# Desert Renewable Energy Conservation Plan: Renewable Energy Acreage Calculator and the 2040 Revised Scenario's Renewable Portfolio

~~June 20, 2012~~July 27, 2012


## Summary

In support of the Desert Renewable Energy Conservation Plan (DRECP), staff of the California Energy Commission's Electricity Supply Analysis Division estimated the quantity of renewable energy development might be needed in the DRECP area in the coming decades in order for the state to meet its climate policy goals. To answer this question, staff developed a spreadsheet model, the Renewable Energy Acreage Calculator (Calculator), capable of testing a range of variables impacting the renewable energy needed to keep the electricity sector on track to achieve an 80% reduction in GHG emissions below 1990 levels by 2050. For each variable, the Calculator estimates the quantity of additional renewable energy needed based on the input assumptions, attributes a fraction of development for each resource to the DRECP planning area,[1] allocates the additional renewable energy needed among the available renewable energy resources, and estimates the quantity of acreage needed in the DRECP planning area. Over the last 12 months, staff used the Calculator to develop a range of plausible scenarios for 2040 and 2050.[2]

This report provides an in-depth discussion of a revised 2040 scenario, representing a plausible lower bound for DRECP planning purposes (the Revised Scenario). Staff shared an earlier iteration of this scenario with stakeholders on December 5, 2011, as well as a 2050 scenario.[3] This Revised Scenario responds to stakeholder comments by adjusting input assumptions, including those relating to load growth (net energy for load), use of plug-in hybrid-electric and full-electric vehicles, and acreage requirements for central station solar resources. In addition, staff assumed the retirement/divestiture of the Palo Verde Nuclear Generation Station and a slight increase in storage needs.

The 2040 Revised Scenario results in a renewable resource portfolio that anticipates the development of distributed generation (DG), substantial reliance on out-of-state renewable resources, and low acreage biofuel and geothermal resources (available feedstock and technical potential, notwithstanding). Parties have noted that technological advances may allow for portfolios consisting of far fewer central station


[1] The acreage "Share in DRECP" for each renewable resource is shown in **Table 1**.

[2] The scenarios developed entail estimating the need for incremental (to that provided by existing resources) in-state renewable energy to meet a long-run GHG emission reduction goal for the electricity sector (the "demand side"), then constructing a portfolio of renewable resources that provides this amount of energy (the "supply side"). Energy demand, and the resulting sets of renewable resources are in-state, statewide, and above and beyond existing renewable resources and the energy they provide.

[3] While staff presented scenarios for both 2040 and 2050 in December of 2011, staff was only asked to provide a revised scenario for 2040. Staff understands this is because the DRECP will rely primarily on California's electricity needs in 2040 for planning purposes.

(CS) locations. Staff acknowledges this possibility, but notes that other factors may encourage/require greater development of such resources later in the century as the 2050 GHG goal nears.

This renewable resource portfolio with associated acreages, both statewide and within the DRECP, is presented in **Table 1** below.

**Table 1: Revised 2040 Staff Renewable Resource Portfolio**

| 2040 | Statewide MW | Statewide GWh | Share in DRECP Boundary | Statewide Acres | Acres/ MW | Acres in DRECP Boundary |
|---|---|---|---|---|---|---|
| **CS Solar Thermal** | 3,612 | 9,492 | 100% | 25,283 | 7 | 25,283 |
| **CS Solar PV** | 7,224 | 16,453 | 70% | 50,566 | 7 | 35,396 |
| **Wind** | 6,155 | 17,253 | 50% | 246,197 | 40 | 123,099 |
| **Geothermal** | 2,998 | 22,320 | 85.7% | 17,985 | 6 | 15,416 |
| **Biomass**[3] | 2,569 | 19,131 | 8.3% | 2,141 | 2.5 | 535 |
| **Utility Side DG**[1] | 9,421 | 19,806 | 27.5% | 52,757 | 7 | 14,508 |
| **Small Rooftop Solar**[2] | 7,000 | 12,264 | | | | |
| **Total** | 38,978 | 116,719 | | 394,930 | | 214,237 |

[1] Only 80% of Utility-Side DG capacity is assumed to require acreage.
[2] Does not include 3,000 MW embedded in demand forecast.
[3] The DRECP does not intend to include biomass as a covered activity in the Plan.

## Introduction to the Renewable Acreage Calculator Process

The following discussion explains the process of estimating the amount of in-state renewable energy needed in 2040 and developing the portfolio of renewable resources that provide the required energy. The Renewable Energy Acreage Calculator (Calculator) consists of three parts: first, the demand for incremental in-state renewable energy, and second, its potential supply sources and associated acreage requirements. Lastly, a comparison of the renewable portfolio changes between the original December 2011 scenario and this Revised 2040 Scenario concludes this document.

### Part 1: Explanation of Revised 2040 Scenario Demand Assumptions

The task of determining the in-state renewable energy requirement (GWh) for 2040 consists of the following steps:

(1) Determine the total demand for electricity (GWh) in California in 2040, excluding that due to electrification of the transportation sector.
(2) Estimate incremental energy demand due to electrification of the transportation sector.
(3) Estimate the GHG emissions allowed from the electricity sector in 2040, given the GHG emissions reduction target and purchases of offsets from other sectors of the economy allowed in meeting the target.
(4) Estimate the GWh of energy provided in 2040 by zero-carbon generation resources other than new renewable generation:
    a. Existing in-state (on-line in 2010) renewable resources that are still operating in 2040
    b. Large hydroelectric
    c. Nuclear
    d. Out-of-state renewables assumed at the 25% limit in SB 1X-2 (Simitian, 2011)
(5) Estimate the GHG emissions and GWh of energy from “preferred fossil” resources:
    a. Combined heat and power (CHP)
    b. Coal and natural gas-fired generation with carbon sequestration.
(6) Deduct the GHG emissions from preferred fossil resources from the allowable GHG emissions in (3) to derive “remaining GHG emissions allowed.” Specify a thermal efficiency (mmBtu/MWh) for natural gas-fired generation to arrive at allowed GWh from gas-fired generation.
(7) Deduct the energy from (4), (5), and (6) from total energy demand in (1) to serve the incremental renewable energy (incremental to that from existing resources) required.
(8) Determine the share of (7) that can come from out-of-state renewable resources. Deduct this value from (7) to determine incremental in-state renewable energy required to meet the GHG emissions reduction target in 2040.

The steps outlined above yielded the demand estimates for 2040 displayed in **Table 2**.

**Table 2: Demand for Incremental In-State Renewable Energy, 2040**

| | **Scenario Values** |
|---|---|
| **Net Energy for Load (GWh)** | |
| Net energy for load in 2040 | 336,597 |
| Needed energy increases in 2040 from electrification | 63,074 |
| Self-generation by 4,500 MW of new CHP | -19,603 |
| Self-generation by 10,000 MW of DG (customer-side) solar | -13,258 |
| Storage Needs | 11,004 |
| Final net energy for load | 377,813 |
| **Carbon Baseline** | |
| Desired carbon reductions from 1990 levels | 58% |
| Allowed offsets | 8% |
| Carbon cap (mmmt) | 54.0 |
| Carbon from CHP (share allocated to sector, mmmt) | 6.7 |
| Remaining carbon allowed (mmmt) | 47.3 |
| **Energy from Other Generation Resources (GWh)** | |
| Allowed gas-fired generation at 7.4 mmBtu/MWh | 120,588 |
| CHP exports | 18,133 |
| Existing in-state renewables | 35,000 |
| Large in-state hydroelectricity | 33,000 |
| Existing out-of-state renewables | 0 |
| Nuclear energy | 0 |
| Out-of-state non-renewables | 3,800 |
| Other (e.g., fossil generation w/sequestration) | 0 |
| **Total energy from other resources (GWh)** | 210,521 |
| Remaining net energy for load | 167,292 |
| Allowed out-of-state under 25% cap | 50,573 |
| **Incremental need for in-state renewable energy (GWh)** | 116,719 |

The next sections will explain each of the 2040 assumptions from **Table 2** that are used in the demand component of the Calculator. These assumptions are presented in three sections to correspond to **Table 2**.

**Net Energy for Load**

This section of the calculation includes five individual assumptions: Net Energy for Load in 2040, Energy Increases from Electrification, Self-Generation by 4,500 MW of New CHP, Self-Generation by 10,000 MW of DG, and Storage Needs. Staff's derivation of each assumption is described here.

### ***Net Energy for Load in 2040***

Net Energy for Load is the amount of electricity that must be generated to meet customer demand; it represents customer demand plus losses incurred at the transmission and distribution level in getting electricity generated to the end user.

As a starting point, staff used the Energy Commission's 2009 forecast of net energy for load for 2012 – 2020.[4] This forecast includes load associated with electrification of the transportation sector (i.e., demand for electricity for electric vehicles), but does not include the effects of uncommitted energy efficiency (energy efficiency programs yet to be designed or funded, but reasonably expected to occur). In order to isolate the incremental demand for electricity from electric vehicles use, staff removed the estimated demand from hybrid-electric and full-electric vehicles from the 2012 – 2020 forecast. The resulting "EV-free" forecast had an annual growth rate of 0.998% over 2012 – 2020. Staff then modified the forecast to account for uncommitted energy efficiency over 2012 – 2020; this yielded an annual growth rate of 0.486%.

Staff used a linear extrapolation of the managed (with uncommitted energy efficiency, but without EVs) forecast for 2012 – 2020 to estimate net energy for load in 2040. This linear extrapolation was modified in two ways. First, uncertainty regarding the long-run funding for/efficacy of energy efficiency programs led staff to increase the post-2020 annual growth rate by 0.1 percentage points to 0.586 percent. This had the effect of increasing net energy for load in 2040 by 6,848 GWh to 347,673 GWh. Second, staff incorporated the likely impact of increasingly slower population growth forecasted for the 2020s and 2030s by adjusting the annual growth rate in net energy for load in the 2020s and 2030s (excluding uncommitted energy efficiency) downward, from the 0.998% forecasted over 2012 – 2020 by an amount indicated by the rate of population growth during the decade. This adjustment, displayed in **Table 3**, reduced net energy for load in 2040 by 11,075 GWh, bringing the final value to 336,597 GWh. For a complete set of values for net energy for load and the impact of uncommitted energy efficiency over 2012 - 2040, see **Appendix A**.

**Table 3: Population and Net Energy for Load Growth Rates, 2012 - 2040**

| Year/Decade Ending | Population | Growth Rate | Share of 2012-2020 Rate | Net Energy for Load Growth Rate Estimated/Assumed |
|---|---|---|---|---|
| **2010** | 39,135,676 | | | |
| **2020** | 44,135,923 | 1.21% | 100% | 0.998% |
| **2030** | 49,240,891 | 1.10% | 91.0% | 0.908% |
| **2040** | 54,226,115 | 0.97% | 80.1% | 0.800% |

[4] Appendix A of this document contains the demand forecast values. *California Energy Demand 2010 – 2020, Commission Adopted Forecast*, California Energy Commission, December 2009, CEC-200-2009-012-CMF, available at http://www.energy.ca.gov/2009publications/CEC-200-2009-012/CEC-200-2009-012-CMF.PDF.

While an upward adjustment has been made to account for uncertainty regarding the impact of uncommitted energy efficiency over 2020 – 2040, per capital consumption, which has remained roughly constant over the past 35 years, drops in every decade over 2012- 2040, as indicated in **Table 4**.

**Table 4: Net Energy for Load Per Capita, 2012 – 2040**

| Year | Population | Net Energy for Load | MW/Capita | Percentage of 2010 Value |
|---|---|---|---|---|
| **2010** | 39,135,676 | 300,000[1] | 7.67 | |
| **2020** | 44,135,923 | 309,300 | 7.01 | 91.4% |
| **2030** | 49,240,891 | 324,767 | 6.66 | 86.0% |
| **2040** | 54,226,115 | 336,597 | 6.21 | 81.0% |

[1]Adjusted upward from actual value to account for economic downturn.

### *Energy Increases from Electrification*

Staff assumed almost 18 million full electric and plug-in hybrid electric vehicles in the California fleet in 2040. While improvements in technology, including the use of hydrogen as a transportation fuel may reduce energy needs arising from electrification, this is less than the 40 million vehicles that might be necessary to meet the state's 2050 GHG emission reduction goals for the transportation sector.[5]

**Table 5** displays the assumptions that underlie the estimated impact of electrification on net energy for load. In response to comments by the Sierra Club, staff reduced Fraction of Vehicle Miles on Full Electric from 90% to 72.6% reducing the total energy needed for electrification in 2040 by 13,661 GWh. While included in some earlier scenarios, the Revised Scenario does not include additional load for high speed rail, which could require an additional 13,000 GWh in 2040.

[5] Energy and Economics, Inc., *Meeting California's Long-Term Greenhouse Gas Reduction Goals*, November 2009.

**Table 5: Net Energy for Load Needed for Transportation Electrification, 2040**

| **Full Electric Vehicles** | **Estimated** | **Units** |
|---|---|---|
| Number of vehicles | 690,000 | Vehicles |
| Average vehicle efficiency (KWh/mile) | 0.33 | KWh/Mile |
| Annual vehicle miles travelled per vehicle | 8,627 | Miles |
| Full electric light-duty vehicles (LDV) electricity consumption (GWh) | 2,124 | GWh |
| | | |
| **Plug-In Hybrid Electric Vehicles (PHEV)** | **Estimated** | |
| Number of vehicles | 17,300,000 | Vehicles |
| Average vehicle electric depleting efficiency (KWh/mile) | 0.33 | KWh/Mile |
| Annual vehicle miles travelled per vehicle | 13,000 | Miles |
| Fraction of vehicle miles on full electric | 72.6% | Percent |
| PHEV LDV electricity consumption (GWh) | 58,250 | GWh |
| | | |
| Total light-duty electricity consumption | 60,374 | GWh |
| Public transportation electricity consumption | 1,000 | GWh |
| Ship electrification | 700 | GWh |
| High speed rail | 0 | GWh |
| Goods movement efficiency improvements | 1,000 | GWh |
| **Total net energy for load needed for electrification** | ~~**63,374**~~ **63,074** | GWh |

***Self-Generation by 4,500 MW of New Combined Heat and Power***

Staff assumed 4,500 MW of new combined heat and power (CHP). This was assumed to be natural gas-fired, combusting 7 mmBtu/MWh, with an annual capacity factor of 92%, consuming half of its output on site and exporting the other half to the grid. GHG emissions associated with on-site consumption are assumed to be attributable to the industrial sector; those associated with exports count against the sectoral emissions cap. 18,133 GWh of energy are exported to the transmission grid. The 18,133 GWh consumed on site reduce net energy for load by 19,603 GWh, as an incremental 1,470 GWh of transmission and distribution losses are avoided.

Parties have commented that the 4,500 MW of new CHP assumed is below the amount targeted by the Governor's Clean Energy Jobs Plan for 2030. To the extent that new CHP generates for export, its exclusion from this scenario has little impact on incremental renewable energy needs as the associated GHG would count against the emissions limits assumed to be achieved, reducing the amount of incremental gas-fired generation that would be allowed. Substantial amount of CHP generating for on-site use would reduce incremental renewable energy needs under the assumption that associated emissions would be credited to the industrial sector, but total GHG emissions across the industrial and electricity sectors would be changed only to the extent that the joint production of industrial output and electricity reduces fossil fuel combustion.

### *Self-Generation by 10,000 MW of DG (Customer-Side) Solar*

Some 10,000 MW of small rooftop solar is assumed to be in place in 2040, with roughly 3,000 MW of this total already embedded in the Energy Commission's 2009 demand forecast. The total energy from this capacity is 17,520 GWh, some 12,264 of which is from the 7,000 MW of capacity not already assumed in the Energy Commission's demand forecast. This 12,264 GWh of energy yields a reduction in net energy for load due to the assumption of 994 GWh of reduced transmission and distribution losses.

### *Storage Needs*

The electricity system in 2040 is expected to require the storage of substantial amounts of energy to effectively meet demand. This storage may serve to:

- Provide additional regulation to the system
- Meet off-peak (charging loads)
- Manage generation and loads on the distribution system
- Shift solar energy to low solar hours (during early morning and early evening ramps)
- Shift early morning energy to morning ramp

The storage of energy comes at the cost of requiring additional energy to losses due to the inefficiency of storage; this depends upon the storage technology deployed. The largest most mature storage technology is pump storage, with facilities capable of exceeding 1,000 MW in size and efficiencies around 70%. Smaller-scale technologies under development have efficiencies that exceed 90%. Staff assumes that the incremental energy need due to storage is equal to 15% of net energy for load, with an efficiency of 80%. While staff previously assumed that a 10% share of net energy for load, this change was made in response to Sierra Club comments that storage needs in 2050 may equal 20% of net energy for load. This change in assumptions resulted in an increase in required net energy for load of roughly 3,500 GWh to 11,004 GWh.

## Carbon Baseline: Desired Carbon Reductions and Offsets

All of the 2040 scenarios developed by staff have assumed a GHG emissions reduction target of 58% of 1990 levels and the ability to purchase offsets for 8% of the allowed carbon emissions from other sectors of the economy. The 8% value is that currently allowed by the California Air Resources Board. The resulting cap on sectoral emissions is 54.0 mmmt $CO_2$-e/year, assuming that 5.4 mmmt of offsets are purchased.

The CHP assumed in the scenario produces 6.7 mmmt of GHG emissions that are attributable to the electricity sector. This leaves 47.3 mmmt of emissions allowed for the remaining generation resources that meet loads.

## Energy from Other Generation Resources

A share of the net energy for load in 2040 will be met by existing and other resources; staff estimates that more than 210,000 GWh of the 377,000 GWh needed will be provided by other non-renewable resources. Seven different generation resources are considered in this portion of the Calculator: Natural Gas-fired Generation, Existing In-State Renewables, Nuclear Plants, Large Hydroelectric, Out-of-State Non-Renewable Resources (zero carbon), Out-of-State Renewable Energy, and Other Resources. Staff's derivation of each of the assumptions is described next.

### *Natural Gas-Fired Generation*

Staff assumes that room under the GHG emission cap will be filled by natural gas-fired generation. 120,588 GWh of energy can be generated under the cap by gas-fired generation at a heat rate of 7.4 mmBtu /MWh. This is above the thermal efficiency of new combined cycles, but well below the current fleet average. This is because a substantial share of gas-fired generation will be needed to integrate renewable resources (i.e., to provide flexibility), which requires sacrificing efficiency in order to cycle on and off on a daily basis or more, and provide greater amounts of ancillary services such as regulation and load-following.

### *Existing In-State Renewables*

Staff assumed that existing in-state renewables would be generating 35,000 GWh of energy in 2040. This is equal to the total amount of in-state renewable generation in 2010 and assumes that a substantial amount will either still be in operation or be re-powered. While many renewable resources generating in 2010 may have retired by 2040, most of these sites will see replacement renewable projects that, therefore, do not require additional, undeveloped acreage. Parties have pointed out that these new projects will be more efficient, producing more energy on the same amount of (already disturbed) land, thus reducing the remaining amount of renewable energy acreage that needs to be developed elsewhere to meet the state's GHG emission reduction targets.

### *Nuclear Plants*

California ratepayers are entitled to output from the nuclear generation facilities at San Onofre and Diablo Canyon (18,000 GWh/year), and a 6,000 GWh/year share of the output from the Palo Verde Nuclear Generation Station.

Staff assumed that the two California facilities would not be operational in 2040, perhaps not being relicensed for operation beyond 2024. In addition, staff assumed that Palo Verde would either be shut down by 2040, or that California utilities would divest themselves of their entitlement prior to that date.[6] The closure of each of the nuclear facilities yields an increase in in-state renewable energy requirements of 13,500 GWh, for a total of 27,000 GWh. The closure/divestiture of Palo Verde increases the in-state

[6] The three units at Palo Verde are currently licensed through 2045 – 2047.

renewable energy requirement in 2040 by 4,500 GWh. Even if none of these operational or divestiture scenarios occur, it is prudent to plan for backfilling this zero carbon energy resource.

### *Large Hydroelectric Resources*

Staff assumed that energy from large hydroelectric facilities (30 MW or more) in California in 2040 would be unchanged from current levels; 33,000 GWh is generated in an average water year. Parties have suggested that climate change may reduce hydroelectric output in California by 25% or more by 2040; such a reduction would increase the need for new in-state renewable energy by more than 6,000 GWh.

### *Out-of-State Non-Renewable Resources (Zero Carbon)*

The demand for in-state renewable energy will be reduced to the extent that energy from non-renewable, zero-carbon, out-of-state resources is available (energy from out-of-state renewables is accounted for separately). This could take the form of large hydroelectricity projects, fossil generation with carbon sequestration, etc. Staff acknowledges the possibility of fossil generation resources that sequester GHG emissions, but considers the widespread adoption of carbon sequestration or related technologies speculative at this time.

Staff assumes that existing surpluses of hydroelectricity in the Pacific Northwest will be somewhat eroded by load growth and possibly, as noted above, by climate change. Furthermore, because of the substantial year-to-year variability in water conditions in the Northwest, neither utilities in the region nor the Bonneville Power Administration have entered into new contracts for firm hydroelectric energy with California load-serving entities during the past decade; these would be minimally necessary for the displacement of in-state renewables.[7] The simultaneous pursuit of zero-carbon resources by all western states will either limit the availability of such out-of-state resources to serve California loads, or raise the cost of their procurement, encouraging the development of in-state resources.

Staff assumes the procurement of 3,800 GWh of energy from out-of-state zero-carbon non-renewable resources in 2040.

### *Out-of-State Renewable Energy*

Staff assumed that 25% of the renewable energy needed to reach 2040 GHG emission reduction targets would be located out-of-state. This is consistent with the limits established by SB 1X-2. This is a key assumption; reducing the share of out-of-state

[7] The resource adequacy protocols established by the California ISO preclude the use of non-firm or short-term energy purchases to meet resource adequacy requirements. To the extent that the owners of entitlements to Northwest hydroelectricity refuse to enter into long-term contracts for the delivery of energy to California's major investor-owned utilities, the latter must procure additional capacity elsewhere.

renewable energy allowed by only 5% yields an increase in in-state renewable energy needed by more than 10,000 GWh.

Staff notes that it may not prove feasible or practical to import 25% of the state's renewable energy in 2040. While the quality of out-of-state renewable resources is quite high (e.g., Columbia River Gorge and Wyoming wind resources), several factors mitigate against reliance on such a large share of renewable energy from out of state.

- As neighboring states establish higher renewable portfolio standards, interstate competition for high quality renewable resources will drive costs up and facilitate development of less efficient resources.
- Neighboring balancing authorities may find it increasingly difficult to balance for intermittent resources dedicated to external loads and require California entities to provide balancing services, increasing the cost of procurement of out-of-state resources.
- Greater reliance on out-of-state resources will require additional bulk transmission, increasing costs relative to in-state resources, which requires less transmission.
- Greater weight may be placed on the value of in-state renewables as sources of jobs, emission reductions, etc. Limits, below 25%, may be placed on out-of-state renewable resource procurement. It should be noted that sample 2022 portfolios recently developed for use in the CPUC's 2012 Long-Term Procurement Proceeding and the California ISO's Transmission Planning Process contain less than 25% of their renewable energy from out-of-state.

## Part 2: Explanation of Revised 2040 Scenario Acreage Assumptions

The second component of the Calculator is the acreage requirement assumptions for each of the renewable generation resources. **Table 6** summarizes the six technology types, their assumed capacity factors (annual output per MW of nameplate capacity), and the assumed number of acres required per MW of each technology.

Staff based these assumptions on existing examples of these technologies or facilities under contract, if not under construction from a variety of sources, including Siting Office files, California ISO, and the Bureau of Land Management's Draft Solar Programmatic Environmental Impact Statement.

**Table 6: Technology Capacity Factors and Acreage Requirements**

| Technology | Capacity Factor | Acreage Requirements (Acres/MW) |
|---|---|---|
| **Central Station Solar Thermal** | 30% | 7 |
| **Central Station Solar PV** | 26% | 7 |
| **Wind** | 32% | 40 |
| **Geothermal** | 85% | 6 |
| **Biomass** | 85% | 2.5 |
| **Utility-Side Distributed Solar (DG)**[1] | 24% | 7 |

[1] Only 80% of this capacity is assumed to have an acreage requirement.

## Part 3: Comparison of Renewable Portfolios in the 2040 Revised and December 2011 Scenarios

The starting point for the 2040 Revised Scenario's renewable resource portfolio shown on page 2 was a scenario presented to the DRECP on December 5, 2011. This earlier scenario, along with the allocation of capacity to the DRECP and its associated acreage, is presented in **Table 7**.

**Table 7: Staff 2040 Renewable Resource Portfolio Presented December 5, 2011**

| 2040 | Statewide MW | Statewide GWh | Share in DRECP | Statewide Acres | Acres/MW | Acres In DRECP |
|---|---|---|---|---|---|---|
| **CS Solar Thermal** | 4,900 | 12,877 | 100% | 44,545 | 9.09 | 44,545 |
| **CS Solar PV** | 9,800 | 22,320 | 70% | 89,091 | 9.09 | 62,364 |
| **Wind** | 8,350 | 23,407 | 50% | 334,000 | 40 | 167,000 |
| **Geothermal** | 3,500 | 26,061 | 85.7% | 21,000 | 6 | 18,072 |
| **Biomass** | 3,000 | 22,338 | 8.3% | 7,500 | 2.5 | 625 |
| **Utility-Side DG** | 11,000[1] | 23,126 | 27.5% | 80,000 | 9.09 | 22,000 |
| **Total** | | | | 576,136 | | **314, 606** |
| **CHP** | 4,500 | | | | | |
| **Small Rooftop Solar** | 7,000[2] | | | | | |

[1] Only 80% of Utility-side DG capacity is assumed to require acreage.
[2] Does not include 3,000 MW embedded in demand forecast.

**Table 8** summarizes changes in demand assumptions between the Revised 2040 Scenario presented today and the 2040 scenario presented on December 5, 2011.

**Table 8: Comparison of Demand for In-State Renewable Energy in 2040 Scenarios**

| | December 2011 Scenario (GWh) | Revised Scenario (GWh) |
|---|---|---|
| Net Energy for Load 2040 | 354,871 | 336,597 |
| Needed energy increases in 2040 from electrification | 77,035 | 63,074 |
| Self-generation by 4,500 MW of new CHP | -19,603 | -19,603 |
| Self generation by 10,000 MW of DG (customer-side) solar | -13,258 | -13,258 |
| Storage Needs | 7,981 | 11,004 |
| Final Net Energy for Load | 407,025 | 377,813 |
| Incremental need for Renewable Energy | 190,504 | 167,292 |
| Allowed Out-of-State under 25% Cap | 56,376 | 50,573 |
| Need for In-state Renewable Energy | 134,228 | 116,719 |

**Table 9** presents a comparison of the renewable supply portfolios in two 2040 scenarios under discussion. The second was realized by applying a pro-rata reduction to the energy from each of the resource types except CHP and small-rooftop solar until the reduced in-state renewable energy requirement was met. The relative amounts of capacity from central station solar and PV were then readjusted to maintain the one-third, two-thirds distribution imposed on the first scenario.

**Table 9: Comparison of Staff Renewable Resource Portfolios in 2040 Scenarios**

| | Dec 2011 Statewide MW (Table 7) | Revised Statewide MW (Table 1) | Dec 2011 DRECP MW | Revised DRECP MW | Dec 2011 DRECP Acres | Revised DRECP Acres |
|---|---|---|---|---|---|---|
| **CS Solar Thermal** | 4,900 | 3,612 | 4,900 | 3,612 | 44,545 | 25,283 |
| **CS Solar PV** | 9,800 | 7,224 | 6,860 | 5,057 | 62,364 | 35,396 |
| **Wind** | 8,350 | 6,155 | 4,175 | 3,078 | 167,000 | 123,099 |
| **Geothermal** | 3,500 | 2,998 | 3,000 | 2,569 | 18,072 | 15,416 |
| **Biomass** | 3,000 | 2,569 | 250 | 214 | 625 | 535 |
| **Utility -Side DG** | 11,000[1] | 9,421 | 3,025 | 2,591 | 22,000 | 14,508 |
| **Total** | **40,550** | **31,979** | **22,210** | **17,121** | **314, 606** | **214,237** |

[1] Only 80% of Utility-side DG capacity is assumed to require acreage. (**Table 9** does not include the CHP and Small Rooftop Solar included in **Table 1** and **Table 7** since no acreage is assumed.)

## Appendix A: Calculating Net Energy for Load, 2040

| Year | Unmanaged 2012 – 2020 Forecast[1] | EV | Unmanaged 2012 – 2020 Forecast w/o EV Demand | | Inc EE | Managed 2012 – 2020 Forecast w/o EV Demand | | |
|---|---|---|---|---|---|---|---|---|
| **2012** | 297,836 | 313 | 297,523 | | 0 | 297,523 | | |
| **2013** | 302,431 | 758 | 301,673 | | 1,743 | 299,930 | | |
| **2014** | 305,802 | 1,364 | 304,438 | | 3,050 | 301,388 | | |
| **2015** | 309,200 | 1,983 | 307,217 | | 4,304 | 302,913 | | |
| **2016** | 312,635 | 2,550 | 310,085 | | 5,932 | 304,153 | | |
| **2017** | 316,233 | 3,058 | 313,175 | | 7,881 | 305,294 | | |
| **2018** | 319,702 | 3,639 | 316,063 | | 9,834 | 306,229 | | |
| **2019** | 323,221 | 4,206 | 319,015 | | 11,462 | 307,553 | | |
| **2020** | 326,882 | 4,758 | 322,124 | | 12,824 | 309,300 | | |
| | | | **Growth Rate 0.998%** | **Adj Growth Down for Slow Pop Growth** | | **Growth Rate 0.486%** | **Growth Rate 0.586%** | **0.586% Growth w/Pop Adj** |
| **2021** | | | 325,339 | 325,049 | | 310,805 | 311,114 | 310,824 |
| **2022** | | | 328,586 | 328,000 | | 312,317 | 312,939 | 312,353 |
| **2023** | | | 331,865 | 330,978 | | 313,836 | 314,774 | 313,887 |
| **2024** | | | 335,177 | 333,984 | | 315,363 | 316,620 | 315,426 |
| **2025** | | | 338,523 | 337,016 | | 316,897 | 318,477 | 316,971 |
| **2026** | | | 341,901 | 340,076 | | 318,439 | 320,345 | 318,520 |
| **2027** | | | 345,313 | 343,164 | | 319,988 | 322,223 | 320,074 |
| **2028** | | | 348,760 | 346,280 | | 321,544 | 324,113 | 321,633 |
| **2029** | | | 352,240 | 349,424 | | 323,108 | 326,014 | 323,198 |
| **2030** | | | 355,756 | 352,597 | | 324,680 | 327,926 | 324,767 |
| **2031** | | | 359,306 | 355,416 | | 326,260 | 329,849 | 325,958 |
| **2032** | | | 362,892 | 358,257 | | 327,847 | 331,783 | 327,148 |
| **2033** | | | 366,514 | 361,122 | | 329,442 | 333,729 | 328,337 |
| **2034** | | | 370,172 | 364,009 | | 331,044 | 335,686 | 329,523 |
| **2035** | | | 373,866 | 366,919 | | 332,655 | 337,655 | 330,708 |
| **2036** | | | 377,598 | 369,853 | | 334,273 | 339,635 | 331,890 |
| **2037** | | | 381,366 | 372,810 | | 335,899 | 341,627 | 333,071 |
| **2038** | | | 385,172 | 375,790 | | 337,533 | 343,630 | 334,249 |
| **2039** | | | 389,016 | 378,795 | | 339,175 | 345,646 | 335,424 |
| **2040** | | | 392,899 | 381,823 | | 340,825 | 347,673 | 336,597 |
| | | | | **Difference** | | **Less Pop Adj** | **Less Pop Adj** | |
| | | | | **(11,075)** | | **329,749** | **336,597** | |

[1] Unmanaged forecast does not includes estimates of the impacts of uncommitted energy efficiency.