Regional Evaluation of Renewable Energy Supply and Demand and Potential for Transmission Development
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Final Report

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The Western Area Power Administration is one of four power market administrations under the Department of Energy, with the primary role of marketing and delivering wholesale electricity from multi-use hydro facilities.
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Chapter 1 - Executive Summary

This report, prepared for the Western Area Power Administration (Western), provides an overview of the current expectation of increased demand for central-station renewable energy capacity from 2015 to 2020, and the potential for new transmission and/or changes to the transmission system that may be required. The report covers four of the fifteen states in which Western operates: California, Arizona, Nevada and New Mexico. Chapter 2 provides an introduction to this report, as well as greater detail on the purpose and background for this assessment. A vetted assumption in this evaluation is the need for additional central station renewable generation generally translates into a need for transmission capacity to connect the renewable resources with load centers.

Generally speaking, we expect significant renewable development to continue within the region of focus over the specified time period, driven primarily by the states’ renewable portfolio standards (RPS). Although many of the major utilities are currently ahead of schedule for their RPS requirements, there is still enough unmet demand to drive renewable development activity and corresponding infrastructure requirements. This is reflected in the utilities’ current procurement activities, requests-for-proposals (RFPs), and their Integrated Resource Plans (IRPs), which show an aggregate commitment to incremental renewable energy capacity additions through 2020 and beyond.

There are several limitations inherent with this study.

A focus on a shorter, earlier period (2015-2020 rather than 2015-2030) has the potential to create “anchor bias” or a view of renewable additions that may ultimately prove to be conservative. On the other hand, the shorter study period has considerably more regulatory and policy certainty which is also important to decision makers.

In addition, there are several market factors that are likely to affect central-station renewable development in this region over the 2015-2020 period. Some of these factors could have either a positive or negative impact, including the fate of federal tax credits, the capital cost trajectory of wind and solar over the next five years, and the level of growth achieved by distributed energy. Other market changes are expected to impact renewable development in a positive way, including electric vehicle market growth, enhanced RPS policies, and regional coal retirements.

Regional renewable growth of utility scale renewables will likely require some transmission system modification or development. These potential changes may include small interconnection projects to connect renewables to existing transmission, or large transmission projects to access renewable resources that are yet to be developed. Additional operational challenges may be introduced by the greater penetration of these primarily variable generation or intermittent resources, and transmission system reconfiguration and upgrades could be needed as a result.

It is important to note that this report examines conditions at a single point in time -based on conditions as of April, 2015. Substantive uncertainties exist within the economic and policy macro-environment related to renewable development, especially beyond 2020. Also, larger transmission system
developments can require a long-lead time and be carried out over multiple years. Consequently, periodic re-evaluation and update of generation and transmission conditions is warranted.

Considering these limitations, the major findings and conclusions of this report include:

- RPS requirements in the four-state region will continue to drive renewables penetration that will likely require incremental transmission investments. In addition, the standards could drive substantial investments through 2020 if resources are developed at a large distance from load.
- Growth in central-station renewables can also drive transmission investments based on system reliability and transmission security needs. This can include investments in substations, terminals, and switches in addition to the new transmission lines to address voltage instability.
- Over 2,100 MW of coal retirements or divestments have been announced or are being discussed for 2015-2020 in the four states studied and additional environmental regulations, such as the CPP, could drive further retirements. The EPA’s CPP modeling projected over 12,000 MW of fossil-fuel retirements in this region through 2020, including about 2,200 MW of coal retirements and over 6,500 MW of oil/gas steam unit retirements. Replacing this generation may also result in transmission investment, depending on the location of the replacement resources.
- Currently scheduled for 2016, the expiration of the 30% Investment Tax Credit (ITC) is likely to spur a rush of renewables investment while the credit is still available.
- While beyond our primary study period, California—the largest and most developed market for renewables within the region, is considering an enhanced 50% RPS requirement by 2030. One study found that meeting a 50% RPS would require capital investments in transmission by 2030 of $5.7 billion to $12.4 billion beyond those required for a 33% RPS.\(^1\)
- High failure rates for projects needed to meet established and future RPS requirements will continue to drive a need for new renewable energy development in California, and presumably in neighboring markets as well. In the past, nearly 40% of California renewable projects approved by the California Public Utilities Commission were never completed, although this number has fallen significantly over the last couple of years.
- While no new major transmission projects were identified by the California Independent System Operator (CAISO) during the 2014-2015 transmission planning cycle to support California's 33% RPS goal, over $7 billion in transmission upgrades and additions have been approved in past planning cycles and are in the process of being developed to meet the RPS goal in 2020.
- Several trends including declining solar costs — utility scale solar has seen a 22% drop in installed costs over the past two years\(^2\) — technological progress on storage, increasing distributed generation, EPA proposed carbon regulations, and increasing market penetration of electric vehicles, will combine in uncertain ways to change demand for central station renewables. These changes will require study and potentially transmission investments to respond to new generation patterns.
- We examined a range of drivers and developed a Base Assessment for renewable energy demand within the region, estimating an order of magnitude increase of over 5,500 MW of added renewable capacity by 2020. In addition, incremental coal retirements beyond current
expectations, which could be driven by anything from changing consumer preferences to regulatory requirements, may have a potentially significant impact on incremental renewables deployment, and could potentially drive transmission upgrades to deal with issues like dynamic stability issues and G-1 N-1 reliability contingencies.

- There is a rapidly evolving energy marketplace in this region, and Western may have a role to play in the ongoing analysis and evaluation of resource and transmission adequacy to integrate a greater proportion of renewable generation and manage changing geographic generation patterns. Several indicators highlighted in this report suggest that renewables growth could result in a need for transmission investment, although this will be a matter of continued study.
Chapter 2 - Introduction and Background

Purpose of Report
This report is designed as a timely and focused market assessment of the current expectations for further renewable energy procurements by major utilities and load-serving entities (LSEs) in the service area of the Western Area Power Administration (Western) through 2020. The report is expected to be used in support of Western’s Transmission Infrastructure Program (TIP) to assist in future resource planning, as well as to validate representations from renewable generation and transmission developers seeking to utilize TIP funding for project loans through 2020. The report is designed to provide a snapshot of the current status of renewable compliance and develop a prognosis for future central station development in Western’s service area; we expect that it will be updated concurrent with further developments in the region. Conversely, this document does not address more technical aspects of electric power and transmission planning, such as a detailed load analysis or a study of the technical requirements of optimal renewable grid integration.

Background
The Western Area Power Administration is a federal agency under the U.S. Department of Energy (DOE) that markets and transmits wholesale hydroelectric power generated at federal dams across the Western United States. Western’s transmission system was developed to deliver federal hydro-power to customers in accordance with federal law. Western owns and operates 17,000 circuit-miles of high voltage, integrated transmission systems and markets power across 15 western states covering a 1.3 million square-mile service area. The agency’s service area includes all of Arizona, California, Colorado, Nebraska, Nevada, New Mexico, North Dakota, South Dakota, Utah, and Wyoming; as well as parts of Iowa, Kansas, Montana, Minnesota, and Texas.

Section 402 of the American Recovery and Reinvestment Act of 2009 (the “Recovery Act”) authorizes Western to borrow funds from the U.S. Department of the Treasury for the purposes of:

(i) Constructing, financing, planning, operating, maintaining or studying the construction of new or upgraded electric power transmission lines and related facilities that have at least one terminus within the area served by the Western Area Power Administration; and

(ii) Delivering or facilitating the delivery of power generated by renewable energy resources constructed, or reasonably expected to be constructed, after the date of enactment of this section.

To implement these activities, Western’s transmission program, known as TIP, provides commercial developers with requested project development assistance, to help prepare eligible projects intending to apply for loans through its borrowing authority.

TIP funding can assist Independent Power Producers (IPPs) or project developers in several ways that enable the effective deployment of marginal renewable energy deployment. For example, new or upgraded transmission lines can open up new areas for renewable energy development. Siting is extremely important when it comes to solar PV and wind deployment, as resource quality can vary greatly from one area to the next. New high voltage transmission projects can open up areas that have
the best resource potential, where projects will achieve the greatest capacity factors. Higher capacity factors, in turn, will lead to projects that have a lower levelized cost of energy (LCOE), which can make new resources more competitive compared to traditional energy sources. In a similar fashion, TIP funding can assist projects be reducing congestion in areas with high renewable energy penetration, as well as facilitate renewable energy deliveries. Projects that accomplish these goals are important, as they can reduce risk for project developers.

One of TIP’s key underwriting parameters requires credit decisions to be, in part, based upon contractual off-take and other transmission revenue-generating agreements with the project proponent. As a statutorily identified priority, the facilitation of the delivery of renewable energy must be a central aspect of these agreements. As a result, TIP sought out an unbiased view of expected renewable procurements and future needs within its service territory.
Chapter 3 – Renewable Capacity Drivers
Renewable Portfolio Standards and Transmission Additions

While some renewable capacity additions would be economic regardless of state or federal policies, RPS or renewable energy standards (RES) are popular state-level regulatory initiatives designed to increase capacity additions from renewable sources. RPS programs provide mandates or targets for generation from renewable energy sources, and these standards require each utility to provide a certain percentage of their retail sales from renewable energy. These policies can differ significantly in their scope, goals, utilities to which they apply, penalties, eligible technologies, and the presence of “carve-out” provisions that create a subset of goals for specific generating technologies. The renewable capacity types covered under many RPS programs include wind, solar, biomass, landfill gas, geothermal, small hydro, and others, with carve-outs applying most frequently to solar.

In general, overall cost and customer bill impacts of an RPS are two important influences on renewable adoption and the potential success of an RPS program. In order to minimize these impacts and facilitate steady growth, these policies contain provisions that:

- Make the RPS well-defined and enforceable
- Ramp up renewable energy requirements slowly
- Make the RPS last at least 10-15 years, to facilitate long-term contracting and financing
- Provide market and consumer flexibility through the use of renewable energy credits (commonly referred to as RECs) with a strong registration and tracking process

Accordingly, all four states within the scope of this report currently have mandatory RPS that were established between 1997 and 2008. In addition to their interim goals, these policies have final target dates that range from 2020 (California and New Mexico) to 2025 (Arizona and Nevada). RPS goals for these four states can be found in Figure 3-1, and a broader overview of each state’s RPS policy can be found in the Appendix.

<table>
<thead>
<tr>
<th>State</th>
<th>RPS goal #1</th>
<th>RPS goal #2</th>
<th>RPS goal #3</th>
</tr>
</thead>
<tbody>
<tr>
<td>Arizona</td>
<td>5% by 2015</td>
<td>10% by 2020</td>
<td>15% by 2025</td>
</tr>
<tr>
<td>California</td>
<td>25% by 2016</td>
<td>33% by 2020</td>
<td></td>
</tr>
<tr>
<td>Nevada</td>
<td>25% by 2025</td>
<td></td>
<td></td>
</tr>
<tr>
<td>New Mexico</td>
<td>15% by 2015</td>
<td>20% by 2020</td>
<td></td>
</tr>
</tbody>
</table>

As their requirements continue to ramp up, these renewable policies have been, and will continue to be, important drivers of transmission growth in this region. On the most basic level, it is clear that some level of transmission upgrades will be required to interconnect new renewable facilities with the bulk electric system. The extent of new transmission needed to interconnect these resources will vary, and is tied to the fact that the best renewable resource supplies (e.g. wind and solar) may be located far away from load centers. This dynamic can make large investments in transmission upgrades and infrastructure necessary, but also worthwhile to provide access to a significant amount of high quality resources. Take,
for example, the $6.9 billion Competitive Renewable Energy Zones (CREZ) project in the Texas panhandle, which comprised 186 projects including several new high voltage 345 kV transmission lines that connect 18,500 MW of wind capacity additions to load centers in the rest of the state. While these transmission expansions can be costly, the 2008 Joint System Coordination Plan’s analysis of the U.S. Eastern Interconnection found that they can provide significantly lower energy-production costs for consumers.

In addition, integrating renewable resources with other conventional generation to collectively serve demand requirements can require other transmission and grid upgrades to solve operational issues caused by increased generation from variable resources. System balance (balancing electrical supply and demand real-time) and frequency response (responding to rapid changes in the electric frequency of the grid) both become more challenging with increasing amounts of variable generation of the kind provided by wind and solar resources, and often require transmission upgrades to maintain system reliability. For example, the CREZ project also included upgrades to dozens of substations, terminals, and switches in addition to the new transmission lines to address voltage instability caused by wind generators being located at the end of very long transmission lines. These upgrades enable grid operational changes to occur, while also preventing reliability problems.

Several organizations have been established in the desert southwest region to study, understand, and enable the development of transmission resources in lockstep with increasing renewable energy goals. These include the Renewable Energy Transmission Initiative (RETI) in California, the Renewable Energy Transmission Authority (RETA) in New Mexico, and the previously active Arizona Renewable Resource and Transmission Identification Subcommittee (AARTIS). These initiatives are a clear signal of the importance of transmission development in conjunction with renewable resource development in these states.

Other Regional Drivers of Renewable Development

**Conventional Generation Retirements**

Central-station coal and nuclear plants are currently facing potential retirement due to age, cost structure, and changes in environmental regulations. In addition to 860 MW of coal retirements in the past two years, over 2,100 MW of regional coal retirements are probable from 2015-2020, which will leave load serving entities (LSEs) with the need to replace this capacity with new resources. In turn, this will create the opportunity for further renewable growth. While the retirement of some of these plants will free up existing transmission capacity for new resource development, in some cases, reconfigured or upgraded transmission lines may also be needed. Proposed coal retirements for this region are provided in Figure 3-2.
The retirement of the San Onofre Nuclear Generation Station (SONGS) in June 2013 provides an example of how conventional capacity retirements can impact renewable development. In order to replace some of the local capacity requirements that the 2,200 MW nuclear plant fulfilled, the California Public Utilities Commission (CPUC) is requiring Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E) to procure at least 600 MW of capacity from preferred resources, which the CPUC defines as renewable energy, demand response and energy efficiency. SCE’s proposal includes 261 MW of energy storage and 44 MW of behind-the-meter renewables, while SDG&E has yet to announce their preferred resource procurements (additional detail on SDG&E’s plan is provided in Chapter 5). In this case, SCE is able to add a relatively small proportion of local resources relative to the size of the deactivated nuclear plant due to the recent addition of transmission capacity into Southern California, which was built to support new renewable resources as well as address system reliability.

In addition to the coal retirements listed in Figure 3-2, the recently proposed Clean Power Plan (CPP), along with existing state level programs (particularly in California) could drive a notable amount of conventional power plant retirements across the region. EPA’s CPP modeling projects over 12,000 MW conventional unit retirements across the region through 2020, including about 2,200 MW of coal retirements and over 6,500 MW of oil/gas steam retirements (note that these are total retirements and not incremental retirements due to the CPP). Figure 3-3 provides the EPA’s full retirement projections.

Production Tax Credit (PTC) and Investment Tax Credit (ITC)

The PTC and ITC are federal tax credits that have been important drivers of renewable energy development in the past; however, their role moving forward is more uncertain.
The PTC is a per-kilowatt-hour tax credit for electricity generated by qualified energy resources, currently at 2.3 cents per kilowatt-hour (¢/kWh) for wind, geothermal, and closed-loop biomass, and 1.1¢/kWh for other technologies. While the PTC, which has traditionally been most effective in spurring wind energy development, was technically extended as part of a “tax extenders” bill passed in December 2014, the extension only applied to projects that began construction before the end of 2014. This provided developers with little time to react to the passage of the extension.

The ITC, which has traditionally spurred solar energy development, is currently set at a tax credit of 30% of expenditures for solar capacity and 10% for geothermal, microturbines (less than 2 MW), and combined heat and power systems (less than 50 MW). In 2017, these credits are set to fall to 10% for solar capacity for business investors and 0% for other projects and personal investors. As a result, the ITC is projected to spur significant capacity additions (mostly solar PV additions) through 2016, as developers rush to take advantage of the more robust credit.

With prevailing uncertainty surrounding the timing of the expiration or winding down of renewable tax incentives, there is increasing interest in potential low-cost federal financing that would help drive down project costs. Similar to past grants in lieu of tax credits (GILTC), which were often used to help renewable developers backstop construction loans a few years ago, it is not surprising that some in the development community views low-cost TIP construction financing as an important tool to assist in keeping project costs down in wake of the GILTC expiration; however, it is important to note that the TIP program can only finance the transmission and storage aspects of renewable expansion.

Renewables and Grid Parity
Several studies currently suggest that unsubsidized utility-scale wind and solar PV have both reached grid-parity on a selective basis as compared to a new combined cycle unit. According to the financial advisory and asset management firm Lazard’s Levelized Cost of Energy (LCOE) Analysis version 8.0 released in September 2014, the current LCOE ranges are as follows:

- Combined Cycle: $61-$87 per megawatt hour (MWh)
- Wind: $37-$81 per MWh
- Utility-Scale Solar: $72-$86 per MWh

The 2015 Department of Energy WindVision report corroborates the Lazard study finding that the LCOE for excellent (wind speeds greater than 7.5 m/s) wind resources was $45 per MWh in 2013. Lazard’s analysis may be somewhat high on combined cycle costs considering that their analysis does not include transmission costs. The report does match a broader consensus that grid-parity is growing for these renewable resources. Widespread grid parity for utility-scale wind and solar technologies could reasonably be expected to lead to increased capacity development independent of RPS policies.

Compared to the retail rate, distributed solar PV is also reaching grid parity in some markets. According to a new report by Deutsche Bank, unsubsidized rooftop solar electricity can cost between $0.08 and $0.13 per kilowatt hour (kWh), a figure they estimate is below the retail rate in up to ten states today. Deutsche Bank’s analysis predicts that rooftop solar PV will reach retail grid parity in all fifty states by

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the end of 2016. Increasing amounts of distributed solar PV come with their own set of transmission and operational challenges.
Chapter 4 – Supply Assessment

This chapter defines the principle utilities or LSEs in this region and examines their current renewable capacity supply, in order to define and project their future development needs through 2020.

Major Utilities and Load Serving Entities Considered

According to the U.S. Energy Information Administration’s 2013 Annual Electric Power Industry Report’s Form 861 data, there were 186 unique load serving entities (LSEs) in California, Arizona, Nevada, and New Mexico in 2013. However, only a fraction of these LSEs had substantial annual retail sales, and as a result, would represent a significant source of demand for renewable energy. Furthermore, some of the largest LSEs, such as cooperative or municipal energy suppliers in Nevada and Arizona, are not subject to their state’s RPS standards. As a result, this review was narrowed their review to the LSEs in Figure 4-1, as these companies had a large number of meters or significant retail sales, are a key player in their state’s electric market, and would have the demand to drive supply for renewable energy.

![Figure 4-1: Major Load Serving Entities by Region](image)

Supply Characteristics of Major Utilities and Load Serving Entities

The majority of the major utilities and LSEs in these four states are investor owned utilities (IOUs), along with three municipalities/political subdivisions (LADWP, SMUD, and SRP). These fourteen utilities serve an average of 1.3 million customers, ranging from nearly 5.4 million (PG&E) to only about 92 thousand (UNS Electric). Retail sales are similarly spread.

As seen below in Figure 4-2, the major LSEs also vary greatly in the amount of generation they own and are contracted to obtain through power purchase agreements (PPAs). Several points are evident in these figures. First, in contrast to the IOUs, the municipal providers tend to own the majority of the generation they use to serve load. On average, the municipal providers own about 85% of their total
capacity (owned and PPA), compared to about 50% for the IOUs. Second, the three major California IOUs are currently dominating the PPA market in this region. PG&E, SCE, and SDG&E have contracts with over 73% of all conventional capacity and over 82% of all renewable capacity, amongst the PPAs signed with these fourteen LSEs.

**Figure 4-2: Major Load Serving Entities Owned Capacity and PPA Participation.**

<table>
<thead>
<tr>
<th>Region</th>
<th>Load Serving Entity</th>
<th>Conventional (MW)</th>
<th>Renewable (MW)</th>
<th>Conventional (MW)</th>
<th>Renewable (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>CPUC</td>
<td>PG&amp;E</td>
<td>3,662</td>
<td>3,986</td>
<td>6,715</td>
<td>6,010</td>
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<tr>
<td>CPUC</td>
<td>SCE</td>
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<td>1,168</td>
<td>7,140</td>
<td>6,785</td>
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<tr>
<td>CPUC</td>
<td>LADWP</td>
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<td>2,071</td>
<td>803</td>
<td>189</td>
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<td>CPUC</td>
<td>SDG&amp;E</td>
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<td>0</td>
<td>1,035</td>
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<td>CPUC</td>
<td>SMUD</td>
<td>1,028</td>
<td>804</td>
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<tr>
<td>AZCC</td>
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<td>AZCC</td>
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<td>241</td>
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<tr>
<td>AZCC</td>
<td>TEP</td>
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<td>50</td>
<td>100</td>
<td>177</td>
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<tr>
<td>AZCC</td>
<td>UNS Electric</td>
<td>191</td>
<td>0</td>
<td>0</td>
<td>20</td>
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<tr>
<td>NMPRC</td>
<td>PNM</td>
<td>1,416</td>
<td>67</td>
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<tr>
<td>PUCN</td>
<td>Nevada Power</td>
<td>4,633</td>
<td>0</td>
<td>1,111</td>
<td>571</td>
</tr>
<tr>
<td>PUCN</td>
<td>Sierra Pacific Power</td>
<td>1,440</td>
<td>0</td>
<td>80</td>
<td>254</td>
</tr>
</tbody>
</table>

**Contracted Generation Supply**

According to the state’s various Public Utilities Commissions, there are currently over 16,000 MW of supply that has been approved for RPS-eligibility by Arizona, California, Nevada, and New Mexico (Figure 4-3). Of this capacity, nearly 60% has been approved for supply in California, with another 25% approved in Nevada. The remaining capacity is contracted with Arizona (10%) and New Mexico (7%).
At least 12,300 MW (out of 13,800 MW that lists a PPA counterparty) of the current RPS supply is contracted with the eleven major IOUs, although this figure may be understated due to information gaps in identifying the contracted utility. This is especially true in Nevada, where nearly 2,500 MW of the current RPS capacity does not contain a PPA counterparty. Figure 4-4 provides a further breakdown in current contracted RPS capacity for each of the eleven large LSEs.

**Figure 4-4: Contracted Capacity by LSE.**

<table>
<thead>
<tr>
<th>Region</th>
<th>Load Serving Entity</th>
<th>Existing Contracted RPS Capacity (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>CPUC</td>
<td>PG&amp;E</td>
<td>4,050</td>
</tr>
<tr>
<td>CPUC</td>
<td>SCE</td>
<td>3,421</td>
</tr>
<tr>
<td>CPUC</td>
<td>LADWP</td>
<td>2,260</td>
</tr>
<tr>
<td>CPUC</td>
<td>SDG&amp;E</td>
<td>1,561</td>
</tr>
<tr>
<td>CPUC</td>
<td>SMUD</td>
<td>1,216</td>
</tr>
<tr>
<td>AZCC</td>
<td>APS</td>
<td>900</td>
</tr>
<tr>
<td>AZCC</td>
<td>SRP</td>
<td>596</td>
</tr>
<tr>
<td>AZCC</td>
<td>TEP</td>
<td>270</td>
</tr>
<tr>
<td>AZCC</td>
<td>UNS Electric</td>
<td>22</td>
</tr>
<tr>
<td>NMPRC</td>
<td>PNM</td>
<td>373</td>
</tr>
<tr>
<td>NMPRC</td>
<td>SPS</td>
<td>259</td>
</tr>
<tr>
<td>NMPRC</td>
<td>EPE</td>
<td>101</td>
</tr>
<tr>
<td>PUCN</td>
<td>Nevada Power</td>
<td>728</td>
</tr>
<tr>
<td>PUCN</td>
<td>Sierra Pacific Power</td>
<td>246</td>
</tr>
</tbody>
</table>

Total Capacity: 16,259 MW
Major Project Developers and Significant Projects
While there is substantial diversity amongst project developers in this region, there are a number of firms that are especially active and as a result, they have significant amounts of capacity under development. Figure 4-5 contains the top ten firms in terms of planned capacity additions for these four states, at all stages of planning. The vast majority of the projects under development by these firms are solar PV and wind projects, although ArcLight Capital Holdings has a couple of geothermal projects in progress as well. Together, these ten companies are developing about 37% of all renewable energy projects in the region.

![Figure 4-5: Planned Renewable Capacity Additions by Company](image)

<table>
<thead>
<tr>
<th>Developer</th>
<th>Total Planned Capacity (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>NextEra Energy</td>
<td>2,664</td>
</tr>
<tr>
<td>First Solar</td>
<td>2,624</td>
</tr>
<tr>
<td>Iberdrola</td>
<td>1,606</td>
</tr>
<tr>
<td>Apex Clean Energy</td>
<td>1,400</td>
</tr>
<tr>
<td>ArcLight Capital Holdings</td>
<td>1,315</td>
</tr>
<tr>
<td>8minutenergy Renewables</td>
<td>1,260</td>
</tr>
<tr>
<td>EDF Group</td>
<td>1,045</td>
</tr>
<tr>
<td>Canadian Solar</td>
<td>1,010</td>
</tr>
<tr>
<td>Sempra Energy</td>
<td>949</td>
</tr>
<tr>
<td>SunEdison</td>
<td>929</td>
</tr>
</tbody>
</table>

In addition to these firms, there are a number of companies that focus on geothermal energy development in this region and also have a number of projects in their current pipeline. Berkshire Hathaway, Oski Energy, Gradient Resources, Ram Power Corporation, and Ormat Technologies all have at least two geothermal projects under development that total at least 200 MW.

There are also a number of significant projects in this region that are scheduled to come online in the next several years. These projects all currently have a PPA with a LSE in this region, and are all at least 250 MW in size. The plants and their characteristics are listed in Figure 4-6.

![Figure 4-6: Major Renewable Energy Projects](image)

<table>
<thead>
<tr>
<th>Power Plant</th>
<th>Owner</th>
<th>Fuel Type</th>
<th>State</th>
<th>Status</th>
<th>Planned Capacity (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>McCoy Solar Energy Project</td>
<td>NextEra Energy</td>
<td>Solar</td>
<td>CA</td>
<td>Partial Construction</td>
<td>750</td>
</tr>
<tr>
<td>Alta East Wind Project</td>
<td>ArcLight Holdings</td>
<td>Wind</td>
<td>CA</td>
<td>Advanced Development</td>
<td>650</td>
</tr>
<tr>
<td>Mesquite Solar I &amp; II</td>
<td>Sempra Energy</td>
<td>Solar</td>
<td>AZ</td>
<td>Early Development</td>
<td>535</td>
</tr>
<tr>
<td>Blythe Solar Power Project</td>
<td>NextEra Energy</td>
<td>Solar</td>
<td>CA</td>
<td>Advanced</td>
<td>485</td>
</tr>
<tr>
<td>Power Plant</td>
<td>Owner</td>
<td>Fuel Type</td>
<td>State</td>
<td>Status</td>
<td>Planned Capacity (MW)</td>
</tr>
<tr>
<td>-----------------------------------------------------------</td>
<td>------------------------------</td>
<td>-----------</td>
<td>-------</td>
<td>-------------------------</td>
<td>-----------------------</td>
</tr>
<tr>
<td>(Photovoltaic)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Imperial Valley Solar PV Project (Mount Signal)</td>
<td>SunEdison</td>
<td>Solar</td>
<td>CA</td>
<td>Early Development</td>
<td>406</td>
</tr>
<tr>
<td>Fremont Solar (Springbok 2)</td>
<td>8minutenergy Renewable</td>
<td>Solar</td>
<td>CA</td>
<td>Early Development</td>
<td>350</td>
</tr>
<tr>
<td>Avalon Wind Project</td>
<td>EDF Group</td>
<td>Wind</td>
<td>CA</td>
<td>Early Development</td>
<td>300</td>
</tr>
<tr>
<td>Stateline Solar Project</td>
<td>First Solar</td>
<td>Solar</td>
<td>CA</td>
<td>Under Construction</td>
<td>300</td>
</tr>
<tr>
<td>Big Boquillas Ranch Wind</td>
<td>Navajo Tribal Utility Authority</td>
<td>Wind</td>
<td>AZ</td>
<td>Early Development</td>
<td>285</td>
</tr>
<tr>
<td>California Flats Solar</td>
<td>First Solar</td>
<td>Solar</td>
<td>CA</td>
<td>Advanced Development</td>
<td>280</td>
</tr>
<tr>
<td>Moapa Southern Paiute Solar Project (K Road Moapa)</td>
<td>First Solar</td>
<td>Solar</td>
<td>NV</td>
<td>Under Construction</td>
<td>250</td>
</tr>
<tr>
<td>Roosevelt Wind Ranch</td>
<td>EDF Group</td>
<td>Wind</td>
<td>NM</td>
<td>Under Construction</td>
<td>250</td>
</tr>
<tr>
<td>Silver State South</td>
<td>NextEra Energy</td>
<td>Solar</td>
<td>NV</td>
<td>Under Construction</td>
<td>250</td>
</tr>
</tbody>
</table>

These facilities are important to track because they represent a significant portion of the renewable development in the region. Furthermore, if one of these projects were to fail, an LSE would have to replace that planned capacity with one or more new projects, which will drive project development in this region. Project failure rates and their implications are explored more fully in this chapter.

**Procurement Locations**

The majority of procurements occur between projects and LSEs that are located within the same state; however, approximately 3,500 MW, or over 25%, of PUC-approved capacity is for projects in which either the project itself or the contracted utility is out-of-state. More than a quarter of the projects approved by the CPUC and AZCC are for projects outside the state, while in Nevada, just under 16% of projects approved by the PUCN are located away from Nevada. In New Mexico, several wind projects totaling about 240 MW are contracted with out-of-state entities.

The majority of out-of-state capacity procurements in the region are for deliveries into California, with PG&E, SCE, SDG&E, SMUD, and Southern California Public Power all contracted with at least one out-of-state renewable project. In particular, PG&E and SCE are both contracted with a large amount of out-of-state renewable capacity; both utilities have more than 1,000 MW of capacity contracted with projects that are spread across a number of other states and provinces in the Western region.
Technology Types
As seen in Figure 4-7, the vast majority of the existing renewable generation supply is from wind, solar (PV and Concentrating Solar Power—CSP), and geothermal technologies. Interestingly, there has been a shift from wind capacity additions to solar PV capacity builds over time in this region: in the utility commission data, while wind capacity represented the greatest amount of capacity additions as recently as 2012, solar capacity additions were nearly three times higher in the 2013 to 2014 time period (1,863 MW of solar PV compared to 670 MW of wind). The looming expiration of the ITC will continue to drive solar additions in this region through 2016.

Figure 4-7: RPS-Eligible Renewable Capacity Additions by Technology Type and Year.21

Current RPS Compliance
Each utility’s RPS portfolio is a function of its current and future demand for electricity and the eligible renewable capacity that it procures to meet that demand. Generally, both load and RPS requirements increase over time, with both factors driving utility RPS demand. Figure 4-8 provides each major LSE’s current RPS compliance progress, including an estimated amount of capacity that each utility is currently contracted with (including planned capacity additions in all stages). RPS compliance data for California is current through March, 2015; the data for all other states is current through 2014.

Figure 4-8: Current RPS Compliance and Estimated Contracted Capacity by LSE22

<table>
<thead>
<tr>
<th>State</th>
<th>Load Serving Entity (LSE)</th>
<th>RPS Requirement</th>
<th>RPS Compliance</th>
<th>Estimated Contracted Capacity To-Date (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>California</td>
<td>PG&amp;E</td>
<td>33% by 2020</td>
<td>23.80%</td>
<td>6,490-7,170</td>
</tr>
<tr>
<td>California</td>
<td>SCE</td>
<td>33% by 2020</td>
<td>21.60%</td>
<td>9,560-10,560</td>
</tr>
<tr>
<td>California</td>
<td>LADWP</td>
<td>33% by 2020</td>
<td>N/A</td>
<td>950-1,050</td>
</tr>
<tr>
<td>California</td>
<td>SDG&amp;E</td>
<td>33% by 2020</td>
<td>23.60%</td>
<td>2,410-2,660</td>
</tr>
<tr>
<td>California</td>
<td>SMUD</td>
<td>33% by 2020</td>
<td>N/A</td>
<td>520-570</td>
</tr>
</tbody>
</table>
While many LSEs are ahead of schedule with their RPS compliance, only one has actually exceeded its state’s final RPS goal (Sierra Pacific), which indicates that incremental renewable generation development will continue over the next several years.

**Project Failure Rates and Implications**

Project failure rates are also an important indicator of future renewable development because they provide further insight into how much additional renewable energy development might be expected, given the current amount of renewable energy projects that has been approved by the respective state’s Public Utilities Commission (PUC) but not completed. In California (where failure rate data is more readily available than for Arizona, Nevada, or New Mexico), historically, nearly 40% of the projects approved by the California Public Utilities Commission are never completed, although this number has fallen in recent years. These issues and more have caused 12,000 MW of project failures since California’s RPS was established. The overarching reason for projects failing to progress to construction is presented in Figure 4-9.
Renewable energy projects can experience challenges for a number of reasons that lead to a situation where a contract is expired, terminated, or withdrawn. On the project side, developers can run into unforeseen permitting or financing issues that cause delays that exceed the terms of the contract. Utilities can also withdraw approval requests or terminate PPAs due to any number of factors. For example, SCE withdrew an approval request with Granite Wind in 2008 simply because the organization, “requires additional time to prepare and present material relevant to the Commission’s consideration of this matter”. The project was never completed. For the Hidden Hills concentrated solar power project, PG&E terminated the PPA due to, “challenges associated with the project schedule and uncertainty around the timing of transmission upgrades”. Small issues associated with permitting, financing, timing, and market conditions often derail projects.

As seen in Figure 4-10, solar thermal has accounted for nearly 45% of failed project capacity in California thus far, as permitting challenges and the rapid decline in solar PV costs have threatened the viability of numerous projects. Wind (33%), solar PV (10%), and geothermal (9%) capacity have also accounted for significant proportions of failed capacity. Going forward, wind and solar PV will almost certainly account for most of the incremental project failures, simply because those technologies are being procured at a much higher rates than other project types.

![Figure 4-10: California Failed Renewable Projects by Reason for Failure](image)

There are currently 5,000 MW of RPS-eligible projects that are contracted with the major California IOUs and have been approved by the CPUC but are still under development. Together, these projects represent over 12 million MWh of annual generation. According to the Q4 California Renewable Portfolio Standards Quarterly Report, “…the IOUs are on track to meet the RPS requirement of 25% renewables by 2016 and are well-positioned to meet the 33% requirement by 2020.” However, despite their current progress, high failure rates for projects needed to meet established and future RPS requirements will continue to drive a need for new renewable energy development in California, and presumably in neighboring markets as well.
Chapter 5 – Demand Assessment of Renewable Procurement

Trajectory Case for Renewable Energy Demand
An accurate long-term forecast for renewable energy demand is important when assessing the need for new transmission capacity to access new renewable energy capacity. To forecast the demand, major utilities and load serving entities were identified as key drivers and facilitators for future renewable energy demand. These major market participants were analyzed for their current progress toward their RPS, their publicly-stated future utility procurement actions (conventional, renewable, and energy storage), and the characteristics of their future renewable procurements. Important considerations include whether they tend to procure renewables bilaterally or through RFPs, and whether they are likely to procure from in or out-of-state resources.

LSE Procurement Actions and Plans
As utilities examine the status quo on their RPS compliance measures and examine the future growth of load in their utility territory, they plan accordingly with future procurement actions and plans. This section summarizes current planned capacity additions and publicly-stated capacity procurements from filings for major LSEs in California, Arizona, Nevada, and New Mexico, which provide a partial, but useful, outlook on planned development activities over the next several years.

Arizona
Arizona’s largest utility, APS, is expecting to add 1,540 MW of renewable capacity by 2029, of which 818 MW will be central-station resources and the remaining 722 MW will be distributed capacity. Firm short-term additions include two 10 MW utility-scale solar PV plants at the Luke Air Force Base and the utility’s City of Phoenix property in 2015, with the potential for an additional 30 MW facility as well. Further capacity additions are possible in the near- to mid-term, as the utility’s estimated RES budget from 2015-2018 is approximately $490 million. Overall, the utility’s Integrated Resource Plan (IRP) indicates that 12.4% of its retail sales will come from renewable energy in 2020. Future procurements for APS are highly likely to come from RFPs; APS has procured new renewable energy exclusively from RFPs in the past. In addition, future capacity additions for APS are likely to come from in-state resources, as the utility has not contracted with an out-of-state project since 2009.

Arizona’s largest municipal utility, the Salt River Project (SRP), is also expecting to expand its renewable resources. In its 2013 IRP, SRP notes that it plans to add 273 MW of wind, geothermal, solar and distributed resources by 2020, including 92 MW of capacity additions in 2015.

Tucson Electric Power (TEP) is currently expecting to add about 60 MW of utility-scale renewables and energy storage between 2015 and 2020. Specifically, the utility has a PPA with the 50 MW Red Horse 2 wind plant, which will come online by the end of 2015. As a result, by 2019 central-station renewables are projected to provide 4.24% of TEP’s generation. In addition, the utility is expecting to add 86 MW of generation on the distributed side from 2015 to 2020 and plans to procure an additional 271 MW of total renewables by 2028. TEP also recently issued an RFP for a 10 MW energy storage facility. The utility is looking to sign a 10-year PPA for a system that would be operational by the end of 2016.
APS, TEP has procured new renewable energy exclusively through RFPs in the past and seems likely to do so in the future. The majority of the utility’s future renewable capacity will likely come from in-state, as TEP is only contracted with one out-of-state wind farm and has not procured out of state renewable capacity since 2011.

Finally, while UNS is relatively small compared to the LSEs mentioned above, the utility does plan on adding at least 20 MW of generating capacity from the Red Horse Solar in 2015, as well as 16 MW of distributed generation from 2015-2020.34

California
Already the leading renewables market in the country, major California LSEs are still projecting significant renewable additions through 2020 as they work toward the 33% RPS goal including both of the large municipal providers in California.

California - SMUD
In their 2014 Annual Report, SMUD reports that 30% of the utility’s power came from renewable sources. While SMUD does not clarify as to whether or not all of the renewable energy is RPS-eligible, they have stated in the past that they are ahead of their compliance requirements and plan on partially using banked RECs to meet future compliance goals. However, SMUD is still selectively adding projects to their renewable portfolio. Future projects include an incremental 2.7 MW of small hydro at the Slab Creek facility in 2017, an incremental 62.5 MW of geothermal capacity at the Patua Geothermal Plant, an incremental 53 MW at the Solano Wind Plant, and the 400 MW Iowa Hill pumped storage facility (which would not qualify for the state’s RPS).35 SMUD has stated that the new pumped storage facility is particularly crucial to their future renewable energy plans, as it will allow them to fill supply gaps cause by variable resources and enable them to use their wind and solar resources more effectively. The project will use the existing Slab Creek reservoir, and so far, there has been no indication that current drought conditions in California will threaten the project.36

California - LADWP
In contrast to SMUD, the Los Angeles Department of Water and Power is expecting to significantly expand their renewable capacity from 2014 to 2020, with Base Case planning procurements of 76 MW of geothermal or biomass, 1,059 MW of utility-scale solar PV, and 396 MW of distributed solar.37 Several of LADWP’s solar PV projects have already been approved by the CPUC, including the 250 MW Copper Mountain 3 and K-Road plants, both of which are under construction, and the 250 MW Beacon Solar Energy Project, which has been approved but is currently on-hold. Notably, LADWP often procures capacity from outside of California and has current or future PPAs in Washington, Nevada, and Oregon. In addition to renewable energy, LADWP hopes to procure 24 MW of energy storage by 2016 and 154 MW of storage by 2021.

However, funding is a pressing issue for LADWP, and their 2014 IRP reveals that their current financial constraints may leave the utility unable to meet their plans and goals. The IRP cites the operational challenges associated with higher renewables penetration, such as supply and demand balance issues and the need for additional quick-ramp capacity, but reveals that, “some (of LADWP’s) programs still
lack the appropriate funding”. Financial constraints have prevented any substantial reliability improvements for the department since 2009. Inadequate funding could certainly threaten LADWP’s abilities to both add renewable capacity and to meet the associated operational changes.

California - Independent System Operator (CAISO) IOUs
All three of California’s major IOUs are planning to procure varying amounts of renewable, energy storage, and other types of capacity to meet their operational and RPS needs (other capacity includes combined cycle and simple cycle natural gas plants and pumped storage facilities). A summary of these activities can be found in Figure 5-1.

Figure 5-1: Planned CAISO IOU Capacity Procurements through 2020 by Type

<table>
<thead>
<tr>
<th>IOU</th>
<th>Procurements (MW)</th>
<th>Renewable/RPS</th>
<th>Energy Storage</th>
<th>Other</th>
</tr>
</thead>
<tbody>
<tr>
<td>SDG&amp;E</td>
<td>430</td>
<td>25</td>
<td>0-600</td>
<td></td>
</tr>
<tr>
<td>SCE</td>
<td>2,249</td>
<td>261</td>
<td>1,382</td>
<td></td>
</tr>
<tr>
<td>PG&amp;E</td>
<td>1,108</td>
<td>74</td>
<td>600</td>
<td></td>
</tr>
</tbody>
</table>

The smallest of the three IOUs, SDG&E, is planning to procure around 430 MW of renewable energy and at least 25 MW of energy storage, but there is considerable uncertainty surrounding their incremental capacity additions. Recently, the CPUC ordered SDG&E to replace their capacity at the San Onofre Nuclear Generating Station (SONGS), and while the utility issued an all-sources Request for Offers (RFO) of 800 MW, they chose to enter bilateral discussions with the developers of a 600 MW gas turbine at the Carlsbad Energy Center. A CPUC judge rejected SDG&E’s plans with Carlsbad in March, 2014 because the utility did not sufficiently consider preferred resources such as renewable energy, energy storage, demand response, and energy efficiency, but the full decision by the five CPUC commissioners that will ultimately decide the fate of the project is expected by the end of May, 2015. Depending on the result, the utility could procure up to an additional 600 MW of capacity from preferred resources, which could lead to additional renewable energy or storage procurements through 2020.

In addition to over 2,200 MW of planned renewable capacity additions to meet the state’s RPS, like SDG&E, SCE is responsible for replacing their SONGS capacity. SCE issued an all-sources RFO for replacement capacity, which resulted in a final procurement of 1,892 MW including 44 MW of behind-the-meter renewables, 261 MW of energy storage, and 1,382 MW of gas-fired generation. SCE is still awaiting the CPUC’s decision on their application. The utility is also procuring significant renewable energy capacity to meet their RPS obligations. SCE’s planned renewable additions include over 2,200 MW of capacity, with over 80% of that capacity coming from solar PV. The remaining capacity will be sourced from wind. SCE plans to procure a large majority of their renewable capacity from in-state resources, with only three out-of-state projects (in Arizona and Nevada) contracted with the utility at this time. In the past, SCE also has sourced renewable capacity from Oregon and Idaho.

Unlike SDG&E and SCE, PG&E is not facing a need for replacement capacity. As a result, their capacity procurements are a bit more standard. The utility is planning to add over 1,100 MW of renewable
energy capacity through 2020, with over 85% of that capacity coming from solar PV technologies. The remaining capacity will come from wind. Non-renewable capacity additions in the next several years will include 74 MW of storage capacity and 600 MW of gas-fired combined cycle capacity at the Avenal Energy Center.43 Similar to SDG&E and SCE, the majority of PG&E’s procurements will come from in-state facilities, with additional renewable procurements from Arizona and Nevada planned as well. In the past, PG&E has also sourced renewable capacity from Alberta.

On an annual basis, CAISO evaluates the need for transmission to support meeting the state’s 33% RPS goal. CAISO did not identify any major new transmission projects to support the RPS goal during the 2014-2015 transmission planning cycle, but over $7 billion in transmission upgrades and additions have been approved in past planning cycles and are in the process of being developed to meet the state’s 2020 RPS goal.44 A full list of CAISO-approved capacity additions through 2020 is listed in Figure 5-2.

**Figure 5-2: CAISO-Approved Transmission Projects through 2020**45

<table>
<thead>
<tr>
<th>Transmission Upgrade</th>
<th>Approval Status</th>
<th>Online</th>
</tr>
</thead>
<tbody>
<tr>
<td>Carizzo Midway</td>
<td>LGIA</td>
<td>NOC Effective Energized</td>
</tr>
<tr>
<td>Sunrise Powerlink</td>
<td>Approved</td>
<td>Approved Energized</td>
</tr>
<tr>
<td>Suncrest Dynamic Reactive</td>
<td>Approved</td>
<td>Approval Not Required 2017</td>
</tr>
<tr>
<td>Eldorado-Ivanpah</td>
<td>LGIA</td>
<td>Approved Energized</td>
</tr>
<tr>
<td>Valley-Colorado River</td>
<td>Approved</td>
<td>Approved Energized</td>
</tr>
<tr>
<td>West of Devers</td>
<td>LGIA</td>
<td>Pending 2019</td>
</tr>
<tr>
<td>Tehachapi (Segments 1,2, and 3a of 11 Completed)</td>
<td>Approved</td>
<td>Approved 2015</td>
</tr>
<tr>
<td>Cool Water-Lugo</td>
<td>LGIA</td>
<td>Pending 2018</td>
</tr>
<tr>
<td>South Contra Costa</td>
<td>LGIA</td>
<td>Not Yet Filed 2015</td>
</tr>
<tr>
<td>Borden-Gregg</td>
<td>LGIA</td>
<td>Not Yet Filed 2015</td>
</tr>
<tr>
<td>Path 42 Reconductoring</td>
<td>Approved</td>
<td>Approval Not Required 2014</td>
</tr>
<tr>
<td>Imperial Valley C Station</td>
<td>Approved</td>
<td>Approval Not Required 2015</td>
</tr>
<tr>
<td>Sycamore-Pesquitos</td>
<td>Approved</td>
<td>Not Yet Filed 2017</td>
</tr>
<tr>
<td>Lugo-Eldorado Line Reroute</td>
<td>Approved</td>
<td>Not Yet Filed 2015</td>
</tr>
<tr>
<td>Lugo-Eldorado and Lugo-Mohave Series Caps</td>
<td>Approved</td>
<td>Approval Not Required 2016</td>
</tr>
<tr>
<td>Warnerville-Bellota Reconductoring</td>
<td>Approved</td>
<td>Not Yet Filed 2017</td>
</tr>
<tr>
<td>Wilson-LeGrand Reconductoring</td>
<td>Approved</td>
<td>Not Yet Filed 2020</td>
</tr>
</tbody>
</table>

**Nevada**

Although both major LSEs (Nevada Power and Sierra Pacific, which are both owned by NV Energy) are significantly ahead of their RPS requirements, NV Energy has indicated that it plans to continue...
developing renewable resources. The utility expects to retire about 800 MW of coal-fueled capacity in the coming years and replace the associated generation by acquiring 482 MW of natural gas facilities and developing two solar facilities: a 200 MW solar project with RES Americas and a 15 MW solar array at the Nellis Air Force Base. The company has also publicly committed to issue further renewable energy requests-for-proposals (RFPs).46

NV Energy will be seeking to secure up to 300 MW of new renewable energy resources in Nevada from 2015 to 2016 as part of their Emissions Reduction and Capacity Replacement plan,47 subject to regulatory approval. While the company issued an RFP in October 2014, the Public Utilities Commission of Nevada wanted to ensure that developers would be able to secure the ITC for as many resources as possible. As a result, the company plans to issue an RFP for 200 MW of solar capacity in 2015, with an additional 100 MW RFP to be issued in 2016. These moves are in-line with previous developments, as NV Energy has shown a commitment to issuing RFPs for all renewable procurements in lieu of bilateral agreements. In addition, neither Sierra Pacific nor Nevada Power are contracted with any facilities outside of Nevada at this time, so it is likely that further renewable procurements will result in further in-state development. Neither subsidiary has indicated that they will procure any incremental fossil-fired or energy storage capacity at this time.

New Mexico
As seen in Figure 5-3, all three of the largest LSEs in New Mexico are planning capacity procurements through 2020. All of the currently planned capacity additions for these utilities are for solar or simple cycle capacity; none of the utilities are planning to procure energy storage at this time. The simple cycle capacity additions are, to some degree, motivated by the region’s renewable capacity additions, as they will enable the utilities to manage their variable resources more effectively. Utilities in New Mexico tend to procure in-state capacity using RFPs; we would not expect these characteristics to change in the future.

Figure 5-3: New Mexico Capacity Additions through 2020

<table>
<thead>
<tr>
<th>LSE</th>
<th>Technology</th>
<th>Capacity (MW)</th>
<th>Online Year</th>
<th>Source</th>
</tr>
</thead>
<tbody>
<tr>
<td>PNM</td>
<td>Simple Cycle</td>
<td>40</td>
<td>2016</td>
<td>IRP</td>
</tr>
<tr>
<td>PNM</td>
<td>Simple Cycle</td>
<td>177</td>
<td>2018</td>
<td>IRP</td>
</tr>
<tr>
<td>PNM</td>
<td>Solar</td>
<td>23</td>
<td>2015</td>
<td>IRP</td>
</tr>
<tr>
<td>PNM</td>
<td>Solar</td>
<td>20-100</td>
<td>2019-2020</td>
<td>IRP</td>
</tr>
<tr>
<td>SPS</td>
<td>Solar</td>
<td>Less than 200</td>
<td>2016</td>
<td>RFP</td>
</tr>
<tr>
<td>EPE</td>
<td>Solar</td>
<td>Less than 30</td>
<td>2018</td>
<td>RFP</td>
</tr>
<tr>
<td>EPE</td>
<td>Simple Cycle</td>
<td>352</td>
<td>2015-2016</td>
<td>EPE Website</td>
</tr>
</tbody>
</table>

Current expectations of future renewable energy procurement and development in New Mexico are low compared to the rest of the region due to the state’s reasonable cost threshold (RCT) that limits RPS costs to 3% per year for each utility. However, all three of the state’s largest utilities are still expecting capacity additions in the near- to mid-term. The Public Service Company of New Mexico (PNM) is planning several solar PV procurements, with 63 MW of utility-scale solar additions through 2016 and an
additional 20 MW to 100 MW of solar from 2018-2020, depending on whether PNM acquires an
additional 78 MW or 132 MW stake in the San Jose coal plant.\textsuperscript{48}

El Paso Electric Company (EPE) and Southwestern Public Service Company (SPS) are also planning on
adding solar capacity in the next several years, with both firms releasing 2014 RFPs for significant solar
capacity in 2014.

- EPE released an RFP for two large-scale solar generating facilities with a maximum combined
capacity of up to 30 MW, and will most likely seek to bring the facilities online before 2017 in
order to take advantage of the full ITC.\textsuperscript{49}
- SPS issued an RFP for up to 200 MW of solar capacity that will come also come online before
2017. The RFP specifies that the company is looking for up to nine 10 MW solar PV facilities at
existing interconnection sites. An additional 110 MW is left to the discretion of the developers.\textsuperscript{50}
- While EPE expected to issue an All-Source RFP for new resources in the first quarter of 2015 that
included renewable load management resource possibilities, the utility has not yet done so.\textsuperscript{51}
The RFP should be forthcoming.

EMERGING DRIVERS OF CHANGE

EMERGING DRIVERS - SOLAR COST TRENDS

In the past several years, there has been a steady and steeper-than-expected decline in solar costs.
Utility scale solar, for example, has seen a 22% drop in installed costs over the past two years.\textsuperscript{52} The
decreasing cost of solar can be attributed both to technological advancements in solar power efficiency
and cheaper cost of production, as well more streamlined financing and permitting measures to bring
down soft costs (customer acquisition, balance of system, etc.). Future solar deployment will depend in
part on the pace of continued reductions in levelized costs as they progress toward general grid parity.
Furthermore, the ratio of utility-scale and distributed solar installations will be dictated by their relative
cost ratio over time.

EMERGING DRIVERS - ENERGY STORAGE

Energy storage growth will also change the structure of how the utilities transmit and distribute their
power. Without energy storage, electric supply must always equal demand in real time and utilities must
always have quick ramp supply capacity available to account for drops in renewable energy supply and
to ensure reliability. Energy storage can fundamentally change this arrangement by charging energy
storage facilities when demand drops and/or supply surges, and vice versa.

Energy storage will have a growing impact on the grid as adoption is expected to increase in the near
future. Currently, more than 99% of existing large-scale energy storage is in the form of pumped
hydro,\textsuperscript{53} but fly wheels, electrochemical batteries, and compressed air are all emerging as viable energy
storage alternatives. California lies at the frontier of energy storage deployment as the CPUC has
mandated annual energy storage goals for the state’s IOUs. Figure 5-4 shows the CPUC’s proposed energy storage capacity installations for the 2014-2020 period.

**Figure 5-4: Proposed California Energy Storage Additions**

<table>
<thead>
<tr>
<th>Utility</th>
<th>Interconnection</th>
<th>Incremental Proposed Capacity (MW)</th>
<th>Cumulative Total (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>SCE</td>
<td>Transmission</td>
<td>50 65 85 110</td>
<td>310</td>
</tr>
<tr>
<td>SCE</td>
<td>Distribution</td>
<td>30 40 50 65</td>
<td>185</td>
</tr>
<tr>
<td>SCE</td>
<td>Customer</td>
<td>10 15 25 35</td>
<td>85</td>
</tr>
<tr>
<td>PGE</td>
<td>Transmission</td>
<td>50 65 85 110</td>
<td>310</td>
</tr>
<tr>
<td>PGE</td>
<td>Distribution</td>
<td>30 40 50 65</td>
<td>185</td>
</tr>
<tr>
<td>PGE</td>
<td>Customer</td>
<td>10 15 25 35</td>
<td>85</td>
</tr>
<tr>
<td>SDG&amp;E</td>
<td>Transmission</td>
<td>10 15 22 33</td>
<td>80</td>
</tr>
<tr>
<td>SDG&amp;E</td>
<td>Distribution</td>
<td>7 10 15 23</td>
<td>55</td>
</tr>
<tr>
<td>SDG&amp;E</td>
<td>Customer</td>
<td>3 5 8 14</td>
<td>30</td>
</tr>
</tbody>
</table>

Growth in energy storage could facilitate greater than expected central station renewable energy generation. The “Duck Curve” (Figure 5-5) quandary arises since peak solar power generation in the middle of day does not coincide with peak electricity demand in the evening. Concerns exist in meeting ramping needs with central-station fossil fuel plants. However, by increasing deployment of energy storage, daytime renewable energy generation can be stored and consumed in the evening. As such, renewable energy and energy storage are seen as complimentary services by CAISO.

**Figure 5-5: California “Duck Curve”**

Emerging Drivers - Distributed Generation

Distributed generation growth will also impact the trajectory of future central station renewable procurement in this region. Aside from RPS carve-outs for distributed generation (DG), DG has grown
and developed through net energy metering (NEM) and rebate programs. Like energy storage, distributed generation disrupts the current power flow model of the grid by generating power at the point-of-use, as opposed to transmitting power through transmission and distribution lines. Thus, greater amounts of distributed generation lower net load and the corresponding need for generation from central-station sources.

Rooftop solar and combined heat and power facilities are a few examples of emerging distributed generation technologies that are expected to continue to grow in the near future. Figure 5-6 illustrates the growth in distributed generation in the Western States. California leads the way with more than half the solar distributed generation market for the country. Together, though, the four states have shown a 54% year-over-year growth in solar distributed generation. Although the market has large potential, distributed generation remains largely based on economic drivers, making it vulnerable to the impacts of the pending ITC expiration currently anticipated in 2016.

**Figure 5-6: Cumulative Distributed Generation Additions.**

![Cumulative Distributed Generation Additions](image)

### Emerging Drivers - Electric Vehicles and Electric Vehicle Supply Equipment

In the same vein as distributed energy resources, current and continuing growth of electric vehicles could significantly impact electrical demand by increasing it beyond current expectations. To charge electric vehicles, utilities will need to increase supply, and in accordance with RPS standards, some of that supply must come from renewable capacity additions.

Of the 299,938 electric vehicles sold in the United States, 123,597 of them have been sold in California, making electric vehicles consequential in the Western territory. Electric vehicle growth in California is propelled by a $7,500 federal tax credit, a $2,500 state rebate, and a 2025 requirement for 1.5 million zero-emission vehicles on the road, many of which will be battery electric vehicles.
Increased adoption of electric vehicles will act as a market pull for increasing electric vehicle supply equipment (EVSE). Electric vehicles obtain grid power through three general types of chargers, as specified in Figure 5-7. SDG&E, SCE, and PG&E plan to build out 5,500, 30,000, and 25,000 EVSE respectively throughout their utility territory over the next five years. While the majority of these EVSE will be Level 2 chargers, a proportion will also be DC fast chargers that require more than 60 kW of capacity. Over time, EVSE will require increasingly significant amounts of power at varying locations across the grid, and corresponding transmission upgrades will be required as well.

**Figure 5-7: Electric Vehicle Charging Types**

<table>
<thead>
<tr>
<th>Type</th>
<th>Voltage (Volts)</th>
<th>Power (kW)</th>
<th>Applications</th>
</tr>
</thead>
<tbody>
<tr>
<td>Level I</td>
<td>120</td>
<td>2</td>
<td>Residents/Public Charging</td>
</tr>
<tr>
<td>Level II</td>
<td>240</td>
<td>2.4-19.2</td>
<td>Workplace/Public Charging</td>
</tr>
<tr>
<td>DC Fast Charger</td>
<td>480</td>
<td>&gt;60</td>
<td>Transit Corridors</td>
</tr>
</tbody>
</table>
Chapter 6 – Consolidated Review

Assessment
The potential for material changes to the regional generation supply and demand balance in Arizona, California, Nevada, and New Mexico between 2015 and 2020 is substantial. These potential changes are driven by many factors, but at least in-part by existing Renewable Standards programs (RPS and RES).

The location of renewable generation relative to load centers under these programs varies – in some cases, distributed energy resources (DER) programs incentivize small-scale generation (such as rooftop solar) broadly across the region, implying changes, improvements, and upgrades primarily to distribution lines. In other cases, supporting deployment of large-scale renewable resources (such as wind, solar PV, or geothermal) could require major expansion of new high voltage facilities. In virtually all cases, changes in resources impact the transmission and distribution system.

Renewable developers have become adept at locating and commercializing project sites designed to deliver substantial generation resources at low cost. In some states, such as California, this has been facilitated by the production of Renewable Auction Mechanism (RAM) Maps. In the case of wind and solar, these projects are often located some distance from larger load centers. Consequently, transmission infrastructure additions and changes will be necessary to commercialize the most attractive generation resources.

While all four states (and many LSEs within the states) appear on track to satisfy their RPS requirements, the high level of project failure rates implies that a focus on new projects continues. While many of these “failures” occur for very specific economic reasons (such as the technology and cost shift in favor of solar PV over solar thermal), some of them fail due to more detailed and commercial reasons. Maintaining a pipeline of new projects in order to overcome this “churn” is likely to continue to be a priority through 2020, and potentially beyond the current planning horizon.

Emerging Factors
Our review demonstrated that there are additional emerging factors that are likely to be supportive of changes to repurpose, reconfigure, and upgrade selected high voltage transmission elements as a result of increased renewable development.

<table>
<thead>
<tr>
<th>Cost</th>
<th>In general, solar and wind renewable resources are competitive on a levelized cost basis with other resources in a number of applications. These costs depend on many factors, including the presence of incentives such as the PTC and ITC. The availability of these incentives depends on Congressional action. At times, the prospects for extension and the terms associated with extension have influenced developers' views of project viability and the timing for moving projects along the development path.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Implication: Uncertainty surrounding federal tax credits can feed uncertainty for transmission additions, which often have long lead-times.</td>
<td></td>
</tr>
<tr>
<td>Demand</td>
<td>One of the major drivers for a continued need for transmission expansion is the management of unmet need for renewable resources by regulators in these four states. CPUC believes utilities are on track to meet current RPS standards in California. However, as the largest national market for renewables, even a small change in requirements could</td>
</tr>
</tbody>
</table>
increase the need for additional transmission to provide access to resources needed to achieve incremental RPS. For example, if the current “33% requirement by 2020” was to be raised not only would resources needed to achieve the increased requirements need to be identified and procured, but transmission needs to enable access to those resources would need to be evaluated.

**Implication:** Larger mandates could increase the need for long haul major transmission expansions to access additional renewable supply.

### Generation Supply Stack

Changes in the marginal cost of dispatching the next generation incrementally affect stakeholders in markets like CAISO. Large-scale solar and wind have time-of-day generation characteristics that require management. Managing these effects, as illustrated in the CAISO “duck” curve, requires changes in dispatch order.

**Implication:** Reliability constraints associated with time of day characteristics may be partly managed with distribution and local transmission upgrades.

### Generation Supply Stack

Conventional generation has an identifiable marginal cost (fuel plus start-up costs) that is normally considered in submitting a bid to a market operator. Other technologies, such as large-scale wind and solar resources, have very low or no marginal costs since they do not incur fuel costs. Thus, large-scale deployments have the potential to change pricing and congestion at particular nodes, altering bidding strategies, and requiring other system users to consider the effects of their addition to the grid when making commercial decisions about resource operation.

**Implication:** Changes in dispatch and congestion costs may be partly managed or alleviated with distribution and local transmission upgrades.

### Intermittency

Providing ancillary services that match the generation characteristics of renewables requires attention to supply and reliability criteria with response times from milliseconds to minutes.

**Implication:** Changes in ancillary service products that facilitate ramping generation output up and down is an important factor in managing greater penetration of intermittent renewable resources such as large-scale wind and solar. Transmission upgrades may reduce the impact of recurring reliability events.

### Intermittency

Resource Planning and new source solicitations will favor “flexible” resources such as quick-start CT’s and in some cases storage to assure reliability.

**Implication:** Regional utilities are already emphasizing the need to respond to this challenge, with APS choosing their latest IRP scenario, “to favor highly flexible natural gas resources over traditional baseload resources.” Additional flexibility may also imply revised path ratings and an assessment of system transients.

### Levelized Cost of Electricity

Since select renewables currently have a similar or lower LCOE in some cases, we anticipate that “all-source” solicitations (such as that agreed to by APS) may become more widespread and lead to continued interest in large-scale renewable facilities.

**Implication:** All-source solicitations may have varying transmission implications and solutions to new constraints that arise.

### Levelized Cost of Electricity, Solar

In some cases, large-scale solar has an LCOE comparable to other low (energy) cost resources such as wind. Additionally, its output is becoming more broadly controllable and dispatchable with improvements in control technology. When coupled with flexible ramping assets such as natural gas and storage, combinations of renewable and conventional assets may become more attractive.

**Implication:** Combinations of assets (some nearby and some remote) may have different transmission limitations and benefits that require upgrades.

### Project Churn and Failure

Under RPS and RES, some projects naturally do not continue as technology advance, cost reductions, changing regulations, and commercial sticking points cannot be overcome. Understanding the reasons for failure can give early insight into future additions, their location, and technology choice.

**Implication:** The failure of a single large, remote generation project may reduce the need for
a particular transmission upgrade.

**Regulatory Attention to CO₂**
The discussed CPP EPA initiative under Section 111(d) may lead to additional retirements of high CO₂ emitting facilities such as coal plants. It may lead to higher dispatch of existing natural gas combined cycle plants, or increased penetration of renewable generation. Multi-regional solutions may be facilitated to reduce emissions. Energy efficiency may increase.

Implication: Substantive changes to the transmission grid may increase the availability of renewables or increase reliability by making alternative resources available in a particular area. Less extensive upgrades may mitigate dynamic stability issues, and potential path rating changes may result.

**Retirements**
Pending retirements of coal facilities in Arizona, Nevada, and New Mexico and nuclear units in California increase the likelihood that new build and purchases are used by regional LSEs to maintain resource adequacy and reliability.

Implication: Transmission upgrades may play a role in delivering energy from alternative sources while maintaining reliability. Dynamic stability issues may be mitigated, and potential path rating changes may be needed. At the same time, retirements may free up transmission capacity that could be repurposed to deliver renewable resources to loads.

**Storage**
A major shift in the cost and availability of electricity storage is possible increasing distribution system resiliency and rapid deployment of DER like small-scale rooftop solar.

Implication: This could result in distribution system upgrades, and voltage control solutions.

**Scenarios and Impact on Assessment**
A scenario-based approach was used to develop a view on how the emerging factors might impact a Base Assessment of expected renewable capacity procurements. The Base Assessment is outlined in Figure 6-1, and provides a range of the expected renewable capacity procurements for each state under their RPS programs. To establish the range, we started with projected renewable energy demand in MWh and applied a 35% capacity factor to convert energy into a capacity value. A 35% capacity factor approximates the typical output of an efficient wind or solar plant in this region. The range was created using a margin-of-error of +/- 5% from the base capacity values, to account for other variables such as differences in actual annual capacity factors and/or demand for energy. The values in Figure 6-1 are rounded to the nearest megawatt.

**Figure 6-1: Total Estimated Required Resource Supply for Renewable Standards in MW (Cumulative)**

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Arizona</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Low</td>
<td>1,740</td>
<td>1,850</td>
<td>2,140</td>
<td>2,530</td>
<td>2,980</td>
<td>3,490</td>
</tr>
<tr>
<td>High</td>
<td>2,050</td>
<td>2,370</td>
<td>2,800</td>
<td>3,290</td>
<td>3,850</td>
<td></td>
</tr>
<tr>
<td>California</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Low</td>
<td>16,960</td>
<td>17,040</td>
<td>17,970</td>
<td>18,280</td>
<td>18,750</td>
<td>18,900</td>
</tr>
<tr>
<td>High</td>
<td>18,840</td>
<td>19,860</td>
<td>20,210</td>
<td>20,720</td>
<td>20,890</td>
<td></td>
</tr>
<tr>
<td>Nevada</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Low</td>
<td>1,920</td>
<td>2,010</td>
<td>2,130</td>
<td>2,370</td>
<td>2,370</td>
<td>2,370</td>
</tr>
<tr>
<td>High</td>
<td>2,220</td>
<td>2,350</td>
<td>2,620</td>
<td>2,620</td>
<td>2,620</td>
<td></td>
</tr>
<tr>
<td>New Mexico</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Low</td>
<td>730</td>
<td>735</td>
<td>750</td>
<td>820</td>
<td>1,260</td>
<td>1,850</td>
</tr>
<tr>
<td>High</td>
<td>770</td>
<td>830</td>
<td>910</td>
<td>1,390</td>
<td>2,040</td>
<td></td>
</tr>
<tr>
<td>Total</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Low</td>
<td>21,350</td>
<td>21,635</td>
<td>22,990</td>
<td>24,000</td>
<td>25,360</td>
<td>26,610</td>
</tr>
<tr>
<td>High</td>
<td>23,880</td>
<td>25,410</td>
<td>26,540</td>
<td>28,020</td>
<td>29,400</td>
<td></td>
</tr>
</tbody>
</table>
These totals represent the range of cumulative capacity that needs to be procured to meet current Renewable Standard programs in these states. This represents a “Business As Usual” or BAU Case. We estimate that these programs will require an additional 5,200-8,000 MW of added renewable capacity from 2015 to 2020 in these four states, but this value may be higher or lower depending on future events. As outlined previously, other drivers may cause these numbers to vary beyond 2020.

Current procurements for major LSEs in this region represent a range of approximately 23,400 MW to 25,800 MW, including 7,800 MW of planned capacity additions in all phases as shown in Figure 4-6. Therefore, except in the case of a future in which renewable portfolio needs are low and a high percentage of planned projects are completed, it is our view that additional renewable capacity will need to be procured in the four-state region. As previously mentioned, nearly 40% of projects in California have failed in the past.

Depending on their location, resource additions could require additional transmission investment. Additionally, new lines to support central station solar development for higher irradiance locations further from load centers could be justified.

**Critical Factors Influencing Scenarios and Trigger Points**

To augment our Base Assessment, we examined two additional factors that would significantly affect the Base Case assessment. The first factor is the potential increase in additional generation related to the retirement of certain coal-fired plants in the Desert Southwest. The second looks at the development of small-scale distributed energy resources that reduce the need for central-station capacity as well as additional large-scale renewables that are located further from load centers.

**Critical Factors - Coal Plant Retirements**

Potential coal unit retirements in the Desert Southwest may be triggered by several events including additional environmental guidance related to regional haze requirements and up to four other federal environmental rulemakings. These include the Cross-States Air Pollution rule (CSAPR), the Mercury and Air Toxics Standards (MATS), the Coal Combustion Residuals rule (CCR), and the “once through cooling” (316(b)) rule. To examine the potential retirement of coal units, the analysis relies on a combination of retirements constructed by the Southwest Area Transmission planning group within WestConnect, the regional transmission planning group for much of the desert Southwest region.

For this scenario, the amount of coal capacity and corresponding generation that may need to be replaced is estimated under Low (or expected) and High retirement case sensitivities. Future planning decisions by the plant owners will decide which case becomes more relevant over the next five years.

**Figure 6-2: Estimated Cumulative Regional Coal Retirements in MW**

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Retirement Low</td>
<td>0</td>
<td>0</td>
<td>800</td>
<td>800</td>
<td>1,807</td>
<td>1,807</td>
</tr>
<tr>
<td>Retirement High</td>
<td>0</td>
<td>0</td>
<td>800</td>
<td>800</td>
<td>4,969</td>
<td>4,969</td>
</tr>
</tbody>
</table>
Under these two cases, the amount of capacity that may be retired ranges from about 1,800 MW to nearly 5,000 MW by 2020. Assuming a 70% capacity factor, retiring these amounts of coal capacity would result in about 11 million MWh to over 30 million MWh of lost coal generation that would need to be replaced by other resources under the Low Retirement and High Retirement cases, respectively. Coal retirements and renewable capacity additions may drive transmission upgrades that are needed to reduce associated problems, such as dynamic stability issues and G-1 N-1 contingencies. Additionally, a recent nationwide study of the CPP by consulting firm ICF International concluded that widespread coal retirements coupled with renewable capacity additions could lead to new transmission flow patterns that would lead to line overloads and disparities in substation voltages. Actual performance and impacts in this region would, of course, vary based on future developments and site-specific factors. Detailed examination typically requires the construction of specific scenarios and analysis using tools like load flow and/or production cost modeling. Scenarios were not constructed or analyzed for this study.

Critical Factors - Distributed Energy Resource Penetration
The section examines the Low Case (or expected) penetration of Distributed Energy Resources (DER) as well as a High Case in which distributed capacity additions are 1.25 times higher. This section focuses on the deployment of distributed rooftop solar, as it is the most viable distributed resource at this time and deployment may be substantially larger than other capacity additions. Current factors influencing rooftop solar adoption include the rate of energy storage adoption (especially in California), which would facilitate and enable solar additions, and the pace of solar cost decreases over the next several years. In addition, continued adoption of distributed solar PV will rely on its current regulatory treatment remaining relatively unchanged.

As with the coal retirements, the “DER” scenario provides cases that represent low and high impact possibilities. The relevancy of each case will depend, in part, on the decisions of home and business owners and how they respond to changing economics and improving technologies.

**Figure 6-3a: Estimated Distributed Solar PV Incremental Capacity Additions by State (MW)**

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Arizona</td>
<td>180</td>
<td>234</td>
<td>202</td>
<td>228</td>
<td>228</td>
<td>228</td>
</tr>
<tr>
<td>California</td>
<td>1,331</td>
<td>2,173</td>
<td>1,846</td>
<td>2,448</td>
<td>2,448</td>
<td>2,448</td>
</tr>
<tr>
<td>Nevada</td>
<td>60</td>
<td>61</td>
<td>48</td>
<td>66</td>
<td>66</td>
<td>66</td>
</tr>
<tr>
<td>New Mexico</td>
<td>39</td>
<td>65</td>
<td>49</td>
<td>71</td>
<td>71</td>
<td>71</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>1,610</strong></td>
<td><strong>2,533</strong></td>
<td><strong>2,145</strong></td>
<td><strong>2,813</strong></td>
<td><strong>2,813</strong></td>
<td><strong>2,813</strong></td>
</tr>
</tbody>
</table>
Figure 6-3b: Estimated Distributed Solar PV Incremental Capacity Additions by State (MW)\(^{69}\)

<table>
<thead>
<tr>
<th></th>
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<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Arizona</td>
<td>225</td>
<td>293</td>
<td>253</td>
<td>285</td>
<td>285</td>
<td>285</td>
</tr>
<tr>
<td>California</td>
<td>1,664</td>
<td>2,716</td>
<td>2,308</td>
<td>3,060</td>
<td>3,060</td>
<td>3,060</td>
</tr>
<tr>
<td>Nevada</td>
<td>75</td>
<td>77</td>
<td>60</td>
<td>83</td>
<td>83</td>
<td>83</td>
</tr>
<tr>
<td>New Mexico</td>
<td>49</td>
<td>81</td>
<td>61</td>
<td>89</td>
<td>89</td>
<td>89</td>
</tr>
<tr>
<td>Total</td>
<td>2,013</td>
<td>3,166</td>
<td>2,681</td>
<td>3,516</td>
<td>3,516</td>
<td>3,516</td>
</tr>
</tbody>
</table>

The Low, or Expected, sensitivity case is based on the Solar Energy Industries Association (SEIA)/Greentech distributed solar PV capacity forecast through 2018. For 2019 and 2020, capacity additions are held steady at 2018 levels. For the High Case, we derived numbers that were 1.25 times higher than the Expected Case values. In the Low Case, generation from cumulative distributed solar PV capacity additions is expected to increase from about 2.2-3.1 million MWh in 2015 to about 20.6-28.3 million MWh in 2020. In the High Case, generation from cumulative distributed solar PV is expected to increase from about 2.8-3.8 million MWh in 2015 to about 25.8-35.5 million MWh in 2020.

The DER scenarios demonstrate that distributed solar PV could be fairly impactful in this region by the end of the period of this study; however, there are additional factors that may alter the rate and magnitude of adoption. For example, several regulatory proceedings are underway between utilities and customer groups and it appears likely that there will be additional proceedings over the study period. In Nevada, states legislators and the public utility commission will decide whether to cap the state’s net metering at 3% of peak (which NV Energy estimates will be met by March 2016), or to increase the cap and allow net metering to continue.\(^{70}\) Net metering credits excess generation sent to the grid by owners of distributed energy systems at the current retail rate, and the cap level is expected to have a significant effect on the rate of solar development in the state. In Arizona, utilities are also filing with state PUC’s and governing Boards to increase monthly fixed charges on utility bills or to introduce monthly charges for owning a solar PV system. If successful, these initiatives would be likely to decrease the economic justification for owning or installing distributed solar. As a result, there is uncertainty surrounding distributed capacity growth in this region.
Chapter 7 – Conclusion

We conclude that renewable energy standards will drive a need for 5,200-8,000 MW of new, central station utility-scale renewable capacity in the 4 states examined in this report (California, Arizona, Nevada and New Mexico) from 2015 to 2020. As a result, the renewable additions in our Base Assessment could require additional transmission investment to access those resources.

We expect significant renewable development to continue within the four-state region over the 2015-2020 time period, driven primarily by the state renewable portfolio standards (RPS). A vetted assumption in this evaluation is the need for additional central station renewable generation generally translates into a need for transmission capacity to connect the renewable resources with load centers and to enable reliable operation of a reconfigured system.

Other environmental factors may affect the amount of renewable capacity and corresponding transmission updates over this time frame. Regional coal retirements driven by environmental initiatives such as the CPP, or higher RPS standards as discussed in California could drive these totals higher; however, the timing and design of these developments is uncertain. Conversely, the acceptance and expansion of distributed energy resources have the potential to reduce the need for remote utility-scale renewable projects and long-haul transmission projects. In most of these cases (higher RPS standards, environmentally-driven coal retirements, greater distributed energy deployment), there are likely to be additional interconnection and reconfiguration needs where Western can play a substantive role.

In addition, there are several market factors that will affect central-station renewable development in this region over the 2015 to 2020 timeframe. Some of these factors could have either a positive or negative impact, including the fate of federal tax credits, the capital cost trajectory of wind and solar over the next five years, and the level of growth achieved by distributed energy. Other market changes are expected to impact renewable development in a positive way, including the growth of electric vehicles and energy storage, enhanced RPS policies, declining costs of solar generation, and regional coal retirements. Finally, the rate at which projects fail will play a part in how much additional renewable capacity the region’s LSEs will need to procure.

Additional investigation as to the timing and mix of distributed energy resources, in-state utility scale resources, and out-of-state utility scale resources hold potential to provide additional insights as to the magnitude and timing of transmission investments. Sub-regional needs, such as those in Southern California may be different than those in Northern California or the Desert Southwest, or those of the broader four-state region. Sub-regional transmission differences may also be created by system-specific changes, such as generation retirements and increasing RPS requirements beyond 2020.

It is important to note that this report examines conditions at a single point in time. Substantive uncertainties exist within the economic and policy macro-environment related to renewable development, especially beyond 2020. Also, transmission development can require a long-lead time and be carried out over multiple years. Consequently, periodic re-evaluation and update of generation and transmission conditions is warranted.
Appendix A – Renewable Technologies and Characteristics

Utility-Scale Solar (PV, CSP)
Photovoltaic (PV) devices generate electricity directly from sunlight via a process that occurs naturally in semiconductors. Photons from light strike and ionize semiconductor material on the solar panel, causing outer electrons to break free of their atomic bonds. Due to the semiconductor structure, the electrons are forced in one direction, creating a flow of electrical current. Solar cells are not 100% efficient in part because some of the light spectrum is reflected, some is too weak to create electricity (infrared) and some (ultraviolet) creates heat energy instead of electricity. Typical cell efficiency is currently on the order of 21.5%.71

Most modern solar cells are made from either crystalline silicon or thin-film semiconductor material. Silicon cells are more efficient at converting sunlight to electricity, but generally have higher manufacturing costs. Thin-film materials typically have lower efficiencies, but can be simpler and less costly to manufacture. All types of PV systems are widely used today in a variety of applications.

There is currently about 63,000 MW of solar PV cell and module manufacturing capacity worldwide, concentrated largely in Asia.72 However, only about 40,000 MW was actually manufactured in 2013, and Bloomberg New Energy Finance (NEF) estimates that global demand for PV modules in 2013 was about 36,000-40,000 MW. As a result, oversupply is expected to continue for the foreseeable future, which will continue to suppress prices. Over the past six years, dramatic growth in utility-scale PV has taken place across the U.S. However, installations may start to level off this year as California, where the majority of U.S. installations occur, is nearing its RPS goals. While Bloomberg NEF reports that module prices ticked up in 2013, they are down substantially over the past five years.

Concentrating solar power (CSP) plants use mirrors to concentrate the energy from the sun to drive traditional steam turbines or engines that create electricity. The thermal energy concentrated in a CSP plant can be stored and used to produce electricity when it is needed, day or night. Four major types of CSP technologies are in use today – parabolic trough, compact linear Fresnel reflector, dish engine, and power tower.73 Today, over 1,400 MW of CSP plants operate in the United States, and another 390 MW will be placed in service in the next year. Several large concentrating solar power (i.e., solar thermal electricity generation) plants were commissioned in 2014: Abengoa’s Mojave (280 MW), BrightSource’s Ivanpah (392 MW) and NextEra’s Genesis (250 MW) projects. However, falling costs mean that PV gained a cost edge in the last several years, and that trend does not appear likely to reverse in the future.
Distributed-Scale Solar

Distributed solar PV consists of the same basic components as utility-scale solar PV, but the smaller installations create a significantly different cost structure. However, due to net metering programs that credit excess generation sent to the grid at the retail rate, distributed solar PV is currently experiencing its greatest growth to-date. In 2014, the U.S. experienced sustained PV cell installations of more than 1,000 MWdc per quarter.

While these installations generally impact distribution systems, they are large enough in aggregate to be viewed in comparison to some large-scale solar applications. Thus, understanding the location of deployment, their role in RPS processes, the rate of customer adoption, their ability to substitute for large scale installations, and other adoption factors is critical for transmission and distribution analysis.

Utility-Scale Wind

Wind power captures the natural wind in the atmosphere and converts it into mechanical energy, and then electricity. Windmills were early sources of wind power, but were generally use for direct applications including pumping water and grinding grain. Most wind turbines have three blades, a hub, and a nacelle which all sit atop a steel tubular tower. They range in size from 80 foot turbines that provide enough power for a single home, to 260 foot utility-scale turbines that can power hundreds of homes. When the wind blows, the blades spin clockwise, capturing energy. This causes the main shaft, which is connected to the gearbox within the nacelle, to spin. The gearbox increases the rotational
speed and sends that energy to the generator, converting it to electricity. Electricity then travels down-
tower to the transformer, where it is converted once again to AC or DC voltage, depending on the grid.

NextEra Energy is the dominant wind developer in the US market, followed by Iberdrola and
MidAmerican Energy (Berkshire Hathaway). In general, regulated utilities have built only a small portion
of the wind assets in the country, and most utilities prefer to sign power purchase agreements with
independent generators rather than build and own the projects themselves.

Large-scale wind installation generation in 2014 rebounded six-fold from 2013 levels (800 MW to 4,900
MW), primarily due to the expiration and subsequent renewable of the PTC.

In recent years, turbine prices have leveled off compared to the steep declines in the early 2000s;
however, cost reductions in the LCOE continue to occur due to increased hub heights and their
corresponding improvements in performance. Turbines with larger rotor diameters (>95m, “new
models”) are generally priced higher than those with smaller rotor diameters (<95m, “old models”), but
in most regions, developers still elect to use newer turbines, due to the associated increase in
production.⁷⁶

\[\text{Figure A-2: Wind Turbine Cost Indicators}\]

<table>
<thead>
<tr>
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<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Bloomberg Wind Turbine Price Index</td>
<td>$1.70</td>
<td>$1.60</td>
<td>$1.61</td>
<td>$1.74</td>
<td>$1.41</td>
<td>$1.35</td>
<td>$1.39</td>
<td>$1.30</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th></th>
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<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Old</td>
<td>$1.17</td>
<td>$1.10</td>
<td>$1.08</td>
<td>$1.17</td>
<td>$1.18</td>
<td>$1.14</td>
</tr>
<tr>
<td>New</td>
<td>$1.28</td>
<td>$1.28</td>
<td>$1.33</td>
<td>$1.29</td>
<td>$1.29</td>
<td>$1.27</td>
</tr>
</tbody>
</table>

Note: Unit = Million USD/MW Nameplate Capacity

**Distributed Wind**

Unlike solar PV, distributed wind is much less common than its utility-scale counterpart. In 2013, 30.4
megawatts (MW) of new distributed wind capacity was added, representing nearly 2,700 units across 36
states, Puerto Rico, and the U.S. Virgin Islands (USVI). Distributed wind capacity additions declined by
83% from 2012 to 2013, in step with the decrease in overall U.S. wind capacity deployed.

While these installations generally impact distribution systems, they are also relatively small in
aggregate total and tend not to impact large-scale adoption.
Geothermal energy is produced as heat from the Earth. Resources range from the shallow ground to hot water and hot rock found a few miles beneath the Earth’s surface, and even deeper to the high temperatures of molten rock known as magma.

There are three types of geothermal power plants: dry steam, flash steam, and binary cycle.78

- Dry steam power plants draw from underground steam resources. The steam is piped directly from underground wells to the power plant, where it is directed into a turbine/generator unit.

- Flash steam power plants are the most common. They use geothermal reservoirs of water with temperatures greater than 360°F. This very hot water flows up through wells in the ground due to its own pressure. As it flows upward, the pressure decreases and some of the hot water boils into steam. The steam is then separated from the water and used to power a turbine/generator. Leftover water and condensed steam are injected back into the reservoir.

- Binary cycle power plants operate at lower temperatures of 225°-360°F. The heat from the hot water boils a working fluid, usually an organic compound with a low boiling point. The working fluid is vaporized in a heat exchanger and used to power a turbine. The water is then injected back into the ground to be reheated.

Geothermal development has lagged behind other renewables (namely wind and solar), due to long project completion periods (4-7 years) and high costs of development. Two projects were commissioned in 2014, totaling 46MW. Both projects are located in Nevada and have PPAs with California municipal utilities with the electricity used for compliance with California’s RPS. Another project, the 45MW Ormat McGinness Hill II plant, secured financing in 2014 and is slated to be commissioned in 2015. The facility currently has a PPA with NV Energy.
Appendix B – Renewable Portfolio Standard Details by State

California

California - Background
The California RPS was originally established in 2002 under Senate Bill 1078, but the standard has since been updated several times. In 2006, Senate Bill 107 was passed requiring that 20 percent of electricity retail sales be served by renewable energy resources by 2010. Subsequently, in late 2008, Governor Schwarzenegger signed Executive Order S-14-08 requiring that "...all retail sellers of electricity shall serve 33 percent of their load with renewable energy by 2020." The following year, Executive Order S-21-09 directed the California Air Resources Board (CARB) to enact regulations that would achieve the goal of 33 percent renewables by 2020. Senate Bill X1-2 was signed by Governor Brown in April 2011.

This new RPS preempts the California Air Resources Boards' 33 percent Renewable Electricity Standard and applies to all electricity retailers in the state including publicly owned utilities (POUs), investor-owned utilities, electricity service providers, and community choice aggregators. All of these entities are subject to RPS goals of:

- 20 percent of retail sales from renewables by the end of 2013,
- 25 percent by the end of 2016, and
- 33 percent requirement being met by the end of 2020.

California - Program Structure
The California Energy Commission (CEC) and the California Public Utilities Commission (CPUC) work collaboratively to implement the RPS.

The CPUC's responsibilities include:

- Determining annual procurement targets and enforcing compliance
- Reviewing and approving each IOU's renewable energy procurement plan
- Reviewing IOU contracts for RPS-eligible energy
- Establishing the standard terms and conditions used by IOUs in their contracts for eligible renewable energy

The CEC responsibilities include:

- Certifying eligible renewable facilities for the RPS
- Designing and implementing a tracking and verification system to ensure that renewable energy output is counted only once for the purpose of the RPS and for verifying retail product claims in California or other states (WREGIS, described below)
- Adopting regulations specifying procedures for enforcement of the RPS for publicly owned utilities
Certifying and verifying eligible renewable energy resources procured by publicly owned utilities and to monitoring their compliance with the RPS
Certifying and verifying RPS procurements by retail sellers
Referring the compliance failure of a publicly owned utility to CARB, which may impose penalties

The Western Renewable Energy Generation Information System (WREGIS) has been used to track RECs in California and the rest of the Western Interconnection since 2007. WREGIS was developed in response to policies set by the California Legislature and the Western Governors’ Association (WGA) to develop and implement a system tracking renewable energy generation.

California - Compliance Periods
In addition to extending California’s RPS program goal from 20% in 2010 to 33% in 2020 and each year thereafter, SB X1-2 made two significant changes to RPS procurement rules. First, the bill mandated new RPS procurement requirements within multi-year compliance periods. Second, it established new portfolio content categories for RPS procurement and set minimum and maximum limits on certain procurements that can be used for compliance with the RPS program.

In Decision (D.) 11-12-020, the CPUC implemented the new RPS procurement quantities for all retail sellers (investor-owned utilities, community choice aggregators, and electric service providers). Compliance is determined by the amount of renewable energy credits (RECs) retired for compliance within three multi-year compliance periods though 2020. The methodology for calculating RPS procurement requirements through 2020 applies a linear trend between the compliance period targets as defined in SB X1-2. After 2020, all retail sellers must procure 33% of their retail sales from RPS-eligible resources.

Figure B-1 describes the methodology used to establish the procurement requirement amounts for each Compliance Period in greater detail.

<table>
<thead>
<tr>
<th>RPS Compliance Period</th>
<th>RPS Compliance Years</th>
<th>Procurement Quantity Base</th>
<th>Procurement Quantity Retirement</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>2011-2013</td>
<td>2011 Retail Sales</td>
<td>20.0%</td>
</tr>
<tr>
<td></td>
<td></td>
<td>2012 Retail Sales</td>
<td>20.0%</td>
</tr>
<tr>
<td></td>
<td></td>
<td>2013 Retail Sales</td>
<td>20.0%</td>
</tr>
<tr>
<td>2</td>
<td>2014-2016</td>
<td>2014 Retail Sales</td>
<td>21.7%</td>
</tr>
<tr>
<td></td>
<td></td>
<td>2015 Retail Sales</td>
<td>23.3%</td>
</tr>
<tr>
<td></td>
<td></td>
<td>2016 Retail Sales</td>
<td>25.0%</td>
</tr>
<tr>
<td>3</td>
<td>2017-2020</td>
<td>2017 Retail Sales</td>
<td>27.0%</td>
</tr>
<tr>
<td></td>
<td></td>
<td>2018 Retail Sales</td>
<td>29.0%</td>
</tr>
<tr>
<td></td>
<td></td>
<td>2019 Retail Sales</td>
<td>31.0%</td>
</tr>
<tr>
<td></td>
<td></td>
<td>2020 Retail Sales</td>
<td>33.0%</td>
</tr>
<tr>
<td>2021 And Each Year After</td>
<td>Annual Retail Sales</td>
<td></td>
<td>33.0%</td>
</tr>
</tbody>
</table>
Renewable generation facilities eligible to participate may be located anywhere within the WECC region and sell energy and/or renewable energy credits (RECs) to a California retail seller of electricity to meet its RPS obligation, provided the facility meets all RPS-eligibility criteria established by the California Energy Commission (CEC).\(^8^4\)

Arizona

Arizona - Program Structure
The regulatory body that oversees the renewable portfolio program in Arizona is the Arizona Corporation Commission (ACC). In 2006, the ACC approved the Renewable Energy Standard and Tariff (REST), which requires electric utilities to generate 15 percent of their energy from renewable resources by 2025 in addition to interim targets (Figure B-2). The REST program covers multiple generation technologies including solar, wind, biomass, biogas, geothermal and other similar technologies to generate “clean” energy. It also includes incentives for customers who install distributed solar energy technologies.

![Figure B-2: Arizona Interim RPS Targets](image)

Important components of the REST include:

- No more than 20% of the annual target can be met with renewable energy credits (RECs), meaning the majority of compliance must come from long-term contracts.
- Over this period, the rules prescribe that up to 30 percent of the annual target requirement is to come from distributed energy resources (DER). Half of the customer–owned DER requirement must be met by residential customers and the other half from business customers.
- In-state resources receive an extra credit multiplier.

Utilities subject to the RES provide annual filings that describe how each utility intends to comply with the RES requirements for the next five years. These filings describe renewable energy resources that will be added during the next five years to achieve annual targets, the estimated customer funding, the surcharge amounts (RES adjustor) required to acquire those resources, and a budget that allocates funding for specific projects and programs.
Arizona - Program Performance
As of the end of 2013, Arizona’s two largest utilities have exceeded their 2015 RES requirements.

<table>
<thead>
<tr>
<th>Utility</th>
<th>Total Retail Sales (MWh)</th>
<th>Overall RES Target</th>
<th>Current RES Progress</th>
<th>Actual RES Generation (MWh)</th>
<th>Overall DER Target</th>
<th>Overall DER Progress</th>
<th>Actual DER Generation (MWh)</th>
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</thead>
<tbody>
<tr>
<td>Arizona Public Service</td>
<td>21,127,133</td>
<td>4.0%</td>
<td>6.8%</td>
<td>1,913,285</td>
<td>30.0%</td>
<td>36.4%</td>
<td>696,375</td>
</tr>
<tr>
<td>Tucson Electric Power</td>
<td>9,278,918</td>
<td>4.0%</td>
<td>5.6%</td>
<td>515,471</td>
<td>30.0%</td>
<td>32.9%</td>
<td>169,401</td>
</tr>
</tbody>
</table>

Arizona - Other Utility Programs Affecting Renewable Development
The Salt River Project (SRP) is the umbrella name for two separate entities: the Salt River Project Agricultural Improvement and Power District, an agency of the state of Arizona that serves as an electrical utility for the Phoenix metropolitan area, and the Salt River Valley Water Users' Association, a utility cooperative that serves as the primary water provider for much of central Arizona. SRP is one of the primary public utility companies in Arizona; however, it is not regulated by the ACC.

Under the current SRP structure, the organization’s Board of Directors performs oversight functions. In 2011, the Board approved a management proposal that directs SRP’s future use of renewable energy resources and energy conservation measures. The approved proposal established a target for 20% of SRP retail sales to be met through sustainable resources by fiscal year 2020.

During fiscal year 2014, SRP reported that its current renewable portfolio was approximately 791 MW including biomass, geothermal, hydro, landfill gas, solar (utility-scale and distributed), and wind resources.

Nevada

Nevada - Program Structure
Nevada's RPS was first adopted by the Nevada Legislature in 1997 but has since been modified substantially. Broadly speaking, electric utilities are required to generate, acquire, or save a certain percentage of clean electricity annually with portfolio energy generation or energy efficiency measures. The Public Utility Commission of Nevada (PUCN) oversees the program. Each year, providers of electric service must submit a report to the PUCN providing evidence of their compliance with the RPS.

The percentage of renewable energy required by the RPS increases every two years until it reaches 25 percent in 2025. Other pertinent details include:

- By 2025, at least 1.5 percent of retail sales must come from solar PV
- Efficiency measures can be used to comply with up to 25 percent of the annual RPS requirement
• Of that 25 percent, 50 percent must come from measures installed at a residential customer’s location.

In Nevada, the RPS is tracked through a system of portfolio energy credits (“PECs”). These credits are issued to any eligible renewable energy producer and may be sold to electric utilities seeking to meet their RPS. Customers who receive a rebate/incentive payment for installing a renewable energy system assign ownership of the PECs generated by the system to the utility administering the program.

**Nevada - Solar Program**
The RPS also contains a number of measures designed to spur investments in various generating technologies. For example, the solar Energy Systems Incentive Program requires public utilities to develop and administer programs that offer rebates to three categories of customers: 1) school property, 2) public and other property, and 3) private residential and small business property, who must all install qualifying solar energy systems on their property. A utility may award a total of over $255 million in incentive funding between July 1, 2010, and June 30, 2021.

**Nevada - Program Performance**
There are two major utilities in Nevada that are owned by NV Energy – Nevada Power and Sierra Pacific Power. Both subsidiaries significantly exceeded the RPS requirements of 15% in 2012 and 18% in 2013 with at least 20% of generation qualifying under the state’s RPS. Both operating companies also surpassed the solar energy credit requirement.

Under the RPS program, customers have also received approximately $203 million in rebates for more than 2,100 solar photovoltaic, solar water heating, small hydro and wind generators installed at customer locations throughout Nevada. Total customer-sited energy installed is more than 55 MW, including 1,869 solar PV projects and 162 wind projects.

**New Mexico**

**New Mexico - Program Structure**
In New Mexico, the Public Regulation Commission (PRC) reviews and approves renewable energy procurement plans and reports of IOU’s and Coops. The governing laws include the Renewable Energy Act (REA) and Rule 572. IOU’s in New Mexico procure renewable energy and renewable energy certificates (RECs) from New Mexico renewable generation facilities to meet RPS requirements of the REA and Rule 572. New Mexico’s current RPS requirements for IOUs are 15% by 2015 and 20% by 2020.

Rule 572 required that IOU’s must offer a voluntary renewable energy program to their customers. In addition to and within the total portfolio percentage requirements, utilities must design their public utility procurement plans to achieve a diversified renewable energy portfolio:

• No less than 30% Wind.
• No less than 20% Solar.
• No less than 5% other technologies.
No less than 1.5% Distributed Generation (2011-2014) and no less than 3% by 2015.

In New Mexico, a public utility is not required to add renewable above a reasonable cost threshold (RCT) established by the Commission. Beginning in 2013, this amount was set at 3% of total revenues in any plan year.

Rural electric cooperatives are also covered under the legal framework. Renewable energy must comprise no less than 5% of retail sales by 2015 and the RPS will increase at a rate of 1% annually until 2020, at which time the RPS will be 10%. In addition, co-ops must offer a voluntary renewable energy program to their customers provided their supplier makes renewable resources available.

IOU’s are typically meeting RPS requirements through power purchases from non-utility or independent power producers ("IPP’s"). Additionally, under other programs, REC’s are also purchased from PV installations of 10kW or less. Similar to California, the RECs are registered under WREGIS.

**New Mexico - Program Performance**

There are three major investor-owned utilities operating in New Mexico – El Paso Electric (EPE), Public Service of New Mexico (PNM), and Southwestern Public Service (SPS, a unit of Xcel Energy).

Thus far, the state’s RPS has spurred significant renewable investments in New Mexico, with utilities procuring a mix of geothermal, wind, and utility-scale and distributed solar PV. In addition, utilities have sought to alleviate short-term compliance concerns by purchasing RECs on the open market, such as PNM’s purchase of 50,000 wind RECs to meet its 2014 compliance obligation.

However, the previously mentioned reasonable cost threshold is expected to slow down capacity deployment in the near future. EPE has also already announced that the RCT will curb its compliance in 2016, when the RPS requirement jumps from 10 to 15 percent. While EPE indicates it expects meet the increased solar and distributed generation requirements, the utility will be excused under RCT from meeting wind and “Other” diversity requirements. EPE has stated that it will continue to seek to procure economic renewable energy outside of the RPS process to provide resources to meet load growth.

For its 2013 RPS report, SPS reported generally favorable results but has indicated that it is likely that it will not meet the full diversity goals, primarily due to cost pressures. SPS has undertaken an extensive building program of wind and other renewable resources.
Appendix C – Other Regional Market Developments

While this memo touches on a number of factors that will affect renewable energy growth in Arizona, California, Nevada, and New Mexico including current federal and state policies, conventional generation retirements, and emerging drivers of change, there are a number of potential developments that could significantly impact regional renewable capacity additions in the short- to long-term but are not fully considered in the scope of this report.

State and Federal Regulatory Developments

Regulatory Developments - Changes to RPS
Revoking, freezing, or expanding a state’s RPS would be one of the most impactful developments to renewable energy capacity development in the region. While no mandatory RPS has been revoked thus far, Ohio was the first state to freeze their RPS (a two year freeze from 2014-2015), and the immediate shift in policy created significant uncertainty for project developers, many of whom are choosing to focus their efforts on other markets.91 The New Mexico House of Representatives recently passed a bill that would limit the state’s RPS to its current level of 15% instead of the final goal of 20% by 2020; however, the measure ultimately stalled in the Senate Conservation Committee.92 While the state’s RPS appears safe for now, the move shows some support for curbing New Mexico’s clean energy targets.

In contrast, California has indicated that they may seek to enhance their RPS standard to 50% by 2030. California Governor Jerry Brown announced his intention to seek the increase in his January inaugural address, and a bill was also introduced into the California legislation that would formalize Brown’s plan.93 Enhanced RPS standards would certainly present their own set of challenges. A study performed by Energy and Environmental Economics entitled “Investigating a Higher Renewables Portfolio Standard in California” found fairly significant operational challenges associated with the increased renewables penetration related to a 50% California RPS. This was especially true when the standard was met with increased amounts of variable wind and solar generation. The study concluded that the largest integration challenge associated with this level of renewables was related to over-generation, which occurs when must-run generation such as non-dispatchable renewables, combined heat and power, nuclear generation, and others exceeded load and export capability. While the study found that these effects could be partially mitigated with a more diverse set of renewable resources and enhanced regional coordination, such measures came with an added cost. The study concluded that meeting a 50% RPS will require capital investments in transmission by 2030 of $5.7 billion to $12.4 billion beyond those required for a 33% RPS.

Regulatory Developments - The Clean Power Plan - NSPS
The proposed Clean Power Plan (CPP), a set of federal regulations by the US EPA, requires significant reductions in state-by-state CO2 emissions and, as previously mentioned, could result in additional retirements and increased renewable builds. Depending on the form of the final regulations to be issued by EPA this summer, as well as the program designs that individual states adopt, the regulations have the potential to drive significant additional renewable growth.
Regulatory Developments - California AB 32
Passed in 2006, AB 32 requires California to reduce its GHG emissions to 1990 levels by 2020 — a reduction of approximately 15 percent below emissions expected under a “business as usual” scenario. Under AB 32, the California Air Resource Board (CARB) must adopt regulations to achieve technologically feasible and cost-effective GHG emission reductions. The full implementation of AB 32 is expected to mitigate risks associated with climate change, improve energy efficiency, expand the use of renewable energy resources, result in cleaner transportation, and reduce waste.

Unlike CPP, which focuses on existing power plant emissions, AB 32 is cross-sectoral and covers many aspects of the state’s infrastructure. Further, while the CPP focuses on measuring and mitigating CO2 emissions, AB 32 is focused on a more comprehensive set of greenhouse gases including carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, and more.

Every five years, AB 32 requires CARB to develop an updated Climate Change Scoping Plan, which defines and updates the programs priorities for the next several years. In May 2014, CARB approved the first update to the scoping plan that included, “the development of a comprehensive greenhouse gas reduction program for the State’s electric and energy utilities by 2016”. The eventual design of that reduction plan could have an effect on renewable energy development in the state, as will any additional updates to the scoping plan.

Regulatory Developments - CAISO Expansion
Over the past year, several utilities in the Western U.S. have announced their intentions to join CAISO’s Energy Imbalance Market (EIM), with PacifiCorp integrating into the market in November 2014 and several additional utilities set to connect to the EIM over the next several years. CAISO’s EIM is a short-term (5-minute) energy balancing market, and the move is likely to have a positive impact on renewable energy development in the region as short-term supply and demand will be optimized over a wider geographic scope. CAISO and Pacificorp’s study of the market benefits of integrating the utility into the EIM concluded that it would lead to, “increase flexibility and reduce renewable curtailment”, amongst other benefits. NV Energy, Puget Sound Energy, and APS are all poised to join the EIM by the end of 2016, which will expand the scope of the EIM to portions of seven states.

In addition, PacifiCorp (and its subsidiaries Pacific Energy and Rocky Mountain Power) and CAISO are exploring the feasibility and benefits of integrating PacifiCorp into full CAISO membership. The move would commit PacifiCorp to CAISO’s other markets including day-ahead energy markets, ancillary services, residual unit commitment, congestion revenue rights, and convergence bidding. While full integration of the utility would lead to incremental renewable integration benefits, it would also have the potential to further open up California’s renewable energy markets. Current deliverability requirements dictate that interconnected renewable energy resources have to deliver into the CAISO system in order to be an RPS-eligible resource. Although renewable energy resources will still have to find adequate sources of demand, transmission costs and barriers will be significantly reduced if high quality renewable energy projects only have to deliver into PacifiCorp’s territory. PacifiCorp currently serves portions of Oregon, Washington, Idaho, Utah, and Wyoming.
Appendix D – Report Scope

Observations

This report is focused on the 2015-2020 period.

There are additional pending sector developments that may have an impact over a longer analysis period including EPA’s proposed Clean Power Plan (CPP) and proposed increases to RPS standards currently discussed in California. In both of these cases, it is likely that regional solutions increase in importance and utility-scale renewables located further from load enters could be a part of a solution. These developments, and others, could serve to materially change the timing and results of this analysis subsequent to the 2015-2020 period.

The role of storage and its contribution in addressing the intermittency and variable generation profile of distributed energy resources (DER) is complex to model. This report is focused on public studies and guidance of DER additions and storage during the period. Detailed production cost and load flow modeling of the potential impacts of combinations of these assets on the distribution and transmission network was not conducted.

Additional commitments to distributed storage assets during the study period could serve to reduce stresses on distribution systems, facilitate enhanced levels of DER resources, and potentially reduce the need for long haul transmission. Furthermore, additions of utility scale storage holds promise to improve the resiliency of existing transmission assets and alter or potentially lower the overall level of transmission asset additions.

This report is drawn largely from publicly available sources.

The public focus of this report is substantially different than that of the traditional developer. Developers generally rely on a certain degree of confidentiality to progress their project to the point that it can be a viable solution. As a result, this type of study cannot capture all of the potential solutions to satisfy a particular demand need for renewables. Further, given the opaqueness of the development process, it is likely that some projects will not progress to completion. This characteristic is partially reflected in the “failure rate” assigned in some jurisdictions, but the effect and outcome is uncertain.

Some load-serving entities may choose to enter into bilateral transactions with developers for renewable and/or transmission supply. Certain details of these contracts may be made public, but they may be part of a larger procurement process (“all-sources” solicitations) or they may be entered into on an “option” basis pending additional policy and regulatory guidance that may occur now at a future
date. This type of study has difficulty capturing and reflecting these types of commitments and developments.

_This report does not attempt to construct scenarios or conduct detailed analysis of impacts._

From a transmission planning perspective, these steps typically include scenario construction, load flow, and production cost modeling.

_This report represents an overview based on conditions as of April, 2015._

Given the substantive policy and macro-economic changes currently experienced in the sector, additional updates appear warranted as these drivers become better defined.
End Notes

2 GTM Research Solar Market Insight Report
3 Source: CPUC.
4
8 http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M088/K978/88978845.PDF accessed on 03/12/2015.
13 EIA 861.
14 EIA 861.
15 Source: SNL
16 This data does not include capacity owned by or contracted with municipal utilities. In California and New Mexico, where municipal utilities are subject to the state’s RPS, municipal utilities serve about 24% of load (EIA Form 861 data).
17 Source: ICF International, State Commissions.
18 Sources: CPUC (IOUs), SNL (Municipal Utilities)
19 Source: SNL
20 Source: SNL
21 Source: Various State Commissions.
22 Source: Various state commissions.
23 Information for municipal utilities is unavailable because it is not published by the state PUC's.
24 Source: CPUC.
27 Source: CPUC.


Source: SNL


https://www.sce.com/wps/portal/home/procurement/solicitation/lcr/!ut/p/b1/hc7BDolwEATQb_ELOIhT6HGriw hlp2E7IX0RlooeB--V5iGudzb1G8mK7zohZ_CK47hGe9TuH6yYOPFBSV2t-UmTzwlcValYoA1agaXGeDHEf71z8KvkX2TvBkXk2YKS1BuHk9GdIkqG6AtTFk1YNu1EixbHBYRBL4LK08-bjOijs3_aA9eQ!!/dl4/d5/L2dBISevZ0FBIS9nQSeh/ accessed on 5/13/15.


Source: CAISO presentation, 2/26/15 Western Planning Regions Coordination meeting
Source: CAISO presentation, 2/26/15 Western Planning Regions Coordination meeting


http://files.shareholder.com/downloads/ABEA-Z0SXJ/4101965087x0x793679/9FC7CEF8-E07D-418F-AC56-B7CECC1DE62B/EEl%202014%20Financial%20Conference.pdf Slide 20, accessed on 03/14/2015.


Source: CAISO.

GTM Research Solar Market Insight Report


Source: CPUC.

Source: ICF International, based on data from various state PUCs.
In most cases, these values are derived from compliance filings that LSEs make with regulators; in public power cases with separate regulatory and reporting mechanisms, estimates were made from public information. Data availability varied by state. Additionally, where feasible, adjustments were made if the technology was not commonly employed in other states. Some states include energy efficiency in their RPS standard, while others do not.

Source: ICF International.


http://www.epa.gov/mats/ accessed on 03/17/2015.

http://www2.epa.gov/coalash/coal-ash-rule accessed on 03/17/2015.


http://www.epa.gov/mats/ accessed on 03/17/2015.

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ICF International and data from 2013 REST Compliance Reports


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