Other technologies may have slightly different characteristics than trough, such as land use, efficiency, or ease of integrated storage; however these differences are not large. The levelized cost of energy as well as energy generation profile from trough should be roughly similar to that of other technologies. For the purposes of the RETI, using a single conversion technology is appropriate.

Representative characteristics for a parabolic trough system without energy storage and using dry cooling are shown in Table 5-5. Dry cooling is assumed due to lack of water and permitting requirements. Capital costs vary from $3600 to $4200 per kW of capacity. The difference between a high cost and a low cost project depends on the level of site preparation needed, such as terracing and the construction of infrastructure.

Table 5-5. Parabolic Trough Costs and Performance.

Performance	
Typical Duty Cycle	Peaking-Intermediate
Net Plant Capacity (MW)	200 MW
Integrated Storage	None
Capacity Factor (percent)*	26 -29
Economics ($2008)	
Total Project Cost ($/kW)**	3600 to 4200
Variable O&M ($/MWh)	N/A
Fixed O&M ($/kW)	66
Levelized Cost of Energy ($/MWh)	137 to 176
Applicable Incentives	30% Federal ITC; 5 year MACRS

Notes:
* Depends on location.
** Costs vary based on site characteristics

5.5 Solar Photovoltaic

Due to its high cost, intermittency, and low capacity factor, solar photovoltaics (PV) have had little penetration into the bulk electricity market. While solar, in general, represents a very small portion of the overall electricity generated in the US, solar PV represents an even smaller fraction. However, there is recent strong growth being observed in the PV industry. In the US in 2006, 100 MW of grid connected PV was installed, which is nearly triple the installations in 2003. This section provides a background into the solar PV industry and the cost and performance of solar PV.

5.5.1 Operating Principles

Solar PV converts sunlight (also known as insolation) directly into electricity. The power produced depends on the material involved and the intensity of the solar radiation incident on the cell. Single or polycrystalline silicon cells are most widely used today. Single crystal cells are manufactured by growing single crystal ingots, which are sliced into thin cell-size material. The cost of the crystalline material is significant. The production of polycrystalline cells can cut material costs, but with some reduction in cell efficiency. Thin film solar cells are made from layers of semiconductor materials only a few micrometers thick. These materials make applications more flexible, as thin film PV can be integrated into roofing tiles or windows. Thin film cells significantly reduce cost per unit area, but also result in lower efficiency cells. Gallium arsenide cells are among the most efficient solar cells and have other technical advantages, but they are also more costly and typically are used only where high efficiency is required even at a high cost, such as space applications or in concentrating PV applications. Additional advanced technologies are under development including dye sensitized solar cells (DSSC) and organic light emitting diodes (OLED). Developers of these technologies hope to achieve dramatic reductions in cell cost, but likely will have efficiencies on the lower end of the range for PV cells.

5.5.2 Markets

Currently, the commercial PV market is dominated by silicon-based cells, with about 85 percent market share for crystalline silicon. Recent shortages and cost increases of silicon have driven the market for new materials, such as Cadmium Telluride and amorophous silicon.

Solar photovoltaics have achieved enviable growth over the last few years. Worldwide grid-connected residential and commercial installations grew from 170 MW per year in 2000 to an estimated 2,500 MW per year in 2007. The majority of these installations were in Japan and Germany, where strong subsidy programs have made the economics of PV very attractive. The US grid connected market was estimated to be 250 MW in 2007, with most of these installations in California.

A new development in the solar market has been the growth of larger, utility-scale systems. In the past, photovoltaics had been seen as a distributed technology suitable for rooftops and industrial applications. The largest photovoltaic system in the US was Tuscon Electric's 4 MW installation in Springerville, AZ. In 2007, two large photovoltaic systems were commissioned in the western US, an 8 MW system in southwestern Colorado and a 15 MW system at Nellis Air Force Base outside of Las Vegas. There are four large photovoltaic systems that have PPA's with California utilities, shown in Table 5-6. In addition, there is significant development interest in utility scale solar photovoltaics. There are over 7,000 MW of large photovoltaic projects in the California ISO queue, and 11,541 MW of applications for BLM rights-of-way in the California Desert District.

Table 5-6. Photovoltaic Projects with California PPAs.

Developer	MW	Location	Utility	Technology
First Solar	7-21	Blythe	SCE	CdTe
Cleantech America	5	Mendota	PG&E	Crystalline
Green Volts	2	Byron	PG&E	CPV
Alternative Energy Development	1	Kern County	SCE	Unk.

Source: CEC contract database

5.5.3 Concentrating Solar Photovoltaic Systems

Concentrating photovoltaic (CPV) plants provide power by focusing solar radiation onto a photovoltaic (PV) module, which converts the radiation directly to electricity. Either mirrors or lenses can be used to concentrate the solar energy for a CPV system. Most of the CPV systems use two axis tracking to achieve point focus images on PV cells. Single axis, line focus CPV systems have been built, but do not appear to have the long term commercial potential that the two axis tracking CPV systems have.

Concentrating photovoltaic (CPV) systems have potential for cost reduction compared with conventional, non-concentrating (also referred to as flat plate) PV systems in two key ways. First, a major portion of the conventional PV system cost is for the semiconductor material which makes up the PV modules. By concentrating sunlight onto a small cell, the amount of semiconductor material can be reduced, albeit at additional cost for mirrors or lenses and for tracking equipment. Recent rises in solar module prices due to semiconductor-grade silicon have made CPV more attractive. Second, use of smaller cells allows for more advanced and efficient cell technology, making the overall system efficiency higher than for a conventional flat plate system.

CPV systems have been under development since the 1970's. This development has included single axis tracking, line focus CPV, and two axis tracking, point focus CPV. Recent development has primarily been on the two-axis tracking systems. Developers of CPV technology include Amonix (Figure 5-8), Energy Innovations, Sharp, EMCORE, Isophoton and SolFocus. Green Volts, a CPV startup, has a contract with PG&E and is planning a 2 MW system.

Amonix systems have been deployed at Nevada Power (75 kW at Clark generating station) and Arizona Public Service (APS) facilities for a total capacity of over 600 kW. Planned deployments in the near future include 10 to 20 MW in Spain.

It is unclear if these CPV technologies will achieve their desired cost targets. It does appear, however, that CPV may be more appropriate for utility-scale PV due to lower land requirements and reduced silicon use.

Figure 5-8. Amonix: Flat Acrylic Lens Concentrator with Silicon Cells (NREL).

5.5.4 Resource Availability

Most PV systems installed today are flat plate systems that use global insolation. Global insolation is the direct normal component along with diffuse radiation. CPV systems require DNI, as discussed under the Solar Thermal section. Because photovoltaics use global insolation, they can be more flexibly sited that solar thermal or CPV systems.

Photovoltaics also have temperature characteristics that must be taken into account when modeling production from these systems. Crystalline silicon systems produce less energy in high temperatures areas. Thin film systems are less susceptible to this temperature effect.

5.5.5 Environmental Impacts

Photovoltaic power systems are silent, unobtrusive, and require minimal water for washing. During normal operation PV power systems do not emit substances that may threaten human health or the environment. Large scale photovoltaic installations, however, would have significant land use impacts. A megawatt of photovoltaics requires roughly 10 acres. Land would be cleared for photovoltaic installations, and installations would likely be fenced, which could restrict wildlife movement. There would be significant disturbance during the construction phase of the project.

5.5.6 Cost and Performance Characteristics

For the purposes of RETI, Black & Veatch chose tracked crystalline photovoltaics as the representative photovoltaic technology. The two most recent utility scale photovoltaic plants in the US, Alamosa and Nellis, both use this technology. While thin film and concentrating systems show great promise, crystalline is the most mature at this point. From a cost of energy standpoint, all photovoltaic technologies should have similar cost of energy characteristics (see Figure 5-9 for a graphical representation). Table 5-7 shows the costs and performance for solar photovoltaic systems.

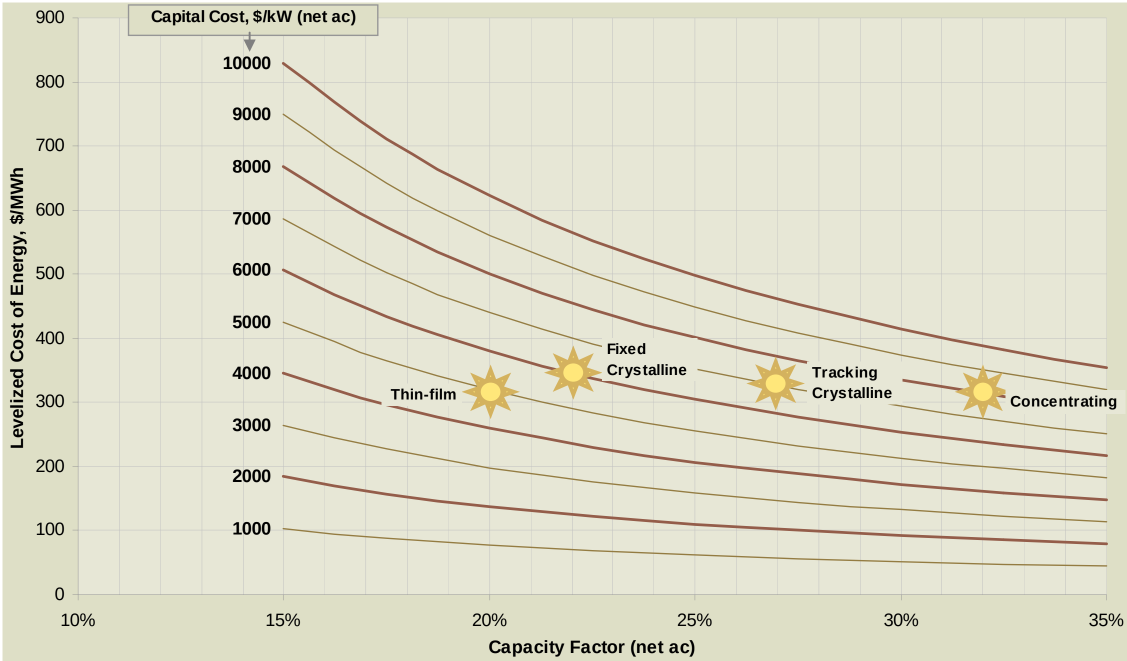


Figure 5-9. Comparative Cost of Electricity for Photovoltaics.

Table 5-7. Photovoltaic Costs and Performance.

Performance	
Typical Duty Cycle	Peaking-Intermediate
Net Plant Capacity (MW)	20 MW
Integrated Storage	None
Capacity Factor (percent)*	25-30
Economics ($2008)	
Total Project Cost ($/kWe)**	6500 to 7500
Variable O&M ($/MWh)	N/A
Fixed O&M ($/kW)	35
Levelized Cost of Energy ($/MWh)	201 to 276
Applicable Incentives	30% Federal ITC; 5 year MACRS

Notes:
* Depends on location.
** Costs are based on kWe – ac rating.

5.6 Hydroelectric

Hydroelectric power is generated by capturing the kinetic energy of water as it moves from a higher elevation to a lower elevation by passing it through a turbine. The amount of kinetic energy captured by a turbine is dependent on the head (vertical height the water is falling) and the flow rate of the water. Often, the water is raised to a higher potential energy by blocking its natural flow with a dam. If a dam is not feasible, it is possible to divert water out of the natural waterway, through a penstock, and back to the waterway. Such “run-of-river” applications allow for hydroelectric generation without the impact of damming the waterway. According to the International Energy Agency, the existing worldwide installed capacity for hydroelectric power is by far the largest source of renewable electricity at over 800,000 MW.

5.6.1 Applications

Hydroelectric projects are divided into a number of categories according to their size. Micro hydroelectric projects are below 100 kW. Systems between 100 kW and 1.5 MW are classified as mini hydroelectric projects. Small hydroelectric systems are between 1.5 and 30 MW. Medium hydroelectric projects range up to 100 MW, and large hydroelectric projects are greater than 100 MW. Medium and large hydroelectric projects are good resources for baseload power generation if they have the ability to store a large amount of potential energy behind a dam and release it consistently throughout the year. Small hydroelectric projects generally do not have large storage reservoirs and are not dependable as dispatchable resources.

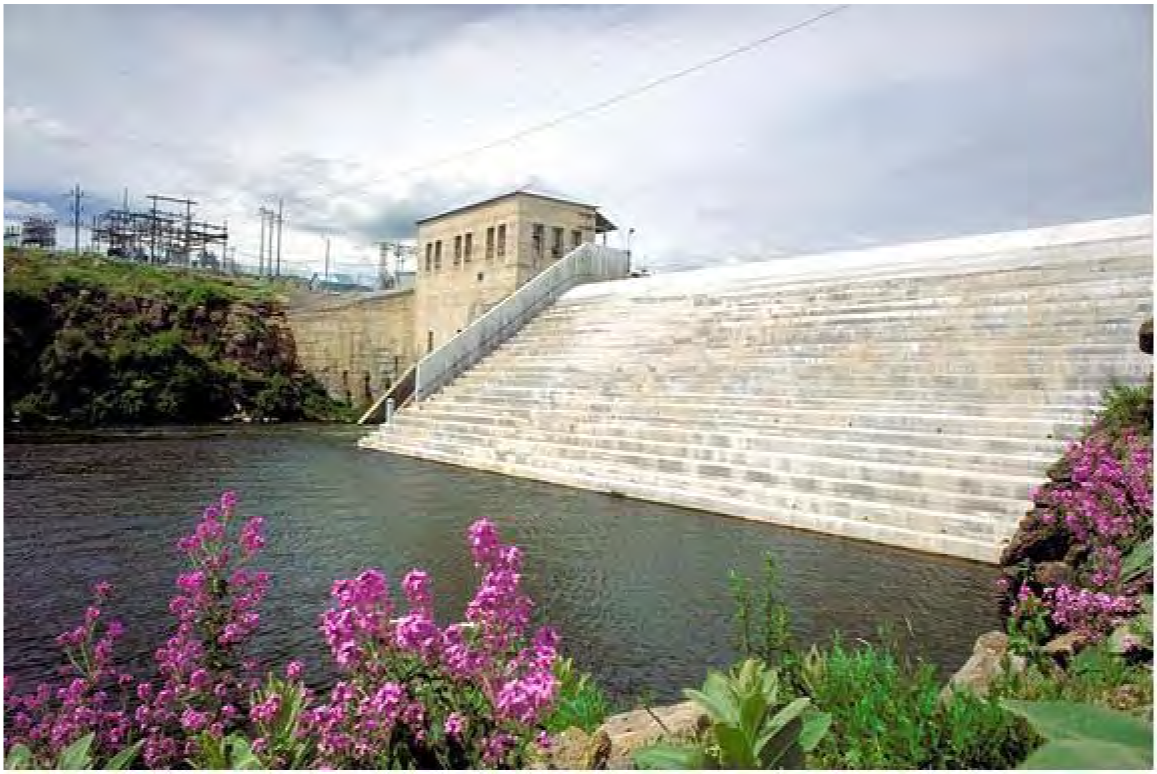


Figure 5-10. 3 MW Hydro Plant.

5.6.2 Cost and Performance Characteristics

Hydroelectric generation is regarded as a mature technology and is already established throughout the U.S. and is not expected to become more efficient due to its already high reliability and efficiency. Turbine efficiency and costs have remained somewhat stable, but construction techniques and costs continue to change. Capital costs are highly dependent on site characteristics and vary widely. Capacity factors are highly resource dependent and can range from 10 to more than 90 percent. Capital costs also vary widely with site conditions. It should be noted that if capital costs can be reduced, which could be achievable with technological improvements, additional capacity of economically feasible projects could be made available.

5.6.3 Environmental Impacts

The damming of rivers for small- and large-scale hydroelectric applications may have significant environmental impacts. One major issue involves the migration of fish and disruption of spawning habits. For dam projects, one of the common solutions to this problem is the construction of "fish ladders" to aid the fish in bypassing the dam when they swim upstream to spawn.

A second issue involves flooding existing valleys that often contain wilderness areas, residential areas, or archeologically significant remains. There are also concerns about the consequences of disrupting the natural flow of water downstream and disrupting the existing ecosystems.

Table 5-8. Hydroelectric Technology Characteristics.

Type	New	Incremental
Performance		
Typical Duty Cycle	Varies with Resource	Varies with Resource
Net Plant Capacity (MW)	<50	1 to 600
Capacity Factor (percent)	40 to 60	40 to 60
Economics ($2008)		
Total Project Cost ($/kW)	2,500 to 4,000	600 to 3,000
Fixed O&M ($/kW-yr)	5 to 25	5 to 25
Variable O&M ($/MWh)	5 to 6	3.5 to 6
Levelized Cost of Energy ($/MWh)	57 to 136	10 to 98
Applicable Incentives	$20/MWh PTC – No dams or impoundments; 150kW – 5MW	$10/MWh PTC
Technology Status		
Commercial Status	Commercial	
Installed U.S. Capacity (MW)*	99,000	

5.7 Wind

Wind power systems convert the movement of air to power by means of a rotating turbine and a generator. Wind power has been among the fastest growing energy sources over the last decade, with around 30 percent annual growth in worldwide capacity over the last five years. Cumulative worldwide wind capacity is now estimated to be more than 94,000 MW. In the United States, wind turbine capacity exceeded 16,000 MW in 2007, with more than 14 percent of this capacity located in California. The U.S. wind market has been driven by a combination of growing state mandates and the production tax credit (PTC), which provides an economic incentive for wind power. The PTC has expired and been renewed several times and is currently set to expire on December 31, 2008.

5.7.1 Applications

Typical utility-scale wind energy systems consist of multiple wind turbines that range in size from 1.5 to 2.5 MW. Wind energy system installations commonly total 5 to 300 MW, although the use of single, smaller turbines is also common in the United States for powering schools, factories, water treatment plants, and other distributed loads. Furthermore, offshore wind energy projects are now being built in Europe and are planned in the United States, encouraging the development of larger turbines (up to 5 MW) and larger wind farm sizes.

Wind is a variable resource, with average capacity factors generally ranging from 25 to 40 percent. The capacity factor of an installation depends on the wind regime in the area and energy capture characteristics of the wind turbine. Capacity factor directly affects economic performance; thus, reasonably strong wind sites are required for cost-effective installations. Since wind is intermittent, it cannot be relied upon as firm capacity for peak power demands. To provide a dependable resource, wind energy systems may be coupled with some type of energy storage to provide power when required, but this is not common and adds considerable expense to a system. Figure 5-11 shows a wind farm in the Palm Springs area of California.

Figure 5-11. Wind Farm near Palm Springs, California.

5.7.2 Environmental Impacts

Wind is a clean generation technology from an emissions perspective. However, there are still environmental considerations associated with wind turbines. Opponents of wind energy frequently cite visual impacts and noise as drawbacks. Turbines are approaching and exceeding heights of 400 feet and, for maximum wind capture, tend to be located on ridgelines and other elevated topography. Turbines can cause avian fatalities and other wildlife impacts if sited in sensitive areas. To some degree, these issues can be partially mitigated through proper siting, environmental review, and the involvement of the public during the planning process.

5.7.3 Cost and Performance Characteristics

Table 5-9 provides typical characteristics for a 100 MW wind farm. The low end of the capital cost range represents sites are relatively flat, have good road access, and have access to existing transmission. The high end of the cost range is for sites that are difficult to construct (such as a ridgeline site) and have limited existing infrastructure. Substantially higher costs are necessary for wind projects that require grid upgrades or long transmission tie lines. Transmission costs are considered separately in the next phase of the RETI process. The low end of the capacity factor range represents moderate class 3-4 wind sites, while the higher estimates are representative of class 5-6 wind sites. Capital costs for new onshore wind projects had remained relatively stable for several years, but current demand, commodity prices, and other factors have driven up the cost significantly over the past three years. Additionally, due to the increased demand and impending PTC expiration, the current earliest delivery date for new turbines is 2009. Significant gains have been made in recent years in identifying and developing sites with better wind resources and improving turbine performance and reliability. As a result, the average capacity factor for all installed wind projects in the United States has increased from about 24 percent in 1999 to over 32 percent in 2005.

Table 5-9. Wind Technology Characteristics.

Type	Onshore	Offshore
Performance		
Typical Duty Cycle	As Available	As Available
Net Plant Capacity (MW)	100	200
Capacity Factor (percent)	25 to 40	35 to 45
Economics ($2008)		
Total Project Cost ($/kW)	1,900 to 2,400	5,000 to 6,000
Fixed O&M ($/kW-yr)	50	75-100
Variable O&M ($/MWh)	Incl. in FOM	Incl. in FOM
Levelized Cost of Energy ($/MWh)	59 to 128	142 to 232
Applicable Incentives	$20/MWh PTC, 5-yr MACRS	$20/MWh PTC, 5-yr MACRS
Technology Status		
Commercial Status	Commercial	Early Commercial
Installed U.S. Capacity (MW)*	16,800	0

Notes:
* Estimate through end of 2007.

5.8 Geothermal

Geothermal resources can provide energy for power production and other applications by using heat from the earth to generate steam and drive turbine generators. The global installed capacity for geothermal power plants is about 9,000 MWe (megawatt electrical). Additionally, about 16,000 MWth is used in direct heat applications. There is currently about 2500 MW of operating geothermal capacity in the US. The total US geothermal potential is estimated by NREL and others to be between 30 and 70 GW of electrical generating capacity. This figure includes only conventional hydrothermal resources, and could be larger if deeper reservoirs and advanced geothermal techniques become available.

5.8.1 Applications

In addition to generation of electricity and direct space heating applications, hot water and saturated steam from a geothermal resource can be used for a wide variety of process heat applications.

5.8.2 Resource Availability

Geothermal power can be developed where subsurface temperature gradients are elevated, such as in areas of young volcanism. However, there are other geologic settings favorable to geothermal development, including (for example) the Basin and Range province of the United States, where the crust is relatively thin, which leads to greater heat flow from the earth's interior. Tectonically active (but not necessarily volcanic) areas are also favorable because of the presence of significant faulting and fracturing that can allow deep circulation and heating of ground waters. Subsurface temperature gradients measured in wells help to determine the potential for geothermal development and the type of geothermal power plant installed. High energy sites are suitable for electricity production, while low energy sites are suitable for direct heating. Most of the known and most easily accessible geothermal resources in the United States are concentrated in the west and southwest parts of the country. Figure 5-12 shows the 90 MW Coso Junction Navy II geothermal plant in California.

Figure 5-12. COSO Junction Navy II Geothermal Plant.

5.8.3 Cost and Performance Characteristics

Geothermal power is generated in two kinds of plants: flash steam and binary. In the former, the produced geothermal fluid is separated into steam and water phases; the steam is supplied directly to the turbine generator, and the separated water is injected back into the ground. In a binary power plant, a working fluid is passed through a heat exchanger, where it is heated by the geothermal fluid to its boiling point. The vapor passes through the turbine generator and condensed to be re-used again. Both the working fluid and the geothermal fluid are kept in separate, sealed loops. After its heat is transferred to the working fluid, the geothermal fluid is injected back into the ground.

For representative purposes, a binary cycle power plant is characterized in Table 5-10 Capital costs of geothermal facilities can vary widely for several reasons, but one of the most important variables is the drilling cost to develop the resource. First, exploration wells must be drilled to find and prove the resource; there are almost always one or two “dry holes” (those that do not provide commercially attractive temperatures and/or flow rates) drilled during this process. Once defined and proven, the development wells (production and injection) are drilled. Well costs increase non-linearly with depth, so the geologic controls on the geothermal system need to be well-understood (as a result of the exploration drilling program) to arrive at accurate cost estimates. However, because the “fuel supply” is developed up-front, fuel price risks are non-existent. This, combined with the high availability of geothermal projects (typically more than 95 percent) makes geothermal attractive for baseload generation and managing portfolio risk.

Table 5-10. Geothermal Technology Characteristics.

Performance	
Typical Duty Cycle	Baseload
Net Plant Capacity (MW)	30
Capacity Factor (percent)	70 to 90
Economics (2007$)	
Total Project Cost ($/kW)	3,000 to 5,000
Variable O&M ($/MWh)	25 to 30
Levelized Cost ($/MWh)	54 to 107
Applicable Incentives	$20/MWh PTC, 5-yr MACRS
Technology Status	
Commercial Status	Commercial
Installed US Capacity (MW)	2,534

5.8.4 Environmental Impacts

Binary geothermal development has relatively few environmental impacts. As with any power project, land area must be set aside for the power plant, substation and power lines. Some road access into remote areas may be required. Areas disturbed for exploration activities, drilling and pipelines are typically restored and re-vegetated.

Although geothermal fluids contain small quantities of non-condensable gases, the power plants are designed to either remove them or keep them in solution to be reinjected underground. Owing to strict well design guidelines, there is no pollution of surface or groundwaters. Geothermal power plants with modern emission control technologies have minimal environmental impact. They emit less than 0.2 percent of the CO2, less than 1 percent of the SO2, and less than 0.1 percent of the particulates of the cleanest fossil fuel plant.

There is the potential for geothermal production to cause ground subsidence. However, proper resource management (most importantly including an effective injection strategy) mitigates this risk.

5.9 Marine Current

Marine renewable energy is still in early stages of concept design and development in comparison to other established renewable energy options. A number of large scale devices have been tested in the offshore environment; however there have currently been no commercial installations.

Extraction and conversion of tidal energy is not a new concept; for thousands of years humans have been harnessing the energy of the tides. In the more recent past, focus has been directed towards tidal barrage technology, which has been used in some locations globally, and has the potential to produce significant amounts of power. Environmental concerns have diminished the attractiveness of the tidal barrage concept however, at least in Europe and most western countries. In recent times there has been a significant increase in the research and development of tidal stream and marine current energy technologies.

5.9.1 Resource

Tides are the result of the interaction of the gravitational forces between the seas and the primary astronomical bodies in our solar system. Hundreds of components have been identified that affect the tides and therefore an exact tidal cycle for a specific site is very complex. The principal tidal harmonic is produced by the gravitational forces associated with the Moon and the Sun. The interaction between tidal harmonics at a site gives a predictable pattern over time. The advantage of tidal stream energy over say wind, wave or solar is this predictability.

The tides that are experienced are a result of the natural balance between the energy generating forces and the energy dissipating forces. The latter forces are largely dependent on bathymetry, and the nature of the sea-bed (e.g. particle sizes and presence of sand waves), but also depend on temperature, salinity etc.

Significant tidal stream currents generally occur where large tidal flows are forced through relatively narrow boundaries. Thus both high tidal ranges and narrow channels are generally required to cause significant tidal stream currents. However, due to local site conditions a high tidal range does not always indicate high tidal currents and similarly low tidal ranges do not always indicate low tidal currents.

Although no detailed assessment of the Global resource has been completed and therefore the results cannot be guaranteed, a number of studies have estimated the resource. Black & Veatch in their study for the Carbon Trust on resource summarized all the available data. The estimates range from 5TW, Isaacs and Seymour, 450GW from Blue Energy (developer) and ~25GW the UK Carbon Trust. The vast resource which is available Globally and in the US is discussed later in this report however this potential prize is important to consider when looking at future renewable energy options and therefore has been included in the review of the West Coast.

This section of the report considers what resource there is available that could be utilised for the development of marine renewable energy, specifically tidal stream energy. Marine renewable energy is still in an early stage of development in comparison to other established renewable energy options. A number of large scale devices have been tested in the offshore environment; however, there have as yet been no commercial installations. Although no detailed assessment of the global resource has been completed and therefore the results cannot be guaranteed, a number of studies have estimated the resource. Black & Veatch in their study for the UK's Carbon Trust on resource summarized all the available data. The estimates range from 5TW from Isaacs and Seymour, 450GW from Blue Energy (developer), and ~25GW from the Carbon Trust. The resource which is available globally, and in the US, is discussed later in this report; however, this potential prize is important to consider when looking at future renewable energy options and it has therefore been included in the review of the West Coast.

5.9.2 Applications

The four main categories that characterize tidal stream devices currently under development, as determined by the "prime-mover" (or principle defining characteristic) are as follows:

- Horizontal Axis Axial Flow Turbine (HAA)
- Vertical Axis Cross Flow Turbine (VAC)
- Oscillating Hydrofoil (OH)
- Venturi Devices (V)

The mechanical energy from the prime-mover may be converted to electricity via a number of conversion steps (e.g. hydraulic, direct electrical, mechanical) embodied in a "power-train".

There are in the region of 50 developers worldwide at varying stages however it is beyond the scope of this project to describe them all therefore; however, a couple of examples of horizontal axis axial flow (HAA) turbines are included - which have both been tested offshore.

Clean Current

Clean Current have been developing tidal technology for 6 years. Their tidal stream device is a bi-directional ducted horizontal axis turbine. It has a direct drive variable speed permanent magnet generator and therefore only incorporates one moving part. The support type is not specified although, as the device is fully submerged, it is likely to be a monopile, support frame, or gravity base.

Since inception, Clean Current has followed a defined development plan, which began with the testing of two prototypes in 2002 and 2003 which were used to validate the concept. In 2006 a 65kW (1/20th Scale prototype), see Figure 5-13, was installed in 22m depth of water and tested in the Clean Current Race Rocks demonstration project in Canada. After 2 months of testing the control system was connected and power supplied to the battery. The Race Rocks project validated the duct design, the blade design, and the generator performance. However the hydrodynamic bearing system did not live up to expectations and will be replaced by a new system during the next phase of the project. This phase will involve reinstalling the 65kW device at Race Rocks in 2008 with a new bearing system and other minor improvements.

In 2009 Clean Current plan to install a 1.2MW device commercial scale device.

Figure 5-13. Clean Current.

Marine Current Turbines - Seagen

The Marine Current Turbines (MCT) “Seagen” device is a commercial demonstrator that has twin axial flow rotors, between 15 and 20m in diameter (refer to Figure 5-14) which drive the generator (via a gearbox). Each rotor consists of two blades which are pitch controlled to optimise the efficiency of the device. The rotors are fixed onto a horizontal bridge which is attached to a surface piercing monopile and the movement of the bridge up and down the monopile allows the rotors to be raised and lowered for maintenance.

Marine Current Turbines (MCT) installed a 300kW prototype tidal turbine device known as “Seaflow” in May 2003 off Lynmouth, Devon, UK. This was the world’s first tidal stream powered device of such size and power rating to be installed in an offshore location. Using experience fostered from the prototype Seaflow device, MCT were able to develop the more advanced, commercially focused Seagen device. The main objective of Seagen is to test the components of the twin rotor machine and verify the performance and engineering integrity of the concept at commercial scale.

Seagen was due to be grid connected in late 2006 in Strangford Narrows, Northern Ireland. However this was initially delayed until August 2007. There has been a further recent delay due to problems with the jack-up barge that was proposed to be used, and MCT are now planningsummerexpecting to install in early-mid 2008.

Interestingly, Marine Current Turbines have recently signed an agreement with Npower Renewables (one of the UK utilities) to form a company called SeaGen

Wales. SeaGen Wales will install 10.5MW of generating capacity off the coast of Wales which will be commissioned by 2012.

Figure 5-14. Marine Current Turbines, SeaGen

Environmental Impacts

Utilization of tidal stream energy for power generation has the environmental advantage of being a zero emissions technology, and is generally not considered to be environmentally harmful. However there are some concerns, including the amount of extractable energy from a tidal stream (i.e. the amount of energy which can be extracted without causing detrimental environmental impacts), or and potential impacts on marine mammals - although a $4million study into the impacts of the commercial scale SeaGen device will be carried out to assess the impacts on mammals when installation occurs in Strangford Lough, Northern Ireland during 2008. In addition, possible adverse visual impacts are highlighted by those who oppose the technology. A strategic environmental assessment has been completed in Scotland which investigated the generic impacts. The aim of this is to substantially reduce the time, effort, and expense for each developer when complying with requirements for development licenses.

5.9.3 Cost and Performance Characteristics

Table 5-11 provides typical characteristics for a 100 MW tidal farm. Generic data has been provided at this stage due to the lack of commercially available technology today. This data has been correlated by B&V against the most up to date costs for the most developed technologies. Capital costs will vary substantially with for example, size of farm installed, the specific site characteristics, the distance to grid, and the type of technology. It is expected that the cost of tidal stream farm development will decrease with improved concepts and optimized designs, economies of scale, and learning in production, construction, installation, and O&M.

Table 5-11. Instream Tidal Technology Characteristics.

Type	Generic offshore
Performance	
Typical Duty Cycle	As Available
Net Plant Capacity (MW)	100
Capacity Factor (percent)	25 to 45
Economics ($2008)	
Total Project Cost ($/kW)	2,200 to 4,725
Fixed O&M ($/kW-yr)	90 to 255
Variable O&M ($/MWh)	Incl. in FOM
Levelized Cost of Energy ($/MWh)	71 to 353
Applicable Incentives	
Technology Status	
Commercial Status	Development and testing
Installed U.S. Capacity (MW)	Not applicable

5.10 Wave

Serious research into the use of wave energy as a viable form of power generation dates back to the 1970s with a large number of Wave Energy Converter (WEC) devices having been developed since. Indeed, a recent categorization study undertaken by B&V shows that there could be as many as 720 unique techniques in which to extract and convert wave energy. There have been over 100 patents issued for different WEC devices which give an indication as to the large array of potential technology in the wave energy industry.

5.10.1 Applications

Serious research into the use of wave energy as a viable form of power generation dates back to the 1970s with a large number of Wave Energy Converter (WEC) devices having been developed since. Indeed, a recent categorization study undertaken by B&V shows that there could be as many as 720 unique techniques by which to extract and convert wave energy.

There are five key design parameters, each containing a number of internal classification groups, that describe a WEC. The design parameters are as follows:

- Configuration
- Working Surface
- Reaction
- Mode
- Energy Transfer

Using these parameters to identify types of wave devices becomerapidly becomes complex, and therefore the proximity to shore is more commonly used to distinguish them. In the first instance, onshore devices can be seen as attractive solution by the wave energy industry given that power transmission issues and maintenance access are straightforward to resolve whilst large waves forces may be avoided. However, the main disadvantage with an onshore device is that their construction is highly dependent on local conditions whilst the available wave energy is generally significantly lower at the shoreline due to energy dissipating processes. Moreover, the visual impact of such devices could be seen as an adverse impact on the surrounding environment – which can result in many difficulties to overcome. By considering these issues, the wave energy industry and device developers have generally steered away from onshore devices and have focused on offshore deployment. As a result, there are only a handful of onshore devices currently under development.

The term “near-shore” is not precisely defined in the marine renewable industry yet, and is often described as the area that is neither offshore nor onshore. In this report, B&V has decided to consider a WEC to be located “near-shore” if the energy converter is in the sea but its generator and substation are located on the shore. Compared to offshore devices, the advantages are maintenance and submarine cable length, but there is not as much power close to the shore as offshore. Most of the developers, even if their first concept were designed for near-shore, tend to develop new designs to go fully offshore.

To access the more powerful waves in deepwater, WECs need to go offshore. The main disadvantage is that the device is then situated in a very harsh ocean environment, and survivability and accessibility for maintenance can become very significant issues. Most of the offshore WECs presented in this section are floating devices moored to the seabed, and only one is moored directly on the seabed. To benefit fully from large waves, an offshore wave energy device must be relatively large itself and, as the visual impact is less of an issue offshore, the devices tend to be much larger and to generate more power than onshore or near-shore devices.

There are a considerable number of wave energy devices in design and development stages; however, they cannot all be covered in this report. Therefore B&V have included information on two offshore devices which have been tested in the offshore environment.

Pelamis

For more information please visit http://www.pelamiswave.com/

Figure 5-15. Pelamis

Pelamis is developed by Pelamis Wave Power (former Ocean Power Delivery), a Scottish company. Pelamis is an attenuator device and consists of four tubular sections, connected by three hinged modules. As a wave passes, the four tubular sections move relative to each other causing movement in the hinge modules. The modules convert this motion by means of an internal hydraulic power conversion system. The design has inherent survivability with a very small frontal area subjected to the hydrodynamic forces of incident waves. The Pelamis is anchored by a slack mooring system which allows the device to weathervane into the dominate wave direction. The device is 120m long with a 3.5m diameter, and weight of 700 tonnes when fully ballasted. The rated power of the device is 750kW (i.e. 250kW per module).

In 2004, Pelamis was the first wave energy device to be installed at EMEC in Orkney. The device had a 9 month residence at EMEC and was subject to an extensive testing regime. Results of the tests are currently being used to improve the device. Since 2005, Pelamis Wave Power has played the lead role in the start-up of the world's first commercial wave farm off Póvoa de Varzim, northern Portugal. In September 2007, it delivered three devices to Babcock & Brown, the developer, which is expected to switch on the first stage of an eventual 20MW project in early-mid 2008.

Pelamis Wave Power is now developing several commercial projects, and in the next few years will begin to install several commercial devices: 4 Pelamis are planned to be commissioned in 2008 off Orkney, in Scotland. 7 other devices are expected to be commissioned at WaveHub (England) in 2009.

PowerBuoy

PowerBuoy is owned by the American Company, Ocean Power Technologies (OPT), which was formed in 1994. PowerBuoy is a free floating point absorber device which is moored to 3 buoys. The device can be deployed in relatively deep waters, from 35m to 60m in depth. Each unit has a rated power of 40kW, a diameter of 5m, a stroke of 3 m, and weighs 26 tons.

Since 2005, OPT has worked in partnership with the US Navy to develop a 40kW PowerBuoy40 device, see Figure 5-16. In October 2005, OPT deployed the first full scale prototype device off the coast of New Jersey (in contract with the local board of Public Utilities).The device was retrieved during October 2006 for planned maintenance and testing, having been operating continuously for a year.

Figure 5-16. PowerBuoy

For more information please visit www.oceanpowertechnologies.com

Following the success of the prototype, OPT has prepared plans for several other commercial projects, including two 5MW demonstration farms; one at WaveHub which has been granted approval, and the other in Oregon, USA, which has been granted a preliminary permit.

The first phase of a 1.39MW farm, to be located off the coast of Santona (Spain) began in summer 2007, and is planned to be fully installed by late 2008. The farm will consist of a number of 40kW rated devices which will operate in a 50m depth of water.

In July 2007, the development of a 150kW PowerBuoy design effort was well underway. The power conversion and controls system were substantially complete for the 150kW PowerBuoy system, and ocean testing is expected in 2008 for this new design. OPT is being supported by the Carbon Trust in the Marine Energy Accelerator (MEA).

5.10.2 Environmental Impacts

The impact of the installation of wave energy converters, as a new technology, is currently not widely understood. The potential impacts are understood nevertheless and they include, the potential disturbance of sediment transportation by the removal of energy from the water, potential ecological impacts, interaction with recreational and shipping/navigation, and potential visual impacts. There are now two full scale Pelamis devices installed in Portugal and this should provide the industry with more information on their impacts offshore. The long term impacts, as with any new technology will not be fully understood until many years time, however there are stringent mitigation measures that can be put in place in order for the potential impacts to be minimized.

5.10.3 Cost and Performance Characteristics

Table 5-12 provides typical characteristics for a 100 MW wave farm. Generic data has been provided at this stage due to the lack of commercially available technology today. This data has been correlated by B&V against the most up to date costs for the most developed technologies. Capital costs will vary substantially with for example, size of farm installed, the specific site characteristics, the distance to grid, and the type of technology. It is expected that the cost of wave energy converter farm development will decrease with improved concepts and optimized designs, economies of scale, and learning in production, construction, installation and O&M.

Table 5-12. Wave Energy Converter Characteristics.

Type	Generic offshore
Performance	
Typical Duty Cycle	As Available
Net Plant Capacity (MW)	100
Capacity Factor (percent)	25 to 45
Economics ($2008)	
Total Project Cost ($/kW)	2,800 to 5,200
Fixed O&M ($/kW-yr)	150 - 270
Variable O&M ($/MWh)	Incl. in FOM
Levelized Cost of Energy ($/MWh)	105 to 384
Applicable Incentives	
Technology Status	
Commercial Status	Demonstration
Installed U.S. Capacity (MW)*	Not applicable

Notes:
* Estimate through end of 2007.

5.11 Technology Cost and Performance Summary

The technology cost and performance assumptions developed in the previous sections are summarized in Table 1-1.

Table 5-13. Renewable Technologies Performance and Cost Summary.

	Net Plant Capacity, MW	Net Plant Heat Rate, Btu/kWh	Capacity Factor	Capital Cost, $/kW	Fixed O&M, $/kW-yr	Variable O&M, $/MWh	Fuel Cost, $/MBtu	Levelized Cost, $/MWh
Solid Biomass	35	14500	80	3000 to 5000	83	11	0 to 3	67 to 150
Cofired Biomass	35	10000	85	300 to 500	5 to 15		-0.5 to 1	-1 to 22
An. Digestion	0.15	13000	80	4000 to 6000		17	1 to 3	100 to 168
Landfill Gas	5	13500	80	1200 to 2000		17	1 to 2	50 to 80
Solar Thermal	200		26-29	3600 to 4200	66			137 to 176
Solar Photovoltaic	20		25-30	6500 to 7500	35			201 to 276
New Hydroelectric	<50		40 to 60	2500 to 4000	5 to 25	5 to 6		57 to 136
Inc. Hydroelectric	1 to 600		40 to 60	600 to 3000	5 to 25	3.5 to 6		10 to 98
Wind	100		25 to 40	1900 to 2400	50			59 to 128
Offshore Wind	200		35 to 45	5000 to 6000	75-100			142 to 232
Geothermal	30		70 to 90	3000 to 5000		25 to 30		54 to 107
Marine Current	100		25 to 45	2200 to 4725	90 to 255			97 to 410
Wave	100		25 to 45	2800 to 5200	150 to 270	11		135 to 445

Notes:
Levelized Cost includes applicable incentives, subsidies, etc.

5.11.1 Relative Costs

The lowest levelized cost of energy is that of biomass cofiring and incremental hydroelectric power. These projects enjoy low capital cost from “piggybacking" on existing projects and have high capacity factors. Landfill gas, geothermal and new hydroelectric projects are also able to divide their costs over a greater number of megawatt hours due to their baseload mode of operation. Wind energy is low cost for renewables, but the relatively low capacity factor means less generation to dilute the costs. The marine technologies are not able to benefit from federal tax subsidies. The solar technologies and offshore wind are hit with both high capital costs and relatively low annual generation totals.

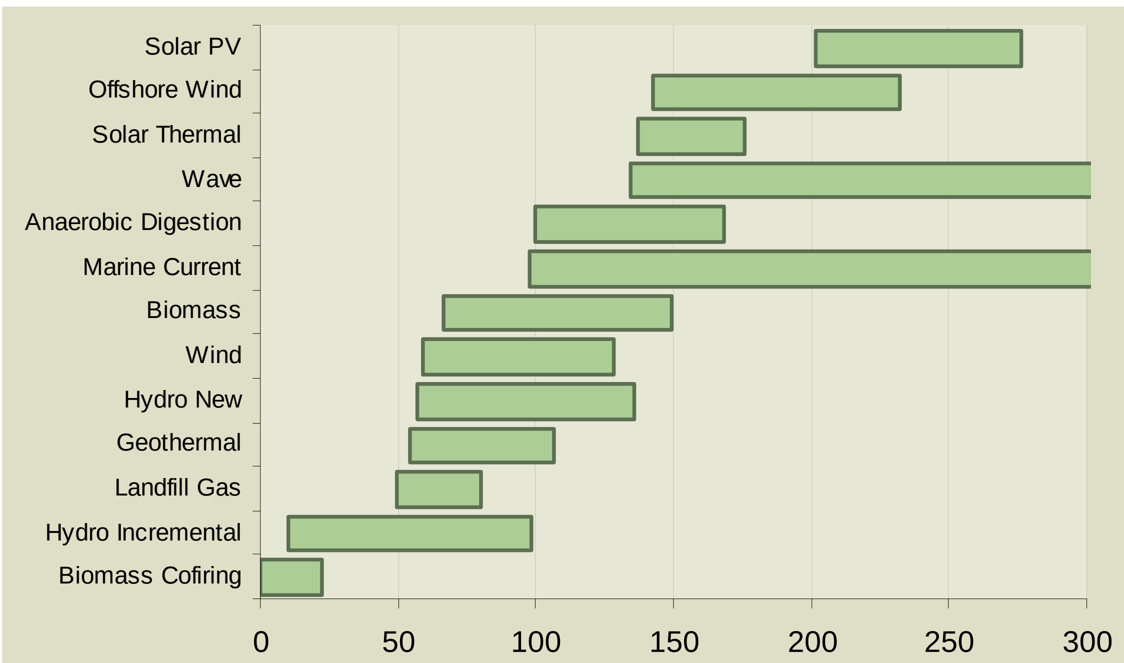


Figure 5-17. Typical Levelized Cost of Generation ($/MWh).

6.0 Resource Screening

This section evaluates the resource for each renewable energy technology. In each case, an assessment is made of the total technical potential for the technology over the RETI region of study, and the total resource is then screened for technical and environmental viability. Ultimately, recommendations are developed for each technology regarding recommended resource areas for further analysis.

6.1 Solid Biomass

Direct-fired biomass (i.e., stand-alone biomass combustion) has been identified as a promising technology for the RETI Phase 1 study. Biomass cofiring is generally more economical than stand-alone biomass facilities, but cofiring is limited to locations where biomass is available near an existing coal plant. If there are no coal plants in the region of interest, biomass cofiring is not a viable option. Due to the lack of possible host facilities for cofiring in the Phase 1 study area, direct fired biomass has been identified as the conversion method for solid biomass. This section presents the methodology used to quantify (at a high level) biomass resource availability and the potential for biomass-derived electrical generation throughout the RETI study region.

6.1.1 Biomass Methodology

Biomass-derived electrical generation potential is based on available biomass resources. The quantification of biomass resources presented here relies primarily on assessments developed by national laboratories, state agencies, and university research centers. The resource information presented in this study has been utilized to identify the most promising areas for development of biomass power projects. To determine the actual available quantities and suppliers of biomass material in the region, a more detailed resource assessment considering fuel price economics is necessary. This will be undertaken in Phase 1B.

To obtain an overview of the biomass resources available across the entire RETI study region, the most recent national biomass resource assessment developed by the National Renewable Energy Laboratory (NREL) was reviewed. In December 2005, NREL published a new set of biomass resource data and documentation, including GIS data layers of major biomass resources on a county level.[16] The data represents a fairly uniform set of biomass resource data, and is the most current nationwide, county-level data source available. As described below, much of the resource data is based on

[16] Milbrandt, A. "A Geographic Perspective on the Current Biomass Resource Availability in the United States," 2005. NREL Technical Report NREL/TP-560-39181.

statistical estimation. Based on the NREL data, the RETI study region contains significant biomass resources, as shown in Figure 6-1.

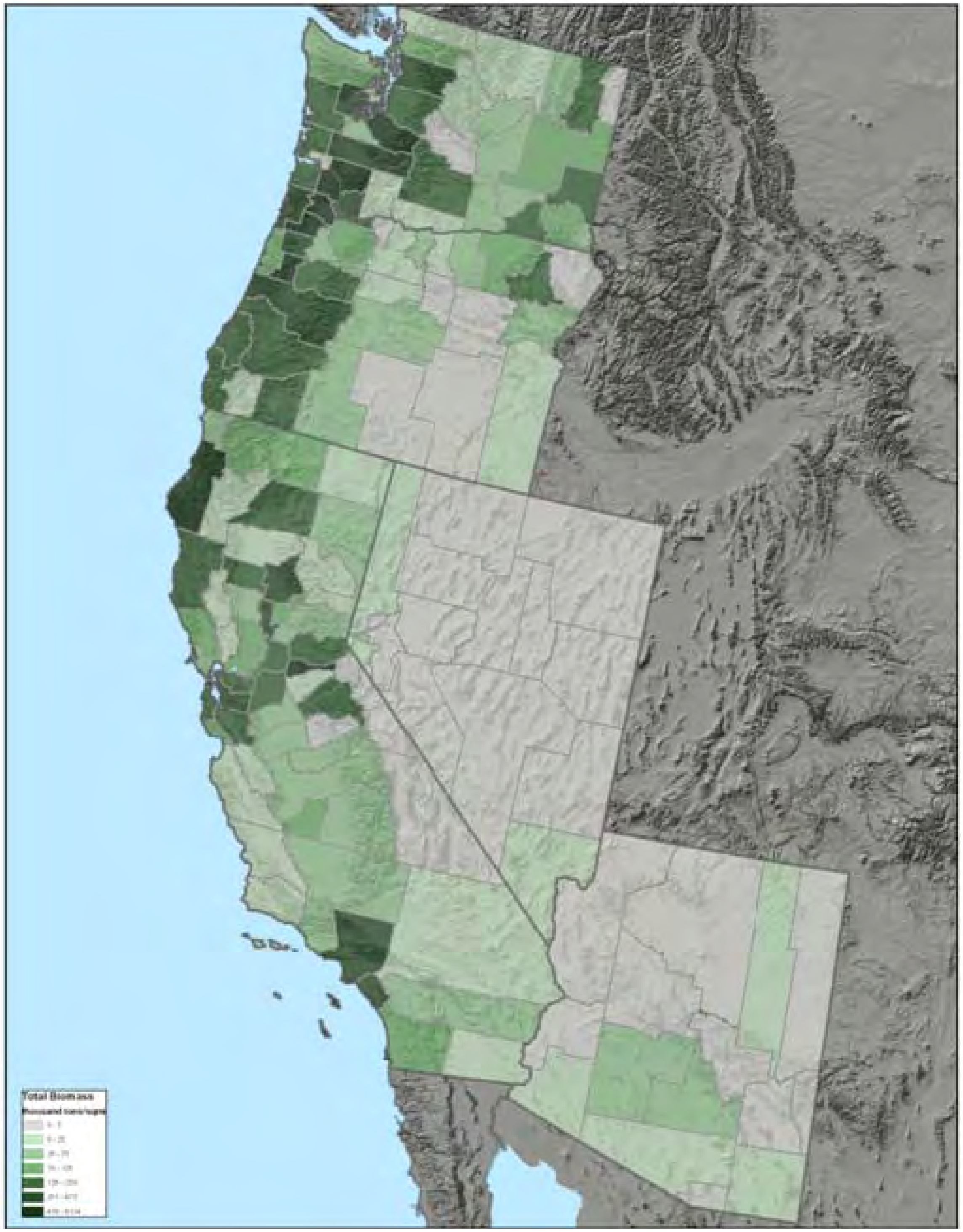


Figure 6-1. Biomass Resource Map of US RETI Study Region (NREL Estimate).

The NREL data is defined as follows:

- **Agricultural Residues –** This data includes residues from corn, wheat, soybeans, cotton, sorghum, barley, oats, rice, rye, canola, beans, peas, peanuts, potatoes, safflower, sunflower, sugarcane and flaxseed. Residue estimates were developed using the total grain production, crop-to-residue ratio, and moisture content. The total grain production data for each county in 2002 were as reported to the US Department of Agriculture. It was assumed that 35 percent of the total residue could be collected, accounting for residue left for soil protection, grazing, bedding, etc. Animal manures are discussed in the anaerobic digestion section of this report.
- **Forest Residues –** Forest residue data is adapted from the 2002 USDA Forest Service Timber Product Output Database. The quantities include commercial logging residues and other practices such as fire management (fuel reduction), pre-commercial thinnings, and land clearing for development. This includes material that is already utilized as well as material that is disposed as waste.
- **Primary Mill Residues –** Primary mill residue data is also taken from the 2002 USDA Forest Service Timber Product Output Database. The quantities include mill residues such as slabs, edgings, trimmings, sawdust, veneer clippings, and pulp screenings. This includes material that is already utilized as well as material that is disposed as waste.
- **Secondary Mill Residues** – Secondary mill residue includes material from wood manufacturing facilities including pallet, truss, and furniture manufacturers. Data from the US Census Bureau was used to determine the number of businesses in each county. The size of the company was then used to estimate the amount of residue each company generates, using data from a previous NREL study which found that pallet and lumber companies generate about 300 tons per year, and a small woodworking company generates about 5 to 20 tons per year of wood waste.
- **Urban Wood Residues –** Includes clean wood segregated from municipal solid waste (wood chips, pallets, and yard waste), tree trimming services, and construction and demolition (C&D) wood. Quantities were estimated using data from a previous NREL study, which found that approximately 3 to 5 percent of municipal solid waste is wood, one tree service company generates about 1,000 tons per year of wood waste, and that C&D wood is proportionate to population. Urban wood waste is a promising source in the study region, particularly around urban centers in southern California.

It is important to note that NREL's estimates are for sustainable harvesting of biomass and not activities such as clear-cut logging.

For each of the regions considered in this study, other state and province assessments were reviewed and compared to the NREL data and methodology. These assessments were typically more focused than the NREL study, and, with some exceptions, the findings of these studies were in general agreement with the NREL assessment. In general, these studies quantified the total biomass resources available for the generation of electricity and did not account for any existing utilization of biomass for power generation or competing uses. This methodology is similar to that of the NREL study, which allows for comparison of the studies. An exception to this is the assessment reviewed for Oregon, which identified resources in excess of existing utilization.

High-level biomass resource assessments for each of the states and provinces in the RETI study region are presented in the following sections. Considering the resources identified and the existing biomass-derived generation within the RETI study region, additional biomass-derived generation potential is estimated for each state and province.

6.1.2 California Biomass Potential

While not as large as the potential for wind and solar generation, there is significant potential for biomass-derived generation in California. Biomass resources are fairly well distributed throughout the state. Agricultural residues are prevalent throughout the Central Valley, while forestry residues are concentrated primarily in the northwestern counties of the state, such as Humboldt, Mendocino, Siskiyou, and Trinity. There are significant quantities of biomass in the municipal solid waste streams associated with metropolitan areas, particularly Los Angeles.

California's biomass resources as estimated by NREL are listed in Table 6-1. NREL estimates that nearly 12 million dry tons of biomass are available per year in California for the generation of biomass-derived electricity. Table 6-1 also lists the generation capacity that could theoretically be supported by the estimated resources within each county. This estimate of potential generation assumes a biomass heating value of 8,500 Btu/lb, a facility heat rate of 14,500 Btu/kWh and a facility capacity factor of 80 percent.

Table 6-1. NREL Estimate of Biomass Resources in California (Dry Tons/Year).

County	Agricult. Residue	Forest Residue	Primary Mill Residue	Secondary Mill Residue	Urban Wood Waste	Total	MW*
Alameda	863	78,121	0	13,974	165,270	258,228	43
Alpine	0	0	0	0	138	138	0
Amador	0	1,822	341,214	12	4,109	347,157	58
Butte	158,525	11,832	408,960	1,617	23,712	604,645	101
Calaveras	0	19,423	0	269	5,005	24,698	4
Colusa	48,209	0	0	4	2,243	50,456	8
Contra Costa	6,064	0	0	6,307	109,250	121,621	20
Del Norte	0	24,198	0	8	3,421	27,627	5
El Dorado	0	32,327	280,770	559	18,164	331,820	56
Fresno	184,125	4,574	3,161	7,797	91,602	291,259	49
Glenn	161,150	1,407	0	253	3,210	166,020	28
Humboldt	242	523,294	1,392,795	571	15,935	1,932,837	323
Imperial	55,822	0	0	984	16,478	73,284	12
Inyo	0	0	0	8	2,236	2,244	0
Kern	112,520	807	0	2,318	77,284	192,930	32
Kings	132,085	0	0	20	14,820	146,925	25
Lake	147	1,193	0	45	6,675	8,060	1
Lassen	1,604	49,615	238,371	12	4,236	293,838	49
Los Angeles	204	0	0	61,285	1,089,985	1,151,474	193
Madera	35,162	8,845	0	290	14,184	58,480	10
Marin	0	0	0	1,808	28,580	30,389	5
Mariposa	0	1,367	0	8	2,052	3,427	1
Mendocino	0	219,404	494,491	2,776	10,874	727,545	122
Merced	80,064	0	0	1,270	24,284	105,618	18
Modoc	9,346	23,499	0	0	1,445	34,290	6
Mono	0	0	0	4	1,562	1,566	0
Monterey	2,336	0	0	1,829	46,627	50,792	8
Napa	0	0	0	3,250	14,317	17,567	3
Nevada	0	28,758	0	816	10,989	40,563	7
Orange	282	0	0	24,698	328,821	353,801	59
Placer	17,709	6,606	0	2,617	28,707	55,640	9
Plumas	0	38,835	0	37	2,928	41,800	7
Riverside	25,379	0	0	9,439	177,905	212,722	36
Sacramento	45,199	0	0	13,002	140,603	198,804	33
San Benito	1,014	0	0	1,278	6,185	8,477	1
San Bernardino	798	0	0	20,118	196,048	216,965	36
San Diego	457	0	0	19,298	322,291	342,045	57
San Francisco	0	0	0	3,445	89,006	92,452	15
San Joaquin	95,655	0	0	5,184	64,971	165,810	28

Table 6-1. NREL Estimate of Biomass Resources in California (Dry Tons/Year).

County	Agricult. Residue	Forest Residue	Primary Mill Residue	Secondary Mill Residue	Urban Wood Waste	Total	MW*
San Luis Obispo	6,383	0	0	1,339	28,329	36,052	6
San Mateo	106	2,235	0	3,413	81,133	86,887	15
Santa Barbara	1,073	0	0	2,609	46,078	49,760	8
Santa Clara	113	1,008	0	7,283	192,702	201,106	34
Santa Cruz	0	6,064	0	1,135	29,714	36,913	6
Shasta	714	55,646	682,133	3,739	19,959	762,192	128
Sierra	0	9,505	0	0	407	9,912	2
Siskiyou	8,035	65,950	526,454	265	6,342	607,046	102
Solano	33,666	0	0	2,082	45,346	81,094	14
Sonoma	728	9,297	110,241	6,173	52,953	179,392	30
Stanislaus	9,700	2,421	0	2,899	51,169	66,189	11
Sutter	175,299	0	0	771	9,126	185,197	31
Tehama	2,905	14,978	0	820	6,778	25,481	4
Trinity	0	33,484	0	12	1,581	35,078	6
Tulare	97,188	6,803	0	1,808	42,764	148,564	25
Tuolumne	0	18,924	293,118	286	6,420	318,748	53
Ventura	0	0	0	2,380	87,220	89,599	15
Yolo	93,143	0	0	1,515	19,489	114,146	19
Yuba	54,646	520	0	779	6,984	62,929	11
Total	**1,658,662**	**1,302,762**	**4,771,708**	**246,521**	**3,900,648**	**11,880,302**	**1,988**

Source: Milbrandt, A. "A Geographic Perspective on the Current Biomass Resource Availability in the United States," 2005. NREL Technical Report NREL/TP-560-39181.

Notes:

* Assumes an average biomass HHV of 8,500 Btu/lb, a heat rate of 14,500 Btu/kWh, and a capacity factor of 80 percent.

In addition to the NREL biomass assessment, several assessments have been conducted in recent years by the California Biomass Collaborative (CBC), including an assessment performed by Williams, et al. in 2006.[17] A more recent assessment was released in 2007, but this study focused on the potential for biofuel production. Therefore, the 2006 assessment was utilized for this review.

The CBC assessment identified both the gross quantities of biomass available within California and the quantities of biomass which were considered feasibly able to be collected (termed “technical” biomass availability) in 2005. This study also projects the gross and technical availability in the following years: 2010, 2017 and 2020. The assessment utilized actual crop production data, actual timber harvest data, actual waste disposal data, and other "actual" data.

The quantities of biomass resources considered technically viable for collection by the CBC in 2010 are listed in Table 6-2. CBC estimates that there are more than 31 million dry tons of biomass available per year in California for the generation of biomass-derived electricity. Table 6-2 also lists the CBC estimate of generation capacity that could be supported by the estimated resources within each county.

There are significant disparities between the NREL and CBC biomass resource assessments. The CBC estimates are approximately 200 to 300 percent higher than the NREL estimates in every category (i.e., agricultural residues, forestry/wood products residues, and urban wood waste). The estimates of statewide generation potential from the NREL assessment and the CBC assessment are 2,000 MW and 4,900 MW, respectively. Due to the utilization of local production and disposal data for the CBC assessment rather than national databases (as utilized in the NREL assessment), the CBC estimates are considered more reliable than the NREL estimates.

Regardless of whether the generation potential in California is 2,000 MW or 4,900 MW, there is substantial potential for increased biomass utilization to generate electricity. Currently, the total operational biomass generation capacity in California is about 700 MW.[18] The potential for additional biomass power in California is promising. Due to the dispersed nature of biomass resources in the state of California, there are likely several locations in the state that could support a biomass-fired facility from a technical perspective. The most viable biomass facilities would likely be:

- Wood-fired facilities in northern California (i.e., Humboldt, Mendocino, Siskiyou, and Trinity counties)
- Facilities in the Central Valley fueled with agricultural residues
- Facilities near urban areas fueled with urban wood waste

Biomass resources in California appear to be technically capable of supporting an additional 1,300 MW to 4,200 MW of biomass power.

[17] Williams, et al. "An Assessment of Biomass Resources in California, 2006," 2006. California Biomass Collaborative Draft Report. Accessed online at: http://biomass.ucdavis.edu/reports.html on February 28, 2008.
[18] Source: Black & Veatch query of Ventyx Energy Velocity database, March 11, 2008.

Table 6-2. CBC Estimate of Biomass Resources in California in 2010 (Dry Tons/Year).

County	Agricult. Residue	Forest Residue[a]	Primary Mill Residue[a]	Secondary Mill Residue[a]	Urban Wood Waste[b]	Total[c]	MW[d]
Alameda	2,300	8,400			380,850	391,550	57
Alpine	0	32,600			550	33,150	6
Amador	4,400	143,100			10,900	158,400	26
Butte	308,000	294,500			45,550	648,050	125
Calaveras	2,000	250,300			11,550	263,850	44
Colusa	381,400	58,300			4,850	444,550	99
Contra Costa	25,800	5,100			247,750	278,650	41
Del Norte	0	157,400			4,800	162,200	27
El Dorado	3,100	545,300			41,550	589,950	99
Fresno	696,400	259,100			198,550	1,154,050	204
Glenn	284,700	60,400			5,050	350,150	78
Humboldt	0	278,900			22,700	301,600	50
Imperial	83,500	1,177,000			61,500	1,322,000	226
Inyo	1,800	135,300			3,950	141,050	22
Kern	456,300	232,000			192,700	881,000	158
Kings	245,300	1,000			28,750	275,050	67
Lake	14,200	265,100			11,250	290,550	48
Lassen	2,500	686,400			5,200	694,100	115
Los Angeles	2,900	125,200			2,749,650	2,877,750	417
Madera	211,700	193,500			30,700	435,900	73
Marin	100	25,900			49,700	75,700	12
Mariposa	600	161,500			3,300	165,400	28
Mendocino	26,400	1,242,200			16,250	1,284,850	216
Merced	309,600	2,500			69,850	381,950	63
Modoc	9,400	425,700			1,450	436,550	74
Mono	0	102,000			7,600	109,600	18
Monterey	79,100	95,600			102,000	276,700	42
Napa	57,400	131,300			39,300	228,000	36
Nevada	400	309,000			19,350	328,750	55
Orange	3,500	10,100			909,750	923,350	134
Placer	33,300	252,300			73,550	359,150	61
Plumas	0	666,800			5,600	672,400	114
Riverside	63,400	228,700			609,100	901,200	137
Sacramento	114,800	700			380,000	495,500	83
San Benito	13,700	42,500			14,550	70,750	11
San Bernardino	6,900	639,500			531,000	1,177,400	179
San Diego	25,600	250,500			932,900	1,209,000	179
San Francisco	0	0			136,400	136,400	20
San Joaquin	452,600	2,400			183,950	638,950	113

Table 6-2. CBC Estimate of Biomass Resources in California in 2010 (Dry Tons/Year).

County	Agricult. Residue	Forest Residue[a]	Primary Mill Residue[a]	Secondary Mill Residue[a]	Urban Wood Waste[b]	Total[c]	MW[d]
San Luis Obispo	50,400	122,400			63,700	236,500	38
San Mateo	500	37,300			156,100	193,900	29
Santa Barbara	40,200	82,900			107,850	230,950	35
Santa Clara	9,000	72,300			362,950	444,250	65
Santa Cruz	4,100	98,900			49,500	152,500	24
Shasta	9,000	897,800			41,800	948,600	160
Sierra	0	193,200			500	193,700	33
Siskiyou	17,300	1,091,000			6,650	1,114,950	190
Solano	56,200	3,100			100,750	160,050	30
Sonoma	72,500	338,400			114,950	525,850	85
Stanislaus	237,800	12,000			134,800	384,600	60
Sutter	307,600	0			32,350	339,950	77
Tehama	41,300	335,500			11,900	388,700	66
Trinity	100	739,300			1,450	740,850	125
Tulare	317,700	200,000			101,900	619,600	112
Tuolumne	0	363,200			10,550	373,750	63
Ventura	31,500	34,200			239,000	304,700	45
Yolo	178,000	22,500			54,350	254,850	56
Yuba	110,600	123,600			31,650	265,850	50
Other – not located	87,500	0			0	87,500	20
Total	**5,494,400**	**14,265,700**			**9,766,650**	**31,565,500**	**4,921**

Source: California Biomass Collaborative (http://biomass.ucdavis.edu/reports.html, accessed 2008).

Notes:

a CBC assessment does not distinguish between forestry residues, primary mill residues, and secondary mill residues.

b Urban wood waste (UWW) includes both biomass reclaimed from municipal solid waste (MSW) streams and biosolids diverted from landfills. The CBC assessment includes diverted biosolids as a separate resource category, but this has been combined with biomass from MSW streams to constitute UWW in this table.

c Total quantity of biomass technically available in 2010 (31,565,000 dry tons) includes 2,000,000 dry tons of energy crops.

d CBC assumes a heat rate of 13,650 Btu/kWh, and a capacity factor of 85 percent. Heating values for biomass fuels were determined for each individual biomass resource (e.g., orchard residues, straw and stover, nut shells, and forestry residues).

6.1.3 Arizona Biomass Potential

When compared to the potential for biomass power generation in California, the potential for biomass power generation in Arizona is modest. With the exception of potential forest thinnings from national forests in the counties of Apache, Coconino and Navajo, the state's biomass resources (primarily agricultural residues and urban wood waste) are concentrated in the southern counties of Arizona. Over 60 percent of the resources identified by the NREL assessment are located in the counties of Maricopa, Pima, and Pinal. Half of the biomass resources of these counties consist of urban wood waste from the Phoenix metropolitan area, while agricultural residues are relatively significant in both Maricopa and Pinal.

The biomass resources in Arizona as estimated by NREL are listed in Table 6-3. NREL estimates that slightly more than 1 million dry tons of biomass are available per year in Arizona for the generation of biomass-derived electricity. Table 6-3 also lists the generation capacity that could theoretically be supported by the estimated resources within each county. This estimate of potential generation assumes a biomass heating value of 8,500 Btu/lb, a facility heat rate of 14,500 Btu/kWh and a facility capacity factor of 80 percent.

Table 6-3. NREL Estimate of Biomass Resources in Arizona (Dry Tons/Year).

County	Agricult. Residue	Forest Residue	Primary Mill Residue	Secondary Mill Residue	Urban Wood Waste	Total	MW*
Apache	0	12,380	0	498	7,403	20,280	3
Cochise	34,207	0	0	20	12,758	46,985	8
Coconino	0	16,125	0	41	11,977	28,142	5
Gila	0	4,083	0	253	5,387	9,723	2
Graham	18,254	0	0	245	3,577	22,076	4
Greenlee	0	1,764	0	0	1,048	2,812	0
La Paz	18,110	0	0	0	2,090	20,200	3
Maricopa	69,267	0	0	28,679	312,337	410,283	69
Mohave	2,394	0	0	1,829	16,628	20,851	3
Navajo	0	24,769	108,588	1,519	10,337	145,213	24
Pima	15,946	0	0	2,964	86,102	105,011	18
Pinal	126,526	0	0	1,025	18,497	146,048	24
Santa Cruz	0	0	0	738	4,073	4,812	1
Yavapai	0	11	0	1,870	17,077	18,958	3
Yuma	66,287	0	0	1,274	16,318	83,878	14
Total	**350,990**	**59,132**	**108,588**	**40,954**	**525,609**	**1,085,272**	**182**

Source: Milbrandt, A. "A Geographic Perspective on the Current Biomass Resource Availability in the United States," 2005. NREL Technical Report NREL/TP-560-39181.

Notes:

* Assumes an average biomass HHV of 8,500 Btu/lb, a heat rate of 14,500 Btu/kWh, and a capacity factor of 80 percent.

Based on the biomass resources estimated by NREL, there is biomass generation potential of 182 MW in Arizona, which is an order of magnitude less than that of

California. There is at least one biomass energy project under development in Arizona (Snowflake White Mountain Power), which will provide 24 MW of generation and will require 100,000 dry tons of biomass per year, or roughly 10 percent of the resources identified by NREL in Arizona. This project has already secured power purchase agreements with Arizona utilities. Other biomass energy projects, including at least one wood pelletizing mill, have also been considered. In addition, Arizona has a renewable portfolio standard which will require 15 percent of the electricity generated within the state to be generated from renewable resources by 2025.

In a previous assessment of biomass resources in Arizona by Black & Veatch, three biomass combustion projects were identified as technically viable. These three projects provided a total generation capacity of 40 MW. Forest thinning residues provide significant potential for biomass-derived generation in Arizona, particularly when compared to biomass resources in the rest of the state. However, the dispersed nature of these resources prevents their full utilization. While the NREL assessment identified over 180 MW of potential, competition and logistical challenges associated with biomass fuel delivery significantly reduce this potential.

Considering all of these factors, the potential for biomass-derived electrical generation that is produced in Arizona and consumed in California is considered poor.

6.1.4 Nevada Biomass Potential

The potential for biomass power generation in Nevada is minimal. The majority of biomass resources in the state are categorized as urban wood waste in Clark County (i.e., the Las Vegas metropolitan area).

The biomass resources in Nevada estimated by NREL are listed in Table 6-4. NREL estimates that about 260,000 dry tons of biomass are available per year in Nevada for the generation of biomass-derived electricity. Table 6-4 also lists the generation capacity that could theoretically be supported by the estimated resources within each county. This estimate of potential generation assumes a biomass heating value of 8,500 Btu/lb, a facility heat rate of 14,500 Btu/kWh and a facility capacity factor of 80 percent.

Table 6-4. NREL Estimate of Biomass Resources in Nevada (Dry Tons/Year).

County	Agricult. Residue	Forest Residue	Primary Mill Residue	Secondary Mill Residue	Urban Wood Waste	Total	MW*
Carson City	0	0	0	1,009	6,187	7,195	1
Churchill	0	0	0	8	2,745	2,753	0
Clark	0	0	0	8,675	157,580	166,254	28
Douglas	0	5,375	0	16	4,995	10,387	2
Elko	0	0	0	8	5,548	5,556	1
Esmeralda	0	0	0	0	202	202	0
Eureka	0	0	0	0	280	280	0
Humboldt	4,011	0	0	0	2,116	6,127	1
Lander	0	0	0	0	754	754	0
Lincoln	0	0	0	0	568	568	0
Lyon	0	0	0	767	4,040	4,807	1
Mineral	0	0	0	0	671	671	0
Nye	0	0	0	269	4,082	4,351	1
Pershing	0	0	0	253	766	1,019	0
Storey	0	0	0	4	480	484	0
Washoe	0	0	0	6,046	39,861	45,907	8
White Pine	0	0	0	0	1,233	1,233	0
Total	**4,011**	**5,375**	**0**	**17,056**	**232,106**	**258,548**	**43**

Source: Milbrandt, A. "A Geographic Perspective on the Current Biomass Resource Availability in the United States," 2005. NREL Technical Report NREL/TP-560-39181.

Notes:

* Assumes an average biomass HHV of 8,500 Btu/lb, a heat rate of 14,500 Btu/kWh, and a capacity factor of 80 percent.

Based on the biomass resources quantified by NREL, there is biomass generation potential of 43 MW in Nevada. The development of biomass power facilities larger than 5 to 10 MW in Nevada is relatively unlikely. Therefore, the potential for biomass-derived electrical generation that is produced in Nevada and consumed in California is considered poor.

6.1.5 Oregon Biomass Potential

Based on the sizable area of forested lands in Oregon, the state has a significant potential for biomass-derived generation. The biomass resources associated with these forested lands are located in the western portion of the state. Woody resources are particularly significant in the southwestern counties of Douglas, Jackson, Klamath and Lane. In addition to the southwestern region, the counties of Baker, Umatilla and Union in northeastern Oregon contain a moderate amount of both forestry residues and agricultural residues.

The biomass resources in Oregon as estimated by NREL are listed in Table 6-5. NREL estimates that 8.5 million dry tons of biomass are available per year in Oregon for the generation of biomass-derived electricity. Table 6-5 also lists the generation capacity that could theoretically be supported by the estimated resources within each county. This estimate of potential generation assumes a biomass heating value of 8,500 Btu/lb, a facility heat rate of 14,500 Btu/kWh and a facility capacity factor of 80 percent.

The Oregon Department of Energy (DOE) has estimated the potential for increased utilization of biomass for the production of energy (i.e., in excess of the current biomass utilization).[19] This includes estimates of underutilized wood resources, unutilized agricultural residues, and potential for efficiency improvements of liquor boilers at pulp mills. The estimates of available biomass for power production and estimates of potential generation are listed in Table 6-6.

The potential for additional biomass power in Oregon is considered fair. There is currently 280 MW of biomass-fired generation capacity in Oregon.[20] The Oregon DOE's assessment indicates that this capacity could be expanded by 425 MW if all available resources are utilized. The most likely location for these additional biomass projects would be in western Oregon. Although it is uncertain what quantity of biomass power generation would be desirable to Oregon utilities to satisfy the state RPS, biomass resources appear to be technically capable of supporting an additional 425 MW of biomass power.

[19] Oregon Department of Energy, "Oregon's Biomass Energy Resources," 2007. Accessed online at: http://oregon.gov/ENERGY/RENEW/Biomass/resource.shtml on March 7, 2008.
[20] Black & Veatch query of Ventyx Energy Velocity database, March 11, 2008.

Table 6-5. NREL Estimate of Biomass Resources in Oregon (Dry Tons/Year).

County	Agricult. Residue	Forest Residue	Primary Mill Residue	Secondary Mill Residue	Urban Wood Waste	Total	MW*
Baker	11,190	12,799	129,865	24	2,090	155,968	26
Benton	3,526	17,691	376,436	547	9,150	407,350	68
Clackamas	2,352	16,774	124,012	14,991	36,083	194,212	32
Clatsop	0	58,491	85,247	257	4,038	148,033	25
Columbia	221	40,887	348,926	1,001	4,856	395,890	66
Coos	0	125,610	179,586	1,001	7,655	313,852	53
Crook	1,913	3,492	193,448	559	2,069	201,481	34
Curry	0	30,224	179,819	253	2,271	212,567	36
Deschutes	536	11,920	53,389	5,135	13,170	84,151	14
Douglas	0	284,612	636,326	596	12,625	934,159	156
Gilliam	24,392	0	0	0	288	24,680	4
Grant	523	1,957	0	0	1,545	4,025	1
Harney	425	711	0	0	1,239	2,375	0
Hood River	28	0	0	261	2,378	2,667	0
Jackson	591	30,459	553,140	6,046	21,874	612,110	102
Jefferson	11,563	38	0	510	2,142	14,254	2
Josephine	134	2,470	0	1,792	8,809	13,205	2
Klamath	35,711	71,867	311,994	1,054	7,758	428,384	72
Lake	794	0	0	16	1,038	1,848	0
Lane	3,157	116,927	1,353,484	11,852	36,670	1,522,090	255
Lincoln	0	29,066	56,438	16	5,132	90,653	15
Linn	6,016	34,251	282,252	1,564	11,993	336,075	56
Malheur	62,688	499	0	980	3,352	67,519	11
Marion	8,338	7,945	0	4,336	31,558	52,177	9
Morrow	91,168	76	0	0	1,225	92,469	15
Multnomah	2,277	14	0	13,570	68,398	84,259	14
Polk	9,302	13,932	268,321	33	7,796	299,384	50
Sherman	40,338	0	0	0	199	40,538	7
Tillamook	0	67,868	219,395	0	2,956	290,219	49
Umatilla	159,128	14,575	178,235	269	8,003	360,210	60
Union	26,629	8,582	313,173	20	2,893	351,297	59
Wallowa	8,879	26	0	0	1,562	10,467	2
Wasco	21,869	2,485	0	257	2,545	27,156	5
Washington	20,978	19,648	300,621	18,151	46,842	406,240	68
Wheeler	338	1,443	0	0	160	1,941	0
Yamhill	12,265	13,383	309,665	828	9,493	345,634	58
Total	**567,268**	**1,040,722**	**6,453,772**	**85,919**	**381,856**	**8,529,537**	**1,427**

Source: Milbrandt, A. "A Geographic Perspective on the Current Biomass Resource Availability in the United States," 2005. NREL Technical Report NREL/TP-560-39181.

Notes:

* Assumes an average biomass HHV of 8,500 Btu/lb, a heat rate of 14,500 Btu/kWh, and a capacity factor of 80 percent.

Table 6-6. Oregon DOE Estimate of Biomass Resources and Generation in Oregon.

Biomass Resource	Available Biomass (dry tons/year)	Generation Potential* (MW)
Woody Biomass	700,000	117
Agricultural Residues	1,500,000	251
Upgrades of Existing Liquor Boilers**		57
Total	**2,200,000**	**425**

Source: Oregon Department of Energy, "Oregon's Biomass Energy Resources," 2007. Accessed online at: http://oregon.gov/ENERGY/RENEW/Biomass/resource.shtml on March 7, 2008.

Notes:

* Assumes an average biomass HHV of 8,500 Btu/lb, a heat rate of 14,500 Btu/kWh, and a capacity factor of 80 percent.

** Several black liquor boilers at pulp mills are expected to reach the end of their serviceable life in the near future. These boilers are expected to be replaced by more efficient boiler systems that will provide additional generation capacity due to process efficiency gains.

6.1.6 Washington Biomass Potential

Washington, like Oregon, has a large amount of forested lands and a moderate quantity of agricultural lands, resulting in considerable potential for biomass-derived generation. The biomass resources associated with woody (forest and milling) residues are located in the western portion of the state. Woody resources are particularly significant in the southwestern counties of Cowlitz, Lewis, and Pierce.

The biomass resources in Washington as estimated by NREL are listed in Table 6-7. NREL estimates that over 9 million dry tons of biomass are available per year in Washington for the generation of biomass-derived electricity. Table 6-7 also lists the generation capacity that could theoretically be supported by the estimated resources within each county. This estimate of potential generation assumes a biomass heating value of 8,500 Btu/lb, a facility heat rate of 14,500 Btu/kWh and a facility capacity factor of 80 percent.

Table 6-7. NREL Estimate of Biomass Resources in Washington (Dry Tons/Year).

County	Agricult. Residue	Forest Residue	Primary Mill Residue	Secondary Mill Residue	Urban Wood Waste	Total	MW*
Adams	147,117	2,311	0	0	2,096	151,523	25
Asotin	12,677	9,146	0	20	2,372	24,215	4
Benton	53,128	0	0	498	16,085	69,711	12
Chelan	0	7,728	0	1,013	7,666	16,407	3
Clallam	0	44,488	168	779	7,434	52,869	9
Clark	0	5,976	194,860	5,606	38,953	245,394	41
Columbia	71,539	0	0	8	451	71,998	12
Cowlitz	0	202,429	726,653	767	11,496	941,345	157
Douglas	74,784	0	0	4	3,619	78,407	13
Ferry	0	11,573	120,758	0	1,169	133,500	22
Franklin	64,892	0	0	257	5,568	70,717	12
Garfield	55,382	0	0	0	357	55,739	9
Grant	169,880	0	0	490	8,291	178,660	30
Grays Harbor	0	109,128	289,054	1,050	8,184	407,415	68
Island	0	116	8,335	771	8,214	17,437	3
Jefferson	0	30,403	140,399	763	3,244	174,809	29
King	0	30,271	177,124	32,280	194,151	433,826	73
Kitsap	0	413	0	2,531	26,472	29,416	5
Kittitas	1,252	246	0	510	4,066	6,074	1
Klickitat	18,323	3,027	0	4	2,217	23,572	4
Lewis	301	151,928	566,015	1,784	9,702	729,729	122
Lincoln	268,819	0	0	0	1,312	270,131	45
Mason	0	19,447	412,135	539	5,756	437,876	73
Okanogan	4,858	40,843	0	253	5,571	51,526	9
Pacific	0	11,731	194,445	4	2,601	208,781	35
Pend Oreille	0	73	0	0	1,393	1,466	0
Pierce	0	93,375	1,356,864	11,382	79,689	1,541,309	258
San Juan	0	104	0	290	1,835	2,228	0
Skagit	23,653	8,756	139,168	828	12,337	184,742	31
Skamania	0	22,278	0	253	1,096	23,627	4
Snohomish	409	46,596	432,471	8,238	68,078	555,793	93
Spokane	96,699	32	0	7,279	46,568	150,578	25
Stevens	4,869	98,461	325,454	510	5,809	435,103	73
Thurston	0	22,699	1,103	1,751	24,648	50,201	8
Wahkiakum	0	8	0	4	424	436	0
Walla Walla	211,603	0	0	24	6,487	218,115	36
Whatcom	4,590	2,627	0	2,371	18,787	28,375	5
Whitman	423,545	0	0	4	5,157	428,706	72
Yakima	37,981	57,642	512,116	2,278	25,248	635,265	106
Total	**1,746,301**	**1,033,855**	**5,597,122**	**85,143**	**674,600**	**9,137,021**	**1,529**

Source: Milbrandt, A. "A Geographic Perspective on the Current Biomass Resource Availability in the United States," 2005. NREL Technical Report NREL/TP-560-39181.

Notes:

* Assumes an average biomass HHV of 8,500 Btu/lb, a heat rate of 14,500 Btu/kWh, and a capacity factor of 80 percent.

A recent study conducted by Washington State University (WSU) and the Washington Department of Ecology[21] reported findings very consistent with the NREL assessment. The primary difference between the two studies resulted from the inclusion of 5.5 million dry tons per year (Mdtpy) of animal wastes, food packing/processing residues and municipal waste not included in the NREL assessment. Less significantly, the WSU assessment identified:

- Larger quantities of agricultural residues (2.25 Mdtpy versus 1.75 Mdtpy)
- Larger quantities of urban wood wastes (1.5 Mdtpy versus 0.6 million Mdtpy)
- Smaller quantities of mill residues (5.0 Mdtpy versus 5.5 Mdtpy)

The WSU assessment identified 16.9 Mdtpy of biomass resources, of which 14.2 million tons were solid biomass resources suitable for thermal conversion (i.e., combustion or gasification) to electricity. This assessment estimated the potential generation from biomass suitable for thermal conversion to be 13,700,000 GWh. If all of this generation were produced from facilities with capacity factors of 80 percent, this would imply a potential biomass generation capacity of 1,955 MW.

The total operational biomass generation capacity in Washington today is approximately 300 MW.[22] Considering the estimates above, the state's potential for additional biomass power is considered promising. Due to heavy concentrations of biomass resources in the southwestern region of the state, the most viable biomass facilities would likely be located in this region. Biomass resources appear to be technically capable of supporting an additional 1,600 MW of biomass power. Of this additional generation, it is uncertain what quantity of power would be available for export to California.

6.1.7 British Columbia Biomass Potential

Biomass resources for British Columbia were estimated based on a study conducted on behalf of the BIOCAP Canada Foundation.[23] The BIOCAP study identified a total of 21.3 million tons of sustainable biomass residues (including MSW) per year. Potential electrical generation capacity based on these biomass resources is estimated to be approximately 3000 MW. A summary of the findings of the BIOCAP study is provided in Table 6-8.

[21] Frear, et al. "Biomass Inventory and Bioenergy Assessment," 2005. Accessed at: http://www.ecy.wa.gov/pubs/0507047.pdf on March 7, 2008.
[22] Black & Veatch query of Ventyx Energy Velocity database, March 11, 2008.
[23] Ralevic and Layzell, "An Inventory of the Bioenergy Potential of British Columbia," 2006. Accessed online at: http://www.biocap.ca/images/pdfs/BC_Inventory_Final-06Nov15.pdf on February 28, 2008.

Table 6-8. BIOCAP Estimate of Biomass Resources in British Columbia.

Biomass Resource	Available Biomass (dry tons/year)	Generation Potential* (MW)
Municipal Solid Waste		
Total MSW	**948,500**	**139**
Sustainable Agriculture		
Crop Residues	143,900	21
Livestock Manure	388,400	56
Energy crops of summerfallow land	147,000	22
Energy crops on new converted land	2,587,000	377
Total Sustainable Agriculture	**3,266,300**	**476**
Sustainable Forestry		
Forestry Residues	11,940,500	1741
Enhanced silvaculture for traditional forest products	1,194,000	174
Enhanced silvaculture for bioenergy plantations	3,980,000	580
Total Sustainable Forestry	**17,114,500**	**2495**
Total	**21,329,300**	**3110**

Source: Ralevic and Layzell, "An Inventory of the Bioenergy Potential of British Columbia," 2006. Accessed online at: http://www.biocap.ca/images/pdfs/BC_Inventory_Final-06Nov15.pdf on February 28, 2008.

Notes:

* Assumes an average heat rate of 14,500 Btu/kWh, and a capacity factor of 80 percent.

** Several liquor boilers at pulp mills are expected to reach the end of their serviceable life in the near future. These boilers are expected to be replaced by more efficient boiler systems that will provide additional generation capacity due to process efficiency gains.

With the exception of California, British Columbia has the greatest potential for additional biomass generation of any of the states and provinces within the RETI study region. The potential generation is more than 3000 MW, and the total operational biomass generation capacity currently in British Columbia is approximately 540 MW.[24] Notwithstanding transmission considerations, the potential for additional biomass power in British Columbia is therefore very promising. Biomass resources appear to be technically capable of supporting an additional 2,500 MW of biomass power. Of this additional generation, it is uncertain what quantity of power would be available for export to California.

[24] Black & Veatch query of Ventyx Energy Velocity database, March 11, 2008.

6.1.8 Baja California Biomass Potential

The RETI Phase 1 study found little information that would help to quantify the biomass resource potential of Baja California. A study quantifying renewable resources in the San Diego region[25] identified the potential for wind, solar photovoltaic, solar thermal, geothermal and even tidal energy systems in Baja California. However, no biomass resources were identified in this evaluation. It is likely that urban wood waste resources are available in the metropolitan areas of Baja California (e.g., the cities of Tijuana and Mexicali). Biomass projects that utilize this resource may be technically feasible, but these are unlikely to be of sufficient size to justify exporting the power to California. Given these considerations, the biomass generation potential for Baja California is considered poor, and no potential biomass generation is estimated for this region.

6.1.9 Biomass Summary

The most promising areas within the study region for the development of biomass generation fall along the western portions of northern California, Oregon and Washington as well as British Columbia. As listed in Table 6-9, there is potential for the addition of over 9,100 MW of additional generation; of this potential, 8,900 MW is located in California, Washington, Oregon, and British Columbia.

It should be noted that this potential assumes the complete utilization of all available resources, which is impractical due to logistical and economic limitations. Further investigation will be required to determine the viable development potential.

It is recommended that biomass resources be assessed further in Phase 1B for California, Washington, Oregon, and British Columbia.

[25] Anders, et al. "Potential for Renewable Energy in the San Diego Region," 2005. Published by the San Diego Renewable Energy Group. Accessed online at: http://www.renewablesg.org/docs/Web/Renewable_Study_AUG2005_v4.pdf on March 7, 2008.

Table 6-9. Summary of Biomass Resource Assessment.

	Estimated Available Biomass (dry tons/year)	Estimated Capacity Potential (MW)	Existing Capacity (MW)	Potential for Additional Capacity (MW)
Arizona	351,000	180	0	180
Baja California	–	–	–	–
British Columbia	21,329,000	3,100	540	2,560
California	31,565,500	4,900	700	4,160
Nevada	258,500	43	1	42
Oregon	8,529,500	1,425	1,000*	425
Washington	14,200,000	1,955	340	1,615
Total	**76,233,500**	**11,603**	**2,581**	**8,980**

Notes:

* The assessment of Oregon included evaluation of current utilization of biomass resources for both generation and non-generation purposes. The current generation capacity from biomass power facilities in Oregon is 280 MW.

6.1.10 Biomass Data Sources

Data sources used in this analysis included:

- Milbrandt, A. "A Geographic Perspective on the Current Biomass Resource Availability in the United States," 2005. NREL Technical Report NREL/TP-560-39181.
- Williams, et al. "An Assessment of Biomass Resources in California, 2006," 2006. California Biomass Collaborative Draft Report. Accessed online at: http://biomass.ucdavis.edu/reports.html on February 28, 2008.
- Oregon Department of Energy, "Oregon's Biomass Energy Resources," 2007. Accessed online at: http://oregon.gov/ENERGY/RENEW/Biomass/resource.shtml on March 7, 2008.
- Frear, et al. "Biomass Inventory and Bioenergy Assessment," 2005. Accessed at: http://www.ecy.wa.gov/pubs/0507047.pdf on March 7, 2008.
- Ralevic and Layzell, "An Inventory of the Bioenergy Potential of British Columbia," 2006. Accessed online at: http://www.biocap.ca/images/pdfs/BC_Inventory_Final-06Nov15.pdf on February 28, 2008.
- Anders, et al. "Potential for Renewable Energy in the San Diego Region," 2005. Published by the San Diego Renewable Energy Group. Accessed

online at: http://www.renewablesg.org/docs/Web/Renewable_Study_AUG2005_v4.pdf on March 7, 2008.

- Black & Veatch query of Ventyx Energy Velocity database, March 11, 2008.

6.2 Anaerobic Digestion

Biogas derived from anaerobic digestion has been identified as a potential renewable resource for the RETI study. This section presents the methodology that was used to quantify biogas resource availability and the potential for electrical generation throughout the RETI study region.

6.2.1 Anaerobic Digestion Methodology

Anaerobic digestion projects can utilize animal manures, typically collected from concentrated animal feeding operations (CAFOs), or can utilize sewage sludge generated in conjunction with waste water treatment plants (WWTP). Food wastes and other organic materials can also be anaerobically digested, although these feedstocks are not widely utilized for power generation projects. Because the anaerobic digestion system is already installed, power generated from biogas at WWTPs can be as little as half the cost of animal manure digestion projects. However, it is usually the case that the power demands of the wastewater treatment process are larger than the biogas generation potential. Therefore, the potential for grid export is limited. In addition, biogas is already widely utilized in California for power generation at larger WWTP. For these reasons, the total potential identified in the RETI study region does not include potential generation from anaerobic digestion processes at WWTPs.

Feedstocks suitable for anaerobic digestion were included in several of the biomass resource assessments reviewed to assess solid biomass resources, including the National Renewable Energy Laboratory (NREL) and California Biomass Collaborative (CBC) assessments. In addition to these studies, anaerobic digestion studies conducted by the Environmental Protection Agency (EPA) and the California Energy Commission (CEC) have also been included in this review.

The majority of the studies reviewed for the assessment of anaerobic digestion potential explicitly reported generation potential in terms of potential power capacity (MW). The study conducted by NREL, however, reports resource availability in terms of tonnes of methane derived from animal manure and sewage sludge. To estimate the generation potential associated with the quantities of methane identified by NREL, the following assumptions were employed:

- Density of methane: 0.4146 lb/ft^3
- Higher heating value (HHV) of methane: 1030 Btu/ft^3
- Net plant heat rate (NPHR) of generation process: 13,000 Btu/kWh
- Capacity factor of facility: 80 percent

The RETI Phase 1A study located little information regarding potential generation of electricity from biogas derived from anaerobic digestion in Baja California. However, the potential of anaerobic digestion in Baja California is not expected to be significantly greater than the remainder of the RETI study region. Due to the lack of relevant data and the relatively small potential of digestion in the remainder of the study region, the anaerobic digestion potential of Baja California has not been quantified.

6.2.2 Anaerobic Digestion Assessment

To evaluate the potential of anaerobic digestion power projects in the RETI study region, several independent assessments were reviewed. Estimates of the potential generation from biogas derived from anaerobic digestion for each of the regions in the RETI study region are presented in Table 6-10.

Table 6-10. Estimates of Anaerobic Digestion Potential in RETI Study region.

	Animal Manure (MW)	Food Wastes (MW)	Sewage Sludge (MW)	Total Potential* (MW)
CALIFORNIA				
NREL (2005)	85	–	34	85
CBC (2006)	275	18	78	293
CEC (2006)	156	37	38.5	193
EPA** (2007)	171	–	–	171
California Range	**85 – 275**	**18 – 37**	**34 – 78**	**85 – 293**
ARIZONA				
NREL (2005)	8	–	5	8
EPA** (2007)	18	–	–	18
Arizona Range	**8 – 18**	**–**	**5**	**8 – 18**
NEVADA				
NREL (2005)	0	–	2	0
Nevada Range	**0**	**–**	**2**	**0**
OREGON				
NREL (2005)	10	–	3	10
Oregon DOE (2007)	13	–	2	13
Oregon Range	**10 – 13**	**–**	**2 – 3**	**10 – 13**
WASHINGTON				
NREL (2005)	24	–	6	24
WSU (2005)	145	58	–	203
EPA** (2007)	18	–	–	18
Washington Range	**18 - 145**	**58**	**6**	**18 - 203**
BRITISH COLUMBIA				
BIOCAP (2007)	60	–	–	60
British Columbia Range	**60**	**–**	**–**	**60**
TOTAL RANGE	**181 – 511**	**76 – 95**	**49 – 94**	**181 – 587**

Sources: See Anaerobic Digestion Data Sources

Notes:

* Total potential does not include generation from waste water treatment facilities (i.e., sewage sludge), as it is assumed that all of the electricity generated at the WWTF is consumed on-site.

** The EPA study provides only generation potential for anaerobic digestion projects located at dairy operations with more than 500 head of cattle.

6.2.3 Anaerobic Digestion Summary

Based on the generation potentials listed in Table 6-10, there may be as much as 500 MW of generation potential from anaerobic digestion projects in the RETI study region. While collectively these projects may be significant, it is unlikely that individual projects would be much larger than 5 MW. Due to the small potential of the individual anaerobic digestion projects, Black & Veatch does not recommend that RETI Phase 1B consider specific anaerobic digestion project opportunities. However, development of a portion of these projects is expected to occur to meet California RPS requirements, and an assumption will be made for aggregate anaerobic digestion development for RETI Phase 1B.

6.2.4 Anaerobic Digestion Data Sources

Data sources used in this analysis included:

- Milbrandt, A. (NREL). "A Geographic Perspective on the Current Biomass Resource Availability in the United States," 2005. NREL Technical Report NREL/TP-560-39181.
- Williams, et al. (CBC). "An Assessment of Biomass Resources in California, 2006," 2006. California Biomass Collaborative Draft Report. Accessed online at: http://biomass.ucdavis.edu/reports.html on February 28, 2008.
- Zhang, Z. (CEC). "Existing Practices and Prospective Development of Wastes to Energy in California", 2006. Accessed online at: http://www.energy.ca.gov/2006publications/CEC-999-2006-013/CEC-999-2006-013.PDF on March 7, 2008.
- Oregon Department of Energy, "Oregon's Biomass Energy Resources," 2007. Accessed online at: http://oregon.gov/ENERGY/RENEW/Biomass/resource.shtml on March 7, 2008.
- Frear, et al. (Washington State University). "Biomass Inventory and Bioenergy Assessment," 2005. Accessed at: http://www.ecy.wa.gov/pubs/0507047.pdf on March 7, 2008.
- Ralevic and Layzell (BIOCAP). "An Inventory of the Bioenergy Potential of British Columbia," 2006. Accessed online at: http://www.biocap.ca/images/pdfs/BC_Inventory_Final-06Nov15.pdf on February 28, 2008.

6.3 Landfill Gas

Landfill gas has been identified as a potential renewable resource for the RETI study. This section presents the methodology that was used to quantify landfill gas resource availability and the potential for LFG-fired electrical generation throughout the RETI study region.

6.3.1 Landfill Gas Methodology

To assess the generation potential of undeveloped landfill gas projects in the RETI study region, the Environmental Protection Agency (EPA) Landfill Methane Outreach Program (LMOP) database of landfills was reviewed to identify candidate landfills and project capacities. The LMOP database provides figures for the landfill status (i.e., open or closed), size of the landfill, waste in place, gas generation, and, in some cases, contact information.

As discussed in Section 5.3.2, gas production (and, in turn, electricity generation) at a landfill is primarily dependent on the depth and age of waste in place and the amount of precipitation received by the landfill. After waste deliveries to a landfill cease and the landfill is capped, LFG production will decline, typically following a first order decay. Accurate estimates of gas flow rates (as a function of time) require analysis of the monthly or annual waste deposition rates and must consider the amount of time that the waste has resided in the landfill. Regional factors such as the amount of precipitation, recycling practices, and waste composition also affect gas production. This type of analysis is not feasible for a high level assessment.

To obtain a rough estimate of a given landfill's generation potential, a simple estiamte, based on waste in place, was utilized to estimate potential generation. This estiamte states that approximately 0.8 MW of electricity will be generated for every million tons of waste in place.[26] As annual precipitation is a key parameter in the production of LFG, this calculation was modified for Arizona and Nevada; for these states, generation potential for each site was estimated assuming 0.26 MW of generation for every million tons of waste in place. Candidate projects with greater than 3 MW of generation potential were identified and are presented in the following section. Candidate projects with less than 3 MW of generation are considered to be of questionable economic viability in the long term, particularly if LFG flow rates are decreasing (i.e., the landfill is closed and no longer accepting waste).

Assessments of potential landfill gas projects that could be installed in the near term are presented in the following sections for each of the states and provinces in the

[26] Landfill Methane Outreach Program, "An Overview of Landfill Gas Energy in the United States," updated 2007. Accessed online at: http://www.epa.gov/lmop/docs/overview.pdf on February 22, 2008.

RETI study region. Considering the candidate projects identified, the potential for new additional LFG-fired generation is estimated for each state and province.

6.3.2 California Landfill Gas Potential

Based on the LMOP database, there are 37 candidate landfills in California. The total estimated generation potential for these 37 candidate landfills is 139 MW. Of these potential projects, twelve have generation potentials greater than 3 MW; these projects are listed in Table 6-11.

Table 6-11. Candidate LFG Projects (3 MW and Greater) in California.

Landfill	City (County)	Project Developer	Waste in Place (tons)	Year of Closure	Generation Potential* (MW)
American Avenue Disposal Site	Kerman (Fresno)	Fresno County	8,022,000	2043	6.4
Arvin SLF	Arvin (Kern)	Kern County	4,000,000	2004	3.2
Chiquita Canyon SLF	Castaic (Los Angeles)	Republican Services, Inc.	18,680,000	2016	14.9
Edom Hill Disposal Site	Desert Hot Springs (Riverside)	Riverside County	6,100,000	2004	4.9
Kirby Canyon Recycling & Disposal Facility	Morgan Hill (Santa Clara)	Waste Management	3,800,000	2022	3.0
Potrero Hills SLF	Suisun City (Solano)	Republican Services, Inc.	4,514,000	2016	3.6
San Timoteo Solid Waste Disposal Site	Redlands (San Bernadino)	San Bernadino County	5,988,000	2016	4.8
Santiago Canyon SLF	Orange (Orange)	Orange Co. IWMD	17,100,000	1995	13.7
Sunshine Canyon Landfill	Sylmar (Los Angeles)	Allied Waste Services	25,000,000	1991	20.0
Sunshine Canyon Landfill - Extension	Sylmar (Los Angeles)	Allied Waste Services	10,133,000	2008	8.1
Tri-Cities Landfill	Fremont (Alameda)	Waste Management	9,600,000	2005	7.7
Vasco Road SLF	Livermore (Alameda)	Republican Services, Inc.	14,000,000	2018	11.2

Source: LMOP Landfill and Project Database, accessed online at: http://www.epa.gov/lmop/proj/xls/lmopdata.xls on February 22, 2008.

Notes:

* Estimate of generation potential based on rough 0.8 MW of capacity per million tons of waste in place.

6.3.3 Arizona Landfill Gas Potential

In a previous assessment of renewable resources in Arizona by Black & Veatch, opportunities for landfill gas were found to be very limited. .Black & Veatch utilized the LMOP database to assess 25 potential sites in Arizona. Black & Veatch attempted to contact each of the landfills to verify data and assess the suitability for power development. Based on this review, fifteen potential projects were identified, totaling 9.7 MW of capacity and 68 GWh of annual generation.

6.3.4 Nevada Landfill Gas Potential

Based on the LMOP database, there are five candidate landfills in Nevada. Of these potential projects, none have generation potentials greater than 3 MW.

6.3.5 Oregon Landfill Gas Potential

Based on the LMOP database, there are five candidate landfills in Oregon. The total estimated generation potential for these five candidate landfills is 23 MW. Of these potential projects, two have generation potentials greater than 3 MW; these projects are listed in Table 6-12.

Table 6-12. Candidate LFG Projects (3 MW and Greater) in Oregon.

Landfill	City (County)	Project Developer	Waste in Place (tons)	Year of Closure	Generation Potential* (MW)
Columbia Ridge LF	Arlington (Gilliam)	Waste Management	20,000,000	2060	16.0
Finley Buttes Regional Landfill	Boardman (Morrow)	Waste Connections	4,000,000	2060	3.2

Source: LMOP Landfill and Project Database, accessed online at: http://www.epa.gov/lmop/proj/xls/lmopdata.xls on February 22, 2008.

Notes:

* Estimate of generation potential based on approximation of 0.8 MW of capacity per million tons of waste in place.

6.3.6 Washington Landfill Gas Potential

Based on the LMOP database, there are eight candidate landfills in Washington. The total estimated generation potential for these eight candidate landfills is 17 MW. Of these potential projects, two have generation potentials greater than 3 MW; these projects are listed in Table 6-13.

Table 6-13. Candidate LFG Projects (3 MW and Greater) in Washington.

Landfill	City (County)	Project Developer	Waste in Place (tons)	Year of Closure	Generation Potential* (MW)
Kent Highlands LF	Kent (King)	City of Seattle	8,000,000	1986	6.4
Terrace Heights LF	Yakima (Yakima)	Yakima County	3,727,000	2012	3.0

Source: LMOP Landfill and Project Database, accessed online at: http://www.epa.gov/lmop/proj/xls/lmopdata.xls on February 22, 2008.

Notes:

* Estimate of generation potential based on rough 0.8 MW of capacity per million tons of waste in place.

6.3.7 British Columbia Landfill Gas Potential

The total potential of landfill gas utilization in Canada is significantly less than that of the United States, due in large part to the differences in population. A 2003 inventory of LFG resources in Canada identified 13 landfills in British Columbia with the capability of collecting and utilizing LFG.[27] There are four existing LFG projects in British Columbia. Therefore, there are nine sites in British Columbia that currently flare gas but have the potential to generate electricity. Based on national averages (28 sites in Canada flaring 139,000 tonnes of LFG), it is assumed that these nine sites in British Columbia are flaring approximately 45,000 tonnes of LFG, which would be sufficient to generate approximately 22 MW of electricity.

6.3.8 Baja California Landfill Gas Potential

The RETI Phase 1 study located little information regarding potential generation of electricity from LFG in Baja California. However, the potential for LFG in Baja California is not expected to be significantly greater than the remainder of the RETI study region. Due to the lack of relevant data and the relatively small potential of LFG in the remainder of the study region, the LFG potential of Baja California has not been quantified.

6.3.9 Landfill Gas Summary

Table 6-14 summarizes the potential for generation from LFG-fired facilities in the RETI study region. Compared with the resource potential of other renewable

[27] Methane to Market Partnership Landfill Subcommittee, “Landfill Gas Management in Canada,” 2005. Accessed online at: www.methanetomarkets.org/resources/landfills/docs/canada_lf_profile.pdf on February 23, 2008.

technologies, the generation potential of LFG projects is relatively insignificant. Furthermore, the majority of candidate projects identified have generation potentials less than 3 MW. The focus of the RETI project is on project opportunities 10 MW and larger. Due to the small potential of the candidate LFG projects, Black & Veatch does not recommend that RETI Phase 1B consider specific LFG project opportunities. However, development of LFG projects is expected to occur to meet California RPS requirements, and an assumption will be made for aggregate LFG development for RETI Phase 1B.

Table 6-14. Summary of Landfill Gas Resource Assessment.

	Number of Candidate Landfills	Estimated Generation Potential* (MW)	Number of Projects with Generation > 3 MW	Est. Generation for Projects with Generation > 3 MW* (MW)
Arizona	15	10	0	0
Baja California	–	–	–	–
British Columbia	9	22	Unknown	Unknown
California	37	139	12	102
Nevada	5	6	0	0
Oregon	5	23	2	19
Washington	8	17	2	9
Total	**79**	**217**	**16**	**130**

Source: LMOP Landfill and Project Database, accessed online at: http://www.epa.gov/lmop/proj/xls/lmopdata.xls on February 22, 2008.
Notes:
* Estimate of generation potential based on rough 0.8 MW of capacity per million tons of waste in place.

6.3.10 Landfill Gas Data Sources

Data sources used in this analysis included:

- LMOP Landfill and Project Database, accessed online at: http://www.epa.gov/lmop/proj/xls/lmopdata.xls on February 22, 2008.
- Jackson, D. "Landfill Gas Management in Canada: What's Going on North of the Border," 2005. Accessed online at: www.epa.gov/lmop/conf/8th/Presentations/jackson.pdf on February 23, 2008.

6.4 Solar Thermal

This section presents the methodology that was used to evaluate solar thermal resources and provides an overview of solar thermal resource availability throughout the RETI region of study.

6.4.1 Methodology

Solar thermal power output is proportional to the amount of direct normal radiation in the area, which makes availability of direct sunlight very significant. Levels of direct normal solar radiation have been rated by NREL on a scale from class 1 to class 5, as shown in Table 6-15. Generally, solar class 2 and higher is considered to be economically competitive, while some class 1 sites may be competitive with low construction costs and available transmission. Resources below class 1 are generally not economic for utility-scale power generation. Figure 6-2 shows the direct normal insolation in the southwestern US. California has not only a large portion of the total resource, but also most of the higher quality resource. The map shows more than just class 1 through 5 solar resources.

NREL's ranking approach to solar thermal resource is based on an average kWh/m^2/day, which ensures that a resource must be high year-round. There may be locations that have high summer insolation, with lower winter insolation, that are still economic due to the time of generation. For example, Ausra is developing a solar thermal facility in the Carrizo plains area of California, where the daily insolation is between 6.0 and 6.5 kWh/m2/day. This area would be ranked below Class 1 by NREL.

Table 6-15. US DOE Classes of Solar Power.

Class 1	6.75 – 6.99 kW/m^2/day
Class 2	7.00 – 7.24 kW/m^2/day
Class 3	7.25 – 7.49 kW/m^2/day
Class 4	7.50 – 7.74 kW/m^2/day
Class 5	7.75 – 8.06 kW/m^2/day

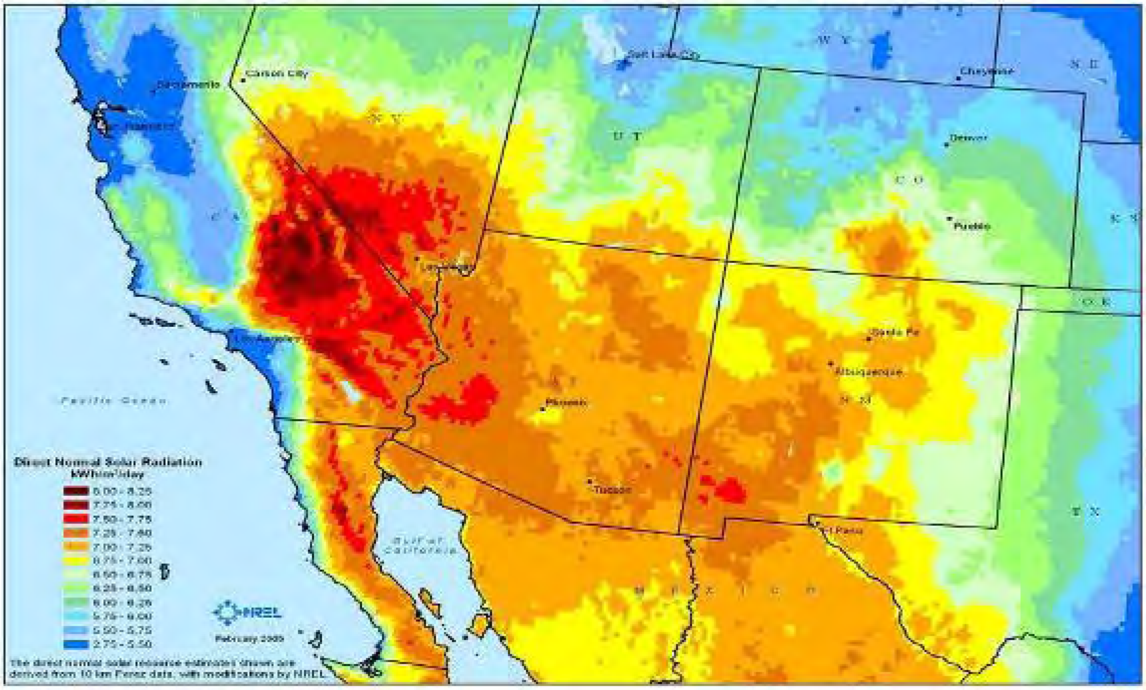


Figure 6-2. Direct Normal Radiation in the Southwest (NREL).

NREL performed a comprehensive solar resource assessment of the southwestern US, using satellite data and GIS mapping. NREL has performed additional analysis on the solar data sets for the Concentrating Solar Deployment System (CSDS) model. The results of this work are a tabulation of solar potential on square kilometers of land by solar class for 32 supply regions across the US southwest. In performing its assessment Black & Veatch assumed that 25 MW of solar capacity could be developed per square kilometer of land (10 acres per MW).[28] This is a typical footprint for solar trough plants, the proxy solar thermal technology.

Not all land in the US can be considered available for solar development, even if it has favorable levels of direct sunlight. DOE and NREL have developed standard "exclusions" for excluding land that may not be suitable for solar development. The key exclusion is for land greater than 1 percent slope. Land with higher slope is considered uneconomic for solar thermal development due to the high cost of civil works required to terrace or level the land.[29] The NREL exclusions also include environmental considerations, such as urban areas, national parks, wetlands, and other sensitive areas. These exclusions ensure that the analysis uses realistic assumptions about where solar power can be developed. NREL's standard land exclusions are shown in Table 6-16.

[28] NREL assumes a more aggressive 50 MW per square kilometer.
[29] Solar thermal technologies other than trough may be able to use land with greater than 1 percent slope.

Table 6-16. Standard NREL Land Exclusions.

Criteria	Rationale
< 6.75 kWh/m2/day annual average direct normal resource (May 2003 Perez data).	Resources below class 1 are generally not economic for utility-scale power generation.
> 1 percent* slope (derived from 90 m elevation data)	Expensive to construct facilities on areas of high slope.
In major urban or water features	Unsuitable for renewable development.
In protected federal lands (wilderness, parks, monuments, etc.)	Assumed to be environmentally or culturally sensitive lands.
Remaining resource is not at least 5 contiguous sq. km.	Difficult to construct facilities on small, non-contiguous land areas..

Source: NREL.
* up to 3% slope may be acceptable for advanced solar thermal technologies.

The value of the CSDS analysis for RETI is that it is recent and it provides a consistent basis of comparison for solar potential across most of the region of study. However, there are several shortcomings in this dataset. First, the solar maps are based on satellite data and atmospheric models and may not match actual solar radiation. Additionally, these estimates represent theoretical or technical potential and are not bound by site-specific constraints such as transmission capacity, constructability, environmental restrictions, or cost. The RETI Phase 1B analysis will include site-specific assessment of the developable potential for solar in the favorable areas identified in Phase 1A. Thus, Phase 1B will identify a much smaller set of resources that could potentially be built and financed in the next decade.

The following sections provide a broad overview of the available potential for solar thermal energy in each state within the RETI study area. Where possible, CSDS data is summarized by CSDS region to show the technical potential of solar development in the western United States. Exceptions are for British Columbia, Oregon, and Washington. Much of the solar resource in these three areas is considered to be less than class 1, and therefore non-economic.

6.4.2 California Solar Potential

Most of California's solar potential is concentrated in southern California. Southern California contains more than 17,600 square kilometers of very flat (less than 1 percent grade) land with class 2 and greater radiation; these solar resources are considered potentially economic. The majority of California's solar potential is located in the Chuckwalla, Imperial, and Owens Valleys, as well as the Mojave Desert. This solar potential translates to 440 GW of generating capacity. Many more solar resources exist on land of up to 3 percent grade, which may become available in the future if newer technologies do not have as strict slope requirements as solar trough.

Figure 6-3 graphically depicts the solar resource in California. Darker colors imply greater solar resource.

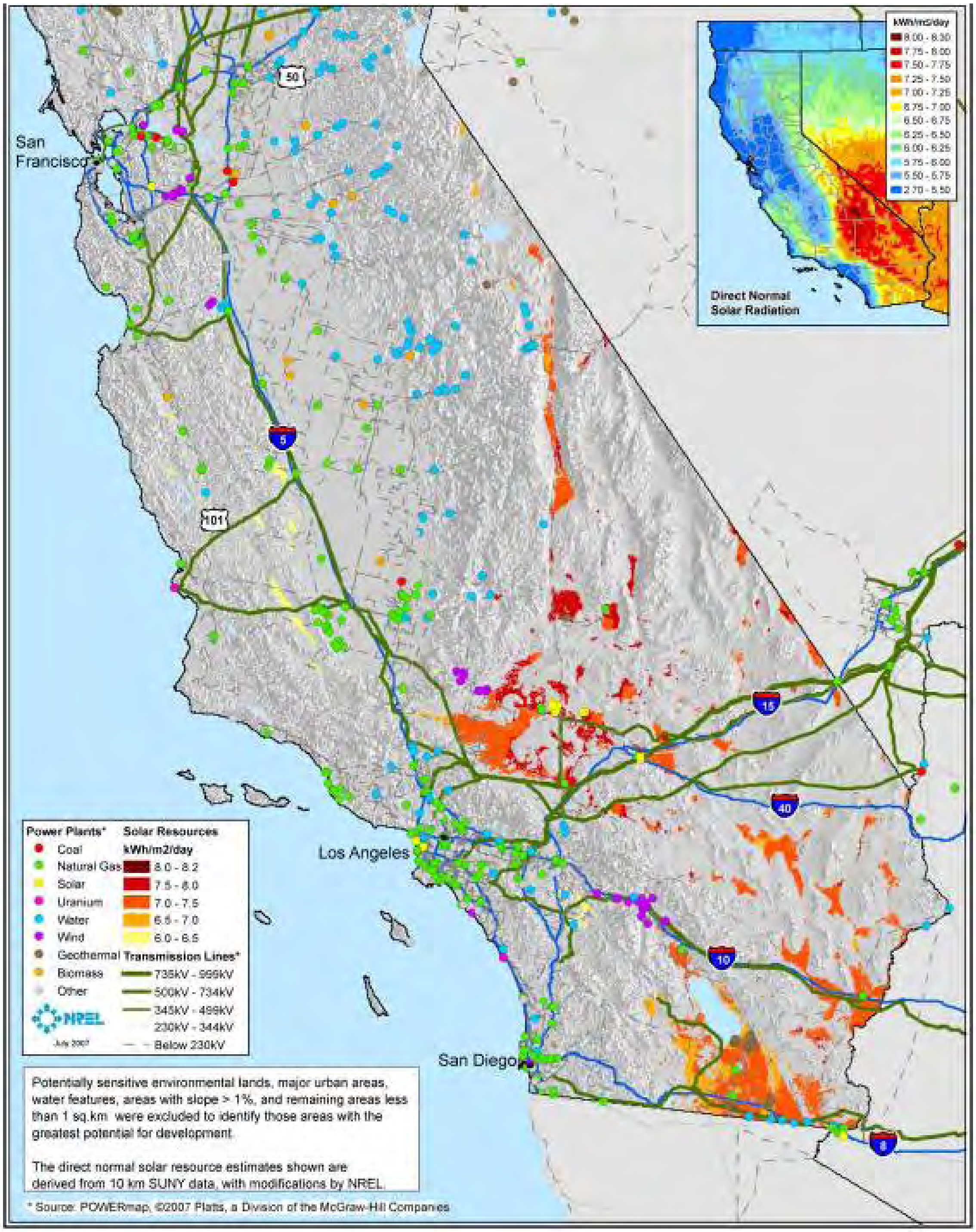


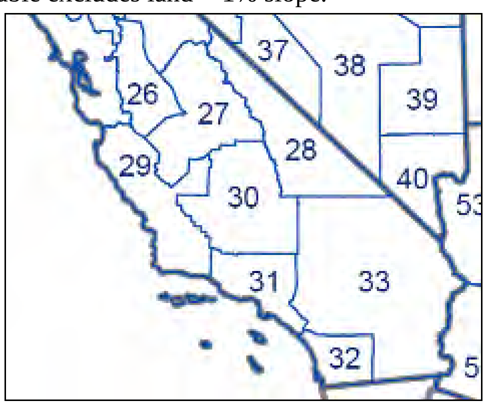
Figure 6-3. Concentrating Solar Power Prospects in California (slope < 1%). Source: NREL.

Table 6-17 shows the technical solar thermal capacity in 5 regions in California as estimated by NREL. This is potential capacity on lands with less than 1 percent slope, not including sensitive lands. The regions correspond to the regions shown in the small map included in the table. The greatest potential is shown in the Mohave and Imperial Valley region (southeastern California), which contains most of the large areas of class 3 resource.

Table 6-17. California Solar Thermal Technical Potential (MW).

Region	Capacity by Solar Power Class					Total Capacity
	1	2	3	4	5	
Region 28: Owens Valley	1,592	2,688	14,585	18,510	3,469	40,844
Region 30: Kern County	-	2,154	6,145	17,073	21,135	46,507
Region 31: Los Angeles Area	2,259	7,390	17,226	7,269	-	34,145
Region 32: San Diego	-	3,904	480	-	-	4,384
Region 33: Mohave and Imperial	-	72,226	158,082	59,181	28,430	317,920
Total	**3,852**	**88,363**	**196,519**	**102,033**	**53,034**	**443,799**

Source: NREL, 2006. This table excludes land > 1% slope.



California currently has 354 MW of operating solar thermal capacity. This capacity is concentrated in the Mojave Desert, west of Barstow. California IOUs have contracted for 1,629 to 2,579 MW of new solar thermal capacity through six power purchase agreements. These are shown in Figure 6-4. There is also 15,567 MW of solar thermal capacity in the CAISO queue (listed by county in Table 6-18).

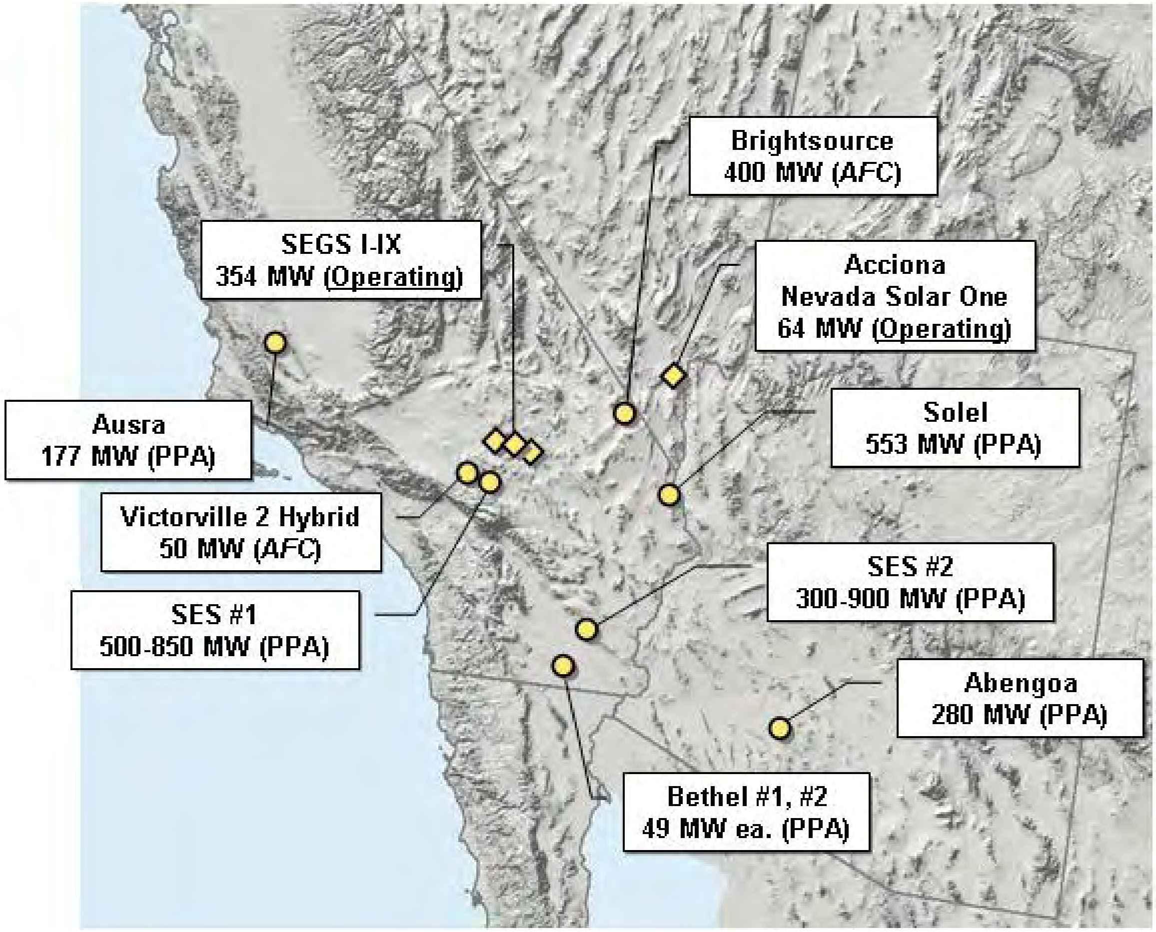


Figure 6-4. Operating and Proposed Solar Thermal Projects (PPA or AFC – Application for Certification).

Table 6-18. CA ISO Solar Thermal Queue by County.

County	Active (MW)
Kern	2,231
Imperial	1,487
Clark	1,000
San Bernardino	9,784
Riverside	500
San Luis Obispo	565
Source: California ISO, January 25, 2008.	

In addition, there are applications for 45,000 MW of solar thermal projects on BLM lands in the California Desert District. This district covers all of the BLM lands in Southern California.

The solar resource potential in California is large compared to other regions under study for RETI, and much greater than the renewable energy demand in California. There appears to be 440 GW of Class 2 and higher solar thermal potential in California alone. This is significantly more potential than is required to meet California's entire energy demand.

6.4.3 Arizona Solar Potential

Arizona has enormous solar potential. There are 48,510 square kilometers of ground with less than 1 percent slope and Class 2 or greater solar resource. This is equal to 1,213 GW of capacity potential. Most of the solar resource in Arizona is in a large area in the southwest quadrant of the state. The map in Figure 6-5 shows all of the solar resources in Arizona on land with slopes of 1 percent or less.

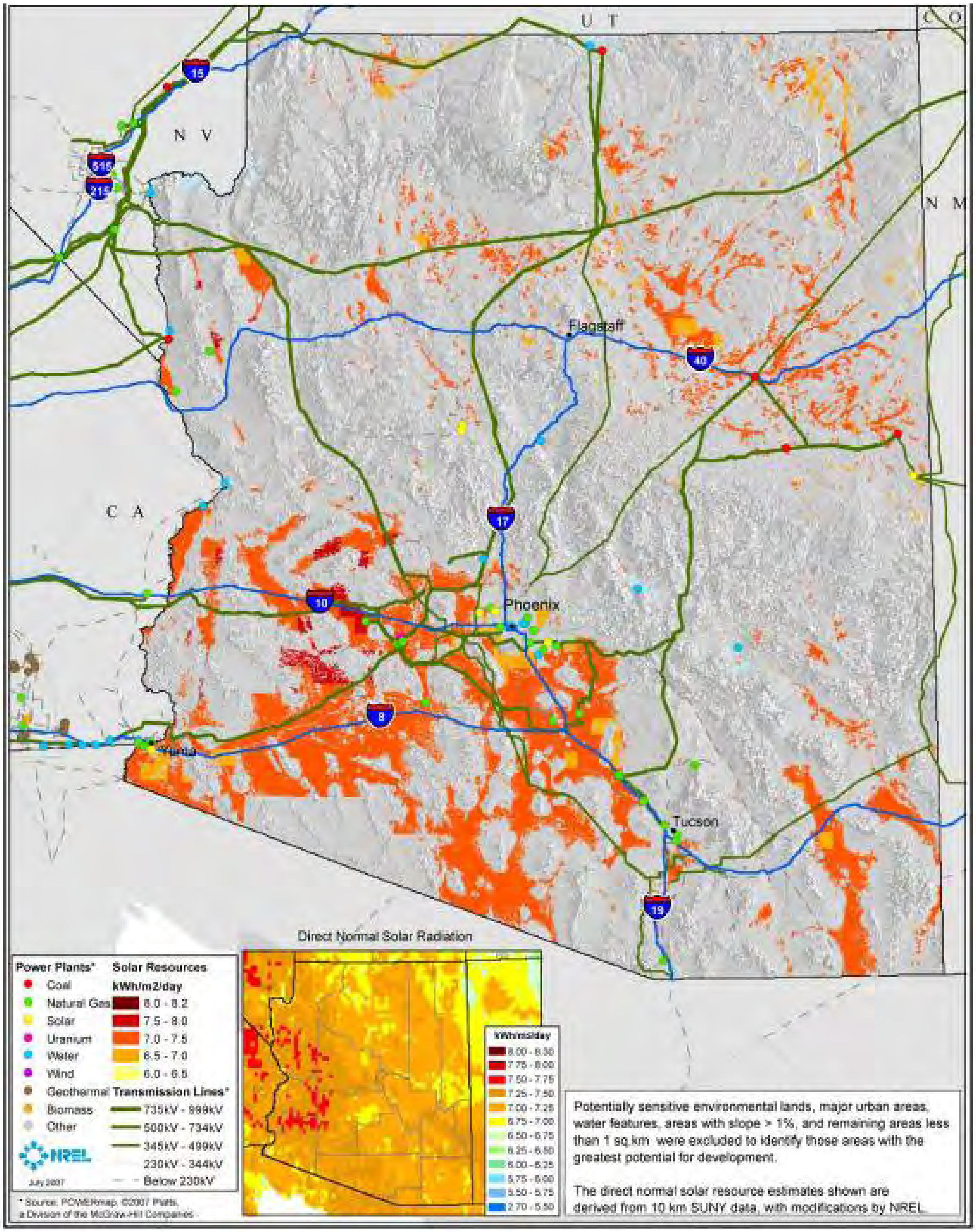


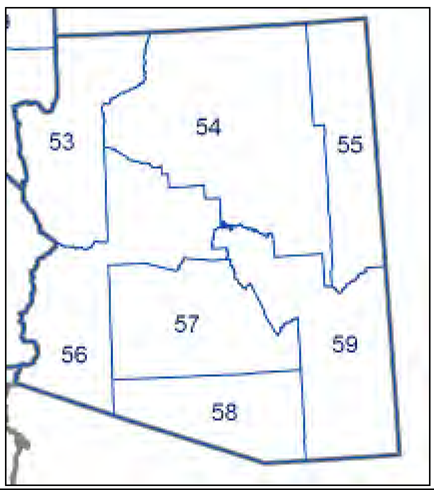
Figure 6-5. Concentrating Solar Power Prospects of Arizona (Slope < 1%). Source: NREL.

Table 6-19 shows the theoretical potential capacity by solar power class in seven regions in Arizona as estimated by NREL. The greatest potential is shown in Region 57 (central Arizona), which contains most of the large areas of class 3 solar resource.

Table 6-19. Arizona Solar Thermal Technical Potential (MW).

Region	Capacity by Solar Power Class					Total Capacity
	1	2	3	4	5	
53	3,076	16,050	24,410	990	-	44,527
54	4,575	83,262	85,441	-	-	173,278
55	2,800	46,173	16,945	-	-	65,917
56	-	29,014	198,642	44,521	-	272,178
57	20,477	144,045	201,485	23,355	-	389,362
58	-	31,373	143,355	-	-	174,728
59	-	40,302	83,367	-	-	123,669
Total	**30,928**	**390,219**	**753,646**	**68,866**	**-**	**1,243,659**

Source: NREL, 2006.



The overall technical potential in Arizona is higher than any other state or province in the RETI region of study. California has more class 5 solar resource than Arizona, but Arizona has more overall resource. The resource potential in just the two Arizona regions adjacent to the California border is over 300 GW.

6.4.4 Nevada Solar Potential

Nevada has abundant solar resource, but is limited by its mountainous terrain. There is significant Class 5 resource in the Amargosa valley, northwest of Las Vegas on the California border. There are 11,270 square kilometers of solar resource of class 2 or better in Nevada. Most of this in the southern part of the state. The map in Figure 6-6shows all of the solar resources in Nevada on slopes of less than 1 percent.

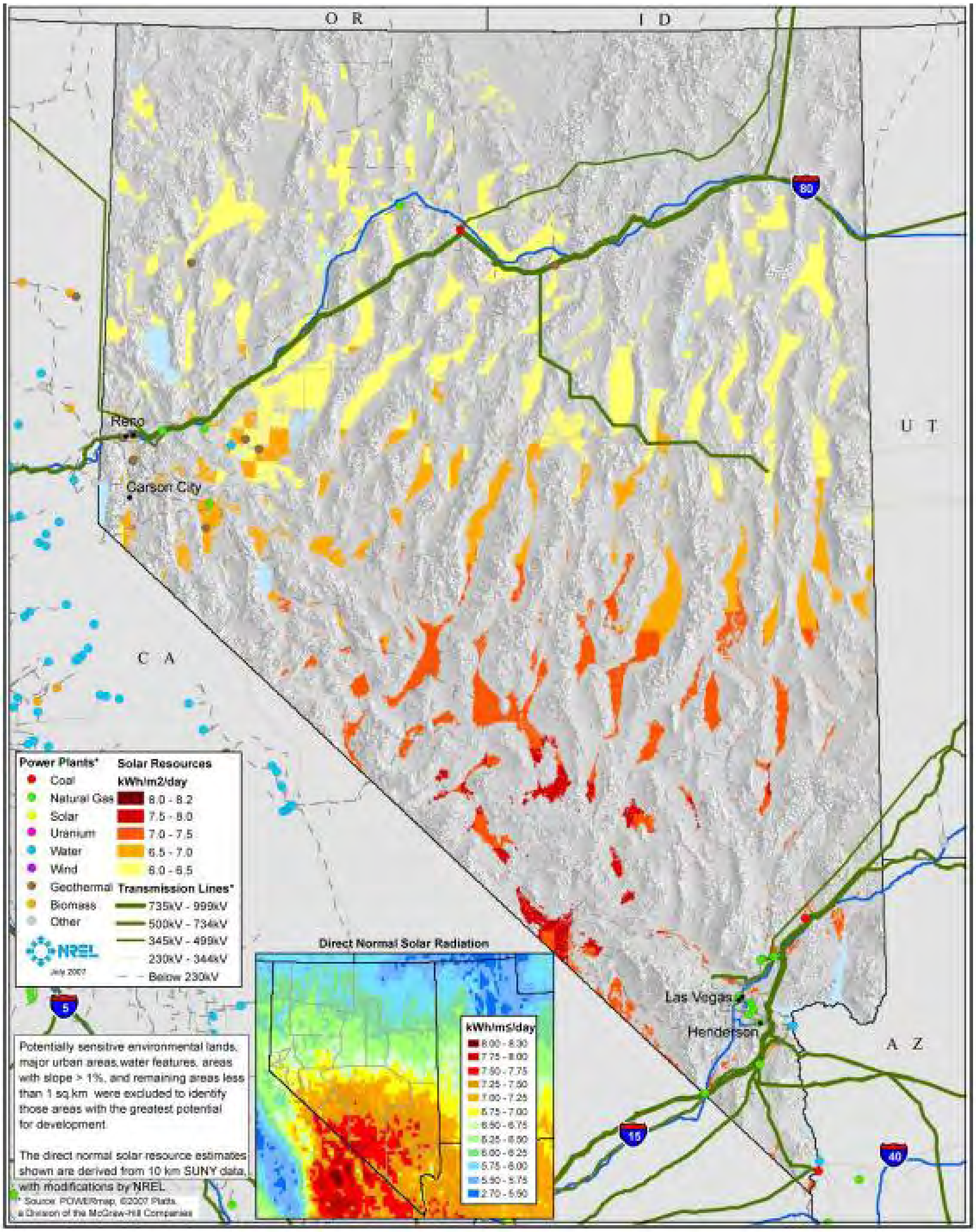


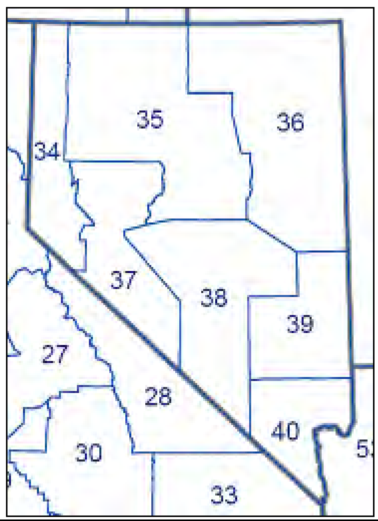
Figure 6-6. Concentrating Solar Prospects of Nevada (Slope < 1%) Source: NREL.

Table 6-20 shows NREL's estimates of the potential solar generating capacity in seven Nevada regions, by solar class. The greatest potential is shown in Region 38 (south central Nevada), which contains most of the large areas of class 3 radiation.

Table 6-20. Nevada Solar Thermal Technical Potential (MW).

Region	Capacity by Solar Power Class 1	2	3	4	5	Total Capacity
34	9,698	-	-	-	-	9,698
35	8,462	-	-	-	-	8,462
36	11,052	-	-	-	-	11,052
37	16,184	7,226	25,093	3,419	305	52,228
38	23,036	50,313	60,100	49,911	13,902	197,263
39	11,797	7,927	29,256	7,493	-	56,473
40	-	7,268	17,694	1,755	-	26,717
Total	**62,069**	**72,735**	**132,144**	**62,579**	**14,207**	**343,734**

Source: NREL, 2006.



There are 1,500 MW of solar projects in Clark County (southern Nevada) in the CAISO queue, and there is one 64 MW solar trough plant currently operating south of Las Vegas.

Nevada has 282 GW of potential solar thermal capacity in regions with a solar resource of class 2 or greater. 172 GW of this potential is in regions adjacent to California.

6.4.5 Other Areas

Other areas in the RETI study region were not considered to have economic solar resources. Oregon and Washington have poor solar resources. Baja California has a good resource, but solar thermal projects located in Mexico would not qualify for US investment tax credits and are thus not expected to be competitive with US-based resources.

6.4.6 Solar Thermal Summary

Solar thermal resources in the RETI study region are summarized in Table 6-21. There is superb solar thermal resource available in southern California, southern Nevada, and western Arizona. These three regions combined have roughly 933 GW of class 2 or better solar resource potential. Clearly, solar thermal development is not limited by the availability of resource. The solar thermal resources already under development in southern California, as indicated by BLM applications and the ISO queue, could easily fill the California RPS needs twice over.

The RETI Phase 1A study recommends including solar thermal resources in California, southern Nevada, and western Arizona for further study in Phase 1B. While Southern California has ample resources for solar thermal development, there is also development in southern Nevada and Arizona planned for the California market.

Table 6-21. Summary of Solar Thermal Resources.

	Potential, MW*	Assess in Phase 1B?	Notes
Arizona	316,628	Yes	Western Arizona only
Baja California	**	No	No ITC
British Columbia	0	No	Resource not viable for power production
California	443,799	Yes	
Nevada	172,181	Yes	Southwestern Nevada only
Oregon	0	No	Resource not viable for power production
Washington	0	No	Resource not viable for power production
Grand Total	932,608		

Notes:
* Nameplate capacity, Class 2 and higher.
** Estimates for Baja California were not available.

6.4.7 Data Sources

Data sources used in this analysis included:

- NREL Insolation Maps, available at http://www.nrel.gov/csp/maps.html
- George Simons and Joe McCabe, "California Solar Resources" California Energy Commission, CEC-500-2005-072 April 2005.

- Bureau of Land Management, California Desert District, http://www.blm.gov/ca/st/en/fo/cdd/alternative_energy.html

6.5 Solar Photovoltaic

While solar thermal requires direct normal insolation, solar photovoltaic uses global insolation, which includes both the direct and diffuse components. The global solar resource is more widespread than direct normal, which allows photovoltaics greater siting flexibility. In addition, photovoltaics do not have as strict a slope requirement as solar thermal, and can therefore access more resource.

While photovoltaics are currently higher cost than solar thermal resources, one advantage is rapid construction time. Most photovoltaic facilities can be completed in 1 to 2 years, compared to several years for solar thermal facilities.

Figure 6-7 shows the solar resource available for photovoltaics for the entire US. The solar resource clearly is widespread and abundant. In addition, the map makes clear that California has not only enormous solar potential, but that its solar resources are as high quality as adjoining states.

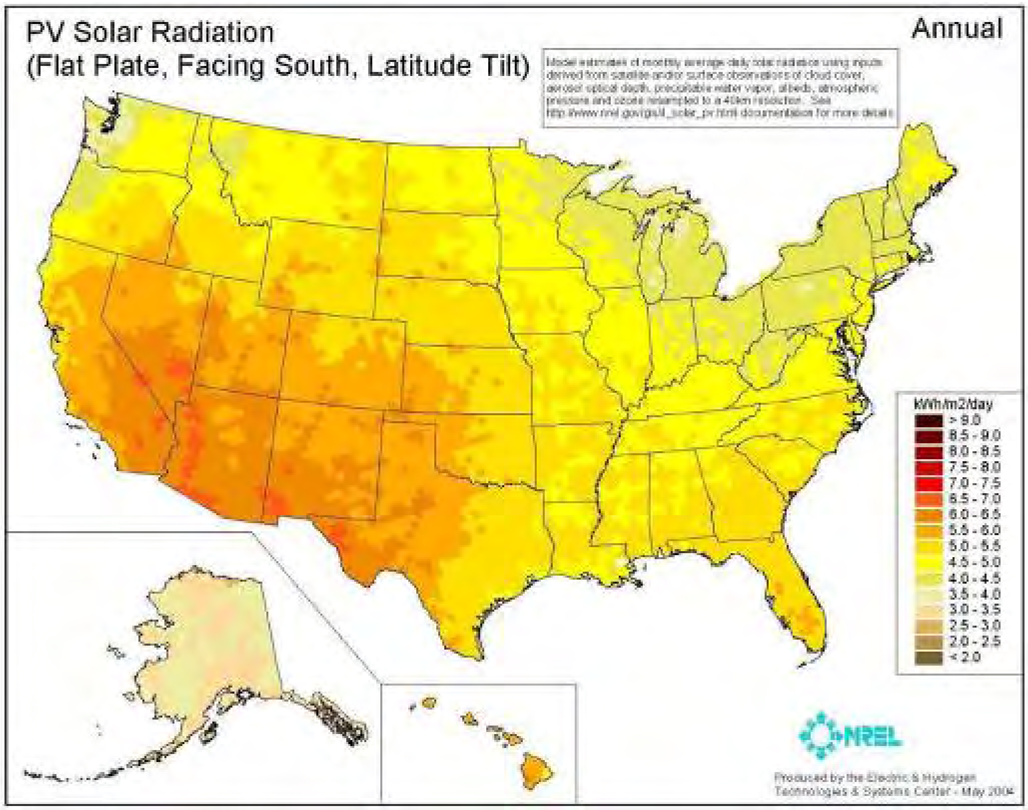


Figure 6-7. US Solar Resource for photovoltaics (NREL).

A 2005 CEC study found there to be close to 17,000 GW of solar photovoltaic technical potential in the state, an enormous number. As with solar thermal, solar photovoltaics are clearly not limited by resource availability.[30]

While neighboring regions also have good solar resources, Black & Veatch does not recommend out-of-state solar PV resources be considered in Phase 1B. Because of the large, high quality resource available in California, and the high cost of photovoltaics, it does not appear economical to consider out of state solar photovoltaic resources.

6.6 Hydroelectric

This section presents the methodology used to evaluate the developable hydropower resources and provide an overview of hydropower resource availability throughout the RETI region of study.

[30] George Simons and Joe McCabe, "California Solar Resources" California Energy Commission, CEC-500-2005-072 April 2005.

6.6.1 Methodology

In the United States, 23 states have some variation of RPS programs. RPS eligibility rules for hydro vary state-by-state. The California definition of eligible renewable resources includes small hydropower (30 MW or less) as eligible for contributing toward the RPS. New hydropower facilities are not eligible if they require new and or increased appropriation of water.

There are several existing dam sites in the RETI region with additional hydropower potential identified by the United States federal government. The U.S. Department of Energy Idaho National Laboratory (INL) provides this information as part of the National Energy Strategy. The INL database served as the primary resource for this high level study for Arizona, California, Nevada, Oregon, and Washington. The Project Environmental Suitability Factor (PESF) developed by INL rates potential sites in one of five categories. For the purpose of this study, only projects identified in the INL database with a 0.90 PESF (0.9 = environmental concerns have little effect on likelihood of development) were considered. Further, per the requirements of the RPS eligibility rules, only sites less than 30 MW were considered.

There are several references available from Canada to identify hydropower potential. One resource is the Canadian Renewable Energy Network (CanREN). CanREN provides this information to identify additional hydropower potential in Canada. CanREN was created through the efforts of Natural Resources Canada (NRCan).

The website of Mexico’s federal Power Agency, the Comision Federal de Electricidad (CFE), was used to assist in identifying potential hydropower sites in the northern region of Baja California as well as other publicly available documents and reports.

6.6.2 Resource Availability

A hydroelectric resource can be defined as any flow of water that can be used to capture the kinetic energy. Projects that store large amounts of water behind a dam can regulate the release of water through turbines and generate electricity regardless of the season. These facilities can generally serve baseloads. Run-of-river projects do not impound the water, but instead divert a part or all of the current through a turbine to generate electricity. At run-of-river projects, power generation varies with seasonal flows and can sometimes help serve summer peak loads.

All hydroelectric projects are susceptible to drought. In fact, the variability in hydropower output is rather large, even when compared to other renewable resources. Based on analysis of reported data from Global Energy Decisions, 2006, the aggregate capacity factor over time for all hydroelectric plants in the United States has ranged from an average high of 47 percent to an average low of 31 percent.

6.6.3 Types of Hydropower Facilities

There are four types of hydropower facilities that were examined this study. They are:

- Impoundment Hydropower - utilizes a dam to store water in a reservoir. Water can be released from the reservoir to generate electricity.
- Run-of-River - utilizes the flow of water within a river, requiring very little or no impoundment. Run-of-River hydropower is typically designed for large flows with low head or small flows with high head.
- Microhydropower Projects - produce 100 kilowatts (kW) or less. Microhydropower plants can utilize low heads or high heads.
- Diversion Hydropower – diverts a portion of river flows through a canal or penstock to generate electricity.

Table 6-22 below summarizes by status of the potential dam sites. Sites identified as “with power” are sites that are currently generating hydropower and are assumed to be upgradeable sites. Sites identified as “without power” are sites that are developed (have a dam) but do not currently have hydropower facilities in place. Sites identified as “undeveloped” do not have hydropower infrastructure in place and would require the greatest initial capital costs.

Table 6-22. Dam Status in the RETI Region.

	With Power	Without Power	Undeveloped
Arizona*	0	0	6
Baja California**	0	0	2
British Columbia	Unknown	Unknown	Unknown
California*	1	46	45
Nevada*	1	5	3
Oregon*	1	6	19
Washington*	1	24	21
Total	4	81	96

Source:
*INL
** Comision Federal de Electricidad

The rest of this section contains a brief summary of each region defined by the RETI project. Figure 6-8 shows a summary of the potential for small hydro power development in the U.S. portion of the RETI study region.

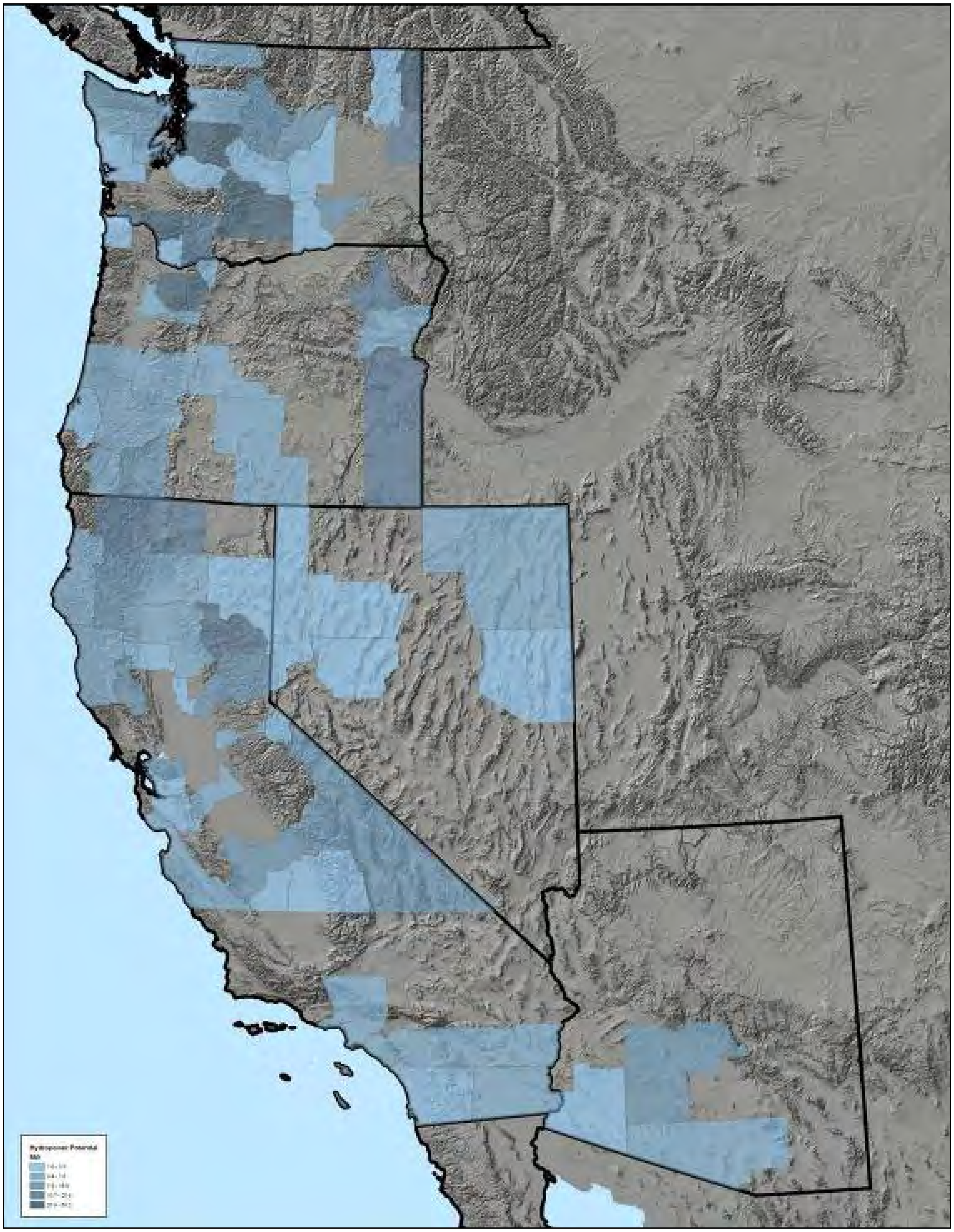


Figure 6-8. Potential for Small Hydro Project Development (MW).

6.6.4 California Hydropower Potential

California has an area of 158,693 square miles and an average annual rainfall of 17.3 inches. INL has identified California with a large hydropower potential. Table 6-23 shows the theoretical potential capacity from hydropower by county in California.

Table 6-23. California Developable Hydropower Technical Potential Per County.

County	Total Capacity (MW)	County	Total Capacity (MW)
Alameda	3.1	Nevada	8.3
Alpine	3.3	Orange	6.0
Amador	4.5	Placer	10.8
Butte	3.8	Plumas	23.5
Contra costa	12.2	Riverside	5.0
Fresno	8.4	San diego	2.6
Glenn	2.9	Santa clara	2.4
Humboldt	4.1	Santa cruz	1.5
Imperial	3.6	Shasta	4.3
Inyo	11.6	Sierra	9.5
Kings	2.0	Siskiyou	17.3
Lake	11.3	Stanislaus	5.0
Lassen	1.6	Sutter	1.0
Los angeles	4.1	Tehama	4.6
Mendocino	4.4	Trinity	15.5
Mono	13.2	Tulare	2.3
Monterey	6.2		
Total	219.9		
Source: INL			

Of the 92 identified sites, 22 are gravity diversion, 49 are run-of-river, 1 is pumped diversion, and 20 are conventional hydropower with storage. There is a total potential capacity of 298 MW, of which 231 MW have a site potential between 10 and 30 MW. The greatest potential is shown in Plumas County, which contains 23.5 MW of capacity.

The southern portion of the state is generally known for its limited water resources. Because of this, California transfers relatively large quantities of water over large distances and this results in a large portion of potential resources coming from numerous manmade conveyances.

Hydropower appears to be a good source of renewable energy for California. It is recommended that further investigation be carried out in Phase 1B of the larger project opportunities to identify site-specific costs and potential.

6.6.5 Arizona Hydropower Potential

To identify specific areas to the development of hydropower energy projects in Arizona, in September 2007 Black & Veatch produced a report for the Arizona Public Service Company, Salt River Project, and Tucson Electric Power Corporation entitled “Arizona Renewable Energy Assessment.” Based on Arizona’s Renewable Energy Standard (RES), the conclusion of this report found that of the projects identified, Glen Canyon and Waddell were the only projects that could be reasonably identified; however, the capacities are too large for California’s RPS.

Arizona has relatively poor water resource availability with an area of 113,909 square miles and an average annual rainfall of 7.1 inches and only 14 MW of capacity potential identified by INL. All of the potential hydropower resources in Arizona are less than 10 MW in capacity. Table 6-24 identifies the locations of the potential hydropower resources in Arizona by county.

Table 6-24. Arizona Developable Hydropower Technical Potential Per County.

County	Total Capacity (MW)
Maricopa	8.2
Pima	4.3
Yuma	1.4
Total	13.9

Source: INL

Of the hydropower projects previously identified and studied by INL all have a relatively small capacity in comparison to the total capacity of hydropower in the RETI region of study.

In summary, the hydropower resources in Arizona are relatively poor compared to other regions under study for RETI. Arizona, projects are more likely to sell their output to local Arizona utilities to meet their state’s RES than sell power to California.

6.6.6 Nevada Hydropower Potential

Nevada has an area of 110,540 square miles and a relatively dry climate with an average annual rainfall of 7.9 inches. Table 6-25 shows the theoretical potential capacity from hydropower by county in Nevada.

Table 6-25. Nevada Developable Hydropower Technical Potential Per County.

County	Total Capacity (MW)
Churchill	1.6
Elko	6.1
Pershing	1.5
Washoe	1.1
White pine	2.3
Total	12.6

Source: INL

Of the 9 identified sites, 1 is run-of-river and 7 are conventional hydropower with storage. Of the hydropower projects previously identified and studied by INL all have a relatively small capacity in comparison to the total capacity of hydropower in the RETI region of study.

In summary, Nevada does not have the natural resources required to develop any additional hydroelectric facilities, and therefore hydroelectric generation is not considered a potential resource for Phase 1B. Any Nevada projects are more likely to sell their output to local utilities to meet the state’s Renewable Portfolio Standard than sell power to California.

6.6.7 Oregon Hydropower Potential

Oregon has relatively good hydropower potential with an area of 96,981 square miles and an average annual rainfall of 37.4 inches. Table 6-26 identifies the location of the developable hydropower resources in Oregon, by county.

Table 6-26. Oregon Developable Hydropower Technical Potential Per County.

County	Total Capacity (MW)
Baker	7.2
Clackamas	41.9
Clatsop	1.6
Coos	1.0
Deschutes	5.7
Douglas	4.0
Hood river	7.8
Jackson	9.0
Josephine	7.7
Lake	3.8
Lane	4.0
Malheur	22.8
Marion	4.0
Umatilla	25.8
Total	146.3

Source: INL

Of the 9 identified sites, 1 is run-of-river and 7 are conventional hydropower with storage. There is a total potential capacity of 147 MW, of which 66 MW have a site potential between 10 and 30 MW. The greatest potential is in northern part of Oregon, which contains half of the identified developable hydropower resources. It is recommended that further investigation be carried out in Phase 1B of the larger project opportunities to identify site-specific costs and potential.

6.6.8 Washington Hydropower Potential

Washington has good hydropower potential, with an area of 68,192 square miles and an average annual rainfall of 27.7 inches. Table 6-27 identifies the location of the developable hydropower resources in Washington, by county.

Table 6-27. Washington Developable Hydropower Technical Potential Per County.

County	Total Capacity (MW)
Benton	1.4
Chelan	15.6
Clallam	13.5
Clark	2.2
Cowlitz	41.5
Douglas	9.1
Franklin	12.2
Grant	1.7
Grays harbor	3.3
Jefferson	4.3
King	56.2
Kittitas	3.0
Mason	6.4
Pend oreille	49.1
Pierce	1.1
Skamania	22.0
Snohomish	4.0
Spokane	23.8
Stevens	2.9
Wahkiakum	17.0
Whatcom	4.5
Yakima	47.3
Total	359.3

Source: INL

Of the 47 identified sites, 29 are run-of-river, 12 are gravity diversion, and 6 are conventional hydropower with storage. There is a total potential capacity of 359 MW, of which 244 MW have a site potential between 10 and 30 MW. The largest potential is in the northern and southern areas with the greatest potential in King county. It is recommended that further investigation be carried out in Phase 1B of the larger project opportunities to identify site-specific costs and potential.

6.6.9 Baja California Hydropower Potential

Development of hydropower in Baja California (Baja) has been limited due to its arid climate. According to the Baja's state government website, Baja is 27,636 square miles in size and has very few lakes, rivers, and springs. Some parts of the state receive less than 7.0 inches of average annual rainfall. The only notable developable hydropower sites are located in the Valley of Mexicali. These two sites would utilize water conveyance in Mexicali's irrigation system with a combined total of 15 MW.

In summary, Baja California's hydropower resources are poor compared to the other regions under study for RETI. Furthermore the climate and size of the projects lend themselves to be more efficiently used locally.

6.6.10 British Colombia Hydropower Potential

British Columbia's hydropower potential falls in the strongest areas for hydropower resources. Bordering the Sate of Washington to the north and with an area of 364,774 square miles and an average annual rainfall of approximately 44 inches, British Columbia hydropower development tends to be large with much of the resource located on mountainous ridges.

One of the largest producers of electricity is the provincially-owned electric utility BC Hydro. According to CanREN, about one-tenth of the electricity generated in a Canada is exported to the United States. Canadian electric utilities and industrial producers generated approximately 353,000 gigawatt hours of electricity in 2002. Currently the capacity of small hydroelectric facilities in Canada is about 2,000 MW. Natural Resources Canada (NRCan), a science-based department in the Canadian Government specializing in the sustainable development and use of natural resources, has identified approximately 1,650 MW of economically feasible potential in Canada.

In summary, there are many potential sites for small-scale hydroelectric facilities. A more detailed review of transmission issues is recommended in the next phase of this study to identify specific sites.

6.6.11 Hydropower Summary & Location Map

Table 6-28 summarizes the potential energy capacity in the RETI region based on information readily available from INL, CFE, and CanREN. Generally lower sites in the range of 1 MW to 10 MW were considered not as economical at sites identified above 10 MW. This is because smaller site generation revenues tend to be offset by O&M costs.

Table 6-28. Developable Hydropower Renewable Energy Capacity in the RETI Region (Nameplate MW).

	Sites in the 1 MW to 10 MW range	Sites in the 10 MW to 30 MW Range	Total
Arizona [a]	14	0	14
Baja California [b]	15	0	15
British Columbia [c]	unknown	162	162
California [a]	67	231	298
Nevada [a]	13	0	13
Oregon [a]	81	66	147
Washington [a]	115	244	359

Source:
[a] INL
[b] Comision Federal de Electricidad
[c] CanREN, unknown distribution in British Columbia, assumed 10% of Canada's national identifiable average

In general, the prospects for new hydropower development are extremely limited in Arizona, Baja California, and Nevada. Most of Arizona, Baja California, and Nevada consist of arid plains. Precipitation in most of the three locations is very low on average and due to the geography and dry climates hydropower potential is limited.

In contrast British Columbia, California, Oregon, and Washington each have higher annual rainfalls on average. It is recommended that further study be performed in Phase 1B to identify specific hydropower sites and characterize costs.

6.7 Wind

This section presents the methodology that was used to evaluate wind resources and provides an overview of wind resource availability throughout the RETI study region of study.

6.7.1 Methodology

Wind turbine power output is proportional to the cube of wind speed, which makes small differences in wind speed very significant. Wind strength is rated on a scale from class 1 to class 7, as shown in Table 6-29. Generally, wind class 4 and higher is considered to be economically competitive, while some class 3 sites may be competitive with low construction costs and available transmission. Class 1 or 2 sites are generally not economically viable for utility-scale power generation.

Table 6-29. US DOE Classes of Wind Power.

Wind Power Class	Height Above Ground: 50 m (164 ft)*	
	Wind Power Density (W/m^2)	Speed** (m/s)
1	0 to 200	0 to 5.60
2	200 to 300	5.60 to 6.40
3	300 to 400	6.40 to 7.00
4	400 to 500	7.00 to 7.50
5	500 to 600	7.50 to 8.00
6	600 to 800	8.00 to 8.80
7	800 to 2000	≥ 8.80

Notes:

* Vertical extrapolation of wind speed based on the 1/7 power law, defined in Appendix A of the *Wind Energy Resource Atlas of the US, 1991.*

** Mean wind speed is based on Rayleigh speed distribution of equivalent mean wind power density. Wind speed is for standard sea level conditions. To maintain the same power density, wind speed must increase 3 percent per 1,000 m (5 percent per 5,000 ft) elevation.

Over the past several years there have been several wind resource assessment initiatives which have generally resulted in the production of high resolution maps showing wind speed and wind power density. This work has been undertaken by public entities such as NREL and CEC, and private companies such as AWS Truewind. NREL has performed additional analysis on the wind data sets for the Wind Deployment System (WinDS) model. The results of this work are tabulation of wind potential (MW) by wind class for 358 supply regions across the country. In performing its assessment for WinDS, NREL assumed that 5 MW of wind capacity could be developed per square kilometer of land.

Not all the land in the US can be considered available for wind development. DOE and NREL have developed standard “exclusions” for excluding land that may not be suitable for wind development. These exclusions include urban areas, national parks, wetlands, and other sensitive areas. These exclusions ensure that the analysis uses realistic assumptions about where wind power can be developed. NREL’s standard land exclusions are shown in Table 6-30.

Table 6-30. Standard NREL Land Exclusions.

Criteria	Rationale
Any National Park Service and Fish and Wildlife Service Managed lands.	These lands are environmentally sensitive.
Any federal lands designated as park, wilderness, wilderness study area, national monument, national battlefield, recreation area, national conservation area, wildlife refuge, wildlife area, wild and scenic river or inventoried road-less area.	These lands are assumed to be environmentally or culturally sensitive lands.
State and private lands equivalent to the above category, if data is available.	These lands are assumed to be environmentally or culturally sensitive lands.
Airfields, urban areas, wetlands and water areas.	These areas are unsuitable for renewable development.
Buffer zone of 3 km surrounding the previous categories.	
Areas with slope greater than 20%.	Areas of high slope are difficult to construct facilities and may be environmentally sensitive.
50% exclusion of remaining Forest Service lands (including national grasslands).	Forest service land may be environmentally sensitive and it is unrealistic to assume all FS land would be open to development.
50% exclusion of remaining Department of Defense lands.	DoD land may not be open to development.
50% exclusion of state forest land, where GIS data is available.	As with FS land, state forest may not be open to development.
50% exclusion of non-ridgecrest forest. If an area is non-ridgecrest forest on Forest Service land, it is just excluded at the 50% level once.	Forest land is environmentally sensitive and may not be suitable for development.
Source: NREL. Note: 50% exclusions are not cumulative	

The value of the WinDS analysis for RETI is that it is recent, and it provides a consistent basis of comparison for wind potential across most of the region of study. However, there are several shortcomings in this dataset. First, the wind maps are based on atmospheric models and may not match actual wind speed. Wind developers typically use meteorological towers to capture several years of wind speed data at sites before placing turbines. This data is far more accurate than climate models. Secondly, the data is modeled for 50 meters above the ground level, while most new wind farms have a hub height of 80 meters or more. The wind speed increases with altitude (called “shear”), and this increase is often described using $1/7^{th}$ power adjustment. Finally, these estimates represent theoretical or technical potential and are not bound by the site-specific constraints such as transmission capacity, constructability, environmental restrictions, or cost. The next phase of this study will include site-specific analysis of the developable potential for wind in the favorable areas identified in this phase. This is a much smaller set of resources that could potentially be built and financed in the next decade.

The following sections provide a broad overview of the available potential for wind energy in each state and province within the RETI study area. Where possible, WinDS data is summarized by WinDS region to show the gross technical potential of wind development in the western United States. Exceptions are for British Columbia and Baja California. These two areas utilize previous wind resource estimates published by other consultants. In states, where more detailed information about the wind resource was available, like California, Black & Veatch presents those estimates as well.

Detailed wind maps for each of the states are provided at the end of this section.

6.7.2 California Wind Potential

California has very large wind potential, although most of it is concentrated in mountain passes and remote areas. There are more than 4,000 square kilometers of class 4 and greater winds, which are considered good wind resources. These are in a located in the extreme northern part of the state, around the Sacramento River delta, and throughout inland southern California. Higher wind resources exist along mountain passes and ridgelines as well.

Table 6-31 shows the theoretical potential capacity from wind power class in 13 regions in California as estimated by NREL. The regions correspond to the large regions shown in the wind resource map. The greatest potential is shown in Region 33 (Southeastern California), which contains most of the large areas of Class 4 winds.

Table 6-31. California Wind Technical Potential.

Region	Capacity by Wind Power Class				Total Capacity
	4	5	6	7	
20	424	161	123	53	760
21	430	115	78	28	651
22	51	11	2	0	63
23	20	4	0	0	24
24	121	47	25	8	201
25	1,138	99	17	0	1,255
26	107	29	5	0	141
27	17	2	0	0	19
28	547	199	64	12	823
29	169	56	29	6	260
30	2,581	1,818	1,619	684	6,702
31	1,921	970	276	48	3,215
32	539	165	97	42	843
33	3,890	1,169	685	401	6,145
Total	11954.7	4842.5	3020.6	1281.1	21,099

Source: NREL, 2006.

In addition to NREL's estimate, California wind resources have undergone more detailed study as part of the California Energy Commission's Intermittency Analysis Project (IAP). As part of the IAP, AWS Truewind did a report on "Characterizing New Wind Resources in California" that identifies and simulates the output of existing and future wind projects as an input to grid impact analyses. The map in Figure 6-9 shows ten areas of interest for new wind generation capacity (brown ovals) and four existing areas.

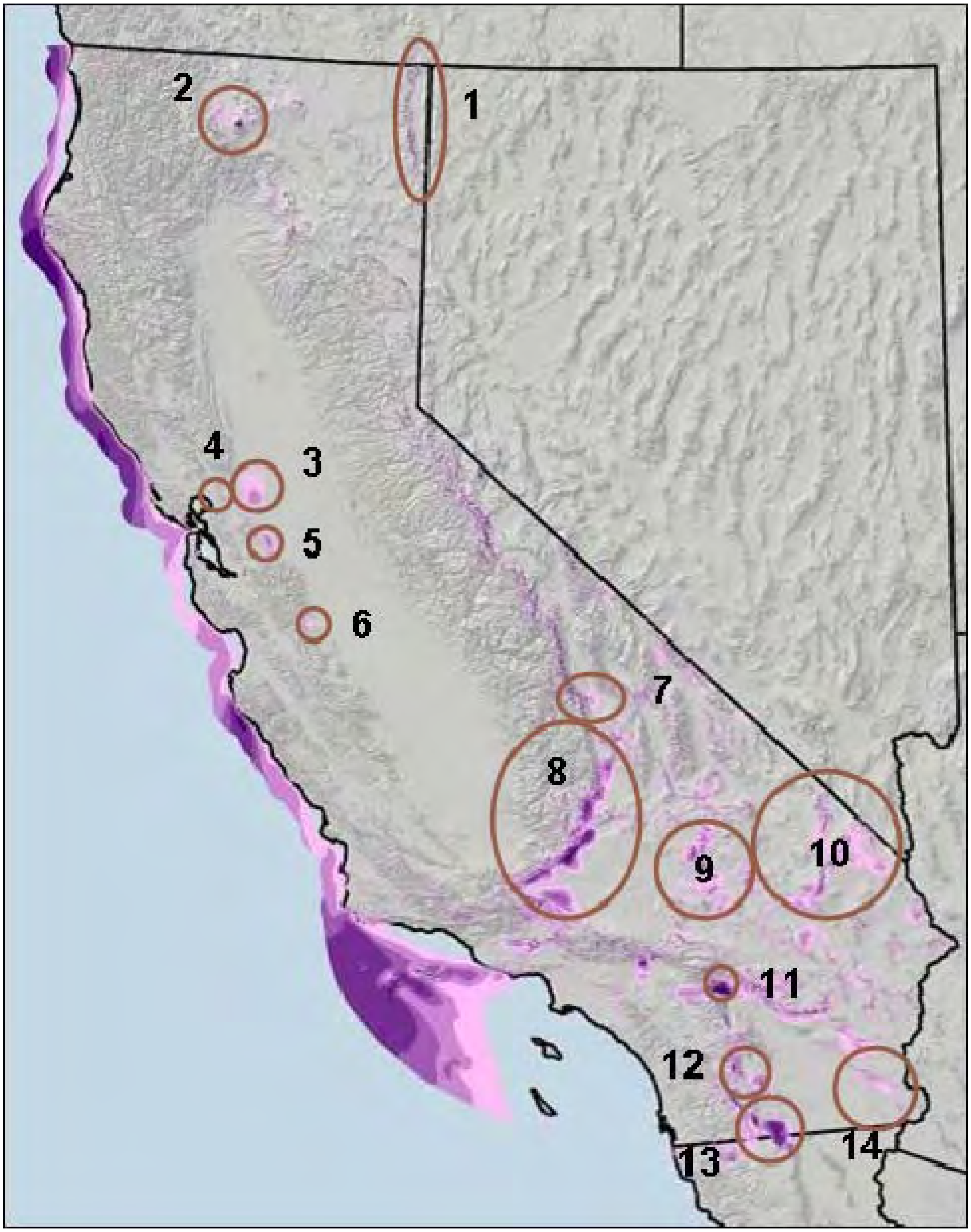


Figure 6-9. Wind Areas Studied by AWS Truewind.

Table 6-32 shows the combined rated capacity in MW of sites chosen within the areas identified in the figure above. AWS Truewind does not expect any capacity to be developed in Shasta or Vallecita (regions 2 and 12, respectively) because of constructability issues. Similarly, they do not anticipate any capacity expansions in Pacheco (region 6) because the area is already built out. By far the largest capacity expansion could take place in Tehachapi, but the Eastern and Western Mojave areas combined also have a large capacity potential.

Table 6-32. Combined Rated Capacity In MW Of Sites Chosen For Each Scenario*.

Region Number	Region Name	Total Number of Sites	Existing Capacity (MW)	New 2010 Scenario (MW)	New 2020 Scenario (MW)	Total Capacity (MW)
1	Warner	10	0	0	1049	1049
2	Shasta	1	0	0	0	0
3	Montezuma	23	210	165	2517	2892
4	Solano	3	0	0	305	305
5	Altamont	26	656	80	0	736
6	Pacheco	1	13	0	0	13
7	Sequoia	4	0	0	433	433
8	Tehachapi	73	760	3555	3720	8035
9	Western Mojave	34	0	0	3810	3810
10	Eastern Mojave	19	0	0	1994	1994
11	San Gorgonio	28	463	2002	0	2464
12	Vallecita	1	0	0	0	0
13	Jacumba	4	0	90	327	417
14	Yuma	6	0	0	634	634
Total		233	2102	5892	14788	22782

Source: Brower, M., (AWS Truewind, LLC). 2007. Intermittency Analysis Project: Characterizing New Wind Resources in California. California Energy Commission, PIER Renewable Energy Technologies. CEC-500-2007-014.

Notes:

* For the 2010 scenario, AWS Truewind selected 42 sites representing about 5,900 MW of new wind capacity utilizing a mix of existing GE, Vestas, and Gamesa turbine models. For the 2020 scenario, they selected 134 sites representing about 14,800 MW of new wind capacity using a theoretical power curve meant to represent advances in wind turbine design.

California currently has 2,439 MW of operating wind capacity with 165 MW under construction.[31] This capacity is concentrated in four areas, which are Altamont, Pacheco and San Gorgonio Pass, and the Collinsville-Montezuma Hills area. There are

2,106 to 2,387 MW of new wind capacity across nine PPAs in California.[32] Most of this is a single 1,500 MW PPA in Tehachapi. There are also 12,500 MW of wind capacity in the CAISO queue (Table 6-33).

Table 6-33. CA ISO Queue by County.

County	MW
Kern	5,949
San Bernardino	2,634
Solano	1,147
San Diego	661
Riverside	545
Santa Barbara	265
Lake & Sonoma	201
Lassen	201
Monterey	200
Lake and Colusa	200
Marin	175
Kern and Inyo	120
Shasta	102
Contra Costa	100

Source: ISO.

6.7.3 Arizona Wind Potential

Compared to the rest of the region of study, Arizona has relatively poor quality wind resource. There are 2,553 MW of capacity potential in areas with class 4 winds or greater. Much of the wind resource in Arizona is considered to be Class 2 or less, which is generally considered to be non-economic. There is one large area of Class 3 winds, which is considered marginal wind resource. This resource is in a long line that passes near Flagstaff and continues to the eastern part of the state. Higher wind resources are predicted to exist along ridgelines as well. The map in Figure 6-13 at the end of this section shows the Class 3 and above wind resources in Arizona.

Table 6-34 shows the theoretical potential capacity from wind power class in seven regions in Arizona as estimated by NREL. The regions correspond to the large

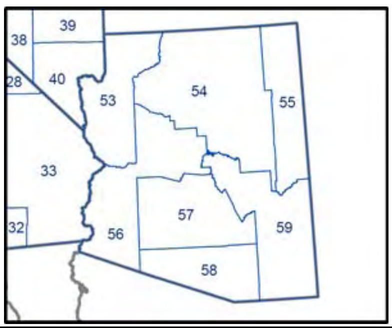
[31] AWEA
[32] CEC

regions shown in the wind resource map. The greatest potential is shown in Region 54 (north central Arizona), which contains most of the large areas of Class 3 winds.

Table 6-34. Arizona Wind Technical Potential.

Region	Capacity by Wind Power Class				Total Capacity
	4	5	6	7	
53	255	47	9	1	312
54	584	240	104	12	941
55	407	62	18	1	487
56	22	2	0	0	24
57	115	33	16	2	166
58	60	12	2	0	73
59	370	123	53	4	550
Total	1,812	519	202	20	2,553

Source: NREL, 2006.



To identify specific areas conducive to the development of a utility-scale wind energy project in Arizona, Black & Veatch produced a recent report entitled “Arizona Renewable Energy Assessment.” After reviewing potential sites for constructability and resource, six sites were chosen as the most promising. The total combined capacity of the six sites identified is 990 MW, with an energy generation potential of 2,550 GWh per year. Arizona currently has no operating wind facilities, but there are 500 MW of already planned wind projects that were not included in the capacity estimate of the six potential sites.

In summary, the wind resources in Arizona are relatively poor compared to other regions under study for RETI. Although wind development is likely to proceed in Arizona, projects are more likely to sell their output to local Arizona utilities to meet the state’s renewable energy standard than sell power to California.

6.7.4 Nevada Wind Potential

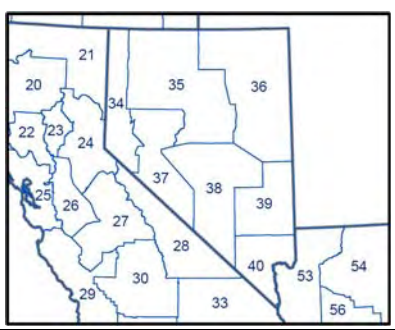
Nevada has relatively modest wind potential, and most of the resource is non-contiguous and located on high ridgelines. There are some fairly large areas of class 3 winds, which are considered marginal wind resources. These are located in southern Nevada near Las Vegas and near Ely. Higher wind resources are predicted to exist on the higher ridge crests throughout the state although these are relatively expensive to construct. The map in Figure 6-13 at the end of this section shows all the wind resources in Nevada.

Table 6-35 shows the theoretical potential capacity from wind power class in seven regions in Nevada as estimated by NREL. The regions correspond to the large regions shown in the wind resource map. The greatest potential is shown in Region 36 (northeastern Nevada), which contains most of the large areas of Class 4 winds.

Table 6-35. Nevada Wind Technical Potential.

Region	Capacity by Wind Power Class				Total Capacity
	4	5	6	7	
34	608	276	200	73	1,156
35	718	250	101	12	1,081
36	1,294	374	186	50	1,905
37	597	189	104	45	935
38	453	109	28	1	591
39	165	34	16	1	215
40	235	49	12	0	295
Total	4,068	1,281	646	183	6,178

Source: NREL, 2006.



There is 1,500 MW of wind capacity in Clark County (southern Nevada) in the CAISO queue, and one announced project on the Idaho-Nevada border. Nevada wind projects are hampered, however, by transmission and permitting issues. The direct transmission from northern Nevada to California is limited to lines less than 230 kV. Larger transmission lines between these two areas are all routed through Oregon and Utah. Projects in southern Nevada face significant airspace and environmental permitting issues.

6.7.5 Oregon Wind Potential

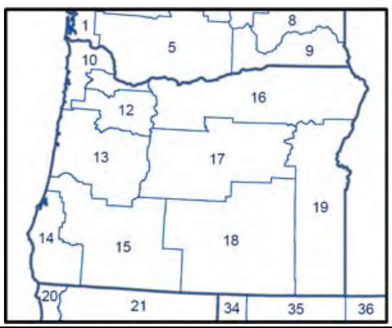
Oregon has relatively good wind potential, with nearly 2,000 square kilometers of class 4 and greater resources, although most of this is concentrated on ridge crests throughout the state. The most significant non-ridge crests areas with at least good resource are located at Vansycle ridge in northeastern Oregon, the area south of the Columbia River east of the Dalles, and southeast of La Grande. The map in Figure 6-15 at the end of this section shows all the wind resources in Oregon.

Table 6-36 shows the theoretical potential capacity from wind power class in ten regions in Oregon as estimated by NREL. The regions correspond to the large regions shown in the wind resource map. The greatest potential is shown in Region 16 (northeastern Oregon along the Columbia River), which contains most of the large areas of Class 4 winds. This theoretical or technical potential is not bound by the constraints of product availability (backordered turbines, for instance), site-specific constraints such as transmission capacity, environmental restrictions, or cost. The next phase of this study identifies the near-term developable potential for wind. This is a much smaller set of resources that could potentially be built and financed in the near term.

Table 6-36. Oregon Wind Technical Potential.

Region	Capacity by Wind Power Class				Total Capacity
	4	5	6	7	
10	380	157	87	15	639
11	11	4	0	0	14
12	136	40	26	9	211
13	297	132	69	6	504
14	630	301	195	39	1,165
15	252	83	42	11	388
16	3,289	492	160	24	3,965
17	261	46	27	7	341
18	1,160	211	107	20	0.0
19	766	87	23	3	0.0
Total	7,181	1,554	736	133	7,226

Source: NREL, 2006.



Oregon currently has ten operating wind facilities totaling 885 MW, and there are several proposed projects for 2008. Transmission lines exist near several of the larger Class 3 areas, and the terrain does not appear to be particularly challenging to development.

6.7.6 Washington Wind Potential

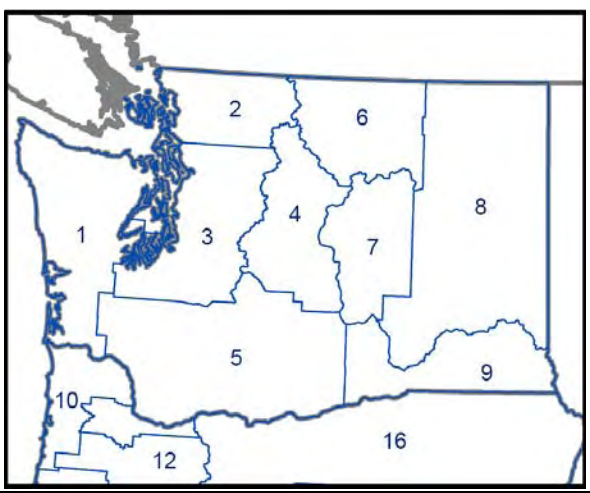
Washington has good wind potential, with close to 2,000 square kilometers of good-to-excellent resource located in the central part of the state. They are concentrated in the Kittitas Valley northwest of Yakima, on the ridges west of the Columbia River northeast of Yakima, and in the Horse Heaven Hills north of the Columbia River near the Oregon boarder. Another area of good-to-excellent resource is north of the Blue Mountains in southeastern Washington. Ridge crest locations throughout the state can also have excellent wind resource.

Table 6-37 shows the theoretical potential capacity from wind power class in nine regions in Washington as estimated by NREL. The regions correspond to the large regions shown in the wind resource map. The greatest potential is shown in Region 5 (south central Washington), which contains most of the large areas of Class 4 winds.

Table 6-37. Washington Wind Technical Potential (MW).

Region	Capacity by Wind Power Class				Total Capacity
	4	5	6	7	
1	299	83	42	19	442
2	69	44	44	17	173
3	246	127	119	68	559
4	2,111	497	88	5	2,701
5	2,549	551	269	61	3,430
6	16	2	0	0	19
7	187	30	4	0	221
8	138	59	26	2	225
9	1,540	209	22	3	1,774
Total	7,156	1,601	612	176	9,544

Source: NREL, 2006.



Washington currently has multiple operating wind facilities totaling 1,163 MW, and several proposed projects. Transmission lines exist near several of the larger class 3 areas, and the terrain does not appear to be particularly challenging to development. However, a more detailed review of at transmission issues is needed (next phase of this study).

6.7.7 British Colombia Wind Potential

British Columbia's wind potential falls in the middle range, with the strongest areas of fair-to-good resource located at the northwest coast, the northern part of Vancouver Island. There are fairly large areas of Class 3 - 4 winds, which are considered fair to good. Much of the resource is remote and or located on mountainous ridges.

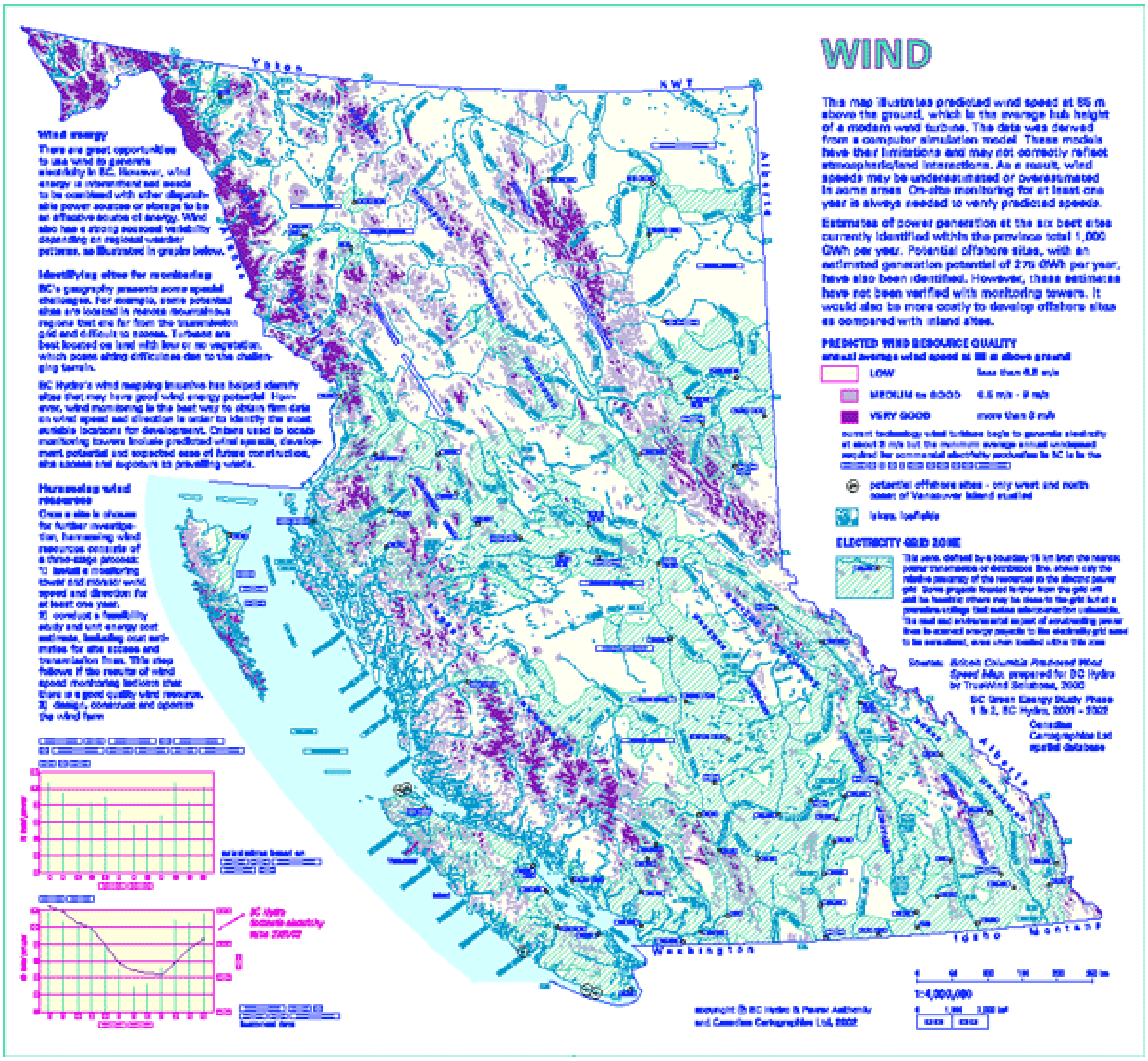


Figure 6-10. Wind Resources in British Colombia. Source: Canadian Cartographics Ltd.

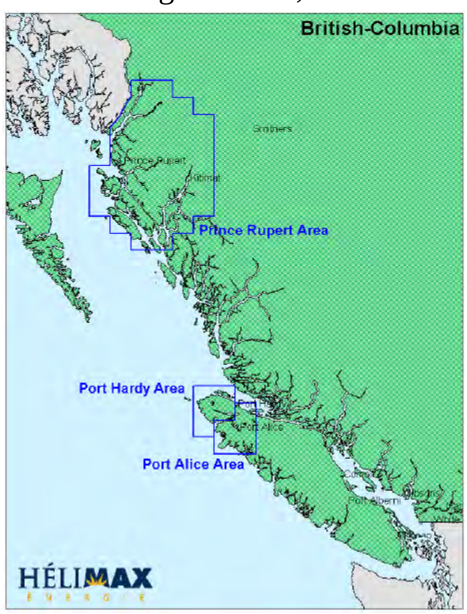
Helimax Energy Inc. did a detailed conceptual evaluation of the top wind sites and indicated a total potential installed capacity of 4,790 MW with the sites ranging from 40 to 2,780 MW of installed capacity. Their study examined the wind energy potential of certain pre-selected areas, namely Port Alice, Port Hardy (both on northern Vancouver Island), and Prince Rupert in the northern coast area.

Table 6-38. British Columbia Potential Wind Project Capacities.

		Potential Capacity (MW)	
Areas	**Site**	**Per Site**	**Per Area**
Port Hardy	PH1	570	570
Port Alice	PA1	40	540
	PA2	50	
	PA3	120	
	PA4	170	
	PA5	80	
	PA6	80	
Prince Rupert	PR1	120	3,680
	PR2	2,780	
	PR3	780	
Total			4,790

Source: Helimax Energy Inc (2002): Wind Energy Study in British Columbia.

Note: The Installed Capacity was estimated by multiplying a power density factors (MW/km^2) by the Net Section Surface (km^2). The power density factor depends on the landscape features and goes down, as the landscape get more complex.



British Colombia currently has no operating wind facilities, but there are several proposed projects. Transmission lines exist near the larger Class 3 areas. A more detailed review of transmission issues is needed (next phase of this study).

6.7.8 Baja California Norte Potential

Baja California Norte has relatively modest wind potential, with the strongest areas of good-to-excellent resource located in the central part of the state. There are fairly large areas of class 3 - 6 winds, which are considered fair to outstanding. They are concentrated in the Rumorosa mountain range and at the Canon de San Marin in the Valle de la Trinidad. Ridge crest locations throughout the region can also have outstanding wind resource.

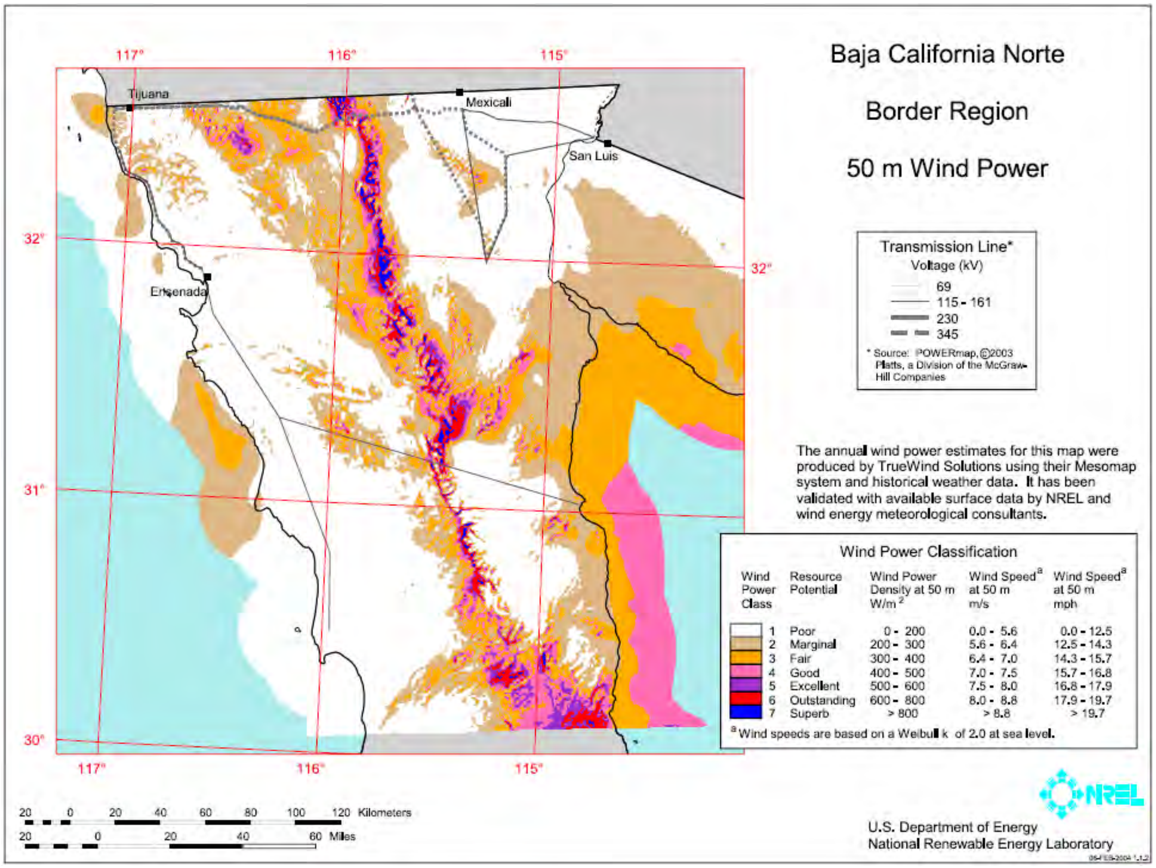


Figure 6-11. Wind Resources in Baja California Norte Border Region. Source: NREL.

Table 6-39 shows the wind energy locations in Baja California with daily wind data. The greatest potential (~1800 MW) exits in Jacume and Pino Suarez,[33] which contains most of the large areas of Class 4 -5 winds.

[33] Anders et al. (2005): Potential for Renewable Energy in the San Diego Region.

Table 6-39. Wind Energy Location in Baja California. Source: Anders et al. (2005): Potential for Renewable Energy in the San Diego Region.

Station	Average (knots)	Average M/s	Stand. Dev.	Energy (watts/m2)
Pino Suárez	20.2	10.9	4.5	1299.6
Jacumé	15.5	8.3	3.7	581.6
La Rumorosa	14.9	8.0	4.0	516.4
El Hongo	12.0	6.5	2.6	274.0
El Pinal	11.7	6.3	2.9	254.7
La Puerta	11.5	6.2	2.5	238.2
El Centinela	17.2	9.3	4.9	793.7

Baja currently has no operating wind facilities, but there are several proposed projects. Sempra Generation has a 200-250 MW PPA with SCE for a wind project in Baja California. There are also 5,000 MW of interconnection requests in the CAISO queue from planned wind projects in Baja. Transmission lines exist near the larger class 4 areas, but the terrain appears to be challenging to development. A more detailed review of siting and transmission issues is needed (next phase of this study).

6.7.9 Offshore Wind Potential

Offshore wind potential is larger than onshore because of reduced turbulence (steadier wind) and higher mean wind speeds; however, current technology limits the access of this resource to shallow water (20 meters deep or less). Much of the offshore wind resource is considered to be deep water, which is generally considered to be non-economic to develop with current technology. There are areas of shallow water, however, which are considered to be developable with the current technology even though this potential is relatively small compared to onshore resources. The Pacific coast's strongest areas of outstanding-to-superb resource are located between central Oregon and Point Arena, California as well as off of British Columbia in the Hecate Strait.

Dvorak et al. (2007) did a conceptual evaluation of the best offshore wind sites in California. Their study, based on four month wind model runs, only considered wind resources greater than 7.0 meters per second. They estimated a total potential installed capacity of 3,369 MW of shallow-water areas with a minimum wind average wind speed of 7.0 meters per second. Additional offshore wind sites probably exist further up the Pacific coast as well; however, these have not yet been inventoried in detail.

Table 6-40. Potential California off-shore wind development (MW).*

Ocean Depth	80 m Avg. Wind Speed	Northern Calif.	SF Bay Area	Southern Calif.	Total
0-20 m	> 7.0 m/s	3,052	8	309	3,369
	>7.5 m/s	746	0	0	746

Source: Dvorak et al. (2007): California Offshore Wind Energy Potential.
Notes:
* Assuming a 33% exclusionary factor for each area.

The Pacific coast currently has no operating wind facilities, although one company has begun to develop an offshore site in Canadian waters. Transmission lines exist near the Eureka, California and southern Oregon coastal areas as well as the central British Columbian coast.

There are currently no offshore wind projects operating in the U.S. Current costs for offshore projects are substantially higher than onshore projects. Given the large potential for onshore wind identified in this study, it does not appear that additional study of offshore wind resources is warranted at this point.

6.7.10 Wind Summary

There is significant wind resource available in California, Washington, Oregon, Nevada, British Columbia, and Baja California. These five regions combined have roughly 50 GW of class 4 or better wind resource potential. Clearly, wind development is not limited by the availability of resource. The wind resource already under development in California, as indicated by CAISO queue, could easily fill half of the California RPS needs.

Table 6-41. Summary of Wind Resources.

	MW*	Assess in Phase 1B?	Notes
Arizona	2,553	No	Limited resource most likely used in state
Baja California	1,800	Yes	No PTC
British Columbia	4,790	Yes	Distant transmission, no PTC
California	21,099	Yes	
Nevada	6,178	Only S. NV	Much of resource is difficult ridge top
Oregon	7,226	Yes	
Washington	9,544	Yes	
Grand Total	53,190		

Notes:
* Nameplate capacity, Class 4 and higher. Estimates for Baja California and British Columbia based on Anders et al. (2005) and Helimax Energy (2002), respectively.

Black & Veatch recommends including wind resources in California, Washington, Oregon, Southern Nevada, Vancouver Island, and Baja California for further study in Phase 1B.

6.7.11 Data Sources

Data sources used in this analysis included:

- AWEA, "U.S. Energy Projects", available at: http://awea.org/projects/ , accessed: March 13, 2008.
- AWS Truewind, LLC, "Intermittency Analysis Project: Characterizing New Wind Resources in California", available at: http://www.energy.ca.gov/2007publications/CEC-500-2007-014/CEC-500-2007-014.PDF , accessed: July 10, 2007.
- CAISO, "The California ISO Controlled Grid Generation Queue", available at: http://www.caiso.com/14e9/14e9ddda1ebf0.pdf , accessed: March 13, 2008.
- Donna Heimiller, an NREL GIS analyst.
- Helimax Energy, "Wind Energy Study in British Columbia", available at: http://livingoceans.org/oilgas/oilandgasreports/windenergy.pdf , accessed: February 21, 2008.
- Michael Dvorak, Mark Jacobson, and Cristina Archer, "California Offshore Wind Energy Potential", available at:

http://www.stanford.edu/~dvorak/papers/offshore-wind-ca-analysis-awea-2007.pdf , accessed: February 7, 2008.

- NREL Wind Resource Maps, available at: http://www.eere.energy.gov/windandhydro/windpoweringamerica/wind_maps.asp , accessed: March 6th, 2008
- NREL, "Wind Deployment System (WinDS) Model", available at: http://www.nrel.gov/analysis/winds/ , accessed: February 28, 2008.
- *NREL*, "Wind Energy Resource Atlas of the US, 1991", available at: http://www.nrel.gov/wind/resource_assessment.html , accessed: February 13, 2008.
- San Diego Regional Renewable Energy Study Group, "Potential for Renewable Energy in the San Diego Region", available at: http://www.renewablesg.org/ , accessed: February 14, 2008.

6.7.12 Wind Maps

High resolution wind maps are provided on the following pages.

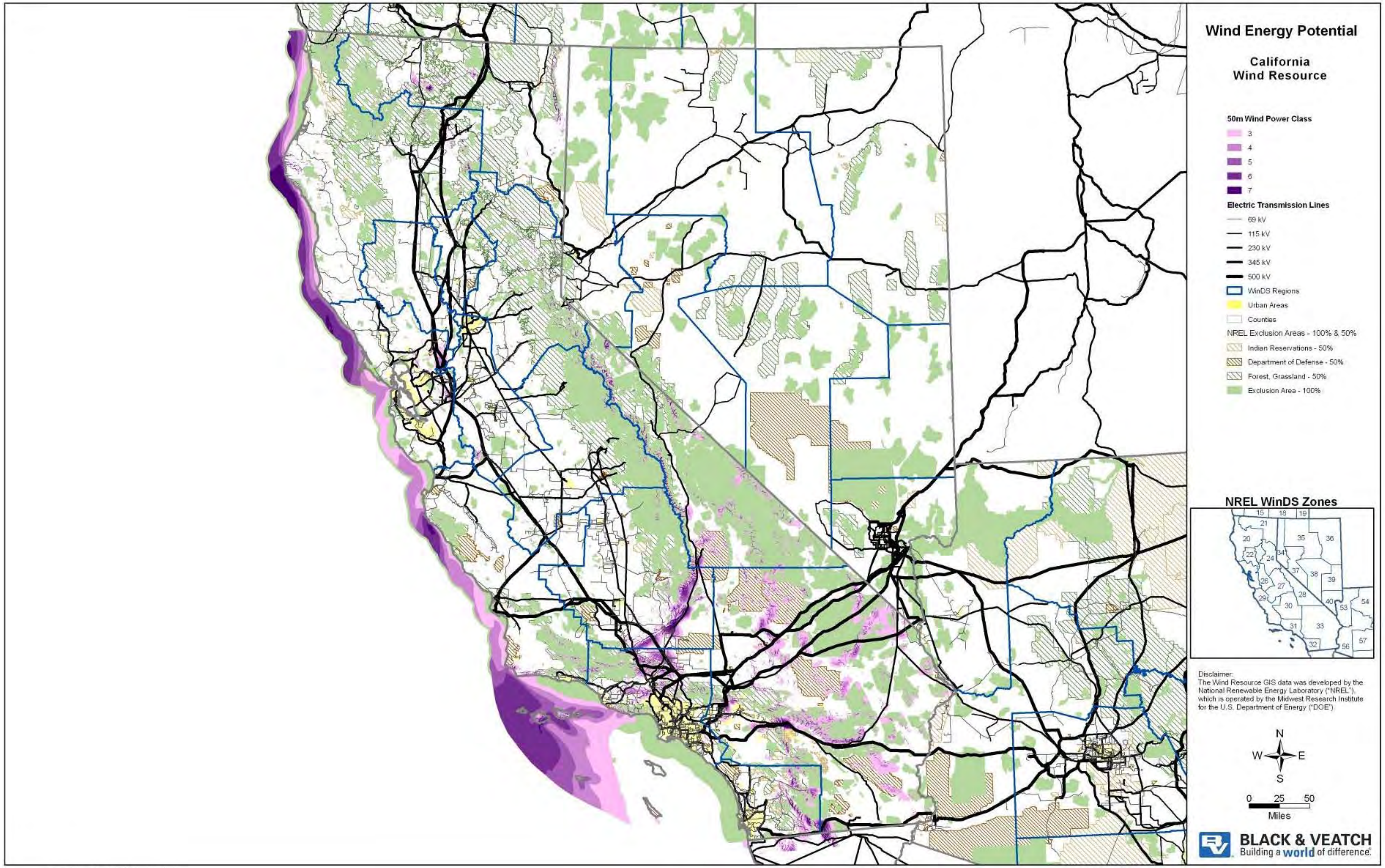


Figure 6-12. Wind Resources in California.

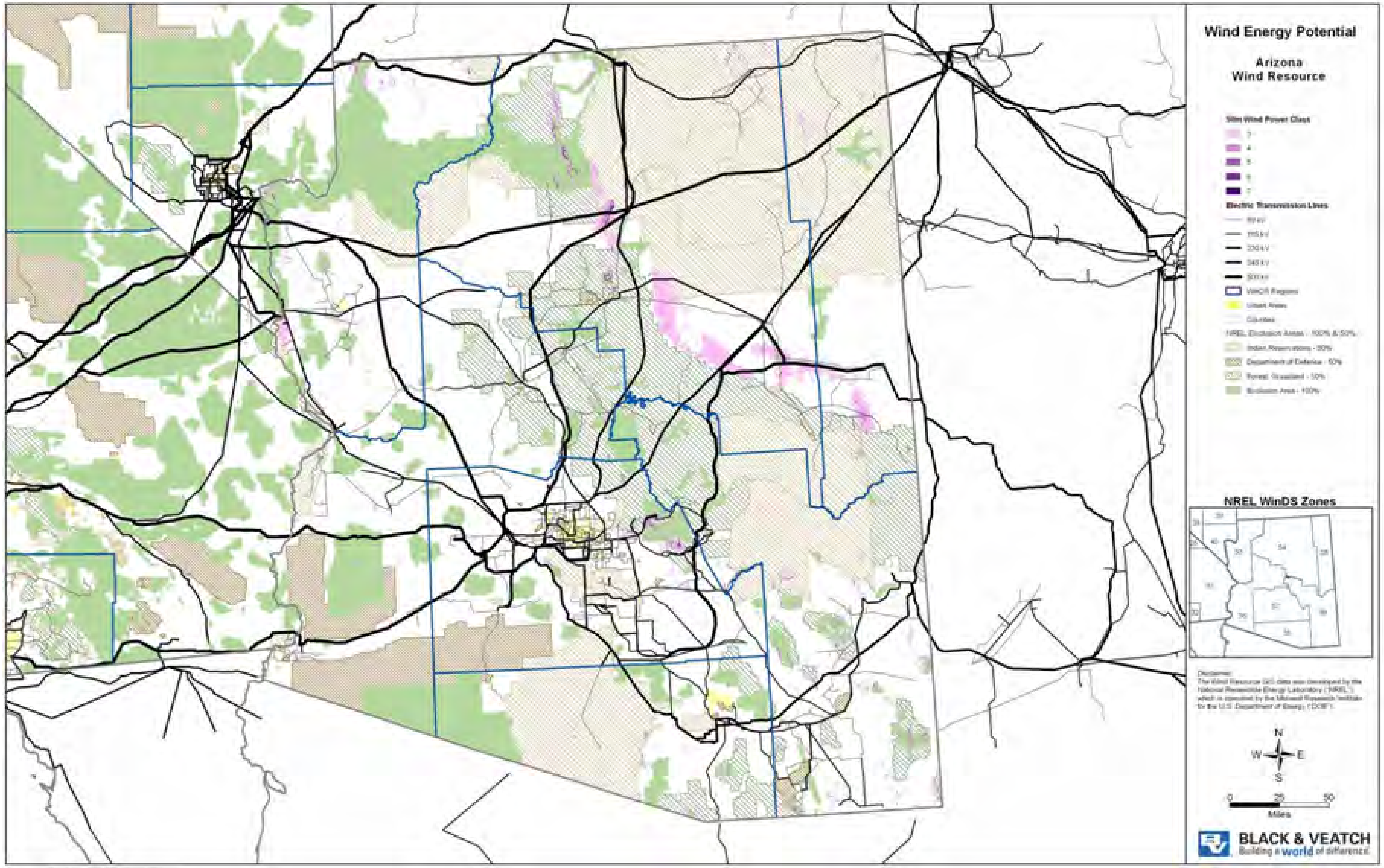


Figure 6-13. Wind Resources in Arizona.

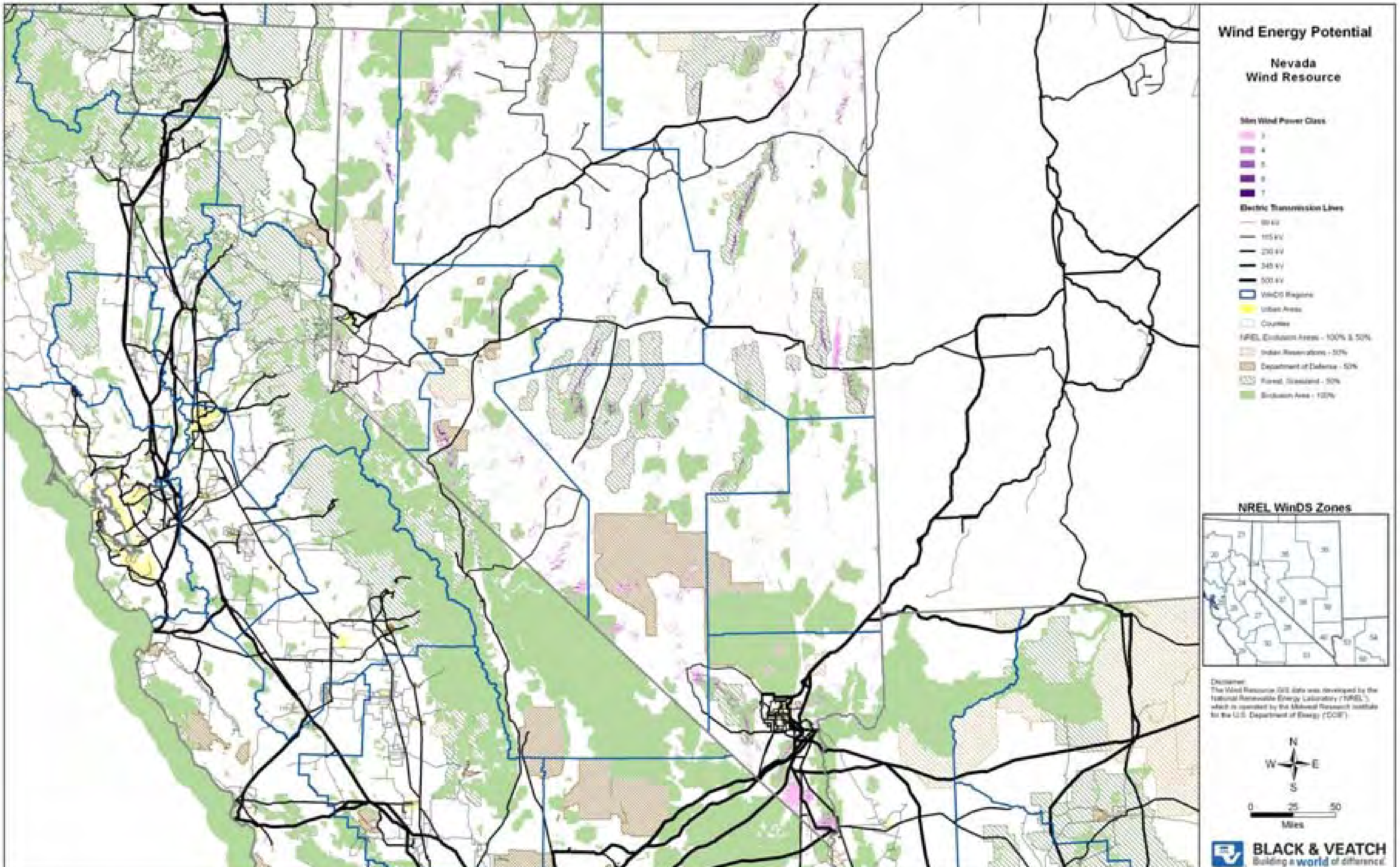


Figure 6-14. Wind Resources in Nevada.

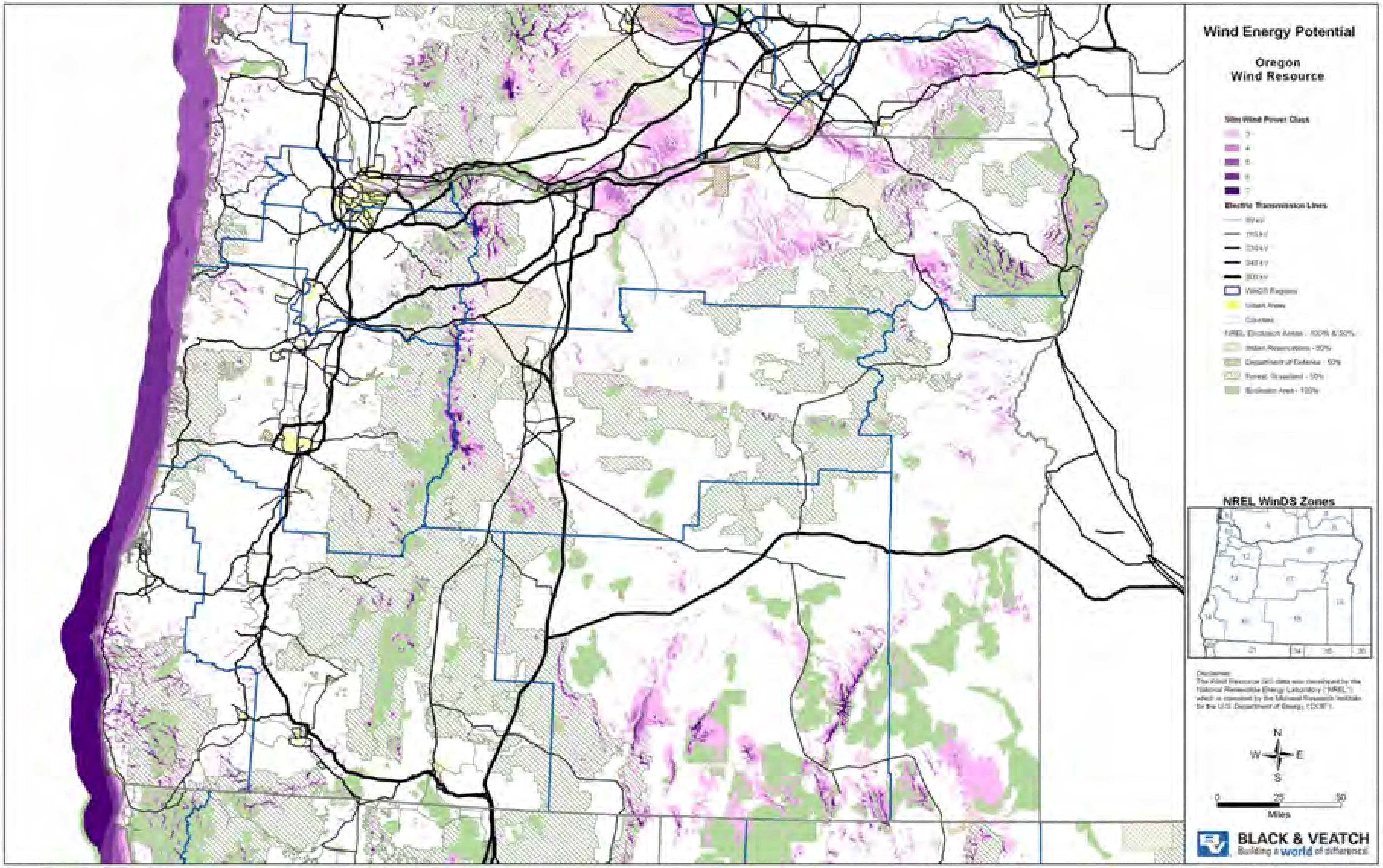


Figure 6-15. Wind Resources in Oregon.

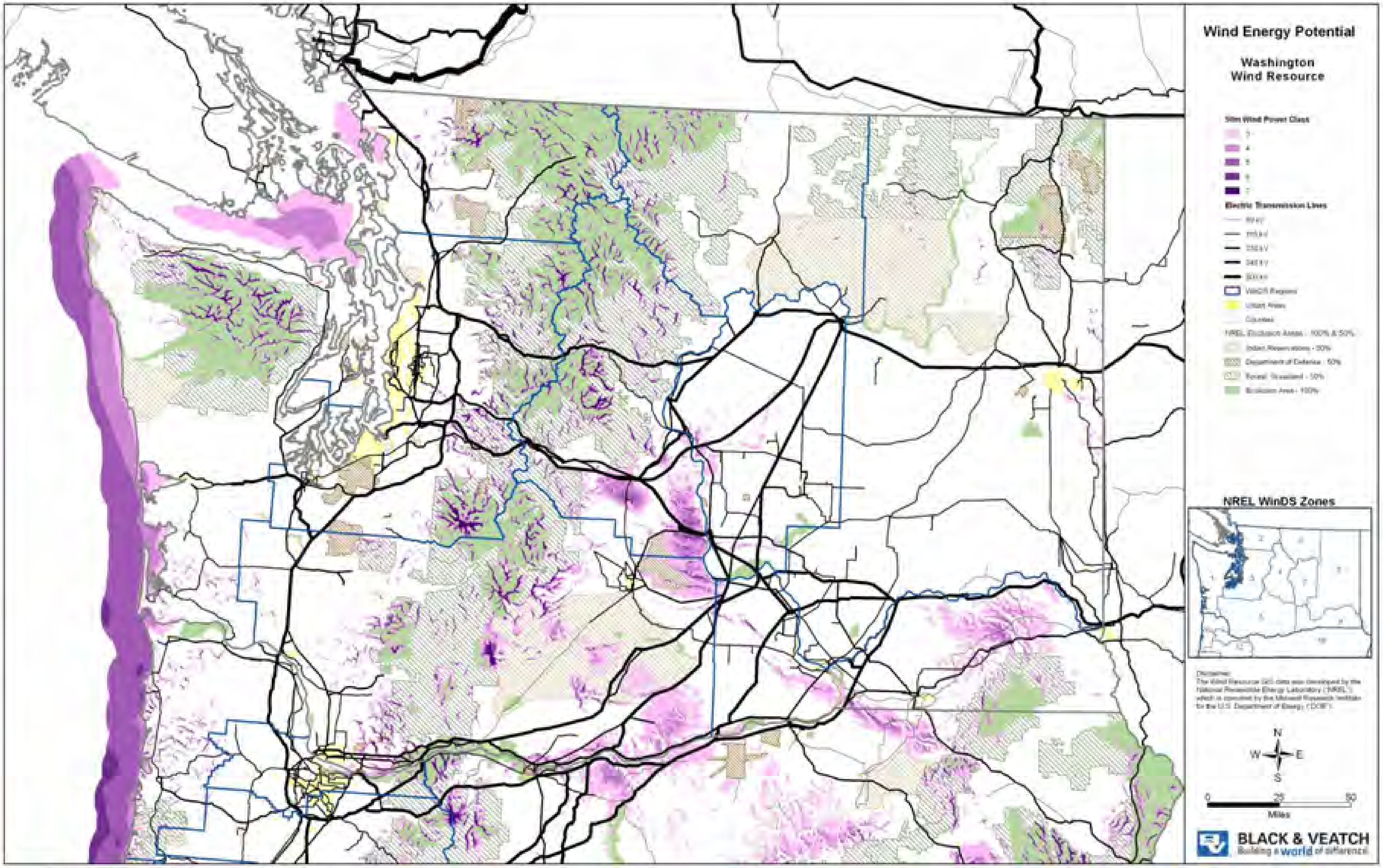


Figure 6-16. Wind Resources in Washington.

6.8 Geothermal

This section presents the methodology that was used to evaluate geothermal resources and provides an overview of geothermal resource availability throughout the RETI region of study. This section has been prepared by GeothermEx, under subcontract to Black & Veatch.

6.8.1 Methodology

For the purposes of this study, geothermal potential has been estimated using a combination of heat-in-place analysis and geological analogy. The heat-in-place approach is preferred when there is adequate information from drilling, geochemistry, and geophysics. The approach entails estimating the area, thickness, and average temperature of the exploitable reservoir in a geothermal area. The potential in megawatts (MW) is then calculated assuming a certain project life and recovery efficiency. A milestone study of U.S. geothermal resources by the United States Geological Survey in 1978 (known as Circular 790) used a heat-in-place approach.[34] GeothermEx has modified the approach to include probabilistic considerations to account for uncertainty in the input parameters. This probabilistic heat-in-place approach was applied in a 2004 study of the geothermal potential of California and Nevada for the California Energy Commission. This 2004 study (referred to herein as the CEC-PIER report[35]) has been cited in several subsequent studies (such as the Western Governors' Association study of 2006[36] and a 2006 map of California resources by the California Geothermal Energy Collaborative[37]). The 2004 study provides the basis for most of the MW estimates in the RETI Phase 1A study for California and Nevada. In general, the MW estimates for particular resources in the CEC-PIER report were lower than the estimates of Circular 790 because of experience gained in the geothermal industry relative to realistic recovery factors.

[34] Muffler, L. J. P. (ed.), 1979. Assessment of Geothermal Resources of the United States – 1978. United States Geological Survey, Circular 790.

[35] GeothermEx, 2004. New Geothermal Site Identification and Qualification. Consultant report for the Public Interest Energy Research (PIER) program of the California Energy Commission (CEC). CEC Publication No. P500-04-051. Available online at: http://www.energy.ca.gov/pier/final_project_reports/500-04-051.html.

[36] Western Governors' Association, 2006. Geothermal Task Force Report, Clean and Diversified Energy Initiative. Available on the Web at: http://www.westgov.org/wga/ initiatives/cdeac/Geothermal-full.pdf.

[37] California Geothermal Energy Collaborative/GeothermEx, 2006. California Geo-thermal Fields and Existing Power Plants. Map and table. Available on the Web at: http://ciee.ucop.edu/geothermal/documents/FinalGeothermalFactSheetAndMap.pdf.

For areas outside California and Nevada, GeothermEx has relied on published estimates of others and its own non-proprietary sources to estimate MW potentials. Most of these estimates involve geological analogy to areas that have had the benefit of more thorough exploration. For instance, regions with volcanic rocks of a certain type and age may be deemed to have a certain MW potential based on their similarity to geothermal resources that have been developed elsewhere.

The distribution of MW potential within each of the areas of interest is discussed in the following sections.

6.8.2 California Geothermal Potential

California has the largest geothermal potential of any of the areas considered. The currently installed capacity totals 1,884 MW gross, and a reasonable estimate of additional capacity to come on line within the next 10 years is 2,375 MW gross. Figure 6-17 shows the geographic distribution of geothermal areas in the state. The diamonds indicate projects with existing plants (some of which have expansion potential), while the circles show areas of identified potential that are not yet on line.

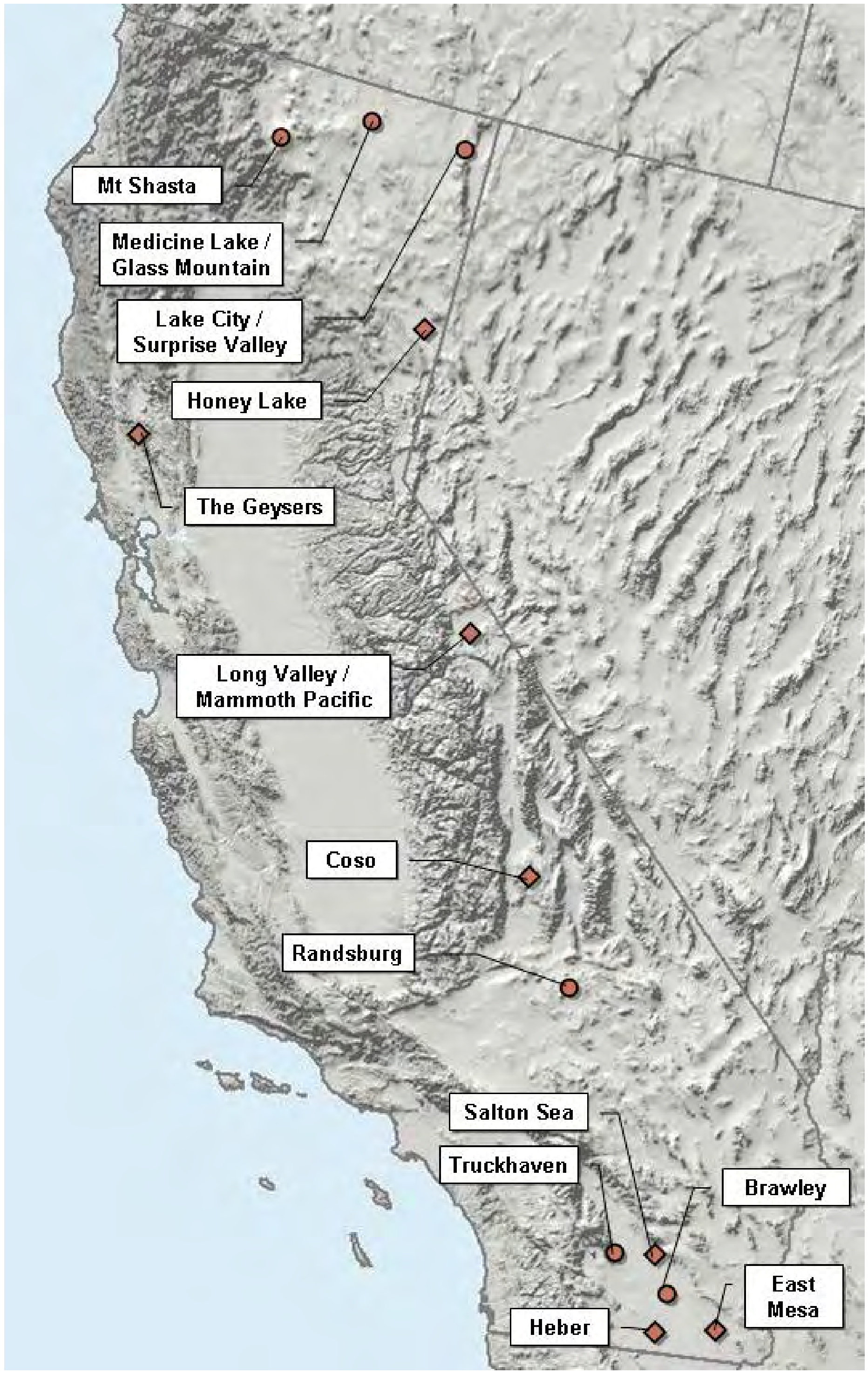


Figure 6-17. Existing and Potential Geothermal Areas in California.

The Geysers field (north of San Francisco) is the largest geothermal field in the world, with an operating capacity of about 850 MW. The Geysers has some potential for new plants in undeveloped areas, but such new plants will effectively be compensating for declining output at older plants, so the MW output of the total field can be expected to remain essentially flat or slowly declining. The largest potential for incremental MW capacity is in the Imperial Valley, which is estimated to have over 1,900 MW of additional geothermal potential. The Salton Sea Field alone accounts for about 1,400 MW of this incremental potential. The other region of the state with significant potential is in the far north, where three areas (Mt. Shasta, Medicine Lake, and Lake City) have a combined potential on the order of 300 to 500 MW. The Coso geothermal field (east of the Sierra Nevada) currently produces over 200 MW, but is not expected to grow significantly. The other fields in the east-central part of the state (Long Valley and Randsburg) have a combined incremental potential on the order of 100 to 150 MW.

6.8.3 Arizona Geothermal Potential

The geothermal potential of Arizona appears to be relatively limited. Potential geothermal resource areas in Arizona are shown in Figure 6-18. The San Francisco Peaks area in the north central part of the state may have potential for up to 100 MW based on geologic conditions, but exploration in this area has been very limited to date. The Clifton and Gillard prospects in the southeastern portion of the state are better known but are believed to be relatively small. Verde Hot Springs and Castle Hot Springs appear to have modest potential, based on the presence of hot springs. For the purposes of this study, GeothermEx has estimated a potential of 50 MW for Arizona, though this could expand with further exploration in the San Francisco Peaks area.

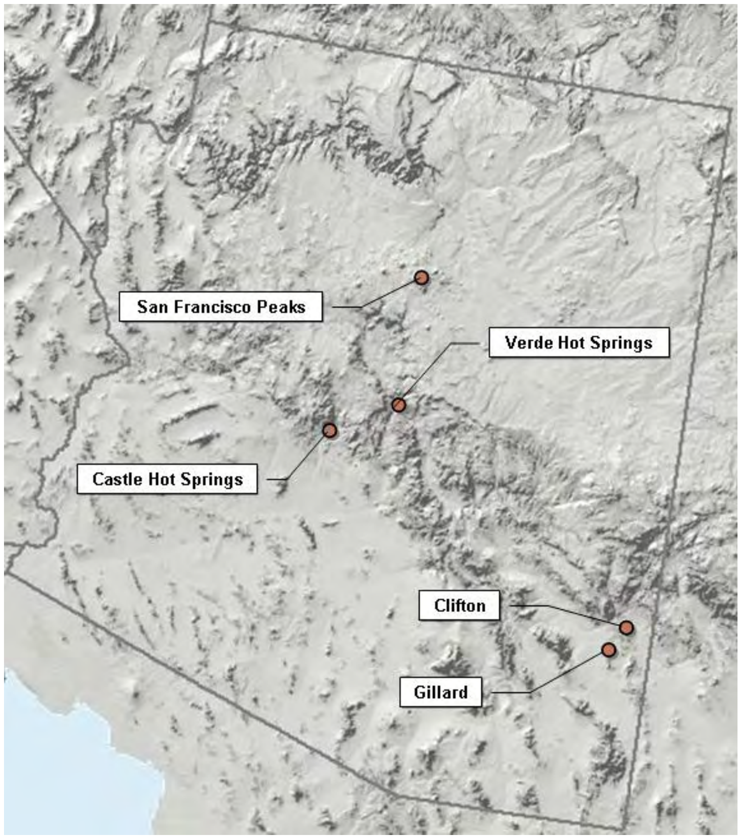


Figure 6-18. Potential Geothermal Resource Areas of Arizona.

6.8.4 Nevada Geothermal Potential

Nevada has significant geothermal resources: about 300 MW currently installed and about 1,500 MW of incremental potential. As shown in Figure 6-19, most of the geothermal fields in Nevada are concentrated in the northern part of the state, particularly along the east-west transmission corridor that parallels Interstate 80 east of Reno. Individual fields in Nevada tend to be smaller than in California, with potentials typically in the range of 20 to 50 MW. A notable exception is Dixie Valley in the west central part of the state, which has about 60 MW on line and a potential for additional capacity on the order of 100 to 200 MW. Dixie Valley exports power into the California market via a privately owned, 270-mile transmission line that connects to the grid at Bishop. Several other prospects could potentially access the California market along this transmission corridor, including Jersey Hot Springs, Sou Hot Springs, Hyder Hot Springs, Wedell Springs, Hawthorne, and Aurora. However, there are transmission constraints south of Bishop that would need to be addressed before significant expansion of fields along the Dixie Valley corridor could take place.

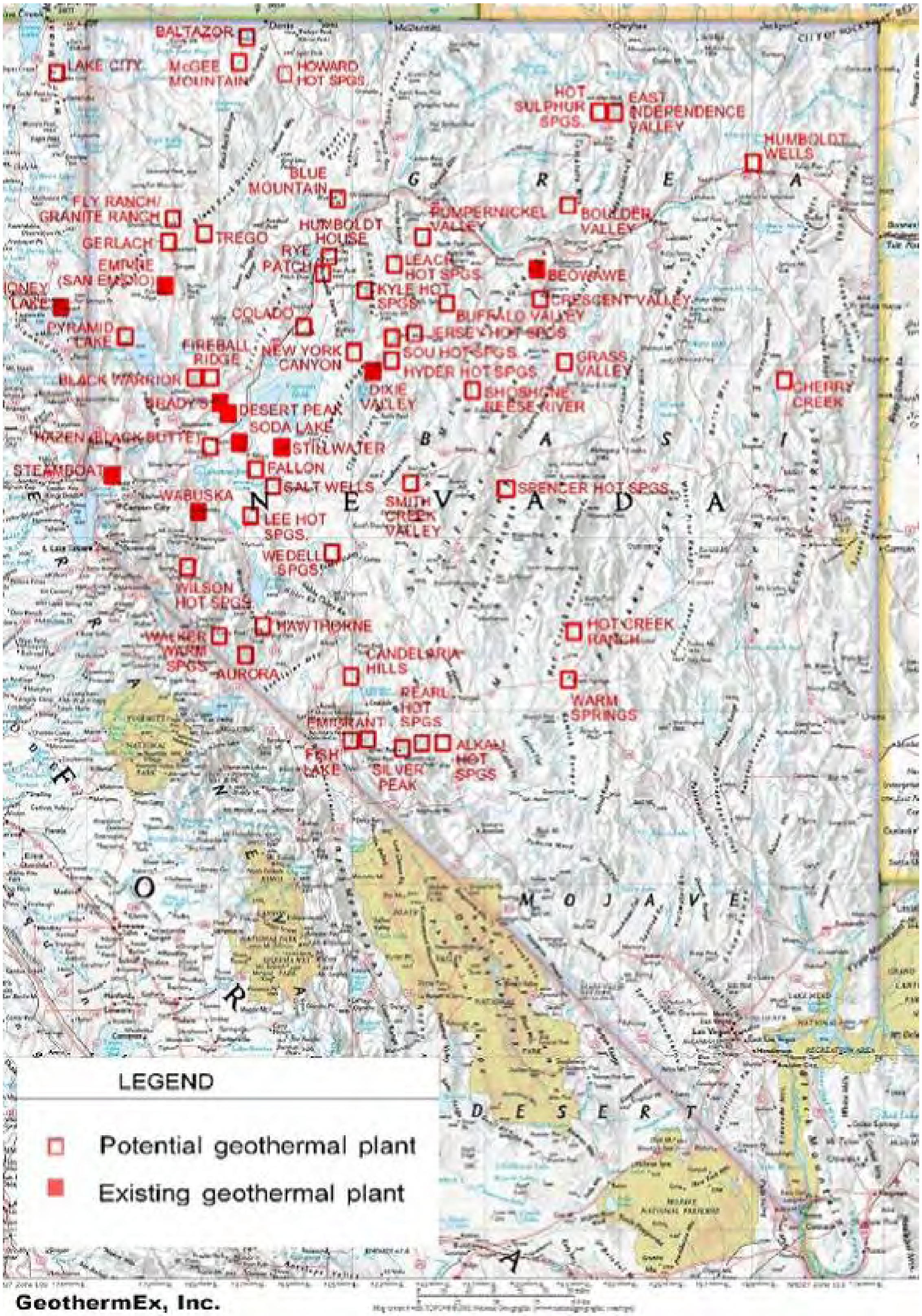


Figure 6-19. Existing and Potential Geothermal Resource Areas of Nevada.

6.8.5 Oregon Geothermal Potential

Oregon has several areas with potential for geothermal development, as shown in Figure 6-20. Drilling at the Newberry prospect in the west central part of the state has encountered high reservoir temperatures (over 500°F).[38] The Western Governors' Association study estimated that Newberry has the potential to develop 240 MW of geothermal power over the next 10 years. Other prospects in the state appear to have more modest potentials (generally in the range of 20 to 50 MW). In the aggregate, the potential of geothermal resources in Oregon is on the order of 380 MW.

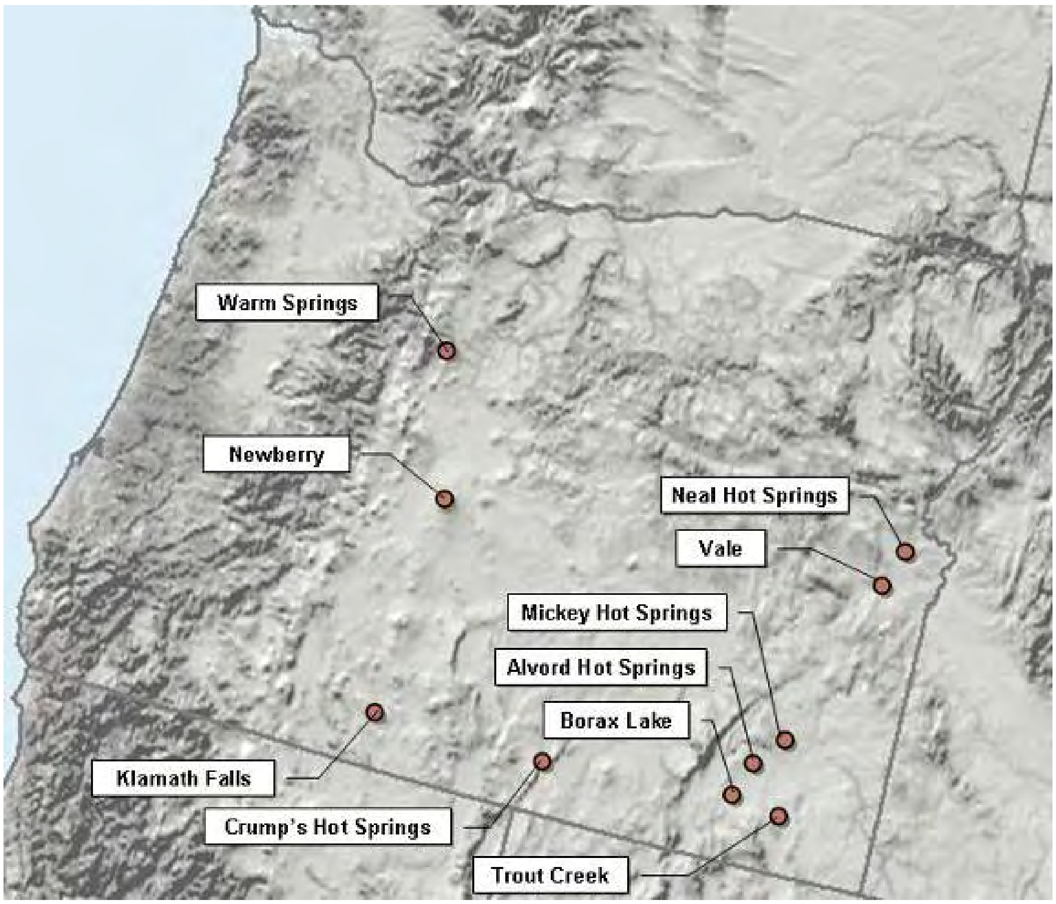


Figure 6-20. Potential Geothermal Resource Areas of Oregon.

6.8.6 Washington Geothermal Potential

Washington appears to have relatively limited potential for geothermal development. Figure 6-21 shows several potential prospects identified on the basis of relatively young volcanic activity and the presence of hot springs. Some prospects may

[38] Finger, J.T., R. D. Jacobson, and C. E. Hickox, 1997. Newberry Exploration Slimhole: Drilling and Testing. Sandia Report No. SAND97-2790.

have difficulty of access by virtue of park boundaries (such as Mt. Adams, Mt. Baker, and Mt. Rainier). The Western Governors' Association study estimated a statewide potential of 50 MW over the next 10 years.

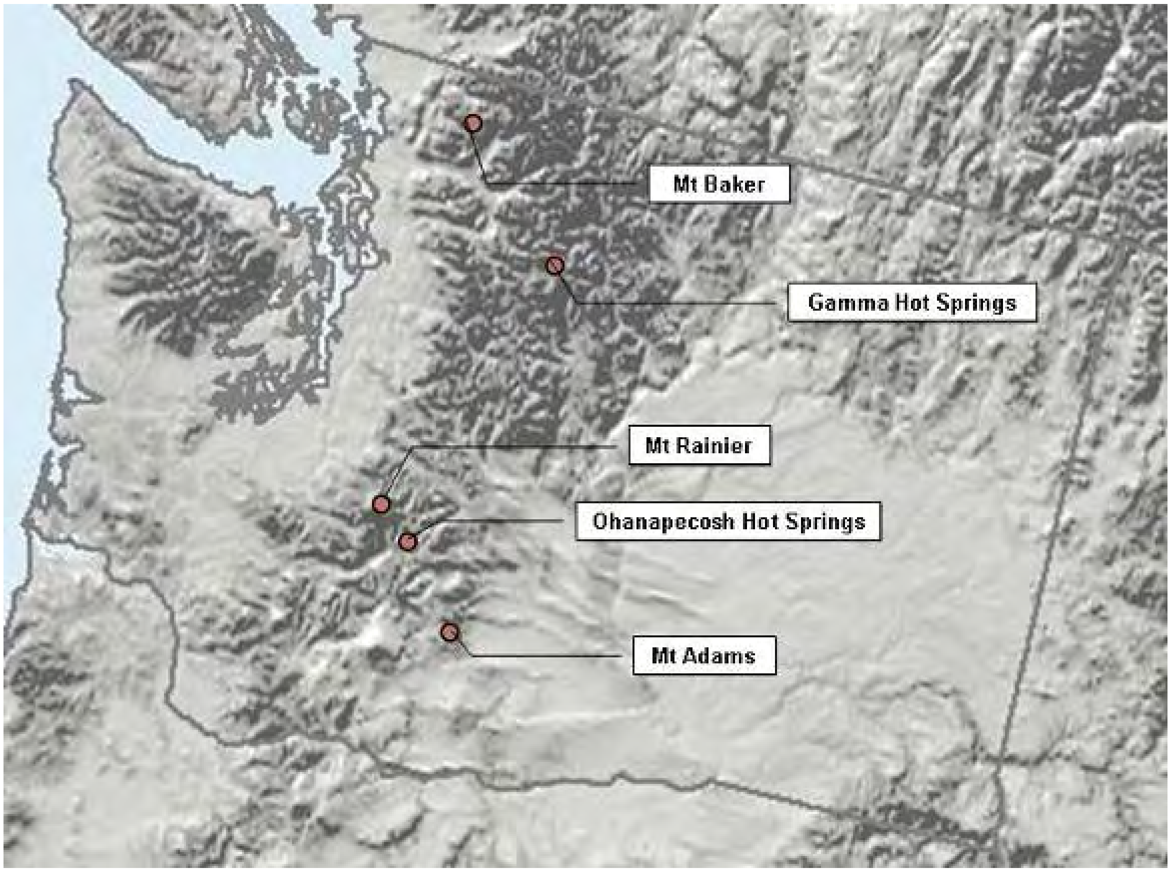


Figure 6-21. Potential Geothermal Resource Areas of Washington.

6.8.7 British Columbia Geothermal Potential

British Columbia also appears to have significant geothermal resources. Potential geothermal resource areas in British Columbia are shown in Figure 6-22. A 2002 study by BC Hydro[39] estimated the province's geothermal potential to be in the range of 150 to 1,070 MW. For the purposes of the current assessment, the province's geothermal potential has been estimated as the average of these high and low values, or 610 MW. None of the British Columbian resources have yet been brought on line. Development is most advanced at Meager Creek, where several full-diameter wells have demonstrated temperatures in the commercial range. Challenges to geothermal development in British

[39] BC Hydro, 2002. Green Energy Study for British Columbia; Phase 2: Mainland. Report No. E44. Chapter 5.2: Geothermal Energy, pp. 18-22.

Columbia include rugged topography and limited transmission access, as well as a geothermal leasing law that may not provide adequate incentives for exploration. Jurisdictional questions with respect to Native American (First Nation) lands have also complicated development efforts in some areas. However, potentially favorable conditions for geothermal development do exist, based on the presence of numerous volcanic centers of recent age, as well as the presence of hot springs. Such geological considerations form the basis for the prospects identified in Figure 6-22.

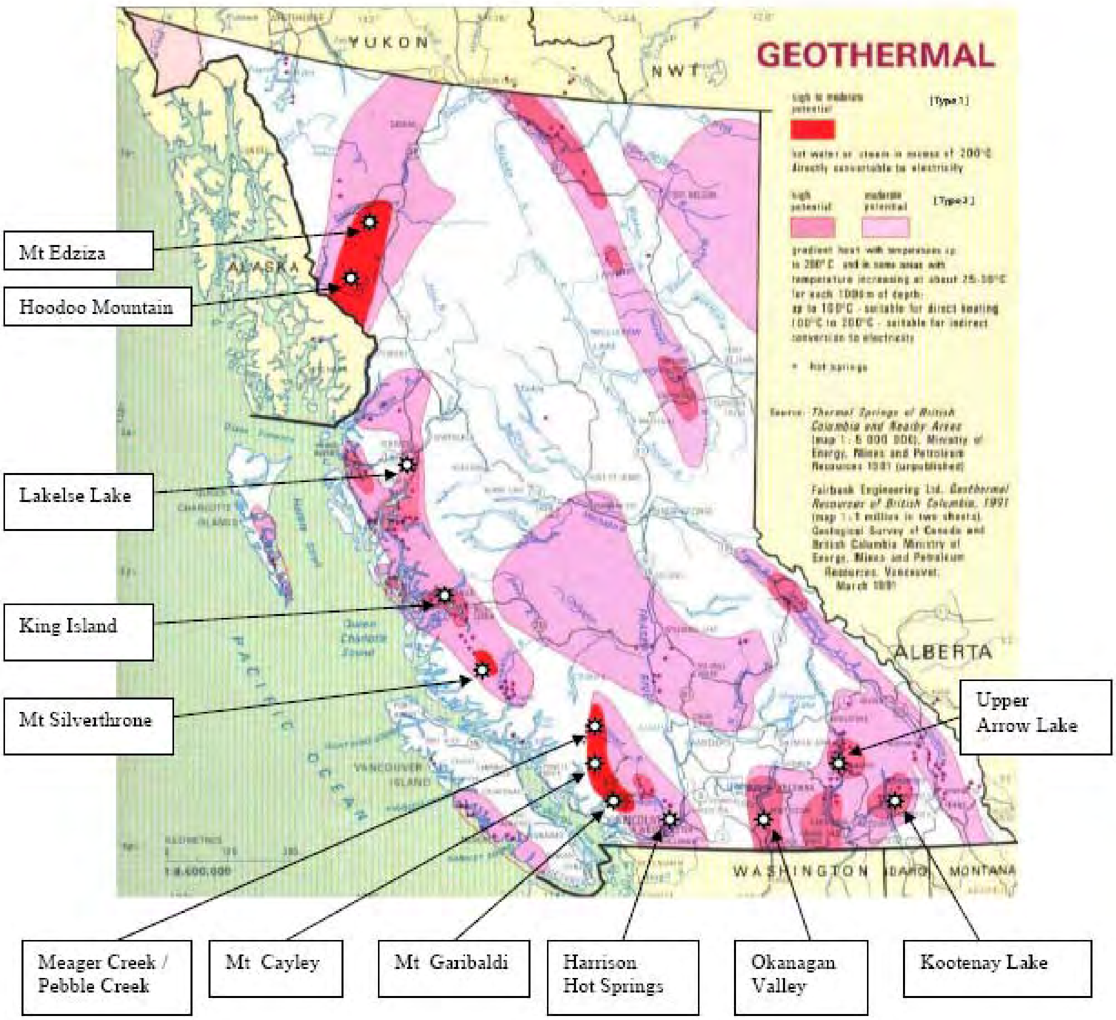


Figure 6-22. Potential Geothermal Resource Areas of British Columbia.

6.8.8 Baja California Geothermal Potential

Baja California has significant geothermal resources, as illustrated in Figure 6-23. However, these are concentrated at the Cerro Prieto field, which has an installed capacity of 720 MW and is approaching its maximum sustainable capacity. Table 6-42 lists 80

MW of incremental capacity for Baja California, which is primarily comprised of the remaining build-out of Cerro Prieto. Other geothermal fields in the area (including Laguna Salada and Tulechek) appear to be relatively small.

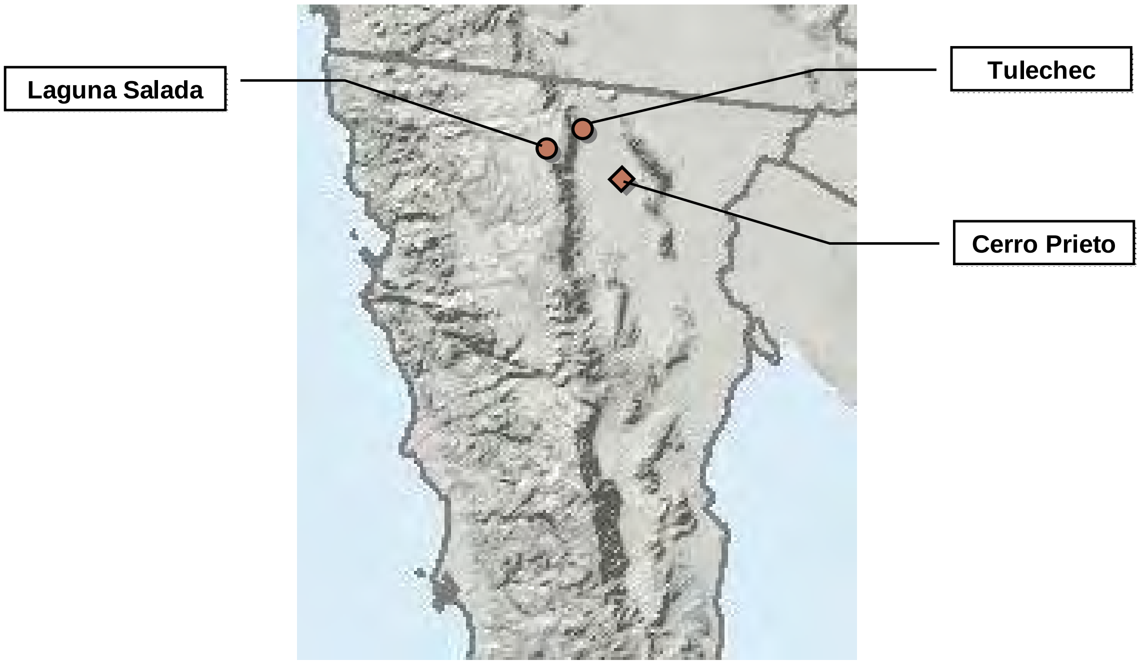


Figure 6-23. Potential Geothermal Resource Areas of Baja California.

6.8.9 Geothermal Summary

Table 6-42 lists the geothermal MW potentials of the RETI study region (i.e., California, Arizona, Nevada, Oregon, Washington, British Columbia, and Baja California), together with the data sources for these estimates. The geothermal potential of the seven areas of interest for RETI totals almost 8,000 MW. Of the 8,000 MW of potential generation, about 2,900 MW is already on line. The greatest potential for incremental MW output within the next 10 years exists within California, Nevada, British Columbia, and Oregon. Within California, the greatest potential for incremental MW output within the next 10 years is in the Imperial Valley, which has about 1,900 MW of potential for new geothermal power.

It is recommended that prospective sites in California, Nevada, British Columbia, and Oregon be examined further in Phase 1B.

Table 6-42. Summary of Geothermal Resource Assessment.

	Currently Installed Capacity (Gross MW)	Reasonable Estimate of Additional Capacity Within 10 years (Gross MW)	Total Capacity (Currently Installed + ReasonableAdditions) Within 10 years (Gross MW)
Arizona	0	50	50
Baja California	730	80	810
British Columbia	0	610	610
California	1,884	2,375	4,259
Nevada	297	1,488	1,785
Oregon	0	380	380
Washington	0	50	50
Total	**2,911**	**5,033**	**7,944**

Sources: See Geothermal Data Sources.

6.8.10 Data Sources

Data sources used in this analysis included:

- Muffler, L. J. P. (ed.), 1979. Assessment of Geothermal Resources of the United States – 1978. United States Geological Survey, Circular 790.
- GeothermEx, 2004. New Geothermal Site Identification and Qualification. Consultant report for the Public Interest Energy Research (PIER) program of the California Energy Commission (CEC). CEC Publication No. P500-04-051. Available on the Web at http://www.energy.ca.gov/pier/final_project_reports/500-04-051.html.
- Western Governors' Association, 2006. Geothermal Task Force Report, Clean and Diversified Energy Initiative. Available on the Web at: http://www.westgov.org/wga/initiatives/cdeac/Geothermal-full.pdf.
- California Geothermal Energy Collaborative/GeothermEx, 2006. California Geo-thermal Fields and Existing Power Plants. Map and table. Available on the Web at: http://ciee.ucop.edu/geothermal/documents/FinalGeothermalFactSheetAndMap.pdf.
- BC Hydro, 2002. Green Energy Study for British Columbia; Phase 2: Mainland. Report No. E44. Chapter 5.2: Geothermal Energy, pp. 18-22.
- Finger, J.T., R. D. Jacobson, and C. E. Hickox, 1997. Newberry Exploration Slimhole: Drilling and Testing. Sandia Report No. SAND97-2790.

6.9 Marine Current

This report discusses via a literature review what resource is available for marine current energy extraction using tidal stream technology, and the subsequent estimated levels of extractable energy. In addition, due to the early stages in technology development and the time scale in which commercial devices will be economically competitive, a timeline (in terms of potential level of installed capacity) has been estimated. Any tidal stream project installed offshore in the U.S. would be subject to licensing under the Federal Energy Research Commission (FERC), and thus the requirements of the FERC licensing process have been reviewed because there is a substantial time involved in preparation and license application. This will give a clear indication as to what the potential installed capacity could be by 2020 given the right investment and funding support.

Tidal resource is a predictable renewable resource and this is the driver for many of the developers, businesses, and countries alike, who are currently looking at tidal stream technology as an option for energy supply. Similarly to wind, the available power is directly related to the cube of the velocity and therefore a slight increase in velocity results in a comparatively substantial increase in available power. One advantage over wind is that the increased density of water means that a tidal device is smaller in diameter than a wind turbine which is generating the equivalent power.

An introduction to the technology was provided previously in the technology overview section, therefore only resource availability, the extractable portion of that available energy, and the time taken to reach large scale installations is discussed in this section.

6.9.1 Methodology

The methodology for marine current assessment is different in comparison to the technologies previously considered because the technology is still in an early stage of development. This means that when the resource that is available to exploit is being reviewed, one must consider the development timescales involved in reaching commercial scale deployment. Not only is reaching this scale going to be a large step in this technologies' development, but the benefits of learning and economies of scale as more farms are installed will help the technology become more competitive with other renewable energy sources.

6.9.2 Marine Current Resource

In 2004, Black & Veatch completed the Global, Europe and UK Marine Current Resource assessment for the Carbon Trust, a UK Government funded body which is tasked with reducing carbon emissions in the UK. The information was gathered from publicly available sources with the intention of collating the information to provide a common method for estimating tidal resource. The methods and the sites assessed were, however, highly variable, and Black & Veatch concluded that developing a standard method was more practical, and more accurate. This method of assessment, described as the flux method of assessment, is used as a check to ensure that a tidal farm in a channel will only extract energy to a level which will not cause environmental deterioration or be economically detrimental to the project. It is considered by experts in the industry to be the most accurate method available to date[40]. Ideally, the maximum extractable energy would be estimated for each area being studied. This allows you to determine what percentage of the energy flux can be extracted without causing environmental or economic impacts to the project. This is known as the Significant Impact Factor (SIF). Although this factor is completely site specific, 20 percent can be used to give a reasonable starting indication as to the level of resource that may be extracted from the available resource. This should always be considered in conjunction with a farm assessment which uses the performance of a specific technology in the given area, which can potentially overestimate the extractable resource. The lower of the two estimates (SIF altered Flux and Farm) is therefore taken.

The global resource has not been assessed in detail; therefore, there is a high variance in the data that is available for the West Coast of the United States and Canada. The results of the present literature study are presented in Table 6-43 below, and are believed at this time to represent the best data on the available tidal resource in North America and Canada. An entire assessment of the coastline has not been completed; however, the most attractive sites have most probably been assessed in British Columbia, California, Oregon and Washington. No information was obtained on Baja California resource.

British Columbia Marine Current Potential

The data for the Canadian West Coast, in particular British Columbia, was taken from Triton Consultants report[41] which was compiled in 2006. The report is clear to state that the potential available resource only has been provided. The method used was a flux assessment. The width and depth of each study area, along with the instantaneous velocity across the front cross section, was averaged over a year to obtain the average energy available at each site. The factors that were not considered include environmental impacts, limitations in tidal power extraction, or any location or economic considerations.

[40] University of Edinburgh, Professor Ian Bryden
[41] Canada Ocean Energy Atlas; Potential Tidal Current Energy Resources, Triton, 2006

The total potential resource for British Columbia was estimated as 4,015 MW. The majority of this resource is predicted to be found around Vancouver Island, for which the total potential available energy is 3,850 MW. Those sites in British Columbia which were included in the top 50 Canadian potential marine current sites are included in Table 6-43 below along with the estimated regional totals. All but one of the individual sites from British Columbia in the top 50 are located around Vancouver Island, the single site which is not is on the Pacific mainland coast.

American West Coast Marine Current Potential

The study completed by EPRI in 2006[42] summarizes all their assessments completed in North America on marine current resource, which included Washington (Tacoma Narrows, 100 MW), and California (San Francisco Bay, 237 MW*). Marine current resource assessments have not been completed in Oregon and therefore no data can be presented. There are known tidal currents in many more areas along the West Coast; however, at this stage further resource assessments would be required to estimate the total potential. EPRI have stated that the overall marine current resource in the USA is lower than that in Canada; however, there are some key sites which could be feasible and economic in the future and therefore should be included in future energy planning.

6.9.3 Extractable Resource

As the overall area of each site is not included in the EPRI assessment, Black & Veatch is unable to determine the maximum extractable energy by a particular technology (i.e. by considering the limitations of device extraction and spacing in the farm assessment). Black & Veatch have therefore considered, in line with EPRI studies, that 15 percent of the available energy provides an average extractable resource for each area. The results are included in Table 6-43 below.

To determine the potential installed capacity of the areas, and thus the likelihood of installation in the future, the FERC applications have been reviewed in the next section. The applications, however, include an assumed rated capacity of the installed farm, not the level of energy that would be extracted. Thus to ensure we are comparing like for like, the equivalent electrical rating has been established by estimating the rated mechanical power and assuming a capacity factor of 35 percent to determine the mean mechanical power which impacts energy extraction. See Table 6-43 below.

[42] EPRI-TP-008-NA North America Tidal Instream Energy Conversion Technology Feasibility Study

Table 6-43. West Coast Tidal Resource of North America and Canada

Location	Available Resource (1) MW	Extractable Resource (Black & Veatch) MW	Rated Electrical (Black & Veatch) MW
British Columbia	4,015	602	1463
(Vancouver Island Total)	3,580	537	1304
Seymour narrows	786	118	286
Northern Boundary Pas.	366	55	133
Discovery Pass S	327	49	119
Boundary Pas.	265	40	97
Current Passage 2	208	31	76
Weyton Pas	200	30	73
Current Passage 1	139	21	51
Dent Rapids	133	20	48
South Pender Is	101	15	37
Yaculta Rapids	94	14	34
Arran Rapids	89	13	32
Secheldt Rapids 2	76	11	28
Gillard Passage 1	52	8	19
Scott Channel	51	8	19
Active Pass	50	8	18
Nahwittis	45	7	16
Nakwakto Rapids	164	25	60
Washington	100	15	36
Oregon	Not available		
California	237	36	86
TOTAL	4352	870.4	2114
Source: North America In Stream Tidal Power Feasibility Study; Final Briefing, EPRI			

6.9.4 Future of Marine Current Installation on North America's West Coast

There are many developers worldwide seeking the most commercially competitive technology; however, to date there has been a limited number of commercial scale tidal stream technologies installed in the offshore environment. This is expected to change in 2009 when at least four further technologies are expected to be installed at commercial scale in a number of locations around the world, including the European Marine Energy Centre (EMEC) in Orkney, Scotland. The increase in developers ready for commercial scale installation is promising in terms of the speed of development of the industry.

There have been numerous applications to FERC for preliminary permits for tidal stream development off the West Coast. There are companies which are developing technology quickly as the industry has increasingly gained support in terms of funding and investment, and there are those who have been developing for many years. Either way, there is still a minimum time until commercial projects can be installed due to licensing and environmental assessments that must be approved.

Permits and Licensing in British Columbia

All applications for investigative use permits, which allow a two year period of environmental and engineering testing before a full license is applied for by developers, are issued through the British Columbia Government.

BC Tidal Energy Corp has been offered a permit from the BC Government. Another company under the name BC Ltd has applied for 23 permits which have been offered; however, all of these are under the ‘Ocean Energy’ title and therefore without further investigation it is presently unclear as to whether these are wave or tidal projects. A further three applications are under review at this stage for BC Tidal Energy Corp, Canoe Pass Tidal Energy Corp, and finally Canada Tidal Ltd.

It is unlikely that the permits mentioned here would come close to a fraction of the resource available in British Columbia, and in particular the Vancouver Island area.

Permits and Licensing in America

Permits and licenses for the development of tidal stream technology (and wave energy converters) are issued by FERC under the Hydrokinetic licensing department.

A full development license from FERC is required to actually construct and install any commercial project; however, it is possible to reserve the first right to apply for a license by obtaining a preliminary permit. The preliminary permit literally reserves a particular area, for up to 3 years, which may be under consideration for development. The 3 years allows the developer time to carry out environmental and engineering assessments to enable them to gather all the relevant information to apply for a license. FERC have recently implemented a strict scrutiny for preliminary permits, for which developers must submit an update report every six months. The licensing process has been criticized as causing a delay in this new industry and thus, in order to support this young industry, FERC have developed a Pilot License which allows developers to install a device for testing commercial scale devices which allows grid connection (in addition to obtaining revenue from the generation). This type of testing and evaluation is the final step in proving a technology and vital in the move to commercial projects. The conditions for pilot license are:

- Projects are under 5 MW
- Maximum 5 year installation
- Not available in areas where environmental designations exist
- Applications must be supported by sufficient environmental analysis
- Any installation is subject to environmental and other safeguards
- The project must be decommissioned

Further information on permits and licenses can be found in the report completed for EPRI by Devine Tarbell Associates "Instream Tidal Power in North America; Environmental and Permitting Issues", 2006.

Currently no licenses for commercial development have been issued by FERC for tidal stream development in Washington, California, or Oregon. There are however 12 preliminary permits which have been issued in the study area and these are provided in Table 6-44 below, along with the capacity for which the permit was granted. The total capacity is 46 MW (CA: 8.6 MW, WA: 36.75 MW, OR: 7 MW). Further site assessments throughout the permit phase for these projects will confirm the potential installed capacity. There are currently no pending permits for marine current developments in the study area.

Table 6-44. Issued Preliminary Permits.

FERC Ref	Project Name	Permittee	Waterway	State	Proposed Cap (kW)	Issuance Date	Expiration Date
12805	Pit 3 Streamflow Generation	Pacific Gas And Electric Co	Pit River	CA	2800	12/12/2007	30/09/2010
13049	Rock Creek Streamflow	Pacific Gas And Electric Co	North Fork Feather River	CA	3600	13/02/2008	31/01/2011
13059	Pit 4 Dam Streamflow	Pacific Gas And Electric Co	Pit River	CA	2200	15/02/2007	31/01/2011
12687	Deception Pass Tidal Energy	Pud No 1 Of Snohomish County (Wa)	Pugent Sound	WA	2800	01/03/2007	28/02/2010
12688	Rich Passage Tidal Energy	Pud No 1 Of Snohomish County (Wa)	Pugent Sound	WA	1400	22/02/2007	31/01/2010
12689	Speiden Channel Tidal Energy	Pud No 1 Of Snohomish County (Wa)	Speiden Channel	WA	8300	22/02/2007	31/01/2010
12690	Admirality Inlet Tidal Energy	Pud No 1 Of Snohomish County (Wa)	Pugent Sound	WA	22100	09/03/2007	28/02/2010
12691	Agate Passage Tidal Energy	Pud No 1 Of Snohomish County (Wa)	Pugent Sound	WA	500	22/02/2007	31/01/2010
12638	Esquatzel Power	Green Energy Today, Llc.	Esquatzel Canal & Columbia River	WA	900	09/06/2006	31/05/2009
12612	Narrows Tidal Energy	Tacoma Power	Pugent Sound	WA	750	22/02/2006	31/01/2009
12672	Columbia Tidal Energy	Oregon Tidal Energy Company	Pacific Ocean	OR	200	23/03/2007	28/02/2010
12585	San Francisco Bay Tidal Energy Proj	Golden Gate Energy Company	San Francisco Bay	DC (OR)	500	11/10/2005	30/09/2008
Total					46,050		

Source: FERC.

6.9.5 Development Timescale

The projects which currently have permits are the most likely to be the initial commercial scale projects seen in North America and Canada, because they have not only reserved the site but are actively developing and working towards an installation, and they have started the permitting process.

Based on the worst case scenario that each of these projects applies for the construction license in the final year of the preliminary permit, these projects will be starting the license process when the permits expire (see table above for dates). The FERC has recently issued a construction license for the first wave farm (this is discussed in the next section), and this license took 18 months to be finalized. Therefore it is sensible to assume that post expiration of the permit there would be a further 18 months until any form of manufacturing/construction starts. The readiness of the developer for the construction and installation process will then impact heavily on time to installation.

There are currently no pending marine current permit applications in the study area (including BC); therefore a conservative estimate for the future number of yearly applications (based on one in 2006 and eight in 2007) is taken as 4 per year each for 10 MW, increasing to 25 MW per year after 2015. Figure 6-24 below indicates that there will be a dip in installation in 2014 and 2015 if there are not further applications made in the near future. This estimation is conservative because there are no pending permits; however, the trend of issued permits has seen a substantial increase in both British Columbia and the West Coast. It is likely that there will be a steady increase in applications.

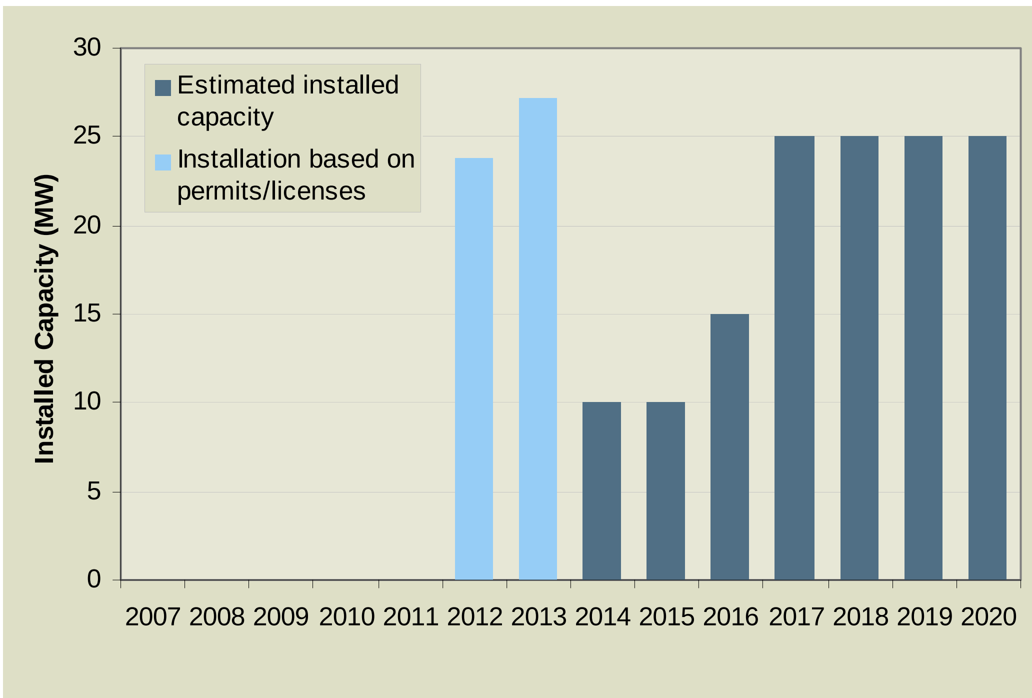


Figure 6-24. Estimation of Installed Capacity Based on Permits and Licenses.

6.9.6 Marine Current Summary and Recommendations

The marine current resource in the RETI study region has been identified as being relatively small in the US but considerable in British Columbia. There is active development underway in the US and British Columbia at several sites although at this early stage in the technological development of tidal stream technology this is comparatively small. From the permits and licenses that are currently issued and pending, it is likely that the first farms will be installed around 2012 unless a particular developer either applies directly for a construction license, or if the investigative permitting phase is considerably shorter than the maximum three years.

British Columbia presents the most exciting opportunity in terms of marine current exploitation with tidal stream technology; however, in terms of electrical connection, it is remote.

Given the developmental state of the technology and the uncertainty in timing of commercial installations, Black & Veatch recommends that marine current consideration not be carried forward to Phase 1B. Black & Veatch further recommends that the resource and development of the industry be re-assessed as new developments happen.

6.9.7 Data Sources

1. Instream Tidal Power in North America; Environmental and Permitting Issues, 2006, EPRI Devine Tarbell Associates www.epri.com/oceanenergy
2. EPRI TISEC Resource/Device Performance Estimation Methodology, www.epri.com/oceanenergy
3. EPRI Washington System Level Design Study, www.epri.com/oceanenergy
4. EPRI California System Level Design Study, www.epri.com/oceanenergy
5. EPRI Tidal Energy; Final Summary Report, www.epri.com/oceanenergy
6. EPRI North America Tidal Instream Energy Conversion Technology Feasibility Study , 2005
7. Canada Ocean Energy Atlas Potential Tidal Current Energy Resources, Triton, 2006

6.10 Wave

This report discusses via a literature review what resource is available for wave energy extraction using wave energy converter (WEC) technology and the subsequent estimated levels of extractable energy.

Today the commercialization of technologies to generate electricity from wave energy is driven by companies that are either generating investment from private industry, utilities and venture capital or are backed by government funding through various R&D schemes. An introduction to the technology was provided previously in the technology overview section of this report.

6.10.1 Methodology

The methodology for wave energy assessment is similar to the tidal stream resource review, because the technology is still in an early stage of development.

Therefore, the wave energy resource along the West Coast of North America, in particular within the boundaries of British Columbia, Baja California, California, Oregon, and Washington, has been reviewed through a literature study. However, this information is of limited use to RETI because the technology is not commercially ready enough to exploit this resource immediately. The development timescales (and associated permits/licenses) involved in reaching commercial scale deployment will therefore be considered to give an indication of the potential installation capacity up until 2020. Not only is reaching commercial scale going to be a large step in this technologies' development, but the benefits of learning and economies of scale as more farms are installed will help the technology become more competitive with other renewable energy sources.

In order to inform RETI of the potential contribution of wave energy to the renewable energy mix, the roadmap to commercialization and competitive cost of energy in relation to other renewable energy sources, resource availability and the extractable portion of that available energy, and the time taken to reach large scale installation, are all discussed in this section. Due to the nature of wave resource, only the coastal states have been included where data has been available (no data for Baja California was sourced).

6.10.2 Wave Energy Resource

The California Ocean Wave Energy Assessment states that "the worldwide coastal potential is estimated to be approximately 2 TW". As 37 percent of the world's population lives within 60 miles of a coast the development of some of that renewable resource seems sensible. The attractive wave energy resource on the West Coast of North America is considerably more abundant than marine current; this is due to the open Pacific Ocean which provides ocean waves with a long fetch, and there is also a steep drop-off along the continental shelf.

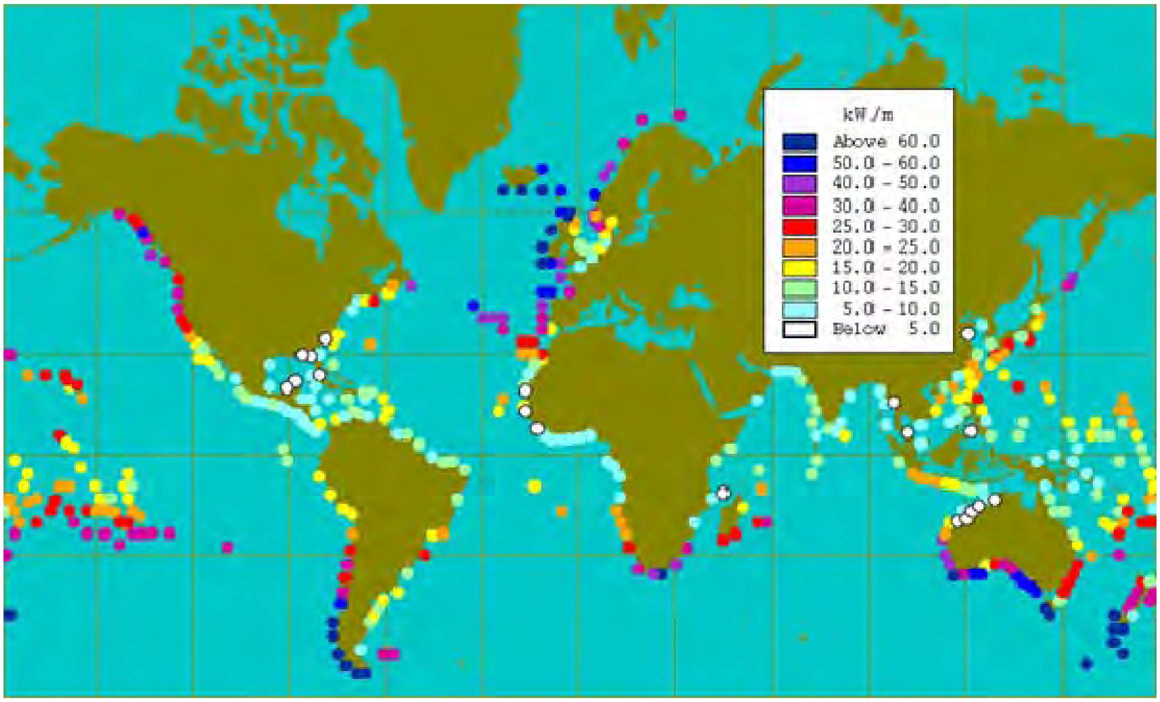


Figure 6-25. Global Wave Energy Potential. Source: EPRI.

6.10.3 British Columbia Wave Energy Potential

British Columbia Hydro carried out an assessment on Green Energy for British Columbia in 2001[43] which included an assessment of potential wave energy. It was estimated that 2 GW of wave energy could be available on the West Coast, and in particular two sites, each of approximately 200 MW, around Vancouver Island were identified. The whole resource for British Columbia is likely to be considerably higher than this; however, this study did not assess the inaccessible sites further north. This is available energy and the rated energy, which is equivalent to the installed capacity, is included in the summary table later in this section.

6.10.4 California Wave Energy Potential

The California coast line extends 1,200 km down the east side of the Pacific Ocean. A full study into the California Wave Resource was commissioned by the California Energy Commission, under its Public Interest Energy Research (PIER) program in order to establish the potential of utilizing the clean supply of energy. The data presented in Table 6-45 below are the results of the study showing the available

[43] Executive Report on the Green Energy Study for British Columbia; Phase 1: Vancouver Island, BCHydro 2001.

energy at each site and in total. In total, approximately 37,000 MW of wave energy is available along the Californian coast.

Table 6-45. Extractable Primary Wave Resource Estimate.

	Energy Flux	Primary Sites		Secondary Sites	
	kW/m	km	MW	km	MW
San Diego	32.18	-		162	5213
Los Angeles	32.18	35	1126	104	3347
Santa Barbara	26.43	127	3357		
Monterey	29.65	-		127	3766
Santa Cruz	28.03	-		127	2838
San Francisco	30.26	104	3147	18	545
Sonoma	32.18	127	4087		
Mendocino	28.53	130	3709		
Humboldt	33.72	116	3910		
Del Norte	27.81	81	2253		
TOTAL (MW)		**720**	**21,589**	**538**	**15,709**

6.10.5 Oregon Wave Energy Potential

Oregon has developed a number of organizations to ensure that it is recognized around the world as having an excellent wave energy resource and is interested in building a future industry for the region. The success of this strategy, combined with their good wave resource, is highlighted because three out of the four preliminary permits (issued as of March 2008) have been issued for testing and preliminary site investigation in Oregon. This includes Finavera's permit for a potential 200 MW farm at Coos County (it is important to note that the potential installed capacity will not be confirmed until further studies have been completed).

The aim of the EPRI study Survey and Characterization of Potential Offshore Wave Energy Sites in Oregon was to determine if it was feasible to install a 500 kW demonstration project and grow that to a 100 MW commercial farm. A number of potential sites (see Figure 6-24 below) were studied, and the potential barriers including environmental designations and grid connection were included to give a clear indication as to the feasibility. The study concluded that both scenarios would be possible. The power density provided has been used in this review by Black & Veatch to estimate the overall potential resource available. The coastline of Oregon is 476 km long. The power density along the coastline (at 10 m depth) is relatively constant at 20 kW/m except for three small dips in the density (the first is caused by a shadow of Port Orford, the other two are not understood by EPRI), therefore 19.5 kW/m has been taken to represent the whole coastline. The power density in the deep water off the continental shelf is between 42-48 kW/m.

Therefore the total available energy for primary sites (closest to shore) is 9,000 MW. Secondary sites could provide an additional 20,000 MW of available energy.

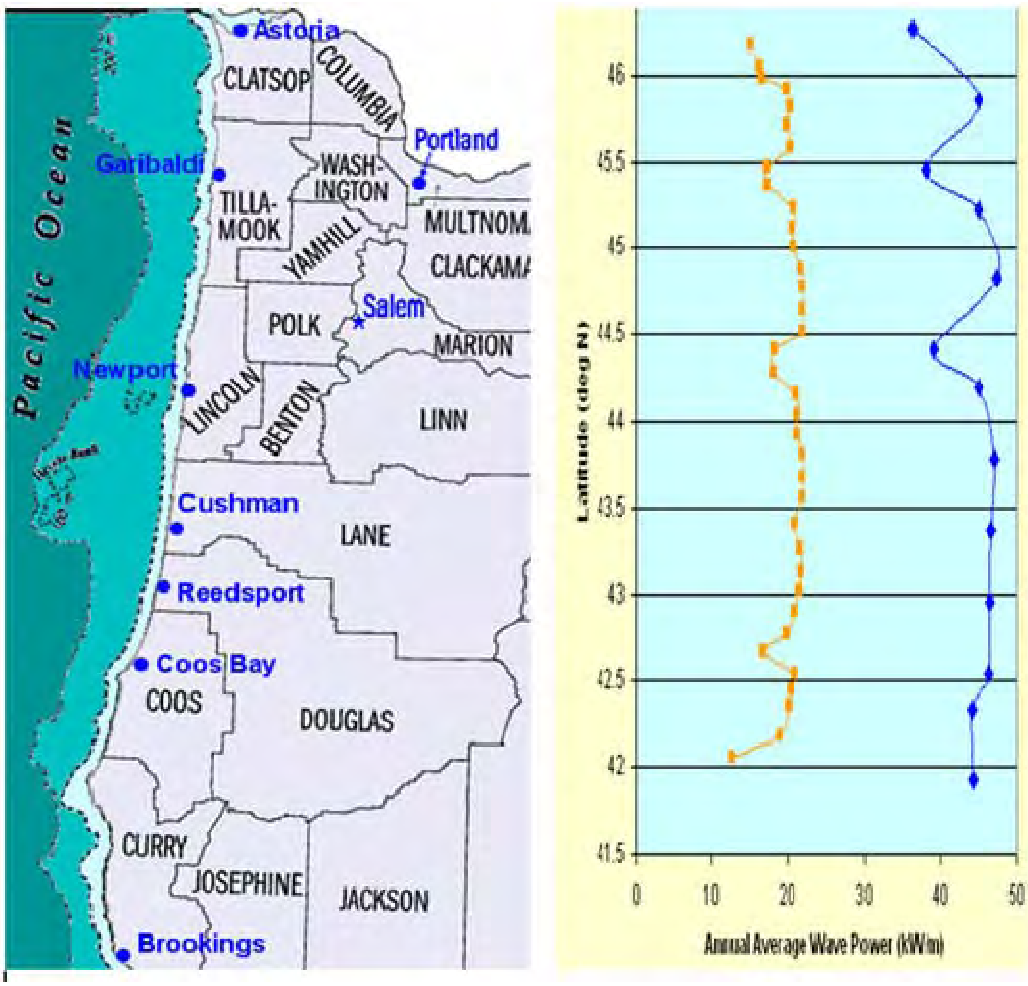


Figure 6 3. Oregon Wave Energy Sites and Coast line Energy Density (source: EPRI).

6.10.6 Washington Wave Energy Potential

In an equivalent study to that completed for Oregon, the feasibility for a 500 kW and 100 MW wave farm was carried out in Washington. Four sites were assessed, the individual site feasibility in terms of power density, bathymetry, and site characteristics were studied, followed by an overview of conflicting constraints (for example environmental designations and shipping), and finally the potential grid connection.

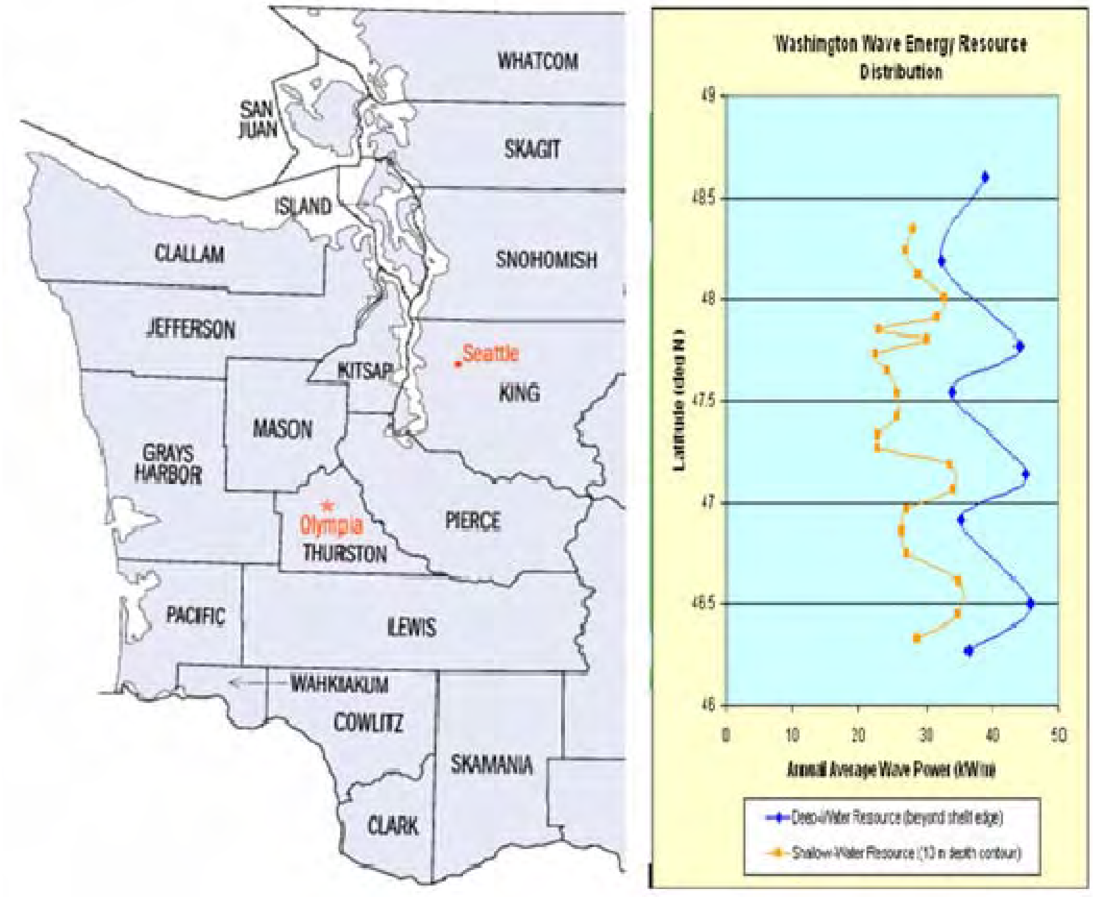


Figure 6 4. Washington Wave Energy Sites and Coast Line Energy Density (source: EPRI).

The wave resource in the shallow water is on average more than that in Oregon; however, the deep water resource is approximately the same although the lows in Washington drop to 38 kW/m. Black & Veatch have assumed that the primary sites would be those closest to shore, and therefore the total available energy taking a coastal average power density of 30 kW/m and a distance of 250 km, is 7,500 MW (secondary sites, at 40 kW/m would add an additional 10,000 MW).

6.10.7 Wave Energy Resource Summary

The extractable resource has been calculated in the tables below. The PIER report carries out a similar assessment to estimate extractable wave resource by considering the efficiency of the WEC, and the availability. EPRI has previously assessed the West Coast of North America; however, individual sites in California were not reviewed as they have been in the PIER study and therefore the EPRI result is higher. The resource is presented in the Table 6-46 for primary sites, and Table 6-47 for the secondary sites. This demonstrates that there is a considerable resource that California could exploit once the technology is commercially ready.

Table 6-46. Extractable Primary Wave Resource Estimate in the RETI Region.

	BC	CA	OR	WA
Available Energy (MW)	2000	21500	9280	7500
Directionality factor	0.76	0.76	0.76	0.76
Spacing factor	0.75	0.75	0.75	0.75
Absorption efficiency	40%	40%	40%	40%
Conversion efficiency	50%	50%	50%	50%
Annual Average Grid Power (MW)	228	2450	1057	855
Equiv. AAE (TWh/year)	2	22	9	8
Rated Capacity (MW)*	760	8,166	3,523	2,850
TOTAL Installed Capacity (MW)	15,299			

Notes:
* Rated capacity has been calculated assuming a 30% capacity factor.

Table 6-47. Extractable Secondary Wave Resource Estimate in the RETI Region.

	BC	CA	OR	WA
Available Energy (MW)	Un-known	15500	20000	10000
Directionality factor		0.76	0.76	0.76
Spacing factor		0.75	0.75	0.75
Absorption efficiency		40%	40%	40%
Conversion efficiency		50%	50%	50%
Annual Average Grid Power (MW)		1767	2280	1140
Equiv. AAE (TWh/year)		16	20	10
Rated Capacity (MW)*		5,890	7,600	3,800
TOTAL Installed Capacity (MW)	17,290**			

Notes:
* Rated capacity has been calculated assuming a 30% capacity factor.
** This excludes the secondary resource in BC.

6.10.8 Wave Energy Converter Development

As discussed in the technology section, there are over 100 patents for WEC technology. There are a number of leaders in the field who are testing commercial scale technology including Pelamis, OPT, Finavera, WaveDragon, Limpet, and Energetech.

Many previous reports have established that there is plentiful available resource, and this report has summarized that there is 45 TWh/y of extractable wave energy on the West Coast of North America.

Offshore wave energy installations are subject to the same licensing laws as marine current developments, therefore this information will not be repeated in detail here. The pending and issued permits and licensing issues are described below.

Permits and Licensing in British Columbia

The British Columbia Government has issued two Investigative Use Permits for wave energy development for Finavera Renewables and SyncWave. In addition, a portion of the 23 permits issued to BC Ltd for investigative works (described in Marine Current Section) may be related to wave; however, as previously mentioned the applications do not all specify which technology is intended. Each of these permits is however for the Vancouver Island area, which is where the most attractive resource has been identified.

Permits and Licensing in America

FERC issued their first license for the development of an offshore marine energy installation to Finavera Renewables in December 2007. It is for the offshore wave energy pilot project at Makah Bay, Washington. As this is a pilot project, a maximum of 5 MW is permitted. This license was applied for in June 2006; therefore it took 18 months to obtain.

There are four permits which have been issued for preliminary investigation and prioritization of a site for license application. Three are in Oregon and total a potential 350 MW installed capacity. The final permit is issued in Washington for Finavera Renewables which is 200 MW potential installed capacity. It is unlikely that the full potential will be realized due to site specific constraints; however, it is not possible at this time to estimate what size of commercial farms would be installed. It is highly likely nevertheless that these companies will make use of the Pilot License and install 5 MW relatively quickly, followed by extension to a commercial scale farm. Table 6-48 lists the issued permits, and Table 6-49 lists the permits which are pending. Interestingly, although there are currently a lower number of wave permits overall, there is considerably more pending permits for wave energy. There are 12 applications for sites in CA, OR and WA.

The Minerals Management Service (MMS) in the US is the federal agency who has the authority to issue leases for investigative testing in the Outer Continental Shelf region. This is the region beyond the 3 nautical mile limit which is the individual state's responsibility. The MMS will therefore issue all permits out to 200 nautical miles. The MMS has recently received an influx of permit applications for various marine projects; the majority for offshore wind projects; however there have been numerous applications for wave projects off the CA, OR and WA coasts. Although the applications have been received there is no information available at this time on the individual developers/companies who have applied, or for what estimated generating capacity.

Table 6-48. Issued Preliminary Wave Energy Permits

Project Name	Permittee	Waterway	State	Proposed Cap (MW)	Issuance Date	Expiration Date
Reedsport Opt Wave Park	Reedsport Opt Wave Park, Llc.	Pacific Ocean	OR	50	16/02/2007	01/31/2010
Coos County Offshore Wave Energy	Finavera Renewables Ocean Energy	Pacific Ocean	OR	200	26/04/2007	03/31/2010
Coosbay OPT Wave Park	OREGON WAVE ENERGY PARK PARTNERS	Pacific Ocean	OR	100	09/03/2007	02/28/2010
Humboldt County Offshore Wave	Finavera Renewables Ocean Energy	Pacific Ocean	WA	200	14/02/2008	01/31/2011
Source: FERC						

Table 6-49. Pending Preliminary Wave Energy Permits				
Project Name	**Permittee**	**Waterway**	**State**	**App Date**
Sonoma coast Hydrokinetic Energy	Pacific Ocean	CA	Sonoma County Water Agency	11/15/2007
Centerville OPT Wave Energy Park	Pacific Ocean	CA	California Wave Energy Partners, LLC	11/09/2007
Green Wave Mendocino Wave Park	Pacific Ocean	CA	Green Wave Energy Solutions, LLC	10/19/2007
Green Wave San Luis Obispo Wave Park	Pacific Ocean	CA	Green Wave Energy Solutions, LLC	10/19/2007
Fairhaven Wave Power Station	Pacific Ocean	CA	Fairhaven O.P.T. Ocean Power	2/28/2007
Mendocino County WaveConnect	Pacific Ocean	CA	PG & E	2/27/2007
Humboldt County WaveConnect	Pacific Ocean	CA	PG & E	2/27/2007
Oregon Coastal Wave Energy	Pacific Ocean	OR	Tillamook Intergovernmental Development Entity	10/01/2007
Florence Oregon Ocean Wave Energy Project	Pacific Ocean	OR	Energetech	4/16/2007
Newport OPT Wave Park	Pacific Ocean	OR	Oregon Wave Energy Partners II, LLC	11/02/2006
Lincoln County Wave Energy	Pacific Ocean	OR	Lincoln County, Oregon	8/17/2006
Grays Harbor Ocean Energy and Coastal Protection	Gray Harbor and	WA	Washington Wave Company, LLC	11/05/2007
Source: FERC				

6.10.9 Development Timescale

Current installations focus around prototype and commercial scale prototype testing, although Pelamis Wave Power have now installed their second 750 kW commercial scale device in Portugal. There will be an increase in the number of developers installing full scale devices over the next couple of years which will increase the early installed capacity. There are numerous plans across the industry to install full scale devices during 2008, although the majority of the installations are planned for test centers; Black & Veatch have estimated the total to be approximately 8 MW around the world.

Now that Finavera Renewables have obtained a license for Makah Bay, Washington, we are also likely to see the commencement of construction for that project. This will initially be 4 devices with a combined installed capacity of 1 MW, which could increase to 5 MW. Figure 6-26 is a graph which gives an indication of what the installed capacity up until 2020 could be, based on the issued and pending permits and licenses, and a steady state of applications and licenses being issued up until 2020. It is likely that there will be an increase in applications for permits and licenses; however, for this assessment Black & Veatch have assumed that there are 5 additional applications each year of 50 MW throughout the study area. This is a conservative estimation. In addition, the full installed capacity that the permits are issued for may not be realized due to complications and constraints at individual sites, therefore a 50 percent reduction to the application capacity has been included. Where a permit for a farm of 50 MW or more has been applied for, it is assumed that when construction commences the project will be installed in phases starting with 25 MW in the first and second years, 50 MW in the third year and 100 MW after that. In reality, it will be dependent on whether a pilot farm has been previously installed, because the initial installation could be considerably smaller than 25 MW. Likewise in the future once the industry has gained confidence, large 50 MW+ farms may be installed in one phase.

Figure 6-26 gives an indication as to how the installation of wave energy devices could occur up until 2020. There is a clear gap in 2010 and 2011. During 2008 and 2009 there are plans for prototype installations, however there will no doubt be more developers that are ready for full scale installation during 2010-2011. Black & Veatch however believe that the earliest a large commercial farm will be installed is 2012.

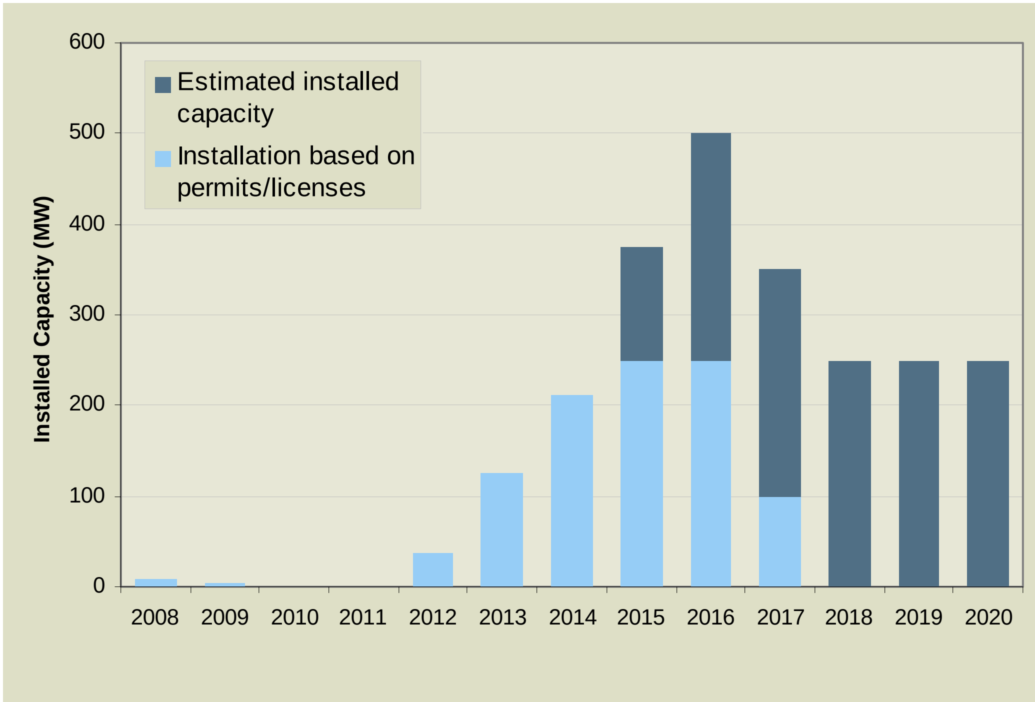


Figure 6-26. Estimated Installed Capacity Based on Permitting and Licenses.

The Future Marine Energy report, completed as part of the Marine Energy Challenge conducted by the Carbon Trust in the UK estimated that there would be 1 – 2.5 GW of installed capacity by 2020 in Europe. Given the size of the resource available on the West Coast the estimations presented here are therefore sensible; however the capacity for design, construction and installation could potentially cause delay.

The cost of energy will depend heavily on the type of technology installed and therefore the current cost of energy and the learning rate that can be achieved. If a 15 percent learning rate is experienced then the cost of energy after 1 GW of installed capacity may be 10-15 cents/kWh (based on the findings from the Future Marine Energy report).

6.10.10 Summary and Recommendations

This review has identified that there is considerable resource available for wave energy converters in the RETI region, for both primary site and secondary sites which would not be developed until the technology is relatively mature. Developers are nevertheless focusing on the prize of the larger resource areas and high power density further offshore because there has already been a number of enquiries to the MMS for wave development permits.

The technology is still at an early stage of development in comparison to more established renewable energy sources. Black & Veatch feels nevertheless that in four years time a number of technologies may be commercially ready, and therefore the RETI region may experience its first wave farms. The current EPRI assessments and feasibility studies have identified a number of locations from which the current grid network is accessible. Those areas with combined resource potential are likely to be where the first farm installations are made.

Given the developmental state of the technology and the uncertainty in timing of commercial installations, Black & Veatch recommends that more detailed evaluation of wave energy not be carried forward to Phase 1B. Black & Veatch further recommends that the resource and development of the industry be re-assessed as new developments happen.

6.10.11 Data Sources

1. Carbon Trust Tidal Stream Resource and Technology Summary Report, and Resource Assessment Report, 2005 http://www.carbontrust.co.uk/technology/technologyaccelerator/tidal_stream.htm
2. EPRI, Survey and Characterization of Potential Offshore Wave Energy Sites in Oregon, 2004 www.epri.com/oceanenergy
3. EPRI, Survey and Characterization of Potential Offshore Wave Energy Sites in Washington, 2004 www.epri.com/oceanenergy
4. EPRI, California Offshore Wave Power Feasibility Demonstration Project, www.epri.com/oceanenergy
5. PIER California small hydropower and ocean wave energy resources, http://www.energy.ca.gov/2005publications/CEC-500-2005-074/CEC-500-2005-074.PDF

6.11 Summary

Table 4-1. shows the summary of the technical potential for each resource across the RETI study region.

Table 6-50. Renewable Energy Technical Potential in RETI Study Region (MW).

	AZ	Baja	BC	CA	NV	OR	WA	Total
Biomass	180	N/A	2,560	4,160	42	425	1,615	8,982
Anaer. Dig.	8-18	N/A	60	85-293	0	10-13	18-203	181-587
Landfill Gas	10	N/A	22	139	6	23	17	217
Solar Thermal	316,628	N/A	0	443,799	172,181	0	0	932,608
Solar PV	N/A	N/A	N/A	*17 million*	N/A	N/A	N/A	*17 million*
Hydro	0	0	162	231	0	66	244	703
Wind	2,553	1,800	4,790	21,099	6,178	7,226	9,544	53,190
Geothermal	50	80	610	2,375	1,488	380	50	5,033
Wave	0	N/A	760	8,166	0	3,523	2,850	15,299
Marine Current			1,436	86		N/A	36	2,114

Sources: see individual report sections

Notes:

The estimates of technical potential are based on the following constraints, described in the Resource Screening section of the report.

- Solar Thermal Class 1 and higher resources, slope < 1 percent
- Solar PV Only California resources
- Hydro Projects >10 MW and <30 MW
- Wind Class 4 and higher resources
- Wave Primary sites, rated capacity

Based on the resource and technology assessments performed, Black & Veatch has developed a set of recommendations as to the resources that should be considered in Phase 1B. The determination of whether to include a resource and technology in Phase 1B was based on several factors including: likely ability of the resource to contribute to California RPS requirements due total resource potential, ability to cost-effectively deliver the resource to the California grid, and technology maturity. Based on these assessments, resources with limited potential to provide energy to California are eliminated from further review in Phase 1B. While there may be discrete resources in these regions that might provide energy to California, there are not sufficient resources in these areas to merit exploring potential new transmission to access these resources.

Each resource is discussed in more detail below.

Biomass - resources were identified in all states and regions, with California and the Pacific Northwest having substantial biomass resource potential. Based on the potential to meaningfully contribute to California's requirements RETI recommends that biomass resources in California, Oregon, Washington and British Columbia are considered further in the Phase 1B analysis.

Anaerobic Digestion - resources were identified in most areas, though the quantity was limited. Due to the small size and distributed nature of these resources, Black & Veatch does not recommend including anaerobic digestion resources in the Phase 1B analysis.

Landfill Gas – There is limited resource potential for landfill gas to meet the RPS requirements. Similar to anaerobic digestion, due to the small size and distributed nature of these resources, Black & Veatch does not recommend including these resources in the Phase 1B analysis.

Solar Thermal – The solar thermal resource is limited to the Southwest U.S. The resource assessment revealed substantial quantities of developable solar thermal resource. Black & Veatch recommends that solar thermal in California, southern Nevada and western Arizona be included in the Phase 1B analysis.

Solar Photovoltaic – Solar photovoltaic (PV) is unique among renewable technologies, as it can be located almost anywhere, and scaled to virtually any size. RETI Phase 1A identified a virtually unlimited amount of PV potential. For Phase 1B, Black & Veatch recommends incorporating only solar PV located in California as there is sufficient high-quality resource within in California to meet almost any level of demand.

Hydro – the Phase 1A analysis determined there is several hundred MW of potential small-scale (10-30 MW) hydro generation available in California, Oregon, Washington and British Columbia. The sites identified are those with the fewest environmental concerns. This is potential cost-effective and reliable generation that can provide substantial amounts of energy. Black & Veatch recommends that the small hydro resources identified between 10-30 MW be included in the Phase 1B analysis.

Wind – Wind resources were identified in all areas, though the quality of the resource differs widely. Based on the wind quality and accessibility, Black & Veatch recommends that wind be included from all regions except Arizona and northern Nevada.

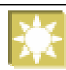
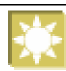
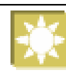
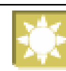
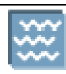
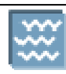
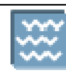
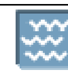
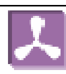
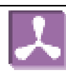
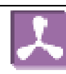
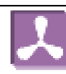
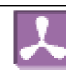
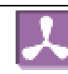
Geothermal - the Phase 1A analysis determined there is substantial geothermal development potential in California, Oregon, Nevada and British Columbia, with limited amounts elsewhere. Like hydro, geothermal has the potential to provide substantial amounts of energy. Black & Veatch recommends that geothermal located in California, Oregon, Nevada and British Columbia should be included in the Phase 1B analysis.

Wave and Marine Current – These technologies offer substantial technical potential but are unlikely to achieve a commercial level of development sufficient to contribute to California's RPS goals within the planning horizon. Black & Veatch recommends that these technologies not be brought into the Phase 1B analysis, but should be monitored for potential future inclusion in the RETI analysis.

The only Baja, Mexico area resource recommended for inclusion in Phase 1B analysis is wind. There is limited information regarding the resource potential in Mexico, but it is unlikely there will be significant renewable development for export, as there are no financial incentives for renewable energy development in Mexico and there is limited transmission between Mexico and California.

Table 1-3 identifies resources that are recommended for consideration in Phase 1B.

Table 6-51. Resource Recommendations for Phase 1B.

	CA	OR	WA	NV	AZ	Baja California, MX	British Columbia, CA
Solid Biomass							
Solar Photovoltaic							
Solar Thermal				 (south)	 (west)		
Small Hydro							
Onshore Wind				 (south)		 (north)	
Geothermal							

7.0 Recommended Phase 1B Scope of Work

Black & Veatch is pleased to provide this draft Scope of Work for RETI Phase 1B. In RETI Phase 1A, an initial resource assessment was conducted to develop a set of potential resources to analyze further. Additionally, the methodology and assumptions required to perform this analysis were identified.

Phase 1B will build on this work, implementing the methodology to develop supply curves of renewable resources and development of Competitive Renewable Energy Zones (CREZ).

The draft RETI Phase 1B Scope of Work includes:

- Project identification and characterization
- Assessment of project costs
- Development of supply curves
- Integration modeling
- CREZ identification
- Final report preparation

Appendix A. Draft RETI Phase 1B Scope of Work

DRAFT

EXHIBIT A, Statement of Work

"Renewable Energy Transmission Initiative, Phase 1:
Identification and Ranking of Competitive Renewable Energy Zones (CREZs)"

PART B: CREZ Identification and Characterization

BACKGROUND

Background and Purpose

California has adopted energy policies that require substantial increases in the generation of electricity from renewable energy resources. Implementation of these policies will require extensive improvements to California's electric transmission infrastructure. The Renewable Energy Transmission Initiative (RETI) is a statewide planning process to identify the transmission projects needed to accommodate these renewable energy goals.

RETI Phase 1 involves a thorough technological assessment of potential renewable resources in California and adjoining states, resulting in the identification of those areas, called Competitive Renewable Energy Zones (CREZs) that hold the greatest potential for cost-effective renewable development. CREZs will be ranked by their cost-effectiveness, based on the supply curves of renewable resources and transmission costs to access each CREZ. To the greatest extent possible and practical, this work will rely on the great body of work that has already been performed to assess renewable energy development potential in California and surrounding areas. RETI Phase 1 will bring together many previously discrete pieces of information to develop a clear picture of a California renewable development pathway, vetted by a public stakeholder process.

The scope of work for Phase 1 has been split into two parts. Part A, to be completed in April 2008, includes:

- Literature review
- Development of base study assumptions
- Development of approach to market valuation, transmission cost assessment, and other concepts
- High-level technology/resource assessment by geographic region
- Screening to identify most viable technology/resources and broad regions for development (e.g., geothermal in northwestern Nevada)

Part B includes:

- Project identification and characterization
- Assessment of project costs
- Development of supply curves
- Integration modeling
- CREZ identification
- Final report preparation

This Work Statement covers Part B of the process.

TECHNICAL SCOPE OF WORK

TASK 1: Renewable Energy Resource Assessment

The Performing Institution shall:

A. Review available renewable energy resource information for the most promising technologies identified in Phase 1A. The assessment will be based on readily available information sources, and will be limited to the following areas and resources:

	CA	OR	WA	NV	AZ	Baja California, MX	British Columbia, CA
Solid Biomass	x	x	x				x
Solar Photovoltaic	x						
Solar Thermal	x			x (south)	x (west)		
Hydropower	x	x	x				x
Onshore Wind	x	x	x	x (south)		x (north)	x
Geothermal	x	x		x			x

B. Collate information on planned and proposed renewable projects that have been announced. Information will be from various sources including the CAISO interconnection queue, CPUC list of contracts, CEC AFC applications, IOUs, Munis, etc.

C. Develop a request for information (RFI) from renewable energy project developers to solicit information on active project developments, including the following:
   1. Technology type
   2. Location
   3. Project status
   4. Expected online date
   5. Capacity
   6. Annual generation
   7. Generation profile
   8. Relevant site-specific cost information that should be considered
   9. Status of transmission studies

D. Evaluate developable potential (MW & GWh/yr) for most promising resources
   1. Collect resource data in GIS compatible form, if available, or other relevant form
   2. Review existing enabling infrastructure (e.g., transmission lines for grid access, roads, roof space, etc.)
   3. Identify resource exclusion zones (national/state parks, high slope areas, military zones, water, wetlands, urban areas, airports, etc.) as applicable by technology
   4. Estimate developable potential (MW and GWh/yr)
      (1) Estimate developable potential of each resource by class (quality, strength, flash/binary, etc.) and/or (as applicable)
      (2) Identify potential (MW and GWh/yr) for specific projects (e.g., hydro upgrade opportunities, landfills)

5. Identify existing or proposed transmission (if available) for facility interconnection.

E. Prepare Resource Supply Tables
   1. Compare information from public sources (B), developer RFI (C) and Black & Veatch resource assessment (D) to eliminate redundancy and check for consistency
   2. Prepare Resource Supply Tables summarizing developable potential by resource class and/or project, as applicable (for example, by class: “Class 4 Wind, 0-5 miles transmission – 200 MW”, “Class 3 Wind, 5-10 miles transmission – 1500 MW”; by project: Coso geothermal flash – 50 MW, Mammoth geothermal air-cooled binary – 30 MW)
   3. Develop estimates of project characteristics (capital cost, O&M cost, capacity factor, fuel cost, transmission interconnection, etc.) for each technology class and/or specific projects
   4. Identify key resource development opportunities and associated time frames. A timeframe (near, mid, long) will be assigned to each project indicating when the project would be available for operation.

F. Define typical production profile (12 months x 24 hours per day) for each resource by region (e.g., Tehachapi wind, Altamont wind, etc.)

Deliverables and Due Dates:

- Request for information for developers
- Preliminary resource supply tables (in Microsoft Excel format) detailing all information discussed above.

TASK 2: Resource Valuation

The Performing Institution shall:

The Performing Institution will implement the methodology for resource valuation adopted in Phase 1A. Areas of valuation are:

A. Cost of generation
   1. Develop, document and present generation cost model
   2. Calculate levelized busbar cost of generation for each technology class and/or specific project (for example, “Class 4 Wind, 0-5 miles transmission – 7.5 cents/kWh”, “Class 3 Wind, 5-10 miles transmission – 9.5 cents/kWh”)

B. Transmission cost: Calculate levelized transmission cost for each technology class and/or specific project. As applicable, transmission costs will be assigned at a conceptual, high level for the following categories:
   1. Interconnection substation
   2. New transmission lines
   3. Trunk-lines
   4. Network upgrades

C. Capacity value: Calculate levelized capacity value for each technology and/or specific project.
   1. Develop typical production profile for each technology and region.
   2. Determine capacity credit as the average capacity factor during noon-6 PM, June-September.
   3. Multiply capacity credit by carrying costs for a simple cycle combustion turbine
   4. Levelize capacity values on a $/MWh basis for each technology and/or specific project
D. Energy value: Calculate levelized energy value for each technology and/or specific project.
   1. Procure zonal energy price forecast from independent provider
   2. Evaluate energy value for each project by combining appropriate production profile per project with energy value forecast by zone
E. Ranking Cost: Calculate ranking cost for each technology and/or specific project. (A+B-C-D)

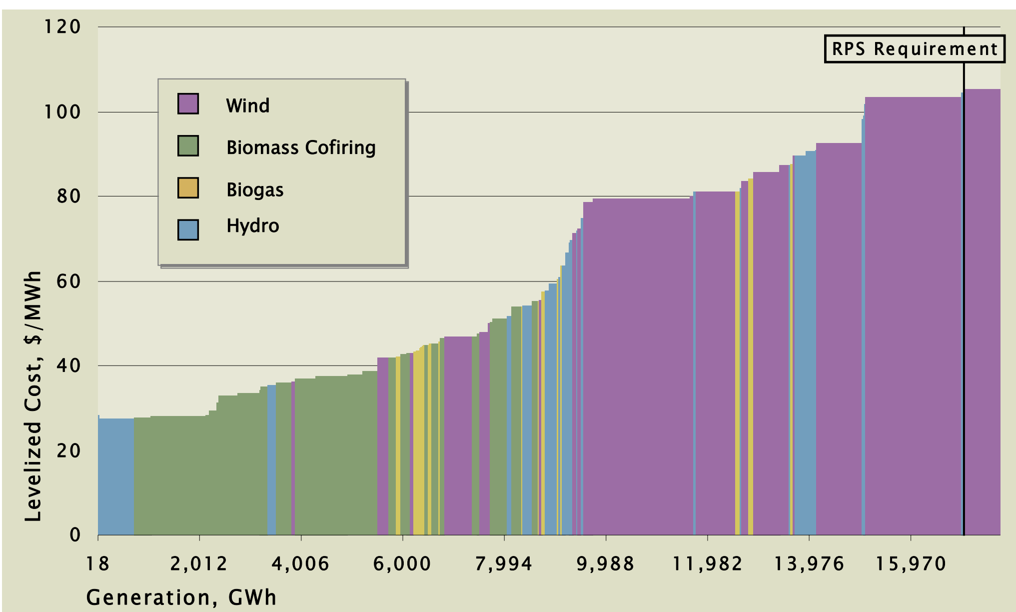
Deliverables and Due Dates:
- Documented resource valuation model for stakeholder review (in Microsoft Excel format)
- Table of cost metrics for all identified projects (in Microsoft Excel format)

TASK 3: Develop Supply Curves and RPS Integration Modeling

The Performing Institution shall:

The Performing Institution will implement the methodology for supply curve creation adopted in Phase 1A.

A. Compare resources on supply curves showing levelized cost and/or ranking cost versus annual energy production (see example)



B. Based on the supply curves and the RPS demand assumptions developed in Phase 1A, develop hypothetical least-cost portfolio of resources and projects to meet the demand in three timeframes: near-term (through 2012), mid-term (2013-2016) and long-term (2017-2020)
C. Supply curves will be developed for each timeframe considering:
   1. The least-cost projects are developed first and can no longer be considered as part of the supply curves for new generation
   2. Minimum project development timelines constrain project development (e.g., not all wind resource could be developed in 2010)
   3. Improvements in technology over time may affect costs (note: no technology improvements assumed in base case)
   4. Timing of development of proposed transmission projects enabling development of new resources
   5. Availability of tax credits and other incentives
D. Summarize Model Results
   1. Levelized cost of energy for each timeframe for each renewable energy technology / project
   2. Supply curves for each renewable energy technology for each timeframe of the model
   3. Aggregated supply curves showing all resources for each timeframe of the model
   4. Projected portfolio mix by timeframe
   5. Summary build-out schedule by timeframe, by technology

Deliverables and Due Dates:
- Draft documented supply curve model (in Microsoft Excel format).
- Draft supply curves (in Microsoft Excel format).
- Draft RPS development model results summary.

TASK 4: Identification of High Priority CREZs

The Performing Institution shall:
A. Rank all projects developed by development timeframe and cost. The ranking will be based on the Ranking Cost.
B. Aggregate project data into CREZs. When identifying a CREZs, the following considerations will be made:
   1. A CREZ will be defined around an existing transmission substation
   2. Need for transmission system upgrades – Projects that do not require upgrades will be included in the overall assessment, but will not be considered as CREZs
   3. Geographical proximity – Projects should be in the same geographic region
   4. Shared transmission constraints – Development of transmission for a CREZ should solve a similar(or the same) transmission constraint for each project

5. Additive economics – Each project, when combined with the others, increases the overall economic benefit of the combination. These smaller clusters will be identified as sub-CREZs. Each CREZ can contain multiple sub-CREZs.
6. Opportunities to use energy storage or combine projects have complementary output profiles (wind and solar in some areas) may be evaluated for special CREZs if initial economic calculations appear promising. This will be done on a case-by-case basis, and only when there appears to be an obvious economic driver.
7. Similar development timeframes: e.g., a resources predicted to be economical in 2010 would not be combined with resources not economic until 2020

C. Composite characteristics for each sub-CREZ and CREZ will be established based on the projects that comprise them. These include:
   1. Total nameplate capacity
   2. General geographic boundaries
   3. Share of each generation type (wind, biomass, etc.)
   4. Annual capacity factor and generation
   5. Generation profile (seasonal and diurnal)
   6. Total capital budget
   7. Operating and maintenance costs
   8. Fuel costs (if applicable)
   9. Development milestones and schedule

D. Rank the sub-CREZs by cost effectiveness. The ranking will be based on the Ranking Cost.

Deliverables and Due Dates:

- Draft list of CREZ rankings including composite CREZ characteristics (in Microsoft Excel format).
- Final Report summarizing and documenting all project activities.
- Final spreadsheet model.

TASK 5: Stakeholder Engagement Outreach

The Performing Institution will work closely with, and be largely directed by, the Stakeholder Steering Committee (SSC). The SSC will meet monthly, and the consultant will report at each meeting as to its work in the past month, soliciting feedback on the analysis completed and advice as to next steps. During the course of Part B, participation in five SSC committee meetings is expected. It has been assumed that Black & Veatch will prepare a presentation for each of these meetings. For the purpose of project budget, these meetings are assumed to be within 100 miles of Walnut Creek, CA.

TASK 6: Project Management

The Performing Institution shall act as Project Manager for Phase 1 of RETI. Responsibilities as Project Manager will include:

- Working with the RETI Stakeholder Steering Committee, CIEE and the CPUC to determine the content, form, and schedule for the stakeholder input that will allow the Performing Institution to complete the tasks outlined in this Work Statement.
- Working with the Center for Energy Efficiency and Renewable Technologies (CEERT) – the RETI Project Facilitator – to ensure that input from SSC is timely and thorough.
- Participating, as needed, in SSC working group meetings to obtain stakeholder input on specific issues.
- Reporting immediately to the SSC and the RETI Coordinating Committee any real or anticipated delays in stakeholder input or completion of tasks outlined in this Work Statement.
- Alerting CIEE and CPUC immediately if schedule of deliverables must be adjusted in order to meet Phase 1 final completion deadline of August 2008.