BC hydro

Integrated Resource Plan

Appendix 5C

U.S. Renewable Energy Credit Markets Report

BUILDING A WORLD OF DIFFERENCE®

BC Hydro

Report on U.S. Renewable Energy Credit (REC) Markets

FINAL REPORT

B&V Project Number: 172047.0300

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1.0 Introduction

The objective of this report is to provide information on the U.S. Renewable Energy Credit (REC) Markets with a focus on the western United States. The report includes an overview of the United States renewable energy market by analyzing some of the key policy drivers for renewable energy development nationally and regionally. One of the main drivers is the establishment of Renewable Energy Portfolio Standards (RPS) in a majority of states. These RPS programs often mandate that electricity providers procure a certain amount of renewable energy to serve their load. National RPS programs have also been contemplated by Congress, though as of March 2011, no legislation has been passed into law yet. An understanding of these existing and future renewable energy regulations will provide the foundation of the outlook for renewable energy markets going forward.

A ***Renewable Energy Credit (REC)*** *refers to the renewable energy attributes associated with the output of a renewable generator, separate from the underlying commodity energy. RECs are also called Green Tags, Renewable Energy Certificates, Portfolio Credits, or Renewable Energy Attributes, amongst other names.*

For this report, Black & Veatch focused on the renewable energy market resulting from existing state RPS requirements in the Western Electricity Coordinating Council (WECC) footprint. Black & Veatch, using its Renewable Energy Market (REM) model and resource data from the Western Renewable Energy Zones (WREZ) project, developed outlooks for Renewable Energy (RE) premiums or implied Renewable Energy Credit (REC) value under five Market Scenarios. This report will discuss the approach taken and ultimate findings.

Following this introduction, the chapters in the report are as follows:

- United States Federal RPS
- Overview of State RPS Programs
- Detailed WECC States RPS Programs
- Overview of Key Factors that influence REC Price
- REM Model
- Scenarios and Assumptions
- REC Prices and Market Markets
- Summary of Findings

2.0 United States Federal RPS

Currently, there is no federal legislation that mandates renewable electricity usage at the national level. Over the past decade, several pieces of legislation have been proposed in the United States (U.S.) House of Representatives and Senate for the establishment of a Federal RPS. Aspects of each piece of proposed legislation have varied considerably, including the targets, timing, eligible resources, efficiency allowances, and alternative compliance payments (ACPs). This section provides insight on recent legislation that has been proposed and the potential for future legislation.

2.1 Proposed Federal RPS Structures

In 2009, H.R. 2454, the American Clean Energy and Security Act of 2009, introduced by Representatives Henry Waxman (D-CA) and Edward Markey (D-MA), received the greatest support of all proposals in the past decade. This piece of legislation was passed by the House in June 2009, although no corresponding legislation was ever passed in the Senate. More recently, Senators Jeff Bingaman (D-NM) and Sam Brownback (R-KS) introduced the Renewable Energy Promotion Act of 2010 (S.3813), which sets less aggressive targets. These two bills are discussed in this section to illustrate some of the common themes in proposed national RPS legislation.

Each bill targets 15 to 20 percent renewable energy–as a point of comparison, the current level of non-hydro renewable energy output in the U.S. totaled about 4 percent of the national supply. The actual amount of renewable energy likely to be implemented by each bill is somewhat lower than the stated target due to energy efficiency program allowances and various exclusions. Key aspects of each bill are highlighted below. The first year that compliance with legislative goals would be required in each is 2012.

Table 2-1 United States Federal RPS Policy Examples.

Bill	Target	Compliance Waivers?	Alternative Compliance Payment	Energy Efficiency Allowance
S.3813	15% by 2021[1]	Yes[2]	2.1 ¢/kWh	26.67%
H.R. 2454	20% by 2020[3]	Very Limited	2.5 ¢/kWh	20%[4]

Notes:
[1] Interim goals: 3% by 2012, 6% by 2014, 9% by 2017, and 12% by 2019
[2] Compliance wavers include a rate impact limit of less than 4 percent per year, transmission constraints, or force majeure.
[3] Interim goals: 6% by 2012, 9.5% by 2014, 13% by 2016, 16.5% by 2018
[4] Could be raised to up to 40 percent with state requests and federal approval.

There are a number of similarities between the bills, as outlined below:

- **Resource Eligibility:** The definition of renewable energy is similar: solar, wind, geothermal, biomass, incremental hydropower,[1] ocean/tidal, and qualified waste-to-energy. With a few exceptions, there are no size limits or in-service date requirements to be considered eligible for most technologies. Hydropower facilities that meet the definition of incremental units are eligible regardless of size. The only exception are facilities in Alaska, where only new facilities smaller than 50 MW are eligible. Efficiency improvements and capacity expansions must have occurred no earlier than 10 to 20 years ago (depending on the bill) on a dam already in operation.
- **Treatment of Certain Non-Eligible Facilities:** Existing hydropower, incremental or new nuclear (depending on the bill), and fossil technology using carbon capture is <u>subtracted</u> from the utility's retail sales when calculating the renewable energy target. The definition of existing hydropower typically means any hydropower not considered "incremental" as defined. Most large hydro units will fall into the existing category and be subtracted from the baseline retail sales for target calculation purposes.

[1] Expansion of existing facilities or addition of power generation on an existing dam previously without power generation

- **Applicable Entities:** Utilities with sales greater than 4 million MWh/year must comply with the RPS requirements.
- **Alternative Compliance Payment (ACP):** An alternative payment option is available for compliance instead of having to procure renewable energy. Money paid under this option typically goes to the state where the utility is located to support local renewable energy programs.
- **Penalties:** The penalty for non-compliance is the same in both bills—200 percent of the value of the alternative payment for every kilowatt-hour short of the goal. That is, if a utility is negligent in meeting their targets or making alternative payments when a shortfall can be foreseen, the penalty is twice the alternative payment for every kilowatt-hour short of compliance.
- **Delivery Requirements and Non-US Imports:** Each bill requires that retail electricity providers obtain electricity or RECs from eligible generation sources. Any qualified renewable energy that is delivered to any entity regulated under these bills could generate RECs. There is no explicit geographic restriction on the location of the generation facilities.
- **Compliance Flexibility:** Under each bill, electricity providers can bank RECs for up to three years but are not allowed to borrow against future generation. Flexibility is also created through a REC trading program and the ability to use alternative compliance payments.

Most proposed federal RPS legislation set up a federal trading system that allows utilities short of their goals to acquire federal RECs from elsewhere in the country. Unbundling of credits from delivered power would be permissible in a federal system. While the rules are not entirely clear, it appears that separate state and federal REC compliance mechanisms have been proposed. That is, a kilowatt-hour of renewable electricity, supplying to states with existing RPS programs, will have both a state and a federal credit associated with it. For states that have a target more stringent than the federal policy, the federal credits generated by meeting state targets could likely be sold to other utilities outside of the state. This mechanism could effectively offset the cost of state RECs for those states that are ahead of the federal targets. Also, Black & Veatch estimates that existing state RPS programs could make up to 8 or 9 percent of national retail sales by 2025, which means that RECs from existing state initiatives could meet around half of the national target if enacted.

There are other variations on the previously discussed structures for RPS legislation that also have been introduced. One is a "Clean Energy Standard" (Senate Bill 20) introduced in September 2010 by Senator Lindsay Graham (R-SC), which allows new nuclear and fossil fuel generation with carbon capture and sequestration (CCS) to count toward defined targets. This approach uses environmental performance, not technology type, as the main qualifier for eligibility, though many of the other aspects of the Clean Energy Standard are similar to the other RPS bills. This bill has a target of 20 percent clean energy by 2020, increasing by 5 percent every 5 years, until 45 percent is reached in 2045. A provision to limit rate impacts, similar to S.3813, is included in this bill.

2.2 Policy Drivers

There are many reasons for the development of a U.S. Federal RPS. One important note is RPS policies serve to bridge the gap between renewable energy options today that may be higher cost relative to conventional generation--which often would not meet utilities' "least-cost" procurement requirements--and future renewable energy options that may be lower cost and are competitive with conventional generation without relying on mandatory RPS programs. Thus, RPS programs will likely not be permanent in the nation's long-term energy policy if renewable energy costs become competitive. In addition, other justifications typically cited for RPS policies are: security, economic, and environmental reasons.

Energy security benefits typically center on "energy independence" by reducing reliance on imported fuels. The major commodities used for power generation in the U.S. that are currently imported in part are natural gas, uranium, and fuel oil from foreign sources of crude oil (see Figure 2-1). Oil boilers represent only 1 percent of total U.S. net electricity generation, making the impact on energy security through reducing oil in the power sector relatively low. This leaves natural gas (23 percent of U.S. electricity production) and nuclear generation (20 percent) as contributors to energy security concern in the power sector. According to the U.S. Department of Energy Information Administration (EIA), the U.S. currently imports roughly 18 percent of its total natural gas demand, with much of that supply being provided from Canadian pipelines–a generally stable source of supply. Roughly 85 percent of the uranium purchased in the U.S. in 2009 came from foreign countries, namely Australia, Canada, Russia, Kazakhstan, Niger, and Namibia. However, due to the baseload nature of nuclear power plants, additional renewable energy would likely not displace much uranium consumption. Thus, energy security benefits of a national RPS may be less significant than touted.

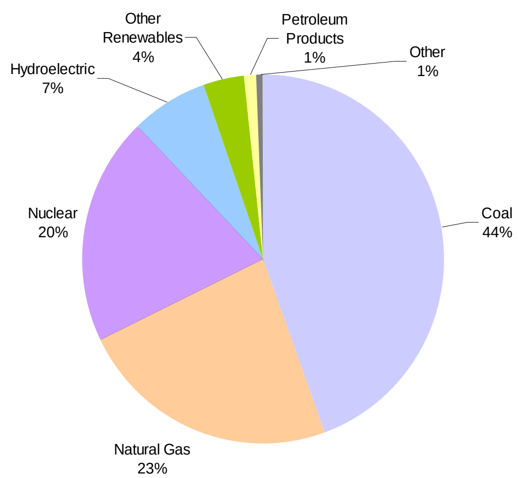

Figure 2-1. 2009 Net Generation by Energy Source (EIA)

Another reason cited for passage of RPS programs is economic benefits. The economic benefits center around the creation of jobs, the improvement of local economies, and the "price suppression" effect of low variable cost renewable energy. While having a high percentage of renewable energy in electricity portfolios may increase average electricity costs slightly relative to conventional methods, this effect is typically small when compared to the economic benefits. Studies show that renewable energy facilities create more construction, operation, and indirect job-years when compared to fossil fuels on an energy output basis.[2] Additionally, price suppression refers to the impact of having renewable energy that have low or zero variable cost in a power dispatch supply curve.[3] This has the overall impact of lowering the marginal cost (and thus market clearing price) of energy as shown in studies performed in Texas, PJM,

[2] An example of this analysis developed in Pennsylvania by Black & Veatch can be seen at http://www.pennfuture.org/UserFiles/File/Legislation/HB80SB92_Report201001.pdf and U.S. Federal results by Navigant at http://www.navigantconsulting.com/downloads/Frantzis_RETECH_2010.pdf

[3] A power dispatch supply curve is comprised of all of the available generation units in an area, rank ordered from lowest to highest variable cost. This helps determine the lowest cost resources to meet a certain level of demand in a given time interval.

and New York. In addition, the decrease in demand for fossil fuels can lower prices for the fuels themselves, leading to overall lower electricity prices.

Lastly, RPS policies are attempting to reduce environmental damage associated with air, water, waste material and natural resources, which can provide health, safety, and economic benefits. Many types of renewable energy have lower or zero criteria pollutants and greenhouse gas (GHG) emissions when compared to fossil fuel based generation. Though specific GHG reduction levels have not been explicitly defined in proposed legislation, the U.S. Department of Energy's analysis of a 25 percent RPS performed in 2009[4] showed a 12 percent reduction in GHG emissions from the electric sector by 2030, when compared to a non-RPS base case. It is expected that renewable energy will play an important role in any GHG reduction strategy for the nation.

2.3 Prospects for a National RPS

Given the new Republican leadership in the U.S. House of Representatives in 2011, Federal renewable energy policy will not be a priority for the House. Legislative priorities other than energy make the chances of success for a federal RPS law in the next two years low. RPS legislation that would be of interest to the House in 2011 and 2012 would likely need to have additional provisions related to nuclear and fossil energy to attract the necessary votes. This implies that there likely will not be any new major federal drivers for renewable energy from an RPS-like bill until 2015 at the earliest.

Furthermore, though there is an apparent link between RPS policy and GHG reduction, combining the two in a single legislation may be problematic. For example, H.R. 2454 failed to garner support in the Senate, not due to the RPS provisions, but rather due to the more contentious GHG cap-and-trade program that was part of the bill. S.3813 has taken a more narrow approach by focusing solely on a federal RPS program without enacting a specific federal GHG management program. A bill focused only on RPS provisions may have a better chance of federal enactment than a broader energy bill given the current legislative environment. RPS laws can be more easily linked to issues that resonate more with voters and lawmakers such as jobs and economic growth. Lawmakers in many regions have realized the benefits of a federal RPS, as

[4] U.S. Department of Energy, "Impact of a 25-Percent Renewable Electricity Standard as Proposed in the American Clean Energy and Security Act Discussion Draft", SR/OIAF/2009-04.

shown by the support of Republican co-authors to the Senate renewable energy bill from Kansas, Nevada, and Iowa.

Without federal legislation, the two main groups that will stimulate U.S. renewable energy through policy development are states and government agencies. State RPS development is already well underway as will be shown in the next section. The U.S. Environmental Protection Agency (EPA) is expected to promulgate regulations for both GHG emissions and coal boiler criteria pollutants that may indirectly impact the development of renewable energy in the U.S. It is unclear at this time what limits the U.S. EPA may put into place and what regulatory restrictions will be placed on the agency by the U.S. Congress.

3.0 Overview of State RPS Programs

State RPS requirements have become a major driver in the development of renewable projects. The first programs were enacted in the late 1990s and have rapidly expanded both in the number of states implementing RPS programs and the goals set by those states. Roughly 50 percent of the total U.S. load is now subject to some sort of renewable mandate. By 2020, these state RPS programs combined, if achieved, can bring the national non-hydro renewable energy usage to about 8 percent, according to Black & Veatch estimates.

Conceptually, RPS programs define the target amount of renewable energy (either as a percentage of total retail sales, an amount of installed capacity, or a total generation amount) to be achieved within a certain period of time. In practice, state RPS programs have developed divergent rules in a number of areas, such as:

- **Targets and Compliance Year(s):** How much and when intermediate and final targets are to be achieved.
- **Carve-outs and Tiers:** Special requirements or treatment reserved for specific renewable types. Can also be different "Classes" or "Tiers".
- **Resource Eligibility:** What types of resources are considered eligible and if existing projects count toward targets, as well as the delivery requirements for the energy.
- **Tradable Renewable Energy Certificates (TRECs):** The flexibility to buy and sell unbundled RECs without buying the underlying energy to meet an RPS.

The individual state rules must be reviewed carefully to determine how each unique set of regulations may impact future development of the market.

3.1 Targets and Compliance Years

Thirty states and the District of Columbia currently have mandatory RPS requirements. Another eight states have non-binding renewable generation goals. The map below shows the overall targets and target years by state.

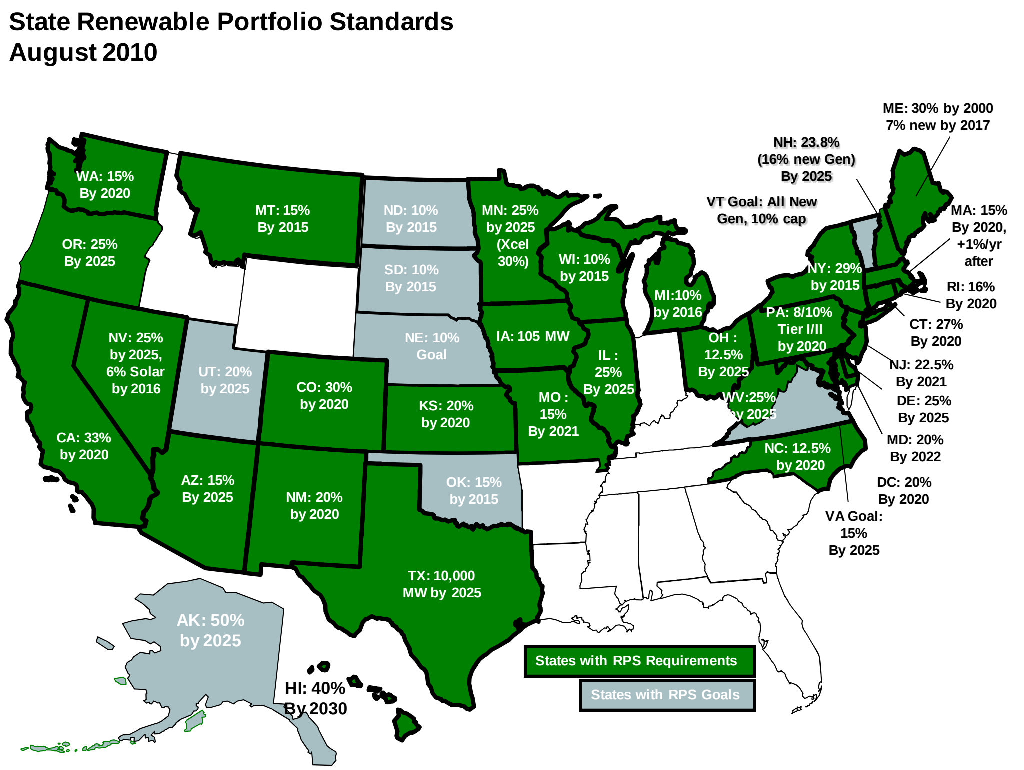

Figure 3-1. US State Renewable Portfolio Standard Goals.[5]

3.2 Carve-outs and Set-asides

In addition to the RPS targets, many states have specific carve-outs or set-asides for certain types of renewable energy that must be used. This is done either through a technology specific focus or through classification of certain types of renewable resources into “Tiers” or “Classes” with each having separate goals. A summary of the major carve-outs by state is shown in the table below. Unless otherwise specified, the percentages shown are percentages of retail sales, not of the RPS requirement.

[5] www.dsireusa.org and Black & Veatch analysis

Table 3-1. RPS Resource Carve-Outs By State.

State	Resource	Carve-Out or Tier Target*
Arizona	Distributed Generation	4.5% by 2025
Colorado	Distributed Generation	3% by 2020
Connecticut	Tiered	20% Class I (solar, wind, biomass, LFG, tidal/ocean, ROR Hydro) by 2020
Delaware	Solar	3.5% by 2025
District of Columbia	Solar	0.4% by 2020
Illinois	Wind and Solar	18.75% wind, 1.5% solar by 2025
Maine	Wind	8,000 MW by 2030, with off-shore goals as part of this target
Maryland	Tiered and Solar	2% solar, 18% non-hydro or WTE by 2022
Massachusetts	Solar	400 MW goal with variable escalation
Minnesota	Wind and Solar	25% wind and solar by 2020, no more than 1% solar
Missouri	Solar	0.3% solar by 2021
Nevada	Solar	1.5% solar 2025
New Hampshire	Tiered	0.3% solar, 1.0% small hydro by 2025
New Jersey	Tiered, Solar, and Off-shore Wind	5,316 GWh solar by 2026; 1,100 MW off-shore wind
New Mexico	Solar, Wind, and Distributed Generation	4% each wind and solar; 0.6% DG by 2020
New York	Customer sited	0.48% by 2015
North Carolina	Solar and Animal Wastes	0.2% solar and swine waste each by 2018; 900 GWh of poultry waste by 2014
Ohio	Solar	0.5% by 2024
Oregon	Small Solar	20 MW by 2020
Pennsylvania	Tiered and Solar	0.5% solar, 8% Tier I (wind, solar, biomass, low-impact hydro)
Texas	Non-Wind	500 MW goal

Notes:
* Percentages are of retail sales, not of the RPS requirement, unless otherwise noted

In addition, energy from certain renewable projects and resources may also receive credit multipliers, meaning one unit of energy from the particular type of renewable resource is translated to more than one unit of credits to meet a state's RPS. The following table summarizes states that allow for multipliers.

Table 3-2. Renewable Energy Credit Multipliers.

State	Resource	Multiplier
Arizona	Solar, Pre-2006 Projects, and In-State Manufacturing	Up to 1.8
Colorado	In-State, <30 MW Community or Municipal Owned, and Solar	Up to 3.0
Delaware	Use of local labor, in-state wind, solar, or fuel cells, and off-shore wind	Up to 3.5
Kansas	In-state projects	1.1
Maine	Community based projects	1.5
Michigan	Solar PV, local projects and projects using in-state labor, projects with storage, and non-wind on-peak power	Up to 2.0
Missouri	In-state projects	1.25
Nevada	Energy efficiency and solar	Up to 2.45
Oregon	Up to 20 MW of Solar PV	2.0
Utah	Solar PV	2.4
Washington	DG <5 MW, and facilities with local labor	1.2 to 2.0
West Virginia	Renewables and projects located on reclaimed surface mines	Up to 3.0
Virginia	On-shore, off-shore wind, and solar PV	Up to 3.0

3.3 Resource Eligibility and Delivery Requirements

Similar to the proposed national RPS programs, most state RPS programs designate solar, wind, geothermal, and ocean/tidal to be eligible resources. The eligibility of other resources, such as biomass, hydro, waste-to-energy, and clean coal technologies, depends on the state and types of fuel or technology used.

One of the divergent set of resource eligibility rules from state-to-state is for hydroelectric generation. Depending on the state, rules may vary based on project size, technology used (new impoundment or run of river, for example), facility age, upgrades on existing plants versus new facilities, and facility location. These differences in hydro eligibility requirements are detailed in the Table 3-3.

In addition, the geographic location of the facility generating the power or RECs can also be an eligibility constraint. In general, the prevailing trend is that RECs should be associated with energy delivered into the state or regional transmission grid where the state is a member, without specific definition of where the project must be located. There are a number of exceptions to this trend, including specific requirements or preferences for in-state generation. Many states have stayed away from mandating in-state generation, since this stipulation risks running afoul of laws that prevent states from placing barriers on interstate commerce. Some restrictions have also been placed on electricity from outside the United States; it is unclear if these types of restrictions are permissible under existing trade regulations, since few challenges to their standing have been made.

A table of new hydroelectric eligibility and power delivery requirements by state can be seen below.

Table 3-3. New Hydroelectric Eligibility and Delivery Requirements By State.

State	Hydro Eligibility	Delivery Requirement
Alaska	Not defined	Not defined
Arizona	<10 MW if run of river or incremental upgrades	Power must be delivered to state since unbundled RECs not allowed
California	Small and conduit <30 MW. Must not have "an adverse effect on instream beneficial uses"	Delivery to an in-state hub. Tradable RECs allowed up to 25% of RPS requirement through 2013

Table 3-3. New Hydroelectric Eligibility and Delivery Requirements By State.

State	Hydro Eligibility	Delivery Requirement
Colorado	<10 MW	Delivery not defined; 125% credit multiplier for in-state projects
Connecticut	ROR <5 MW	Power must be delivered into NEPOOL
Delaware	<30 MW, provided that certain environmental attributes are met	Power must be delivered into PJM
District of Columbia	Being phased out for future eligibility	Power must be generated within PJM or a state adjacent to PJM
Hawaii	Allowed with no restrictions	In-state only
Illinois	No new dams or "significant" expansion of existing dams allowed	IL only through 2011; "states adjoining IL" allowed if IL resources are not available; "elsewhere" only allowed if resources from adjoining states are not available
Iowa	Small hydro allowed, but no definition	Energy must be generated in IA or wheeled into IA utility service territory
Kansas	Existing and new hydro <10 MW	Energy must be sold to KS customers, but no restriction on location of generation
Maine	<100 MW	Power must be delivered into NEPOOL or the Maritimes Control Area
Maryland	Being phased out for future eligibility	Power must be delivered into PJM
Massachusetts	<25 MW are eligible. Must meet specific environmental requirements	Power must be delivered into NEPOOL
Michigan	New dams are not eligible; only upgrades to existing facilities	Generation must be located in the state or in the service territory of retail providers that operate in the state
Minnesota	<100 MW	Any M-RETS registered RECs are eligible. No deliverability requirements
Missouri	<10 MW and no new water diversions are eligible	No deliverability requirements, but the use of RECs is limited to 10 percent
Montana	New <10 MW and does is not a new water diversion	Must be delivered to MT; specifies eligibility as MT or other states
Nebraska	No specific definition or limitation	Not defined

Table 3-3. New Hydroelectric Eligibility and Delivery Requirements By State.

State	Hydro Eligibility	Delivery Requirement
Nevada	Run of river <30 MW; dams must be existing and used for irrigation only	Power must be delivered into NV
New Hampshire	Upgrades/expansions of existing hydro regardless of size allowed	Power must be delivered into NEPOOL
New Jersey	<30 MW allowed as Class II; most of NJ's requirement is Class I	Power must be delivered into PJM
New Mexico	All facilities on-line after 7/1/07 allowed.	Power must be delivered to NM. "Preference" given to NM facilities
New York	Upgrades or new <30 MW	Preference in NYSERDA solicitations given to projects in NY providing state economic development. Hourly matching for power delivered from outside of NY.
North Carolina	<10 MW, except munis and coops which can use large hydro for up to 30% of their goal	No deliverability requirements for unbundled REC; out-of-state unbundled RECs can be used for up to 25 percent compliance
North Dakota	Allowed with no restrictions	Any M-RETS registered RECs are eligible
Ohio	Major environmental guidelines on eligible facilities, but no explicit size limit	50% of goal must be in-state generation; remainder must be deliverable into OH
Oklahoma	No limits on eligibility	Must be located in OK
Oregon	Efficiency upgrades to existing facilities made after 1994 eligible.	Bundled RECs must be located within the U.S., while unbundled anywhere in the WECC (limited to 20 to 50 percent of compliance)
Pennsylvania	Distinction made between Low Impact (Tier I) and Large (Tier II). Both are required	Generation must be located in PA, PJM, or the parts of MISO serving PA load
Rhode Island	<30 MW eligible	Power must be delivered into NEPOOL
South Dakota	Hydro in service prior to 6/1/08 is excluded from baseline sales; after this date is eligible	RECs from other states allowed, but nothing regarding provinces
Texas	Facilities after 9/1/99 are eligible; repowered facilities are limited	Must deliver to ERCOT
Utah	Any size or timing allowed for in-state hydro; out-of-state limited to upgrades and <50 MW	Delivery to WECC

Table 3-3. New Hydroelectric Eligibility and Delivery Requirements By State.

State	Hydro Eligibility	Delivery Requirement
Vermont	<200 MW and in service after 2004	VT generation only
Virginia	All hydro resources are eligible	Resources must be in-state or from the "regional transmission entity"
West Virginia	ROR hydro only	Must be from WV or PJM
Washington	Efficiency improvements after March 1999	Must be delivered to Washington on a real time basis
Wisconsin	<60 MW	Must be delivered to WI

3.4 Use of RECs in State RPS Programs

A REC, in general, is defined as the renewable energy or "green" attributes associated with each unit of output for an eligible renewable energy project, separate from the underlying commodity energy. RECs are used as a mechanism for electric suppliers to demonstrate compliance with RPS requirements and for regulators to verify compliance. Most RPS states use RECs, either bundled or unbundled with underlying power, as the compliance verification mechanism.

For background, a bundled renewable energy product includes both RECs associated with the renewable power and the underlying power itself. Many states with Power Purchase Agreements (PPAs) with renewable generators require the delivery of bundled products. Other states, especially those that are part of a regional power pool, allow for unbundled RECs, as long as the energy is delivered to somewhere in the regional power pool. Unbundling is the process of disassociating the renewable and environmental attributes of the renewable power from the underlying commodity power itself. However, prior to unbundling, the energy associated with the RECs often must meet minimum requirements, including delivery. There may be some differences in the delivery requirements of the energy, such as real-time matching, hourly matching, or firming/shaping. Also, the state or region to which the energy is delivered will also govern the eligibility of the unbundled RECs for RPS compliance Typically, the RECs can either be retired to demonstrate RPS compliance or sold to other entities. The ability to sell or resell the RECs alone without the accompanying power defines the tradability of unbundled RECs for RPS compliance, though the eligibility of the unbundled RECs must meet either broad or narrow delivery requirements for the associated power.

The use of unbundled RECs for state RPS compliance is the norm and not the exception. It is important to keep in mind that unbundled RECs do not mean the energy associated with the RECs can be generated and delivered anywhere in the U.S. Most RPS states still require the energy to be delivered to the state or RTO or be located in certain areas. Each state program varies in how unbundled RECs can be applied. There may be limitations to some degree on the number of RECs that can be used, the highest price allowed for RECs, and who is allowed to generate or trade RECs. A list of states that do not allow unbundled RECs and those that greatly restrict the use of unbundled RECs for RPS compliance can be seen below. Of the mandatory RPS programs, only Arizona, Hawaii, and Iowa do not allow unbundled RECs for compliance as of March 2011. California has enacted rulemaking to allow limited unbundled RECs, called Tradable RECs (TRECs), which is discussed further in the California-specific section below.

Table 3-4. Restrictions on Unbundled RECs by State.

Allowed With Restrictions	Not Allowed
Kansas[1], Missouri[2], Oregon[3], Utah[4], California[5]	Arizona, Hawaii, Iowa, Oklahoma, Vermont

Notes:
[1] Only a "portion" (amount not defined) allowed to be used in the years 2011, 2016, and 2020. Use in other years requires explanation to state regulatory authorities.
[2] Limited to 10 percent of obligation
[3] Limited to 20 to 50 percent of total compliance amount
[4] Limited to 20 percent
[5] SBX1-2 limits the use of REC-only and TRECs associated with firmed/shaped products to a total of 25% of CA's 33% RPS by 2020.

Each state must deal with a number of other details in defining what is acceptable under a tradable REC program. These include, but are not limited to, the following issues:

- **Allowance of Banking and Borrowing:** Many states do allow banking (overprocuring to meet future growing requirements) and borrowing (underprocuring with make-up in future years) to increase flexibility, but limits are typically placed in how much is allowed and what the timeframe is for each.

- **REC Tracking System:** A common requirement is to assure that any RECs generated are certified and retired through a third-party tracking system. Systems have been set up in the West (WREGIS), Midwest (MRETS), East (NEPOOL GIS), Mid-Atlantic (PJM GATS), and Texas (through ERCOT). Individual states may also have specific tracking systems (such as Nevada) which must be followed.
- **Trading and Utilization Limits:** States typically address who is permitted to trade RECs, the amount of unbundled RECs allowed to be used to meet RPS goals, the delivery requirements for the associated power, and what (if any) price caps exist.
- **Trading Between States:** Trading of RECs between states is common for those that are part of a wholesale power pool, which is predominant in the Midwest, Northeast, and Mid-Atlantic regions. These states still require delivery of the energy to their respective power pools. The use of unbundled RECs without any delivery requirements to meet RPS requirements is rare.

4.0 Detailed WECC State RPS Requirements

The states in the Western U.S. represent potential markets for exporting renewable power due to their proximity, demand, and strong policies supporting renewable energy. A summary of the key components of the RPS policies enacted in WECC states is outlined in Table 4-1. Additional details on each state for deliverability requirements, the allowances for the eligibility and use of hydro, unique resource eligibility requirements and restrictions, applicable load, and potential future modifications to existing RPS policy are discussed below.

Table 4-1. WECC States RPS Summary.

State	Target and Ramp	ACP	Carve-Outs[1]
Arizona	15% by 2025; 0.5% ramp 2010-2015, 1% 2015 to 2025	None[2]	4.5% DG by 2012
California	33% by 2020; at least 1% ramp annually	$50/MWh[3]	None
Montana	15% by 2015; 1% ramp 2010-2015	$10/MWh	75 MW of "community RE projects"[5]
Nevada	25% by 2025; 3% ramp every 2 years	None	1.25% solar through 2015; 1.5% thereafter
New Mexico	20% by 2020; 1% ramp per year	None[6]	4% each wind and solar; 0.6% DG by 2020
Oregon	25% by 2025; 1% ramp per year 2015-2025	$50/MWh[7]	20 MW small solar by 2020
Utah	20% by 2025; no interim targets	None	None
Washington	15% by 2020; 6% step changes every 5 years	$50/MWh	None

Notes:

[1] In percent of total customer sales, not of the RPS requirement, unless otherwise noted

[2] Customer surcharges to comply with the RPS must be approved by the Arizona Corporation Commission; this could create a de facto future limit on price.

[3] Reflects the penalty that could be enacted for non-compliance, limited to $25MM total per utility. Total payments for renewables over market prices for power is capped per statute.

[4] Rulemaking has begun to allow tradable RECs, but is currently in the process of modification before enactment.

[5] Projects under 25 MW in size with a controlling interest from local owners.

[6] Customer rate increases are limited to 2 percent per year through 2011, rising by 0.25 percent per year through 2015.

[7] Can be adjusted every even-numbered year.

4.1 Arizona

Legislation for the current Arizona RPS was enacted in 2006. Prior to 2006, Arizona had an "Environmental Portfolio Standard" with weaker overall requirements yet strong carve-outs for solar power. RPS eligible projects currently supply just over 1 percent of the state's load, putting the state roughly on-target based on the compliance requirements.

- **Deliverability:** RPS eligible power must be delivered to Arizona entities that must comply with the RPS or be utilized by ratepayers in the state. RECs from distributed power can be purchased by utilities without having to take delivery. Tradable RECs from non-distributed power are not allowed.
- **Use of Hydro:** Projects that are less than 10 MW in size and are run-of-river or incremental upgrades to existing facilities are eligible. No known hydro facilities are currently being utilized for compliance.
- **Unique Resource Eligibility or Restrictions:** The special carve-out for distributed generation has made eligible a wide range of small-scale renewable technologies not typically used in state RPS policies such as solar water heating and solar space cooling. Municipal solid waste (MSW) is only eligible if approved conversion technologies are applied.
- **Applicable Load:** All utilities with retail load in Arizona, with the exception of public utilities and those with more than half their load outside Arizona, must comply with the RPS. Roughly 63 percent of the state's load must comply, since one of the largest utilities in the state (Salt River Project) is a public entity.
- **Future Changes Being Considered:** No major changes are currently expected or proposed for the Arizona RPS. Legislation was proposed in 2010 by a state legislator that would likely weaken the state's RPS. While this bill did not receive broad support, it is possible that there could be future attempts to weaken the existing policy.

4.2 California

California has the largest projected renewable energy demand in the country owing to the state's size and renewable energy target. First enacted in 2002, the state has since increased the renewable energy goal twice, now at 33 percent by 2020 through Executive Order. Utilities that must comply with the state RPS are currently supplying 15 percent of their load with renewable power, below the goal of 20 percent established for 2010. Meeting future goals will require aggressive procurement of new renewable resources. Failure to meet compliance levels will results in a penalty charge of $50/MWh for each MWh shortfall unless the utility can show good cause for missing the target (e.g. PPA sellers fail to perform, needed transmission is not built, etc,).

- **Deliverability:** To count as a bundled renewable product for RPS eligibility, an eligible renewable facility must be either directly interconnected to a California balancing authority area or the facility must use a dynamic transfer arrangement (either electronically moved into the receiving balancing authority AGC system or allowing automatic changes to the intertie schedule to the receiving balancing authority). A dynamic transfer arrangement typically would require the reservation of firm transmission. The California Public Utility Commission (CPUC) continues to consider possibly allowing eligible renewable resources that are not directly connected to a California balancing authority to be considered a bundled renewable product if they have firm transmission to California but do not have a dynamic transfer arrangement. Power that is firmed and shaped (not dynamically scheduled) is eligible for RPS compliance, but whether it is classified as bundled or REC-only (TREC) is part of CPUC's consideration."Firming and shaping refers to the process by which resources with variable delivery schedules may be backed up or supplemented with delivery from another source to meet customer load."[6] The issue of TREC designation is important because the California PUC ruled in January of 2011 that, for California investor owned utilities, TRECs will be limited to 25 percent of annual renewable targets through 2013. Allowable amounts of TRECs purchased during this period have a price cap of $50/MWh. Black & Veatch estimates that, if the currently approved contracts for out-of-state generation from variable output projects are considered REC-only transactions due to inability to dynamically transfer energy to the state, these existing project could comprise about 20 to 25 percent of the near term target in 2013. Furthermore, there are about 4000 GWh of additional contracts of a similar nature pending approval at the CPUC. Thus, before 2013, there appears to be limited opportunities for additional TREC transactions to meet IOU RPS demands in California. The CPUC will revisit, at a later date, the use of TRECs for RPS compliance for investor owned utilities in California for periods beyond

[6] "Renewable Portfolio Standard (RPS) Eligibility Guidebook: Fourth Edition," California Energy Commission (CEC), January 2011, [CEC-300-2010-007-CMF].

2013, so there is additional uncertainty regarding whether future limits on the use of TRECs would be lifted or continue indefinitely.

- **Use of Hydro:** Small (<30 MW), conduit (also <30 MW), and upgrades to facilities in existence prior to 2007 are allowed. To be eligible for the RPS, facilities must not have "an adverse effect on instream beneficial uses". Over 1,000 MW of hydro currently counts toward RPS compliance.

- **Unique Resource Eligibility or Restrictions:** Out-of-state facilities must meet California environmental requirements to be considered eligible resources. No unique resources are eligible in California's RPS. MSW is largely ineligible, and some restrictions are placed on the type of biomass conversion technologies that can be employed.

- **Applicable Load:** All of the state's investor owned utilities (Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric) must comply with the RPS. While publicly owned utilities are not required to comply per current regulations, most have set targets that match the RPS requirements. In addition, the Executive Order raising the RPS target to 33 percent included publicly owned utilities for future compliance requirements. Roughly 98 percent of the overall state's load is covered by the RPS.

- **Future Changes Being Considered:** On September 15, 2009, Executive Order (EO), S-21-09, directed the California Air Resources Board (CARB) to adopt regulations requiring 33 percent of electricity sold in the state to come from renewable energy by 2020. The EO used the authority provided by the state's GHG reduction goals (AB 32) as the legal framework. On March 30, 2011, the California legislature passed a bill (SBX1-2) to codify the Executive Order; past efforts had failed due to restrictions placed on the use of out-of-state renewable energy in the new law. The RPS targets laid out by SBX1-2 are: 20% by end of 2013, 25% by end of 2016, and 33% by end of 2020. The loading order in the bill specifies how much must or is allowed to come from each of three categories of projects.

    a. CA resources or dynamically scheduled to CA: **Minimum** of 50% in 2013, 65% in 2016, and 75% by 2020.

b. Unbundled RECs (must be in the WECC, but electricity does not have be delivered to CA): **Maximum** of 25% 2013, 15% in 2016, and 10% by 2020.

c. CA delivered product that is shaped and firmed: Remainder

4.3 Montana

Montana enacted its RPS in 2006, with few changes made to the basic regulatory structure since that time. Roughly 7 percent of the state's RPS eligible load was served by renewables in 2009; the 2010 target is 10 percent.

- **Deliverability:** RPS eligible resources must be delivered to Montana from either facilities located in Montana or other U.S. states. From the wording of the statute, non-U.S. resources are not eligible.
- **Use of Hydro:** Existing projects smaller than 15 MW or new projects under 10 MW in operation after 2004 are eligible. New water diversions are not permitted. Two small hydro projects, comprising 2 MW of capacity, are currently counted toward RPS requirements.
- **Unique Resource Eligibility or Restrictions:** No unique resources are included or excluded from Montana's RPS. MSW is not permitted for conversion to power.
- **Applicable Load:** All utilities regulated by the Public Service Commission must meet RPS requirements. While municipal and cooperative utilities are not explicitly required to meet the requirements, they must develop a renewable plan that follows the "intent of the legislature". Roughly 72 percent of Montana's state load must meet the RPS requirements.
- **Future Changes Being Considered:** Legislation introduced during the 2009 legislative session attempted to increase the RPS requirement to 25 percent by 2025, since the current RPS ends in 2015, and to allow incremental hydro power to be an eligible generation resource. While neither passed in 2009, the 2011 legislature could reintroduce similar legislation. Support for a stronger RPS exists in both the executive and legislative branches of Montana's government.

4.4 Nevada

The first RPS requirements were passed by the Nevada legislature in 1997 and have been subsequently increased to the current level of 25 percent. The regulated utility in the state is currently meeting the existing target of 12 percent renewables/energy efficiency, but will need to continue to be aggressive in procurement to meet future targets.

- **Deliverability:** RPS compliant power must be delivered and used in Nevada.
- **Use of Hydro:** The eligibility statutes for the Nevada RPS make it challenging for hydro resources to qualify. Only run-of-river facilities less than 30 MW, or existing dams which are less than 30 MW in size, with water used exclusively for irrigation, are eligible. Roughly 12 MW of total hydro capacity is currently utilized for RPS compliance.
- **Unique Resource Eligibility or Restrictions:** Nevada considers a wide range of technologies and feedstocks as eligible for RPS compliance including customer sited solar technologies, MSW, and energy recovery technologies. Energy recovery technologies include power derived from the reduction in pressure in water or gas pipelines, and the use of waste heat to power except in facilities with power generation as their main function. Additionally, energy efficiency measures can be used to meet up to 25 percent of Nevada's requirement.
- **Applicable Load:** Only utilities regulated by the Public Utilities Commission of Nevada must comply with the RPS. Co-ops and municipal utilities are not required to meet RPS obligations. In practice, this means that only one utility, NV Energy, must meet the state mandates. NV Energy has separate obligations in both the northern (former Sierra Pacific service territory) and southern (former Nevada Power service territory) segments of the state.
- **Future Changes Being Considered:** The most recent legislative session (2009) saw an increase in both the overall RPS target and solar energy carve-out, as well as greater compliance flexibility by allowing the use of out-of-state energy. The legislature meets again in 2011, with a new governor at the head of the executive branch; no firm initiatives for major modification of the RPS are currently foreseen.

A recent ruling by the Public Utility Commission of Nevada requiring that the price for new renewable contracts must be publicly released has placed greater scrutiny on the cost of the RPS. Given the condition of Nevada's economy at this time, efforts may be made to slow or limit future increases in RPS targets.

4.5 New Mexico

The RPS in its current form was passed by the New Mexico legislature in 2007. New Mexico has some of the most extensive carve-outs in the country, with specific requirements for wind, solar, and distributed generation. Current renewable generation is roughly 6 percent of applicable load; the state target increases to 10 percent in 2011.

- **Deliverability:** The RPS requires that power used for RPS compliance be delivered to New Mexico. "Preference" is given to facilities located in New Mexico, although it is unclear what this specifically means.
- **Use of Hydro**: Few restrictions are placed on the use of hydro in New Mexico. Any new facilities placed on-line after 1 July 2007 are eligible.
- **Unique Resource Eligibility or Restrictions:** Few unique resources are included or excluded per RPS definitions. MSW is not included in the definition of renewable resources.
- **Applicable Load:** Retail suppliers regulated by the Public Regulation Commission and rural cooperatives must comply, although the RPS requirement for rural cooperatives is lower (10 percent by 2020). Municipal electric providers are exempt. Regulations cover roughly 88 percent of the state's load.
- **Future Changes Being Considered:** No major changes are currently envisioned to impact New Mexico's RPS. Expanding the use of abundant of renewable energy resources in the state has been mentioned as a priority for many within the current government. New Mexico has some of the most aggressive environmental laws in the U.S., with state specific GHG regulations passed in 2010.

4.6 Oregon

Oregon passed RPS legislation in 2007 with an initial target of 5 percent renewables by 2011, rising to 25 percent by 2025. Minor modifications have been made since that time to promote the development of a diverse renewable portfolio. Roughly 8 percent of the RPS eligible load comes from renewable energy today, exceeding the 2011 target.

- **Deliverability:** Relative to other U.S. states in the WECC, Oregon has less strict requirements for the delivery of RPS eligible energy to the state. Unbundled RECs do not need to be associated with power delivered to the state, while bundled RECs can be firmed and shaped before eventual delivery to the load serving entity. Unbundled RECs can make up 20 to 50 percent of the yearly RPS requirement, depending on the size of the utility. Unbundled RECs can originate from any facilities within the WECC, while bundled RECs must come from facilities in the U.S. portion of the WECC.
- **Use of Hydro:** Only limited types of hydro are RPS compliant. Efficiency upgrades to existing facilities made after 1994 are eligible, as well as up to 90 MW of pre-1995 hydro that is "low impact".
- **Unique Resource Eligibility or Restrictions:** MSW is eligible for the RPS. The amount of power from new MSW facilities to meet RPS requirements is limited to a total of 9 MW. Very specific definitions are provided for the biomass resources that are and are not RPS eligible.
- **Applicable Load:** All utilities must comply with RPS requirements, although the target for each utility differs depending on their size. Utilities that have at least 3 percent of the state's load must meet the 25 percent requirement, while smaller utilities only have to meet a 10 or 5 percent target.
- **Future Changes Being Considered:** Renewable energy has strong support in Oregon among the population and the incoming government. Utilities will be aggressively procuring new energy sources to meet 2015 targets; it is unlikely any changes will be made in the target amounts. Recent statements regarding enhanced support for energy efficiency may lead to its eventual inclusion as a carve-out or as eligible for RPS compliance.

4.7 Utah

Utah passed its RPS in 2008. Unlike the other states reviewed in this section, Utah's RPS is only a goal, not a mandate, with regulated utilities only encouraged to procure renewables only "to the extent that it is cost effective to do so". There are no interim goals for the amount of renewables to be procured, and limited restrictions on the eligible resources. Roughly 8 percent of the RPS eligible load is from qualifying renewables, giving the state a good start at meeting future goals.

- **Deliverability:** Power does not need to be delivered to Utah to be RPS eligible; unbundled RECs that are utilized must be generated within the WECC. Unbundled RECs are limited to 20 percent of a utility's RPS obligation.
- **Use of Hydro:** Any size or timing is allowed for in-state hydro; out-of-state hydro is limited to upgrades after 1 January 1995 and limited to 50 MW.
- **Unique Resource Eligibility or Restrictions:** A wide range of resources are RPS eligible per Utah statute including solar hot water and heating, coal mine methane, MSW, cogeneration, ocean, tidal, energy efficiency and compressed air energy storage (if the power used to compress the air is renewable).
- **Applicable Load:** All utilities in the state have the RPS statute as their renewable energy goal.
- **Future Changes Being Considered:** Utah has strong potential for the development of both fossil and renewable energy. The current setting of a renewable goal rather than a mandate is a balance between the interests of these industries. The current administration has made development of both low cost and clean energy a priority; there does not appear to be any major efforts underway to change the existing voluntary goal to a mandated goal.

4.8 Washington

Washington's RPS was passed through a voter initiative in 2006, with only minor modifications to the policy since the original legislation was placed into law. Roughly 6 percent of eligible load is served by renewable energy today, surpassing the current requirement of 3 percent. Currently, some renewable energy produced in Washington is being sold to California to help meets its RPS. The target will increase to 9 percent in 2016.

- **Deliverability:** RPS eligible power must come from a specific geographic location (in the Pacific Northwest only) and/or must be delivered to Washington on a real-time basis.
- **Use of Hydro:** Very few hydro resources are RPS eligible in Washington. Only efficiency improvements after March 1999 are eligible for RPS credit. Currently, small hydro makes up roughly 60 MW of RPS eligible capacity.
- **Unique Resource Eligibility or Restrictions:** Tidal and wave energy is RPS eligible, while MSW is not. The combustion of black liquor from pulp and paper manufacturing is also excluded from RPS compliance. All “cost-effective” energy conservation must be employed in the state, although energy savings are not counted toward RPS goals.
- **Applicable Load:** All utilities with more than 25,000 customers must abide by the RPS goals. This represents roughly 85 percent of the state’s electricity load.
- **Future Changes Being Considered:** Although Washington gets roughly 70 percent of its power from hydroelectric sources, very little counts toward the state’s RPS requirements and the load of the regulated utilities is not adjusted to account for this supply. State utilities have been working to increase flexibility in the RPS, while other groups have been attempting to raise the RPS goals. This could have an impact in future eligible resources and procurement efforts.

5.0 Overview of Key Factors that influence REC price

Since there is not an actively traded, liquid REC market in existence in the WECC, REC prices, as discussed in this report, refer to the annual Renewable Energy Premium required to stimulate incremental new renewable energy (RE) projects. This reflects the implied long-term REC value, rather than a spot market price.

RE premiums are calculated for energy delivered from each RE project to each delivery load zone. The premium reflects the amount required, above or below the energy and capacity value at the delivery load zone, to make a project whole. In other words, the RE premium is the difference between a project cost and the delivered value. The cost of a project includes its levelized cost of energy (LCOE or busbar cost), as well as transmission costs and losses associated with delivery of the energy. The energy and capacity value incorporates the weighted average (based on time-of-day) value of the particular Project's production pattern. The simplified formula is as follows:

RE Premium = (LCOE + Transmission + Losses) – (Energy Value + Capacity Value)

Given the calculation method of the RE Premium, the main factors that impact REC prices are:

- RPS demand
- Capital cost and change in technology over time
- Availability of tax incentives
- Forecasted energy and capacity value
- Incremental transmission cost and transmission utilization
- Financing
- Delivery requirement

Though all of these components can impact the RE Premium significantly, Black & Veatch chose to focus on the RPS demand, capital cost, grants and tax incentives, and forecasted energy/capacity value in this discussion.

RPS demand is determined by both RPS targets and the anticipated load growth, since RPS targets are usually a percentage of retail sales. Different load growth trajectories for retail sales will impact the amount of renewable energy needed to meet RPS targets over time. The amount of incremental demand determines the marginal

REC premium required to meet each year's RPS demand, based on supply/demand curve principles.

Furthermore, a decline in capital costs over time would mean future projects would require lower levels of REC premiums to be made whole. The rate of decline will also impact how quickly REC premiums fall over time. On the other hand, if grants or tax incentives are reduced or discontinued, then the level of REC premium needed could be significantly higher.

Looking at the value side, the underlying energy and capacity values have a significant impact on the REC premium required. In forecasts where energy prices are relatively high due to factors such as high natural gas prices and GHG policies, REC premiums are low to zero, implying renewable energy projects can be competitive with conventional options. On the other hand, if energy and capacity values are relatively low, due to low natural gas prices and little environmental restrictions, then REC premiums required would be high, which means it would be challenging for renewable energy projects to compete with conventional generation.

Furthermore, there is a timing element in REC prices. If energy and capacity values are expected to increase over time, at a rate faster than inflation, then the REC premium required should shrink for future projects, assuming project costs do not increase faster than inflation. However, as RPS requirements continue to increase, higher cost resources will need to be accessed, since the lower cost (better capacity factor) resources are selected usually in the earlier years. Thus, the impact of energy/capacity value may not be easily discernable without considering all of these factors together.

6.0 REM Model Principles

In support of BC Hydro's Market Scenarios, Black & Veatch developed REC price forecasts to correspond to the Market Scenarios. Black & Veatch used an in-house model, called the Renewable Energy Market (REM) model, to capture the potential range of REC price outcomes under various scenarios. The REM model contains the following underlying principles in the modeling approach:

- The RE premium reflects the difference between the "Cost" of delivered renewable energy and the underlying energy and capacity "Value". The Cost includes the levelized cost of busbar energy (LCOE), the cost of incremental transmission, and transmission losses. The Value is based on forecasted energy and capacity prices for the respective scenario being modeled.
- Descriptions and costs of "Projects" are based on different resource classes identified in each Qualified Resource Area (QRA) developed through the Western Renewable Energy Zones (WREZ) Phase I project.[7]
- Since definitions of "Projects" may consist of an entire class of resources in a QRA, an availability constraint is placed on all projects in any given year. This means only a portion of a defined "Project" is available to be built each year, mimicking the reality of project development.
- All RE premiums, costs, and energy/capacity values are based on 20-year levelized calculations. The LCOE also assumes Independent Power Producer financing, even though some projects may be built by regulated utilities.
- The incremental cost of new transmission acts as the economic constraint on transmission between project hub and delivery load zone and is included in the levelized cost of a Project. Transmission losses are also incorporated.
- REC Prices are based on the RE Premiums of marginal units that satisfy each state's RPS requirement. To determine which projects are the marginal units, supply curves are developed by rank ordering the REC premiums for all available projects from lowest to highest. Then, the projects are allocated to

[7] Black & Veatch used updated QRAs and resource classifications from the WREZ Phase I process that has not been published yet, as well as updated QRAs for British Columbia data provided by BC Hydro. The base cost for all wind projects in the WREZ model was also updated, but have not been published yet. Background methodology and analysis on WREZ resources can be found at: http://www.westgov.org/index.php?option=com_content&view=article&id=311&Itemid=81

states, starting with the lowest REC premium projects and then moving higher up the supply curves. If a whole or portion of a project is allocated to a state, then that portion cannot be allocated to another state nor can it be used to satisfy incremental demand in future years. The marginal unit used to meet a state's RPS demand sets the marginal REC premium or "price" for that year.

- The model goes to 2025 when most state RPS programs end. Beyond that time horizon, Black & Veatch has not assumed any additional increases in RPS targets.

Transmission costs and financing assumptions are assumed to be the same across all scenarios. Since transmission costs can vary dramatically depending on the utilization factor and requires extensive iterative analysis, a 50 percent utilization factor was assumed in calculating the incremental transmission cost for all scenarios. For financing, Black & Veatch used the same default Independent Power Producer (IPP) assumptions contained in the WREZ model for all renewable resources and transmission.[8] These assumptions were developed through a public stakeholder process.

As run, the REM model also assumes that any renewable power that is physically delivered using firm transmission to a state will count toward the RPS requirement of that state. The model assumes that states generally do not allow the use of REC-only transaction that do not have accompanying delivered energy. Since it is assumed that all of the states in this analysis require delivery of renewable energy to the state,[9] models were set to look at each state's RPS demand individually and calculate the RE premium based on delivery to the state.

[8] WREZ Transmission Model Version 2.0
http://www.westgov.org/wga/initiatives/wrez/gtm/documents/GTMWG%20Version%202_0%20June%202009.xls

[9] This is a simplifying assumption for modeling purposes. It is noted that Oregon does allow some unbundled RECs without delivery to the state, as well as California's new SBX1-2 legislation.

7.0 REC Price Scenarios and Assumptions

Using the REM model, Black & Veatch modeled five REC Price forecasts that correspond to each of the Market Scenarios for energy and capacity price forecasts previously developed for BC Hydro.[10] As discussed in the previous section, RE premiums are derived from the cost of renewable energy minus the underlying energy and capacity value. Since energy and capacity price forecasts can be drastically different, depending on the scenario, REC prices were modeled for each of the GHG scenario. Furthermore, the load growth trajectories for each scenario were used to establish the annual RPS demand for renewable energy by state, since RPS targets are typically based on percentage of load.

The five Market Scenarios are summarized in Table 7-1. The description "EMP" refers to Black & Veatch's Energy Market Perspective, which was used as the baseline scenario for the GHG price forecast conducted for BC Hydro.[11]

Table 7-1 Market Scenario Assumptions.

Market Scenario	**1**	**3**	**4**	**8**	**9**
Global Economic Growth	High	Medium	Low	Low	High
Government Policy Maker	National	Reg/Nat	Reg/Nat	Regional	Regional
Gas Prices	High	EMP	Low	Low	EMP
Load Growth	High	EMP	Level	Level	High
Nuclear Adds	50%	150%	50%	EMP	EMP
PEV[1]	Yes	Yes	No	No	Yes
Renewables	High	High	Low	Low	EMP
CCS Cost[2]	-25%	+25%	+25%	+50%	50%
2020/2030 GHG Caps	Less Stringent	EMP	EMP	Base WCI	Base WCI
LRS of Offsets[3]	Full	Full	Full	Full	Full
Case Reference	16	29	46	41	5
Tree Probability	1.68%	10%	3.78%	0.81%	0.63%

[1] Plug-in Electric Vehicle
[2] Carbon Capture and Sequestration
3 Load Ratio Share

[10] Refer to "BC Hydro Greenhouse Gas Price Forecast: Scenario Development and Modeling" Black & Veatch (2010) for additional detail regarding the GHG scenarios used for this analysis.
[11] EMP Study of Spring 2009

7.1 REC Price Scenario Assumptions

In all of the scenarios, it is assumed that the investment tax credit (ITC), which is equal to 30 percent of a project's capital cost, is extended for all eligible renewable energy types through 2016. After that, the scenarios diverge with respect to the incentive assumptions as discussed below. Additionally, the capital cost for renewable energy projects are the same in Year 1 for all scenarios, but the rates of cost decline for wind and solar technologies are different depending on the scenario.[12] Table 7-2 summarizes the renewable energy assumptions for each scenario, which are discussed in more detail below.

Table 7-2 Renewable Energy Assumptions.

Market Scenario	ITC/PTC[13]	Renewables Cost
1	ITC expires after 2016, no incentives after	Faster decline
3	ITC (2016), PTC after	Faster decline
4	ITC (2016), PTC after	Slower decline
8	ITC expires after 2016, no incentives after	Slower decline
9	ITC (2016), PTC after	Baseline

7.1.1 Scenario 1

This future involves a National action for GHG, under high global economic growth. Natural gas prices are higher than baseline. There are less stringent CO2 caps in the 2020-2030 timeframe. Load growth is baseline. It is a future where higher than "baseline" levels of electric vehicles are expected to occur and more renewables than baseline will be developed. It is a future where renewable energy incentives are allowed to expire by 2016 due to the implementation of a National program for Carbon and high natural gas prices. With accelerated deployment of renewable energy

[12] The costs for resource technologies, such as biomass, geothermal, and hydro, were assumed not to decline over time because these resources rely on mature, conventional technologies with little opportunity for cost or performance improvements.
[13] PTC refers to the federal production tax credit that provides unit tax credits to certain renewable energy technologies. Prior to the ITC, the PTC was main tax incentive for renewable energy. In 2010, the PTC level was 2.2 cents or 1.1 cent per kilowatthour, depending on the resource type.

projects, renewable costs decline more quickly than baseline due to greater federal and private investment in renewable R&D to meet national CO2 caps.

Assumptions: ITC is allowed to expire by 2016 with no additional incentives available thereafter due to expectations that renewable energy projects can be self-sustaining with a national carbon program and high natural gas prices. Faster rate of decline and lower than baseline cost of renewables as a result of assumed federal R&D to bring on the higher levels of renewables.

7.1.2 Scenario 3

This future involves Regional action on GHG until the year 2020, then National action, under medium global economic growth. Natural gas prices are baseline. Mid-level/Baseline CO2 caps in the 2020-2030 timeframe. Load growth is baseline. It is a future where higher than "baseline" levels of electric vehicles are expected to occur and more renewables than baseline will be developed. As such, it is expected that PTC continues and research on renewables causes the cost of renewables to drop somewhat faster than baseline expectations.

Assumptions: After ITC ends in 2016, federal policy switches back to production tax credits (PTC) to continue supporting renewables, since the National Carbon program is delayed and gas prices are baseline. Faster rate of decline and lower than baseline cost of renewables as a result of assumed federal R&D to bring on the higher levels of renewables.

7.1.3 Scenario 4

This future involves Regional action on Carbon until the year 2020, then National action, under low global economic growth. Natural gas price levels stay lower than baseline. Mid-level/Baseline CO2 caps in the 2020-2030 timeframe. It is a future where loads are expected to be lower than baseline and lower than baseline levels of electric vehicles are adopted. As a result of the lower loads, there is not as much need for renewables. However, due to lower energy prices and continuance of state RPS programs, the federal government will be pressured to continue supporting renewable energy development with tax credits, but will not put as much R&D into lowering renewable costs.

Assumptions: PTC continues and renewable costs decline at a slower rate and level off higher than baseline.

7.1.4 Scenario 8

This future, which also experiences low global economic growth, does not include a National program for carbon. Instead the carbon programs are regional only. It is a future where national interests move away from concerns of climate change, leaving those concerns to be dealt with at the regional levels. It has lower than baseline natural gas prices. Load growth is relatively flat which takes away from the desire for national focus on electric vehicles and renewable R&D. In this future, there is less electric vehicle penetration (in part caused by the lower cost of natural gas/oil) and results in less renewables. It is a future where renewable energy incentives are allowed to expire by 2016, due to lack of interest at the national level, and renewable costs do not decline as quickly as baseline due in part to the low cost of natural gas and less federal and private investment in renewable R&D.

Assumptions: Renewable energy incentives are allowed to expire after 2016 and renewable costs are higher than baseline.

7.1.5 Scenario 9

This future, under high economic global growth, does not include a National program for carbon. Instead the carbon programs are regional only. It is a future where national interests move away from concerns of climate change, leaving those concerns to be dealt with at the regional levels. This future has higher than baseline load growth. As opposed to the lower than baseline natural gas prices in Scenario 8, this future has baseline natural gas prices. This scenario involves baseline levels of electric vehicles and baseline levels of renewables. With continuance of state-level RPS programs and regional carbon caps, the federal government will be pressured to continue supporting renewable energy development with tax credits. With the existence of the PTC, continuance of state RPS programs and baseline gas prices, private industry does invest in enough R&D to achieve baseline renewable cost reductions.

Assumptions: PTC continues after 2016 and renewable costs are baseline. State RPS targets continue.

7.2 WECC RPS Demand Forecast

The amount of renewable generation projected to be developed was determined by considering existing state RPS targets, WECC Energy Demand (varies with Scenario) and existing resources eligible for RPS. A description of each is covered below.

7.2.1 State RPS Targets

Current RPS targets and goals for WECC states were used to determine the RPS Demand Forecast. The WECC states included in the REM analysis and discussed collectively as "WECC states" are listed in Table 7-3. While California's SBX1-2 mandates an RPS target of 33 percent by 2020, Black & Veatch has assumed that this target is not achieved until 2025 for modeling purposes. Black & Veatch has assumed the delay in achieving the RPS target in California due to the many challenges (permitting, contractual, transmission, changing regulations) California has faced and will face with deploying so many renewable energy projects. In 2010, California fell short of its target of 20% and, in fact, the new SBX1-2 has allowed the 20% target to be pushed back to the end of 2013, though still holding to the 33% target at 2020.

Additionally, many states do not have interim targets for their RPS, so annual targets were developed to reflect projected incremental procurements each year. Only main tier RPS requirements (excluding carve-outs) and goals were used to establish each state's RPS demand. Main tier RPS resources are defined by the individual states and typically include large wind, solar, geothermal, biomass and small hydro. The main tier RPS targets were reduced for states with solar carve-outs, distributed generation requirements, and energy efficiency allowances. A summary of the RPS targets used in the REM model is provided in Table 7-3.

Table 7-3. RPS Target.

State	2010	2015	2020	2025
Arizona[1]	2.0%	3.5%	7.0%	10.5%
California	16.0%	21.0%	26.0%	33.0%
Montana	10.0%	15.0%	15.0%	15.0%
Nevada[2]	9.5%	13.8%	15.2%	17.3%
New Mexico[3]	7.1%	11.6%	15.4%	15.4%
Oregon[4]	5.0%	15.0%	19.9%	25.0%
Utah	2.0%	7.0%	12.5%	20.0%
Washington	3.0%	7.5%	15.0%	15.0%

Notes:

1 Excludes portion of the RPS target to be met by distributed generation
2 Excludes solar carve-out and energy efficiency required for RPS target
3 Excludes solar carve-out and distributed generation requirements
4 Excludes solar carve-out

7.2.2 WECC Energy Demand

Load growth in WECC varies by Scenario as discussed in REC Price Scenario Assumptions. Scenario 3 reflects baseline growth, while Scenario 1 and 9 have higher than baseline growth and scenario 4 and 8 have lower than baseline growth. Figure 7-1 shows the Total WECC retail sales for RPS states by Scenario. Additional load growths associated with different levels of plug-in electric vehicle deployment for GHG scenarios 1, 3, and 9 begin in 2020.

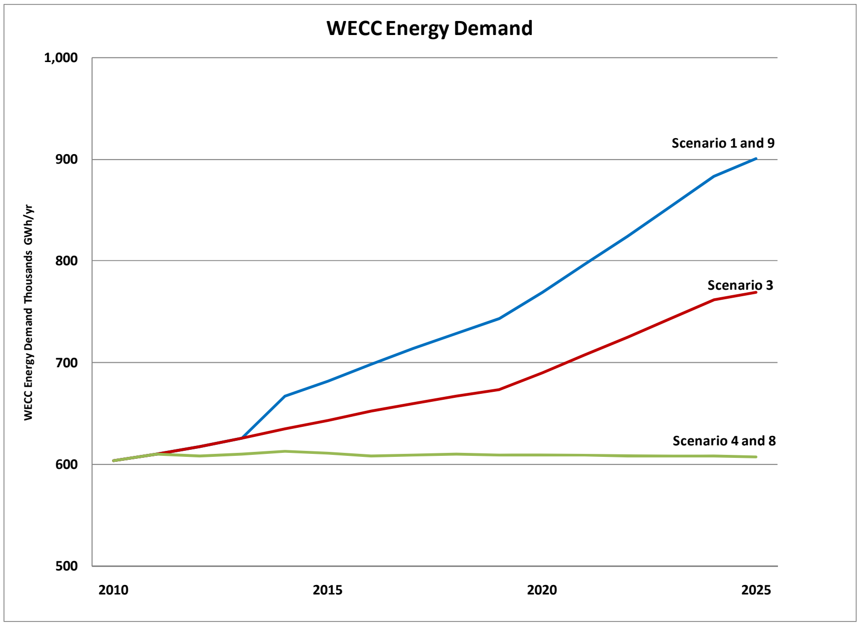

Figure 7-1. WECC Retail Sales for RPS States.

7.2.3 Existing and Planned Projects

States with RPS requirements are using existing capacity for current RPS compliance while working on acquiring additional capacity for meeting their increasing requirements in the future. These existing and planned projects are subtracted from the overall RPS new renewable energy demand for each state for modeling purposes. Since the REM model uses incremental demand to "clear" the supply curves each year, existing and planned generation are being used to meet or will meet some of that demand and, thus, will reduce the incremental demand for "new" generic resources in the model.

To determine what amount of existing and planned generation would be used to reduce the incremental RPS demand, Black & Veatch used a recent study by the WECC Studies Work Group (SWG). The study was developed to create a base case for transmission expansion for the year 2020. The analysis was a comprehensive review of many of the renewable energy projects in the WECC being used or proposed for RPS compliance. These were then categorized as Existing, Under Construction, Planned, and Future and were assigned to specific states to meet their RPS requirements. Based on the WECC analysis, almost 13,000 MW of existing generation is being used to meet RPS compliance in the WECC region presently and another 1,500 MW of projects are under construction. Approximately 3,600 MW of generation is classified as planned.[14] The total planned capacity was discounted by 50 percent or 1,800 MW to account for projects that may not move forward to the construction phase. Projects currently in the "Future" phase were not included in the estimate because these comprised of projects that did not meet the "planned" criteria or were generic facilities inserted to meet RPS requirements by 2020 for transmission modeling purposes. Details of the existing and planned capacity dedicated to each state's RPS are provided in **Error! Reference source not found.** by Compliance State, not originating state.

[14] Planned projects include projects that 1) received regulatory approval, or are undergoing regulatory review, 2) have a signed interconnection agreement, and 3) have an expected on-line date by end of 2016.

Table 7-4. Existing and Planned Capacity for RPS Compliance (MW)

Compliance State	Existing	Under Construction	Planned*	Future**	Total
Arizona	214	0	140	0	354
California	7,510	795	1,269	0	9,574
Montana	146	0	0	0	146
Nevada	344	85	49	0	479
New Mexico	204	30	10	0	244
Oregon	1,757	452	200	0	2,409
Utah	810	0	0	0	810
Washington	1,930	150	125	0	2,205
Total	**12,915**	**1,512**	**1,793**	**0**	**16,221**

Source: 2020 Renewables_09-01-2010_SPSC Forecast
(http://www.wecc.biz/committees/BOD/TEPPC/TAS/SWG/SWG_Sep9/default.aspx?InstanceID=1)
Notes:
* Planned projects discounted by 50 percent
**Future projects discounted by 100 percent

Forecast generation from the existing and planned capacity was also reported in the source data by WECC. Approximately 56 terawatt hours of generation is expected from-existing, under construction and planned (discounted by 50 percent) projects. A breakdown by generation for reducing the overall RPS new renewables demand by state is presented in Table 7-5 and Figure 7-2.

Table 7-5. Existing and Planned Generation for RPS Compliance (GWh)

Compliance State	Existing	Under Construction	Planned*	Future**	Total
Arizona	773	0	516	0	1,290
California	29,796	2,495	3,164	0	35,455
Montana	456	0	0	0	456
Nevada	2,033	690	366	0	3,089
New Mexico	620	186	47	0	853
Oregon	4,442	873	475	0	5,790
Utah	2,770	0	0	0	2,770
Washington	5,578	334	272	0	6,184
Total	**46,468**	**4,578**	**4,840**	**0**	**55,887**

Source: 2020 Renewables_09-01-2010_SPSC Forecast (http://www.wecc.biz/committees/BOD/TEPPC/TAS/SWG/SWG_Sep9/default.aspx?InstanceID=1)

Notes:

* Planned projects discounted by 50 percent

**Future projects discounted by 100 percent

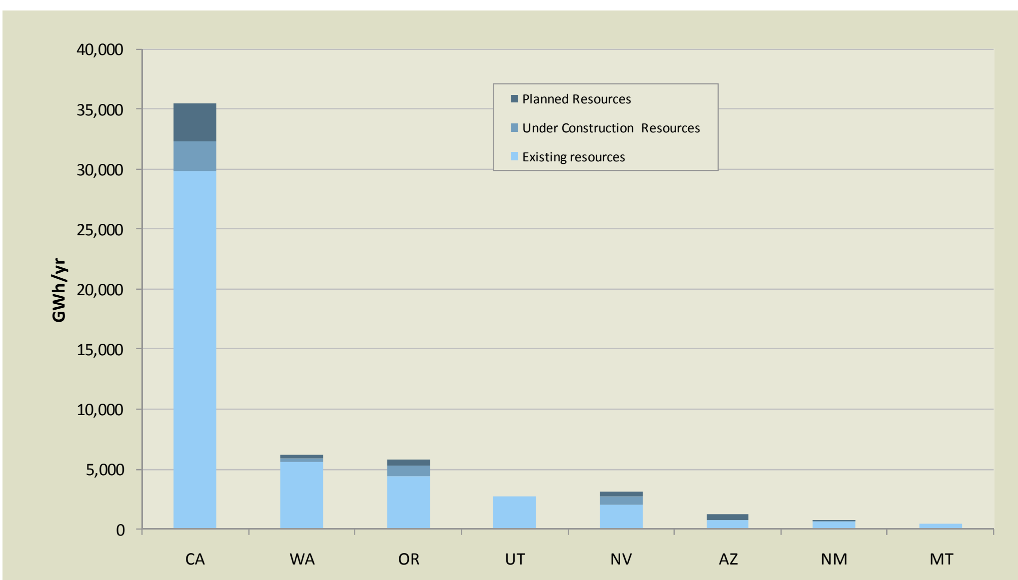

Figure 7-2. Existing and Planned Generation.

7.2.4 Net RPS Demand

States with mandatory RPS requirements (Arizona, California, Montana, Nevada, New Mexico, Oregon, and Washington) are assumed to attempt to meet 100% of their renewable generation requirement with a steady ramp-up in demand to meet the final goals. RPS targets were applied to the portion of load in each state subject to an RPS, since some states allow certain utilities to be exempt or have reduced requirements. It is assumed that California's large municipal utilities will have RPS targets that mirror the requirements of the investor owned utilities (IOUs). Utah, with a voluntary RPS goal is assumed to achieve only 50 the generation necessary to meet the goal, since it is not a mandatory goal. Further, existing and planned projects contracted to meet RPS requirements are subtracted from this demand, assuming contracts are renewed throughout the period. Thus, the Net RPS generation demand reflects only new incremental demand for non-carveout resources. The resulting cumulative net RPS demand starting in 2011 to 2025 by scenarios is shown in Figure 7-3. The differences are due to the assumed variation in energy demand. Figure 7-4, Figure 7-5 and Figure 7-6 provide the RPS Demand for each scenario by state.

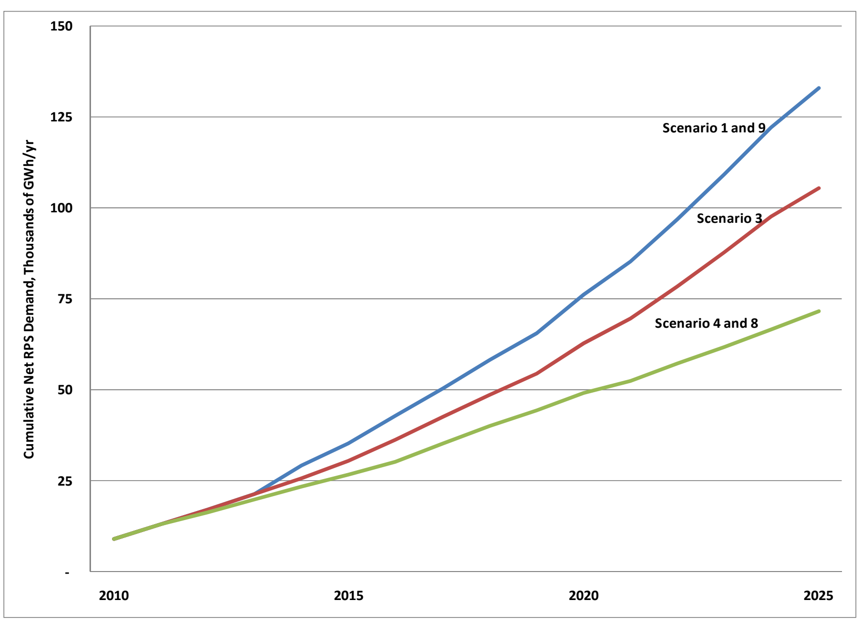

Figure 7-3. Cumulative Net RPS Demand (2011-2025).

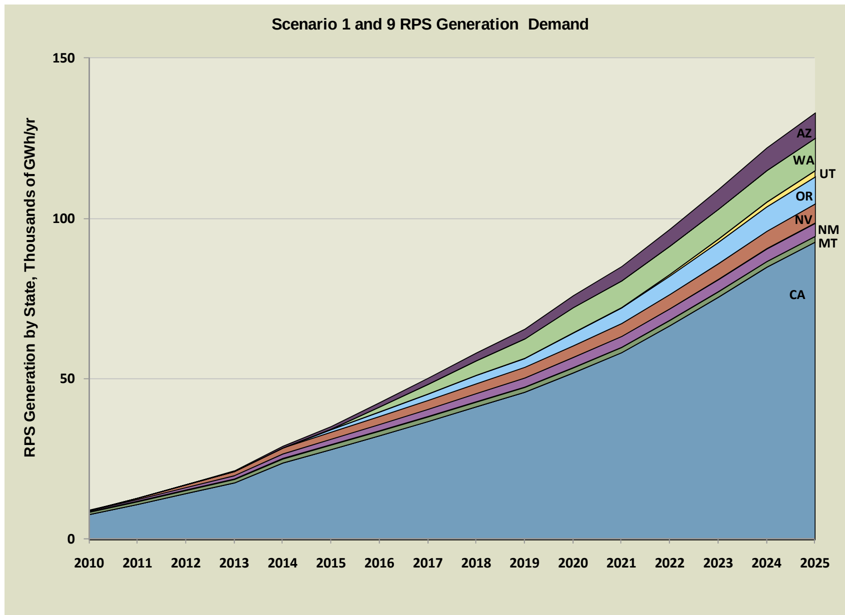

Figure 7-4. Scenario 1 and 9 Net RPS Generation Demand (2011-2025).

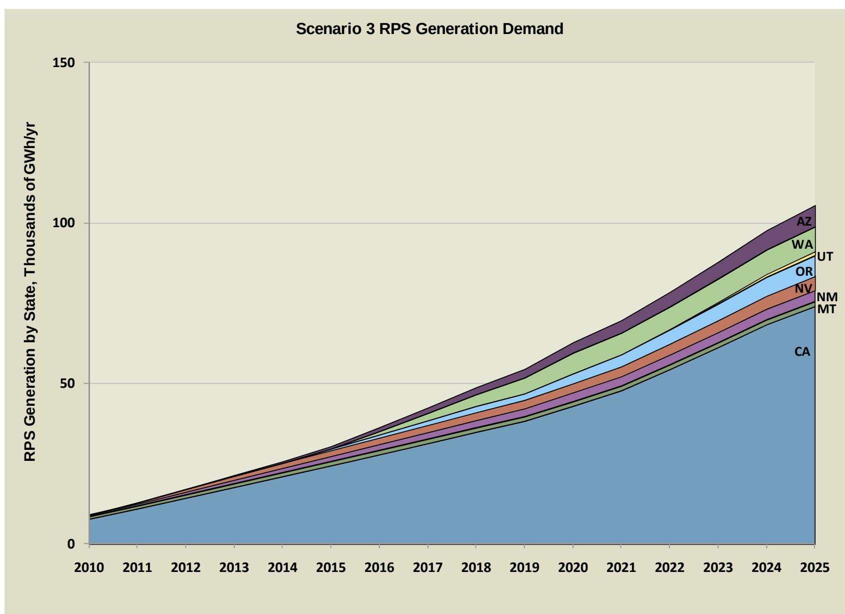

Figure 7-5. Scenario 3 Net RPS Generation Demand (2011-2025).

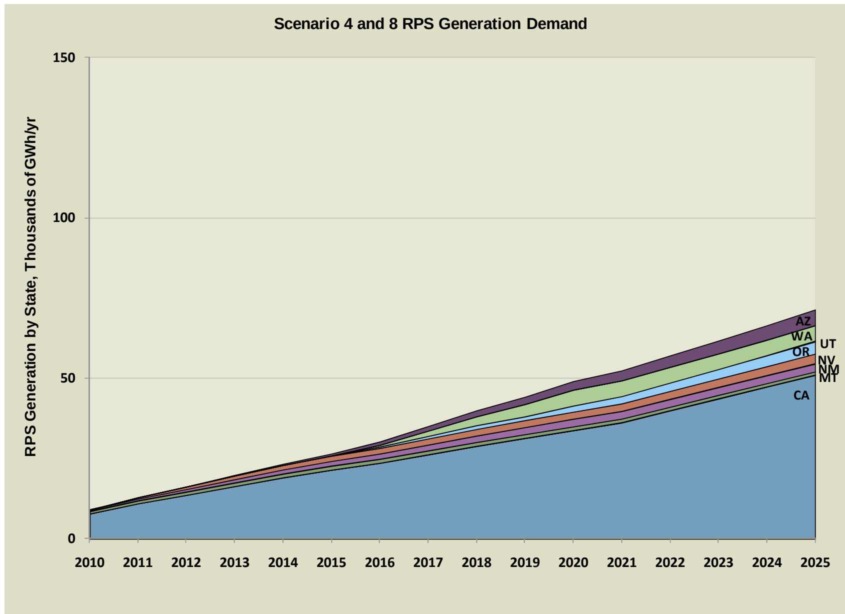

Figure 7-6. Scenario 4 and 8 RPS Net Generation Demand (2011-2025).

8.0 REC Price Results

The REC price results for the five scenarios reflect the marginal RE premium required to meet each year's incremental RPS demand for each state. As discussed previously, since each state has a delivery requirement, REC prices reflect the cost of delivery to the state. As a result, most scenarios contain different price forecasts for each state.

8.1 Scenario 1

Due to a relatively high energy price forecast in this scenario and fast declining cost of solar and wind technologies, Figure 8-1 shows that the REC premium is zero or close to zero for most states throughout the forecast period. As a result, all of the projects installed cost nearly at or below the forecasted energy and capacity value. Essentially, there is no REC premium value for this scenario.

The capacity build by resource type across the WECC is shown in Figure 8-2 with close to 40,000 MW of additional renewables built by 2025. This is a much higher level of capacity built than other scenarios, due to high demand for renewable energy as load growth is high. The locations of projects are shown in Figure 8-3. In this scenario, a mix of wind, solar, geothermal and hydro projects are deployed, as well as 74 MW of biomass. Solar makes up a significant amount of capacity in later years as the cost for solar panels fall. Small hydro (39 MW), geothermal (350 MW) and wind (204 MW) projects from British Columbia (BC) and wind (1150 MW) projects from Baja (BJ) Mexico also contribute to the mix. These imports were needed to satisfy the high renewable energy demand.

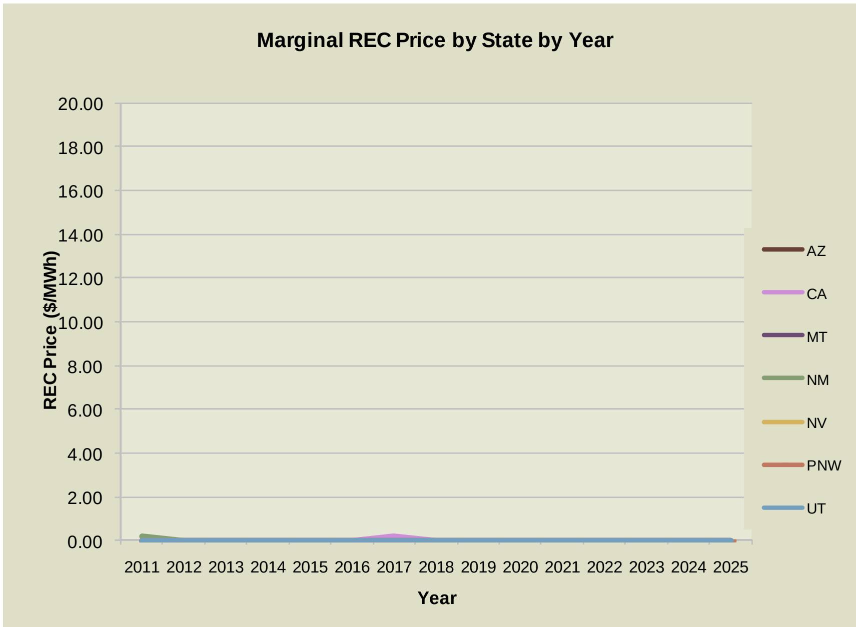

Figure 8-1. Scenario 1 REC Prices by State (2011-2025)

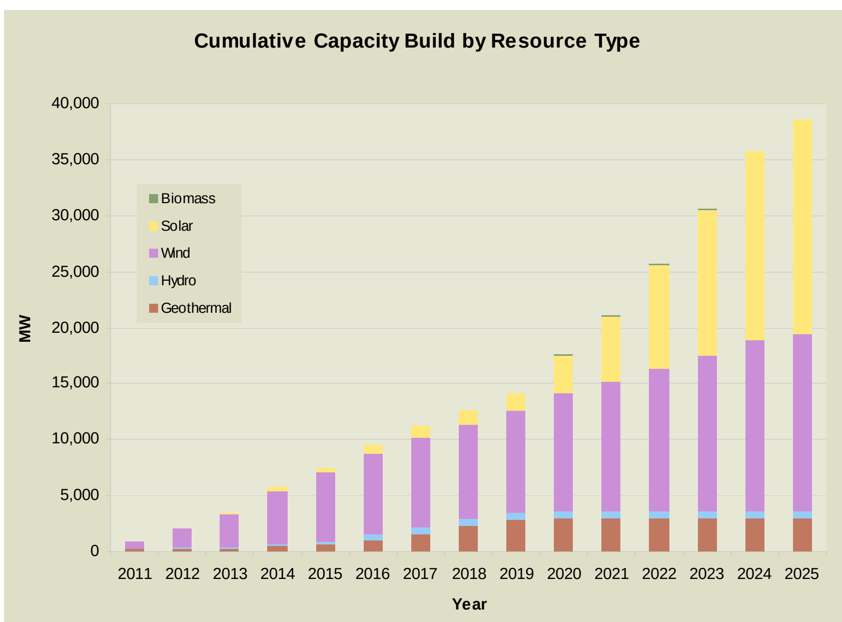

Figure 8-2. Scenario 1 Cumulative Capacity Build for RPS Demand (2011-2025)

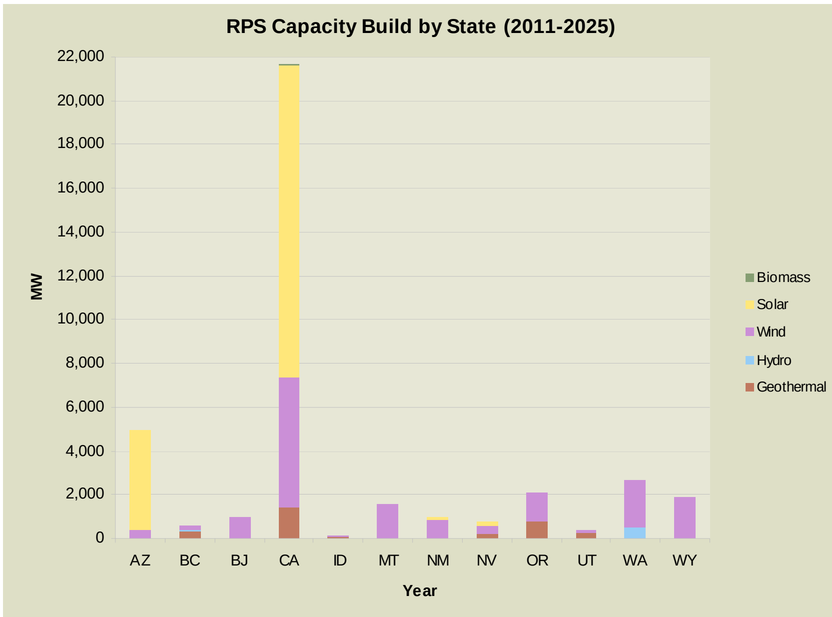

Figure 8-3. Scenario 1 Total Capacity Build for State (2011-2025)

8.2 Scenario 3

Due to a moderate energy price forecast in this scenario and fast declining cost of solar and wind technologies, REC prices are below $50/MWh in all years (Figure 8-4). They do vary quite a bit across all states, with California having the highest REC prices in most years due to its high demand for RPS generation. The Pacific Northwest (PNW), consisting of Oregon and Washington (OR&WA), have REC prices at or below zero due to low cost resources available in the area, especially with the PTC in place in future years. The capacity build by resource type across the WECC is shown in Figure 8-5 and the locations of projects are shown in Figure 8-6. In this scenario, a mix of wind, solar, geothermal and hydro projects are deployed, but no biomass. Due to the fast declining cost of solar and wind, as well as the persistence of tax incentives, biomass projects tend to be relatively more expensive. Only a few MW of small hydro is imported from BC. Due to the persistence of the PTC in future years, projects in Canada or Mexico have difficulty competing with U.S. projects.

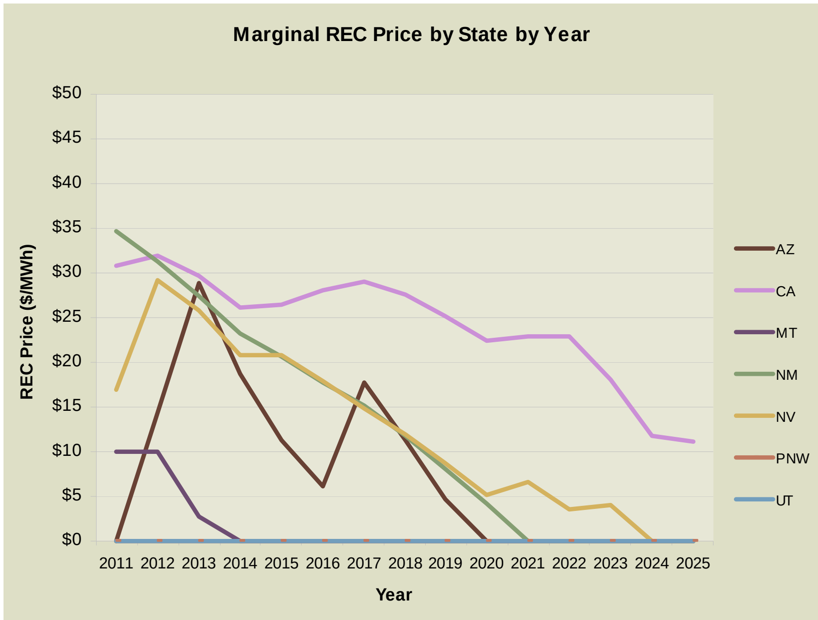

Figure 8-4. Scenario 3 REC Prices by State (2011-2025)

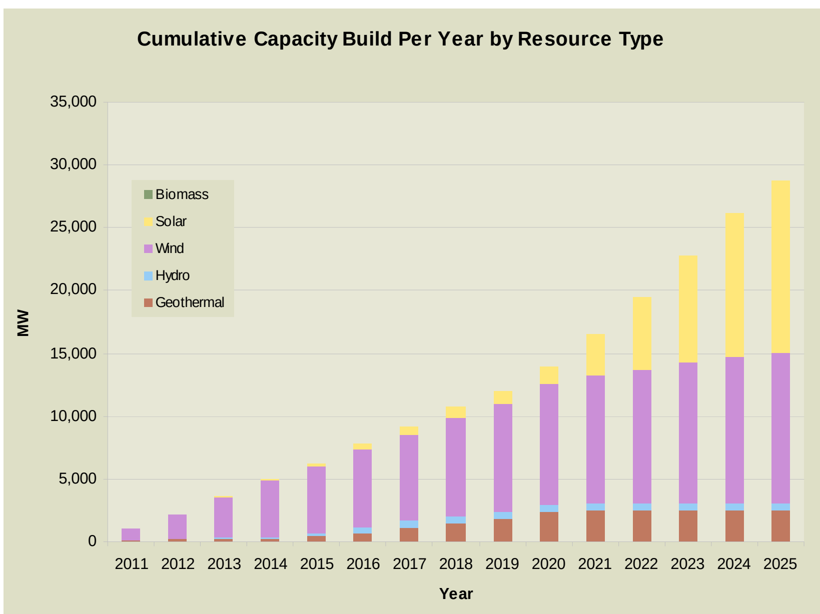

Figure 8-5. Scenario 3 Cumulative Capacity Build for RPS Demand (2011-2025)

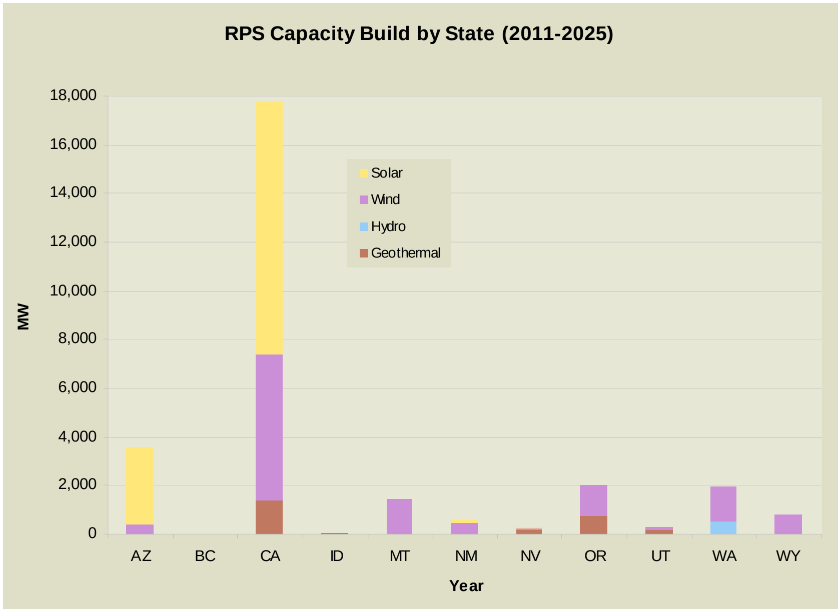

Figure 8-6. Scenario 3 Total Capacity Build by State(2011-2025)

8.3 Scenario 4

Due to a very low energy price forecast in this scenario and slow declining cost of solar and wind technologies, REC prices increase to high levels or hit alternative compliance payment (ACP) caps (see Figure 8-7), despite the PTC being in place for the duration of the forecast. California, Washington, and Oregon hit their ACP caps of $50 per MWh, so procurements fall short of RPS requirements. Montana also hits its $10 ACP cap. Arizona, Nevada, and New Mexico prices escalate to $70-$95 per MWh since they do not have ACP limits, though the impact of these high prices on retail rates were not calculated. Thus, the build-out in these states may be more limited than shown due to the RPS retail rate impact constraints. The capacity build by resource type across the WECC is shown in Figure 8-8 , which reflects significant underbuild of renewable energy projects due to the ACP cap restricting most of the build in California in future years. The locations of projects are shown in Figure 8-9 Due to the persistence of the PTC in future years, projects in Canada or Mexico cannot compete with U.S. projects. Furthermore, due to the low energy price forecast, high REC premiums constrained the amount of total build to about 6,500 MW in the region.

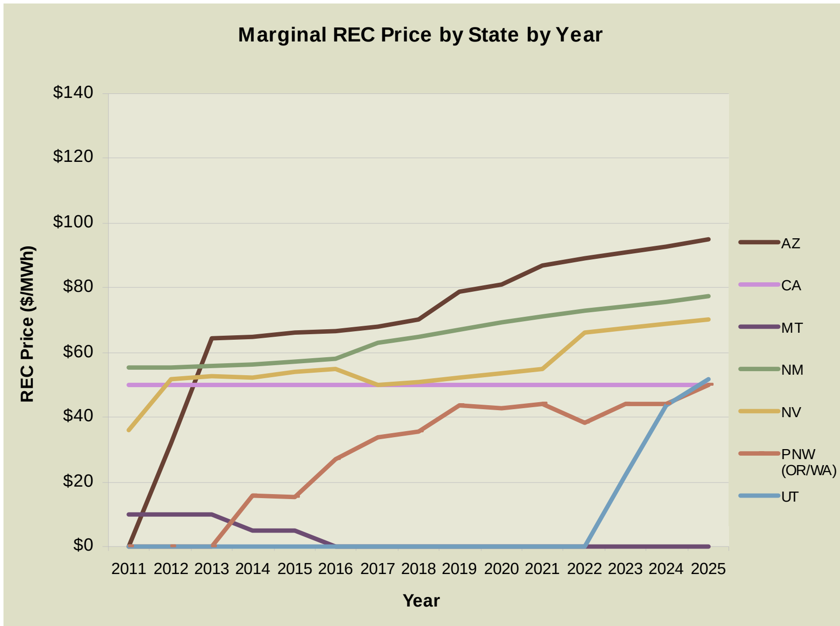

Figure 8-7. Scenario 4 REC Prices by State (2011-2025)

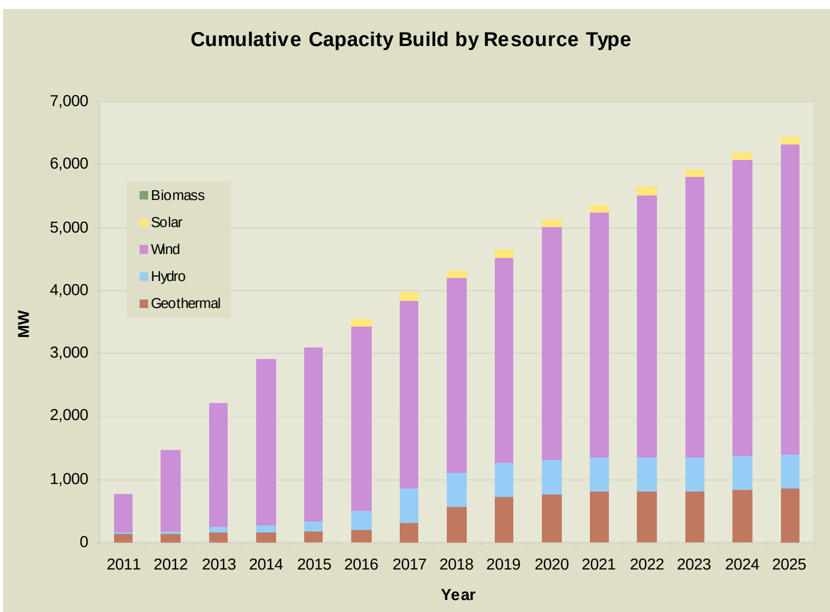

Figure 8-8. Scenario 4 Cumulative Capacity Build for RPS Demand (2011-2025)

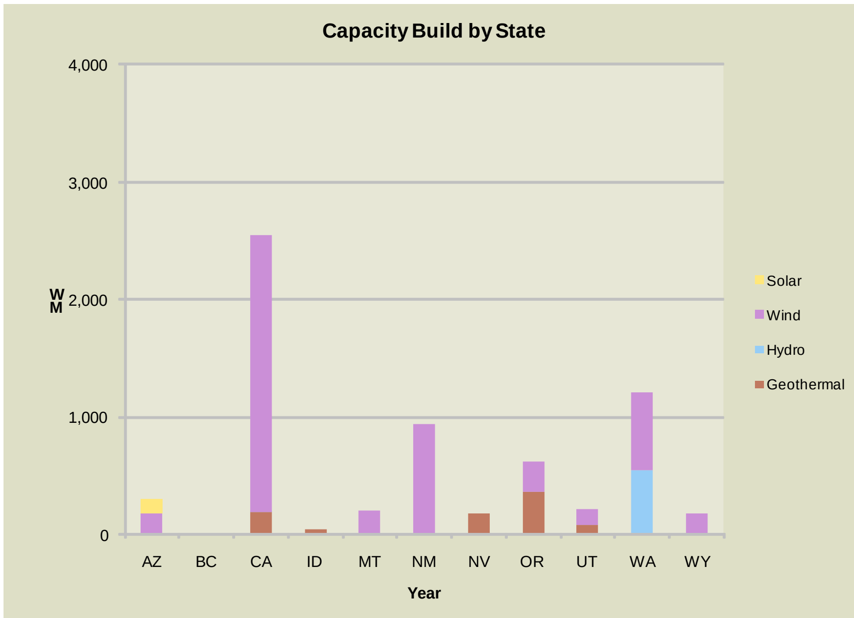

Figure 8-9. Scenario 4 Total Capacity Build by State (2011-2025)

8.4 Scenario 8

Due to a very low energy price forecast in this scenario and slow declining cost of solar and wind technologies, REC prices increase to high levels or hit alternative compliance payment (ACP) caps as shown in Figure 8-10. The prices are even higher than Scenario 4 because no incentives are available beyond 2016. Overall, very little renewable capacity is built during this period because the low energy prices for REC premiums to be very high, which are constrained by the ACP in many of the large RPS states. California, Washington, and Oregon hit their ACP caps of $50 per MWh, so procurements fall well short of RPS requirements. Arizona, Nevada, and New Mexico prices escalate to well above $100 per MWh. As in Scenario 4, the build-out in these states may be actually more limited than shown, due to constraints on rate impacts in these states. The capacity build by resource type across the WECC is shown in Figure 8-11 , which reflects significant underbuild of renewable energy projects due to the ACP cap restricting most of the build for California RPS in future years. The locations of projects are shown in Figure 8-12. A few MW of hydro from BC are built in this scenario because Canadian and U.S. projects are closer in cost, without a federal tax incentive in place.

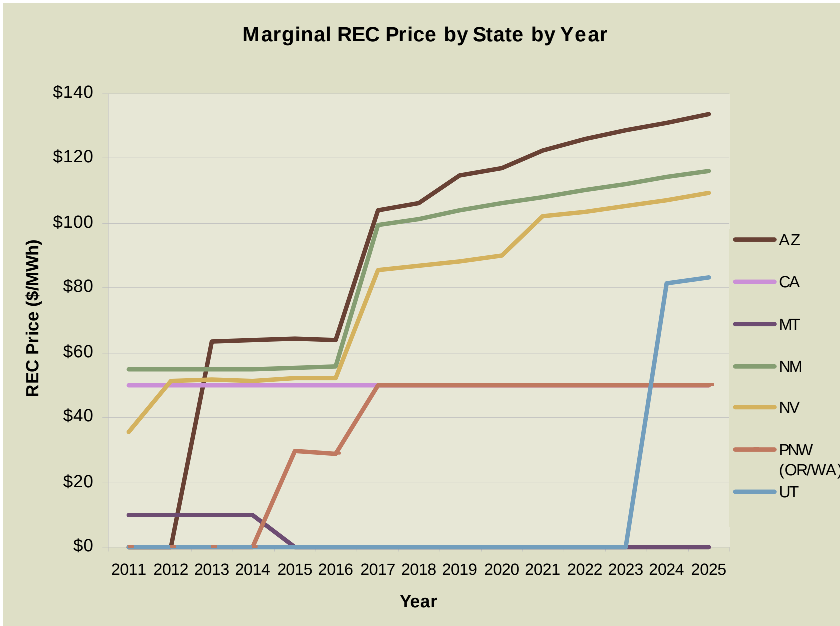

Figure 8-10. Scenario 8 REC Prices by State (2011-2025)

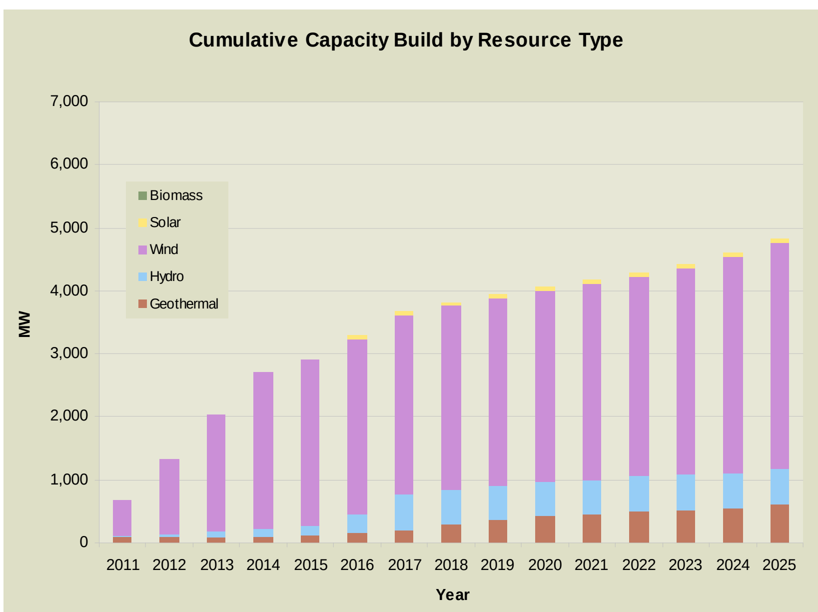

Figure 8-11. Scenario 8 Cumulative Capacity Build for RPS Demand (2011-2025)

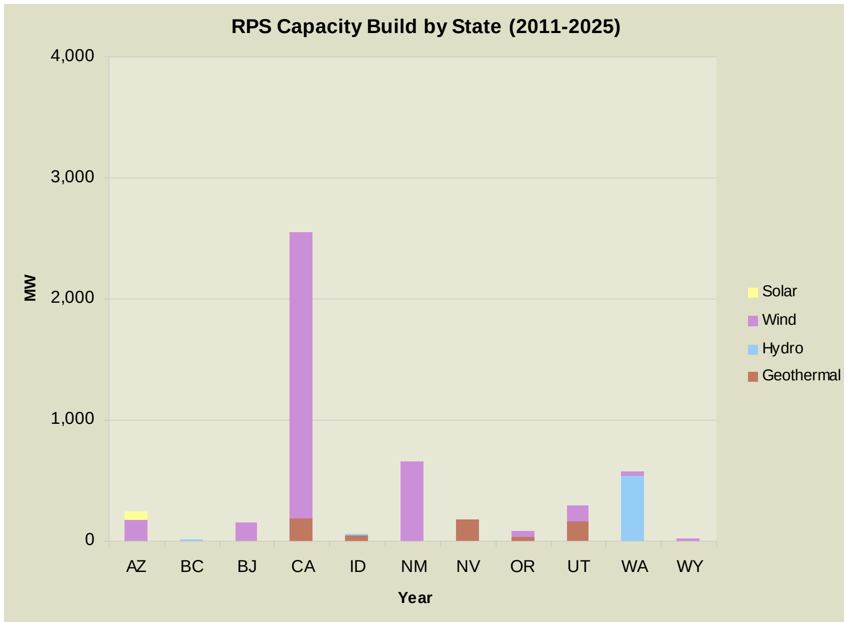

Figure 8-12. Scenario 8 Total Capacity Build by State (2011-2025)

8.5 Scenario 9

Due to a relatively high energy price forecast in this scenario and continuance of the PTC after 2016, Figure 8-13 shows that REC prices are relatively low or zero, depending on the state. Many of the projects that are used to meet the state RPS programs cost below the forecasted energy and capacity value. California, with its high level of RPS demand, does show REC prices averaging about $7/MWh over the study period.

The capacity build by resource type across the WECC is shown in Figure 8-14, with over 35,000 MW of renewable energy project built by 2025. The locations of projects are shown in Figure 8-15. In this scenario, a mix of wind, solar, geothermal and hydro projects are deployed, as well as 74 MW of biomass. A few small hydro projects (18 MW) from BC are built in this scenario because high demand for renewable energy across WECC makes a small amount of BC Hydro projects attractive for importing to the U.S. However, because the PTC is still in place in later years, very few international projects can compete. Additionally, more wind is built in this scenario compared to Scenario 1, which has the same level of projected RPS demand, because the cost of solar PV is assumed to decline at Baseline rates, rather than accelerated rates. Since the PTC is still in place, wind from states like Wyoming, Washington, and Montana more attractive than solar.

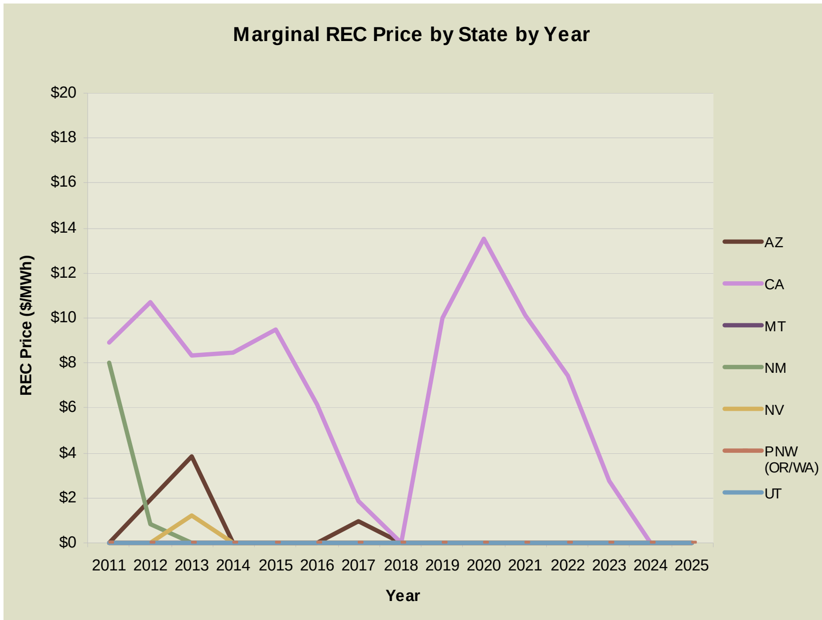

Figure 8-13. Scenario 9 REC Prices by State (2011-2025)

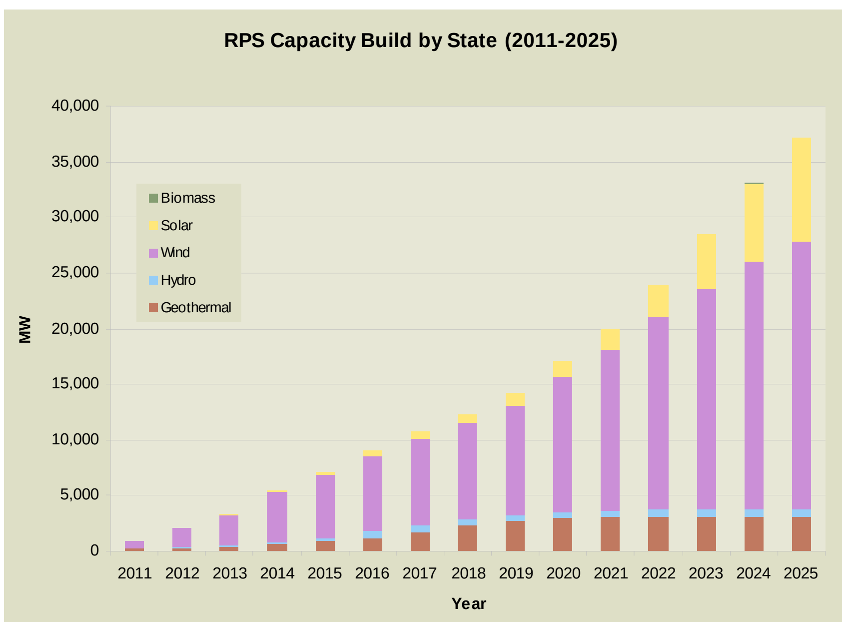

Figure 8-14. Scenario 9 Cumulative Capacity Build for RPS Demand (2011-2025)

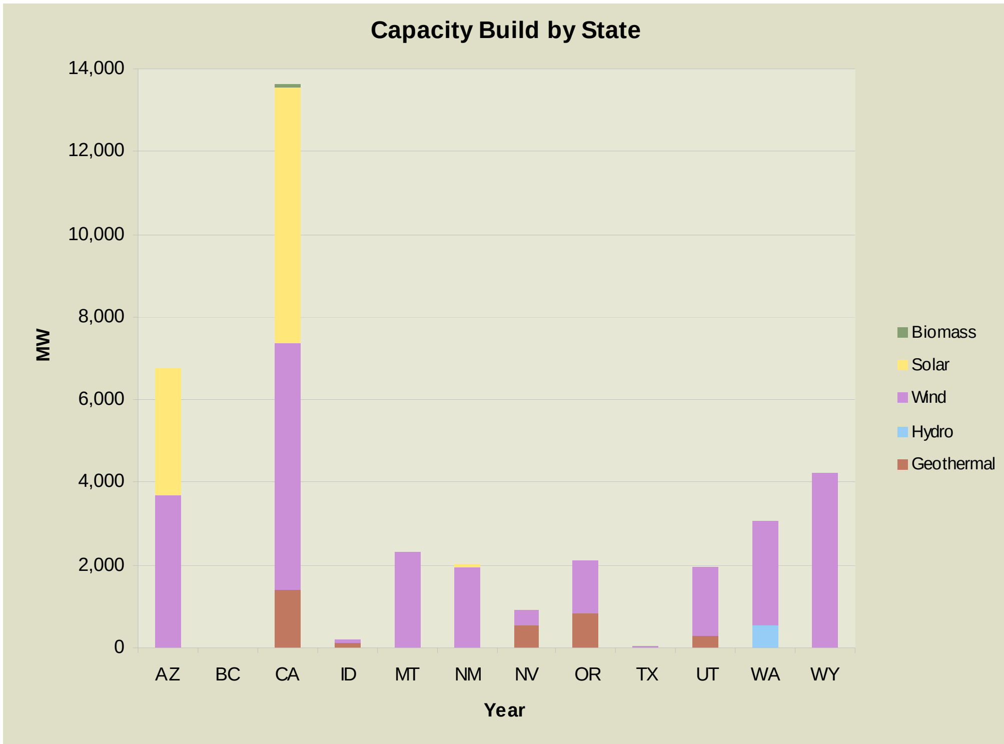

Figure 8-15. Scenario 9 Total Capacity Build by State (2011-2025)

9.0 Summary Findings

The discussion of federal and state RPS programs and the modeling of future REC markets demonstrate considerable uncertainties regarding the future for renewable energy. With different state RPS policies in place, the market is quite fragmented and demand for renewable energy is subject to change as a result of ACP limits and rate impact constraints, as well as continuation of targets beyond the 2025 horizon. California, potentially the largest renewable energy market in the U.S., continues to adjust its policies and eligibility requirements, which creates uncertainties about entering this market in the long-term.

9.1 REC Prices and GHG Policy

From the REC price analysis, it is evident that the five Market Scenarios that incorporate different GHG policies, natural gas prices, load growth, and electric vehicle implementation will have a significant impact on REC prices. Furthermore, assumptions regarding the availability of various tax incentives in the future and rate of decline for certain renewable energy options will also impact the level of REC prices. The differences in assumptions and scenarios can result in a wide range of REC prices in a given year, from $0 to over $100 per MWh.

Table 9-1 Market Scenarios and Corresponding REC Prices.

Market Scenario	**1**	**3**	**4**	**8**	**9**
Global Economic Growth	High	Medium	Low	Low	High
Government Policy Maker	National	Reg/Nat	Reg/Nat	Regional	Regional
Gas Prices	High	EMP	Low	Low	EMP
Load Growth	High	EMP	Level	Level	High
RE Incentives in US (ITC through 2016)	no PTC after	PTC after	PTC after	no PTC after	PTC after
RE Cost Decline (Wind and Solar)	Fast	Fast	Slow	Slow	Baseline
Results	**1**	**3**	**4**	**8**	**9**
GHG Price Level	Mid	Mid	Low	Zero	High
Energy Price Level	Very High	Mid	Low	Low	High
REC Price Level	Zero	Mid	High	High	Low

Upon examination of the resulting GHG prices, energy prices, and REC prices of each Market Scenario, it is evident that when energy prices are high, REC prices are low or zero. The combination of natural gas prices and GHG prices contribute to the high energy price forecast. In other words, if future energy prices are high, resulting from either high GHG or high natural gas prices, there is no REC premium required for developing renewable energy projects because renewable energy would be directly competitive with conventional generation. RPS targets, as well as GHG reduction goals, could easily be met as massive amounts of renewable energy projects are deployed. In light of the changing focus of the U.S. Congress away from GHG policies, however, a nationally-driven, stringent GHG policy is not foreseen in the near-term. Regional GHG programs could support renewables development if GHG prices are sufficiently high.

On the other hand, if GHG policies are modest or do not exist, the GHG prices would be low or zero. Coupled with low natural gas prices, the resulting energy prices are also low. This means renewable energy projects cannot directly compete. In fact, the price gap is so high for many renewable energy options (>$50 per MWh) that ACP constraints cause many states not to meet their RPS targets. For the states that do not have ACP constraints, REC prices may rise to $100 per MWh or more; though at these levels, the states with rate impact constraints may also end up not meeting their RPS targets. With the current state of the natural gas market being so low and no national RPS or GHG policies in place, regional RPS and GHG targets may not be achievable if caps on REC prices persist.

In a scenario where both GHG prices and natural gas prices are considered moderate, the resulting energy prices are also moderate. At this level, there is still a gap between the future cost of renewable generation and energy prices, so some RE premium is still needed to make a project whole. The resulting REC prices start at around $30 per MWh in the near term for most states and then decline over time as energy prices rise, due to increasing GHG and natural gas prices. This means that less of a premium will be needed in the long term, assuming the PTC continues to be in place. It is debatable whether PTC or RECs would be the preferred mechanism to address revenue shortfalls of renewable energy projects in later years. If PTC is removed in later years, the REC prices would increase instead of decrease.

Overall, increased penetration of renewables will reduce GHG emissions. What will be necessary to firm and shape the renewable, for the portion of RPS programs that can be met with these products, is still to be determined. If the renewables added are quite variable, new firming and shaping resources may be needed. The extent of such need will be in part driven by the diversity of such resources (more diversity reduces the need) and the ability to forecast the variability. The technology of new firming and shaping resources will impact the quantity of GHG emissions they introduce into the environment. It is often assumed that new flexible gas fired generation will be used to firm and shape new renewables. Whenever such gas fired resources need to be run, GHG will be emitted. If firming and shaping is done with hydro facilities, then there will be no GHG emissions associated with the firming and shaping.

9.2 Renewable Energy and GHG Policy

State Renewable Goals (i.e. RPS targets) were originally established to bridge the gap between renewable energy and "least-cost" conventional generation, to reduce local emissions such as NOx, SOx, Mercury, Particulates, etc and to create local jobs. As climate change concerns grew, it became clear that the construction of renewable resources would be a key activity in reducing GHG emissions also. As climate change legislation is designed and planned, establishing RPS targets have been considered as one major element of meeting GHG reduction goals. However, the interaction between market-based GHG reduction schemes and RPS targets has created concerns over double-counting and misconceptions in the market place.

The misconception is that a REC can be used to comply with an RPS target and act as a carbon offset. To understand this issue, one must understand the different entities that are responsible for meeting RPS and GHG targets. In an RPS program, the responsible parties are the load serving entities who must ensure a portion of the energy used to serve load is renewable. The RECs associated with the renewable energy will also be used by these entities to report its portfolio mix and the GHG emissions associated with the mix. However, load serving entities generally are not responsible for GHG emissions reductions of their portfolio mix, except for the portion of generators that are owned by them. The owners of power generators and other emitting sources are responsible for GHG reduction targets and expect to incur additional costs for the right to emit, either in the form of a carbon tax or carbon allowances. Non-emitting or carbon neutral renewable energy projects do not emit, but an emitter cannot use RECs from these projects to claim reductions (offsets) to its own GHG emissions. This is because the electricity produced by a renewable energy project may have already displaced an equivalent amount of electricity from an emitting generator, who has reduced its own overall emissions by not generating. Thus, a second emitter cannot take credit for that same reduction.[15] In most jurisdictions, RECs cannot be counted twice or be sold as two separate products.

In market-based GHG reduction schemes, there is usually a carbon cost adder to electricity generated by emitters, which non-emitters do not face. GHG policy often increases the marginal price for electricity, which, in turn, increases the electricity revenue that non-emitting renewable energy projects may be able to receive. In this way, GHG policy implicitly supports renewable energy projects through elevated energy price revenues, but does not provide an explicit revenue stream in the form of carbon offsets. The value components of renewable energy projects, thus, are: (1) energy (with implicit carbon adders); (2) capacity; and (3) RECs (for RPS compliance). As discussed in previous chapters, the value of RECs may be bundled with the power or unbundled, depending on the state RPS program.

[15] One known exception to this is the GHG scheme in Alberta, where GHG emissions reduction goals are based on carbon intensity (per MWh generation), so renewable energy can help reduce emitters' carbon intensity.