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BEFORE THE ARIZONA POWER PLANT AND TRANSMISSION LINE SITING COMMITTEE

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OCT 22 2015
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IN THE MATTER OF THE APPLICATION OF SUNZIA TRANSMISSION LLC, IN CONFORMANCE WITH THE REQUIREMENTS OF ARIZONA REVISED STATUTES 40-360, ET SEQ., FOR A CERTIFICATE OF ENVIRONMENTAL COMPATIBILITY AUTHORIZING THE SUNZIA SOUTHWEST TRANSMISSION PROJECT, WHICH INCLUDES THE CONSTRUCTION OF TWO NEW 500 KV TRANSMISSION LINES AND ASSOCIATED FACILITIES ORIGINATING AT A NEW SUBSTATION (SUNZIA EAST) IN LINCOLN COUNTY, NEW MEXICO, AND TERMINATING AT THE PINAL CENTRAL SUBSTATION IN PINAL COUNTY, ARIZONA. THE ARIZONA PORTION OF THE PROJECT IS LOCATED WITHIN GRAHAM, GREENLEE, COCHISE, PINAL, AND PIMA COUNTIES.	DOCKET NO. L-00000YY-15-0318-00171 Case No. 171 **NOTICE OF FILING OF EXIBITS**

Arizona Corporation Commission
DOCKETED
OCT 22 2015
DOCKETED BY

Pursuant to Paragraph 15 of the Procedural Order issued by Chairman Chenal on September 11, 2015 for the above-referenced case, I am herein filing a single copy of the exhibits in support of the testimony that I will present as my own witness.

Respectfully submitted this 22th day of October 2015

Norm "Mick" Meader

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EXHIBITS IN SUPPORT OF THE TESTIMONY OF NORM "MICK" MEADER

IN PROCEEDINGS BEFORE THE POWER PLANT AND TRANSMISSION LINE SITING COMMITTEE

FOR SUNZIA TRANSMISSION, LCC
DOCKET NUMBER L-00000YY-15-0318-00171

OCTOBER 19–NOVEMBER 20, 2015

EXHIBIT NO.	TITLE
TOPIC 1	**MEETING ARIZONA AND CALIFORNIA RENEWABLE ENERGY NEEDS**
NMM-1	Excerpted page from Arizona Public Service's *2014 Integrated Resource Plan* referencing their 12% level compliance with Arizona's Renewable Portfolio Standard
NMM-2	Arizona's solar energy potential as determined by the National Renewable Energy Laboratory
NMM-3	Excerpted pages from Mark Etherton's report, *Enhancing Arizona's Ability to Export Renewable Energy* that address Arizona's renewable energy export potential and the barriers to exports
NMM-4	Table 1, Arizona renewable energy facilities with California power purchase agreements; and Table 2, Partially permitted but unbuilt Arizona renewable energy projects
NMM-5	Solar applications on Arizona BLM lands as of 2012
NMM-6	Current and projected use of utility-scale renewable energy by major Arizona utilities
NMM-7	Full reference for comments by Carmine Tilghman of Tucson Electric Power Company noting that only use of SunZia by California utilities could justify the project
NMM-8	Future cost comparisons by Arizona Public Service Company of various generation technologies
NMM-9	Comparison of solar resource and wind resource capacity factors by Tucson Electric Power Company
NMM-10	Full reference for statement that the number of California renewable energy projects scheduled to go online by January 2017 represents more than double the capacity the state needs to achieve a 33 percent renewable portfolio standard
NMM-11	Full reference for statement that developers proposed 1,000 renewable energy projects in California in 2011 totaling 91,000 megawatts of capacity
NMM-12	Email message from Michael Picker, Senior Advisor to Governor Jerry Brown for Renewable Energy Facilities, to Norm Meader regarding SunZia
NMM-13	Full reference for the statement that the California BLM has received 375 applications for renewable energy since 2007 and has approved only 18 of them
NMM-14	California utility websites that provide information and bid instructions on current requests for renewable energy procurement
TOPIC 2	**RELIABILTY, CONGESTION, AND TRANSFER CAPABILITY NEEDS**
NMM-15	Transmission Path 47 in southwestern New Mexico
NMM-15A	States from SunZia Path Rating Re-Study showing that SunZia will now not interconnect with the southwestern New Mexico grid
NMM-16	A measure of the congestion on Path 47 by using the 75% and 90% utilization levels

NMM-17	A measure of congestion on Path 47 in southwestern New Mexico using scheduling
NMM-18	The southeastern Arizona transmission system
NMM-19	General route of the Southline Transmission Project
NMM-20	Plans by El Paso Electric Company to cease using its 108-megawatt share of the Four Corners Power Plant in 2016
NMM-21	Future plans by El Paso Electric Company to build 1,195 megawatts of natural gas generating capacity in and around El Paso by 2034
NMM-22	Planned natural gas generation additions by Public Service Company of New Mexico through 2033
NMM-23	Proposed locations of planned natural gas generation additions by Public Service Company of New Mexico
NMM-24	Public Service Company of New Mexico's transmission needs through 2033
NMM-25	Natural gas power plants planned by 2021 by the Salt River Project for Pinal County at the Pinal Central (1,150 megawatts) and Abel (900 megawatts) substations
NMM-26	Planned resource additions by Arizona Public Service through 2029
NMM-27	APS's first step in expanding its natural gas generation
NMM-28	Planned natural gas generation additions by Tucson Electric Power Company through 2026
TOPIC 3	**CONFLICTS WITH CENTRAL AND WESTERN ARIZONA'S TRANSMISSION SYSTEM**
NMM-29	Electrical District 4 Petition to Intervene in SunZia Petition for a Declaratory Order to the Federal Energy Regulatory Commission
NMM-30	Statement by David Getts of SunZia about the level of pre-build transmission purchases needed to finance SunZia
NMM-31	Components of Arizona's extra-high-voltage transmission system and 230-kilovolt lines outside the Phoenix metropolitan area
NMM-32	Definitions of Available Transfer Capability and Total Transfer Capability
NMM-33	Detailed view of high-voltage transmission lines in central Arizona
NMM-34	Locations of new natural gas power plants proposed for construction by the Salt River Project at Pinal Central and Abel by 2020
TOPIC 4	**CONFLICTS WITH ARIZONA'S SOLAR ENERGY DEVELOPMENT**
NMM-35	Concentrating solar prospects for Arizona defined by the National Renewable Energy Laboratory for areas of 1% slope or less
NMM-36	The status of renewable energy interconnection requests on Arizona transmission lines through 2010
NMM-37	Statements of Interest for solar energy development received for Western's (WAPA's) new 230-kilovolt line from Electrical District 5 northwest of Tucson to Pinal West
TOPIC 5	**CONFLICTS WITH THE PLANNED SOUTHLINE TRANSMISSION PROJECT**
NMM-38	Southline Transmission Project fact sheet
NMM-39	The Southline preferred alternative from the BLM's Draft Environmental Impact Statement

NMM-40	The preferred alternatives for the SunZia and Southline projects
NMM-41	The initial SunZia Project showing its similarity to the Southline Project
NMM-42	Map showing the three sections of the SunZia Project that the Department of Defense requires be buried across the Northern Call-up Area of the White Sands Missile Range
TOPIC 6	**MEETING JOB NEEDS – SUNZIA'S ACTUAL POTENTIAL**
NMM-43	*Albuquerque Journal* article about SunZia's job potential
NMM-44	Number of construction workers needed to build the full project across *both* Arizona and New Mexico
NMM-45	Percentage of SunZia construction workers hired in Arizona (30%)
	WILLCOX AREA TOUR
NMM-46	Conservation lands around Cascabel as mapped by The Nature Conservancy

TOPIC 1

MEETING RENEWABLE ENERGY REQUIREMENTS IN ARIZONA AND CALIFORNIA

EXHIBIT NMM-1

EXHIBIT NMM-1

Excerpted page from Arizona Public Service's *2014 Integrated Resource Plan* referencing their 12% level compliance with Arizona's Renewable Portfolio Standard.

Full reference: Arizona Public Service Company, *2014 Integrated Resource Plan*, April 2014, 449 pp. Available at https://www.aps.com/library/resource%20alt/2014_IntegratedResourcePlan.pdf. Accessed October 9, 2015.

ENERGY EFFICIENCY AND RENEWBLE ENERGY STANDARDS

The ACC has enacted rules regarding energy efficiency that mandate a 22% cumulative energy savings requirement by 2020. The RES requires 15% of retail sales be met by renewable energy by 2025. As part of the RES, APS must also meet a portion of the renewable energy requirement with distributed energy resources – namely, rooftop solar installations.

From a planning perspective, the degree to which customers engage in these programs represents a significant uncertainty and has a direct impact on projected customer demand levels. If customer participation is lower than projected, then demand for energy could exceed forecasted levels as would the need for resources to supply that demand. Conversely, higher than anticipated participation in these programs would lower customer demand for energy resulting in reduced resource needs. Over the 15-year Planning Period, penetration of these programs may be higher or lower than originally forecast depending on many factors such as customer preferences, general economic conditions and availability of affordable technology.

RENEWABLE ENERGY STANDARD (RES)

In 2006, the ACC adopted the RES, under which electric utilities under its jurisdiction must supply an increasing percentage of their retail electric energy sales from eligible renewable resources, including solar, wind, biomass, biogas and geothermal technologies. The renewable energy requirement was 4% of retail electric sales in 2013 and it increases annually until reaching 15% in 2025. The RES also includes a carve-out for distributed energy systems of 30% of the overall RES requirement per year.

In addition, APS's 2009 rate case settlement agreement[15], requires APS to obtain an additional 1,700 GWh of new renewable resources to be in service by year-end 2015. When combined with compliance obligations under the RES, APS estimates that by the end of 2015, renewable energy in the portfolio is estimated to be approximately 12% of retail sales, which is more than double the RES target of 5% for that year.

Table 4 summarizes the RES percentage requirement (not including the additional commitment required by the settlement agreement discussed above) and its timing for each year under the Planning Period. The Selected Portfolio in addition to the other portfolios that were considered in developing the 2014 IRP meet or exceed the RES requirement percentages.

TABLE 4: RES PERCENTAGE REQUIREMENTS

YEAR	RES REQUIREMENT*
2014	4.50%
2015	5.00%
2016	6.00%
2017	7.00%
2018	8.00%
2019	9.00%
2020	10.00%
2021	11.00%
2022	12.00%
2023	13.00%
2024	14.00%
2025	15.00%

*RES requirement includes a 30% carve-out for distributed energy systems

DEMAND SIDE MANAGEMENT

In 2011, the ACC's Energy Efficiency (EE) rules became effective which include an Energy Efficiency Standard of 22% of cumulative annual energy savings by 2020.

Table 5 summarizes the EE Standard percentage requirement and its timing for each year under the Planning Period. The Selected Portfolio in addition to the other portfolios that were considered in developing the 2014 IRP used the requirement percentages in formulating the 15-year plan.

TABLE 5: EE STANDARD PERCENTAGE REQUIREMENT

YEAR	EE REQUIREMENT
2014	7.25%
2015	9.50%
2016	12.00%
2017	14.50%
2018	17.00%
2019	18.50%
2020	22.00%

[15]ACC Decision No. 71448 (December 20, 2009)

aps

2014 INTEGRATED RESOURCE PLAN

APRIL 2014 | FILED IN COMPLIANCE WITH A.A.C. R14-2-703

Forward-Looking Statements

This report contains forward-looking statements based on current expectations. These forward-looking statements are often identified by words such as "forecast," "estimate," "projection," "may," "believe," "expect," "plan," "require," "intend," "assume," and similar words. Because actual results may differ materially from expectations, APS cautions against placing undue reliance on these statements. A number of factors could cause future results to differ materially from historical results, or from outcomes currently expected or sought by APS. A discussion of some of these risks and uncertainties is contained in APS's Annual Report on Form 10-K filed with the Securities and Exchange Commission, available on APS corporate parent's website at www.pinnaclewest.com, which should be carefully reviewed before placing any reliance on APS's forward-looking statements, financial statements or disclosures. APS assumes no obligation to update any forward-looking statements, even if internal estimates change, except as may be required by applicable law.

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EXECUTIVE SUMMARY

The 2014 Resource Plan at a Glance

The 2014 Integrated Resource Plan (2014 IRP) lays out how APS is planning to meet the projected nearly 13,000 MW resource requirement within its service territory by 2029. When combining load growth with contract expirations and unit retirements, APS anticipates needing over 6,600 MW of additional resources. To meet that need, APS evaluated several combinations of resource options in compliance with the Arizona Corporation Commission (ACC) Resource Planning and Procurement Rules, and Renewable Energy and Energy Efficiency Standards. The 2014 IRP details the inputs that went into the portfolio evaluation process, including a broad array of resources, costs and environmental variables, and the analytical framework used in the evaluation. The conclusion of this process was clear: low natural gas prices combined with the cost of environmental regulations and increases in self-dispatching solar generation will favor highly flexible natural gas resources over traditional baseload resources. Continued investment in advanced grid technologies is expected to provide further flexibility to the APS system.

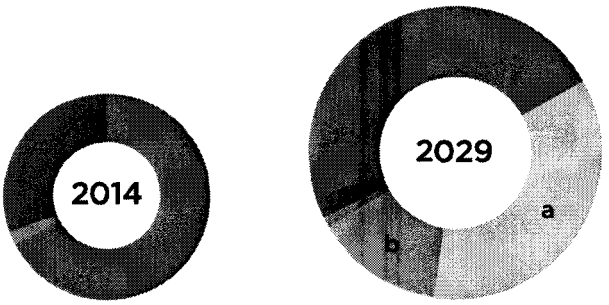
2014-2029 (PROJECTED)

FUTURE ADDITIONAL RESOURCES:
6,613 MW AT PEAK MET WITH

a. New Utility-Scale Resources
   Natural Gas - **4,205 MW**
   Renewable Energy - **425 MW** (818 MW Nameplate Capacity)

b. New Customer Resources
   Energy Efficiency - **1,447 MW**
   Distributed Energy - **261 MW** (722 MW Nameplate Capacity)
   Demand Reponse - **275 MW**

Exisitng Customer Resources
Existing Contracts
Existing Utility-Scale Resources
a New Utility-Scale Resources
b New Customer Resources



8,124 MW
peak requirement
100% met with
existing resources

12,982 MW
peak requirement
50% met with
existing resources

Figure ES-1 - 2014 vs. 2029 Peak Requirements

INVESTING IN ARIZONA'S ENERGY FUTURE

ENERGY PORTFOLIO INVESTMENT

$13.6 billion

Planned to secure sufficient assets to meet requirements under the Selected Portfolio

TRANSMISSION INVESTMENT

$496 million

Needed to support reliability, coordination, aging infrastructure and integration of renewable energy

ADVANCED GRID INVESTMENT

$300 million

Planned to support reliability, integrate distributed energy and emerging technologies

HOW THE PORTFOLIO MAY CHANGE

COMPOSITION OF ENERGY MIX BY RESOURCE (GWH)

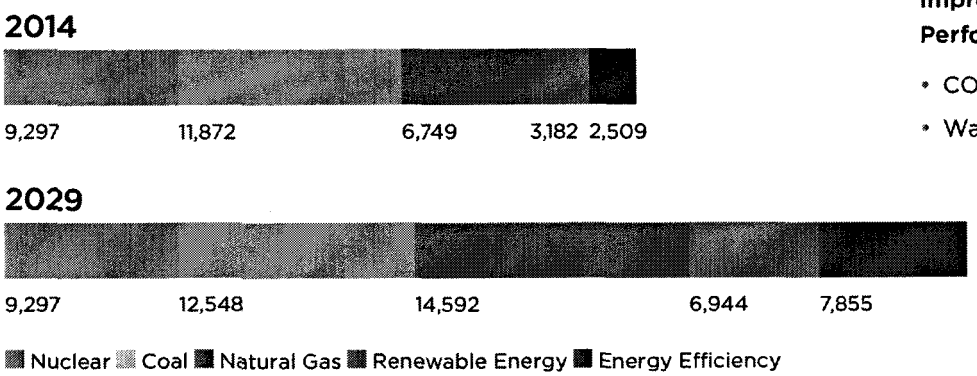


Figure ES-2 - 2014 vs. 2029 Energy Mix

Improves Environmental Performance:

- CO2 Intensity ▼ **14%**
- Water Intensity ▼ **24%**

Portfolio Selection

APS analyzed four portfolios before arriving at the Selected Portfolio as the most reasonable mix of resources for the 2014 IRP. The analysis focused on flexibility, reliability, cost, environmental impact and risk, among others.

The following table summarizes the analysis of the portfolios, including criteria considered for each. All portfolios include modernizing the Ocotillo power plant to support Valley reliability and renewable energy integration.

TABLE ES-1 - 2014 IRP PORTFOLIO SELECTION

2014 IRP PORTFOLIOS CONSIDERED	SELECTED PORTFOLIO	ENHANCED RENEWABLE PORTFOLIO	COAL REDUCTION PORTFOLIO	COAL-TO-GAS CONVERSION PORTFOLIO
Description	Modernize Ocotillo; continue coal operations; EE and RE compliance	Modernize Ocotillo; continue coal operations; EE compliance; RE well above compliance	Modernize Ocotillo; replace Cholla with gas and renewable generation; EE compliance; RE slightly above compliance	Modernize Ocotillo; convert Cholla to gas operation; EE and RE compliance
RESOURCE CONTRIBUTIONS (2029 PEAK CAPACITY CONTRIBUTION / % ENERGY MIX)				
Nuclear	1,146 MW / 18.1%	1,146 MW / 18.1%	1,146 MW / 18.1%	1,146 MW / 18.1%
Coal	1,932 MW / 24.5%	1,932 MW / 23.4%	1,285 MW / 16.9%	1,285 MW / 16.9%
Natural Gas	7,137 MW / 28.5%	6,933 MW / 21.9%	7,749 MW / 35.0%	7,784 MW / 36.1%
Renewable Energy & Distributed Energy	1,088 MW / 13.6%	1,298 MW / 21.3%	1,117 MW / 14.7%	1,088 MW / 13.6%
Energy Efficiency & Demand Response	1,722 MW / 15.3 %	1,722 MW / 15.3%	1,722 MW / 15.3%	1,722 MW / 15.3%

WHY THE SELECTED PORTFOLIO WAS CHOSEN

Resource planning does not establish a guarantee of future conditions or develop a transactional roadmap. Rather, the IRP process enables APS to develop long-term plans and evaluate which resource options may be appropriate given today's forecasts of future energy needs, resource costs and associated uncertainties. In the formulation of the 2014 IRP, uncertainties regarding environmental regulation and the evolving nature of the electric industry significantly influenced the selection process. The Selected Portfolio was chosen because it provides the most reasonable combination of overall economic performance, and flexibility in the generation fleet to support grid reliability, integrate renewable energy and manage uncertainties. Moving through the Planning Period, circumstances governing current assumptions and forecasts will undoubtedly change and will be updated in future resource plans, potentially shifting the preferred portfolio.

EXHIBIT NMM-2

EXHIBIT NMM-2

Arizona's solar potential as determined by the National Renewable Energy Laboratory.

Full Reference: Burr, J., Hallock, L., and Sargent, R., 2014. *Star Power: The Growing Role of Solar Energy in Arizona*, Environment Arizona Research & Policy Center, 40 pp. Available at http://www.environmentarizona.org/sites/environment/files/reports/AZ_Star_Power.pdf. Accessed October 9, 2015.

Executive Summary

Arizona could meet its energy needs by capturing just a sliver of the virtually limitless and pollution-free energy that strikes the state every day in the form of sunlight. With solar installation costs falling, the efficiency of solar cells rising, and the threats of air pollution and global warming ever-looming, solar power is becoming a more attractive and widespread source of energy every day.

Solar energy is on the rise across the country. The amount of solar photovoltaic (PV) capacity* in the United States has tripled in the past two years. More than half of all new U.S. electricity generating capacity came from solar installations in the first half of 2014, and the United States now has enough solar electric capacity installed to power more than 3.2 million homes. Arizona installed more solar electric capacity than any other state in 2013, and it was the state with the highest amount of installed solar capacity per person at the end of that year.

Arizona should build on the recent growth in solar energy by setting a goal of obtaining at least 25 percent of its electricity from solar power by 2025. Achieving that goal would result in a cleaner environment, less dependence on fossil fuels, and a stronger economy.

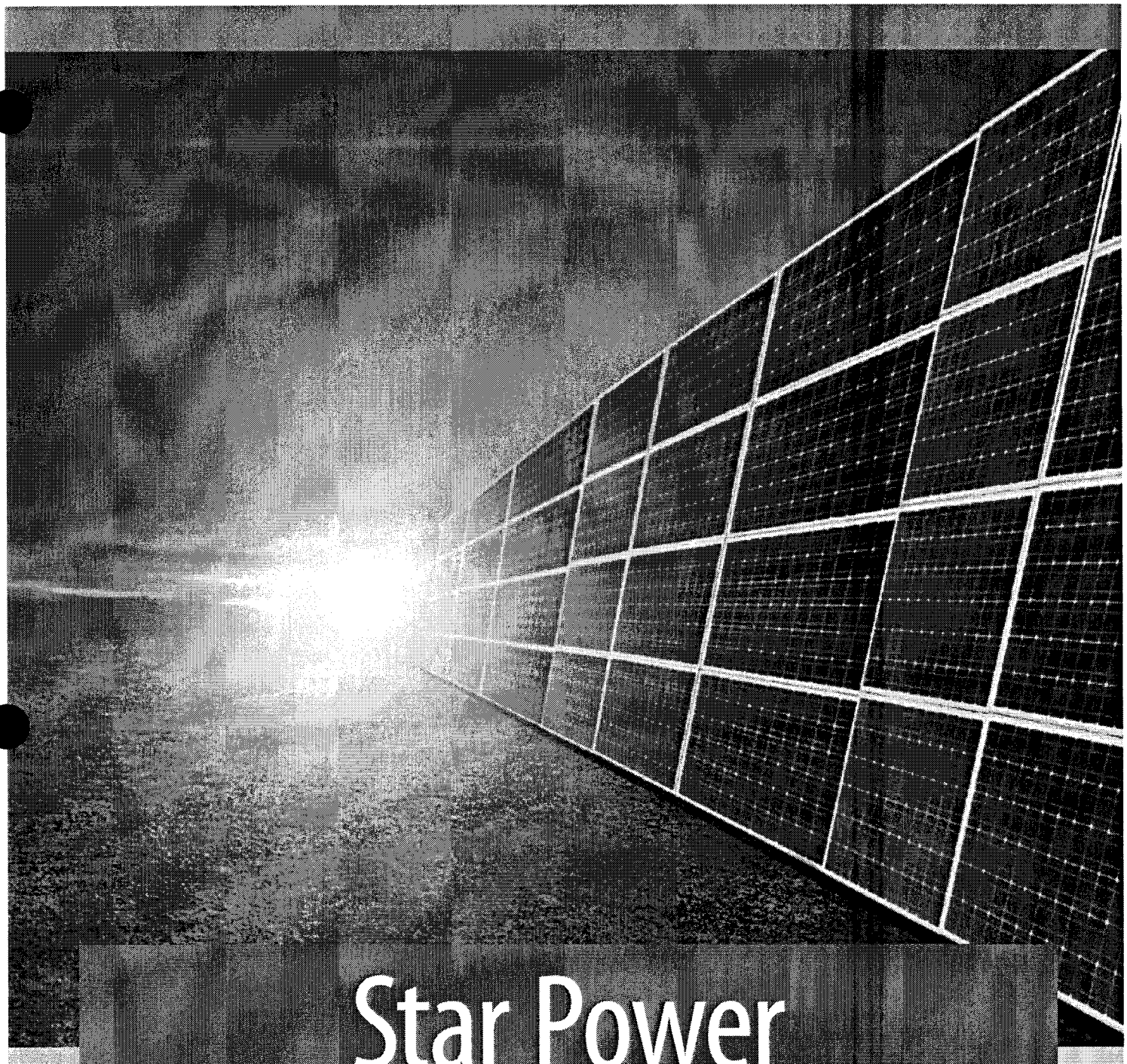
Arizona's solar energy potential is nearly limitless. Based on renewable energy technical potential reported by the National Renewable Energy Laboratory:

- Arizona has the potential to produce more than 320 times as much electricity from solar PV and concentrating solar power (CSP) installations as the state consumes each year. Each of the 50 states has the potential to generate far more electricity from the sun than its residents consume. (See Figure ES-1.)
- There are 35 million residential and commercial rooftops that could host solar panels across the United States, including more than 800,000 rooftops in Arizona.

Continued growth in solar energy in Arizona would bring a goal of 25 percent solar electricity within reach.

- Solar PV capacity in Arizona increased at a rate of 142 percent per year from 2010 to 2013. If solar PV installations continue to increase at just one-seventh of that rate (20 percent) annually between 2013 and 2025, Arizona would have enough solar energy to generate 25 percent of its electricity. (See Figure ES-2.)

* In this report, "solar photovoltaic (PV) capacity," or "solar PV," refers to installed solar photovoltaic systems, both distributed and utility-scale. "Solar electricity capacity" refers to all solar technologies that generate electricity, including concentrating solar power systems that use the sun's heat – rather than its light – to generate electricity. The figures in this report do not include other solar energy technologies, such as solar water heating.



Star Power

The Growing Role of Solar Energy in Arizona

ENVIRONMENT ARIZONA
RESEARCH & POLICY CENTER

Star Power

The Growing Role of Solar Energy in Arizona

Written by:

Judee Burr and Lindsey Hallock
Frontier Group

Rob Sargent
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November 2014

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Executive Summary

Arizona could meet its energy needs by capturing just a sliver of the virtually limitless and pollution-free energy that strikes the state every day in the form of sunlight. With solar installation costs falling, the efficiency of solar cells rising, and the threats of air pollution and global warming ever-looming, solar power is becoming a more attractive and widespread source of energy every day.

Solar energy is on the rise across the country. The amount of solar photovoltaic (PV) capacity* in the United States has tripled in the past two years. More than half of all new U.S. electricity generating capacity came from solar installations in the first half of 2014, and the United States now has enough solar electric capacity installed to power more than 3.2 million homes. Arizona installed more solar electric capacity than any other state in 2013, and it was the state with the highest amount of installed solar capacity per person at the end of that year.

Arizona should build on the recent growth in solar energy by setting a goal of obtaining at least 25 percent of its electricity from solar power by 2025. Achieving that goal would result in a cleaner environment, less dependence on fossil fuels, and a stronger economy.

Arizona's solar energy potential is nearly limitless. Based on renewable energy technical potential reported by the National Renewable Energy Laboratory:

- Arizona has the potential to produce more than 320 times as much electricity from solar PV and concentrating solar power (CSP) installations as the state consumes each year. Each of the 50 states has the potential to generate far more electricity from the sun than its residents consume. (See Figure ES-1.)
- There are 35 million residential and commercial rooftops that could host solar panels across the United States, including more than 800,000 rooftops in Arizona.

Continued growth in solar energy in Arizona would bring a goal of 25 percent solar electricity within reach.

- Solar PV capacity in Arizona increased at a rate of 142 percent per year from 2010 to 2013. If solar PV installations continue to increase at just one-seventh of that rate (20 percent) annually between 2013 and 2025, Arizona would have enough solar energy to generate 25 percent of its electricity. (See Figure ES-2.)

* In this report, "solar photovoltaic (PV) capacity," or "solar PV," refers to installed solar photovoltaic systems, both distributed and utility-scale. "Solar electricity capacity" refers to all solar technologies that generate electricity, including concentrating solar power systems that use the sun's heat – rather than its light – to generate electricity. The figures in this report do not include other solar energy technologies, such as solar water heating.

Figure ES-1. Solar Electricity Technical Potential Compared with Electricity Consumption

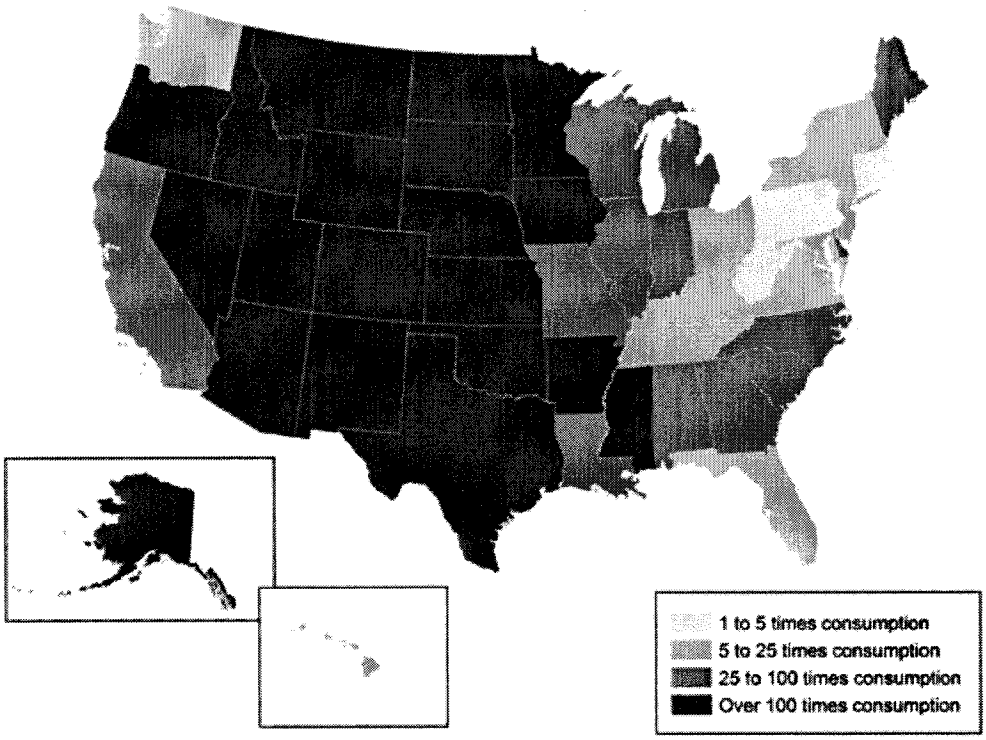
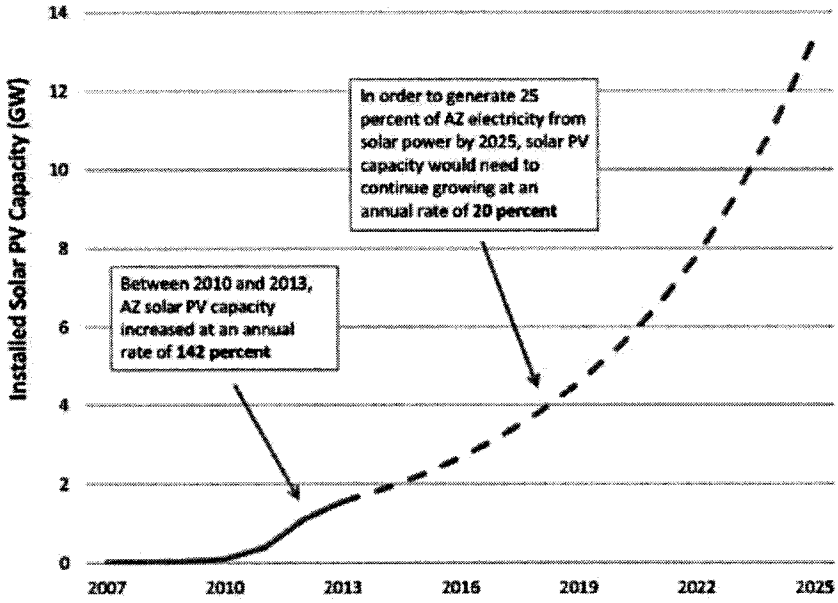


Figure ES-2. Arizona Can Generate 25 Percent of Its Electricity from Solar Power by 2025



Getting at least 25 percent of Arizona's electricity from the sun by 2025 would represent a major step toward stabilizing the climate, cleaning our air and building a prosperous, sustainable economy.

- Producing 25 percent of its electricity from clean, solar power would reduce Arizona's global warming pollution by 13 million metric tons in 2025 – the equivalent of taking 2.8 million cars off the road. Solar energy at that scale would help Arizona comply with the goals of the Clean Power Plan – the Environmental Protection Agency's (EPA's) proposed plan to reduce U.S. global warming pollution from the power sector by 30 percent below 2005 levels by 2030. If the EPA decides that distributed generation can help states achieve their goals under the Clean Power Plan, producing 25 percent of Arizona's electricity from clean, solar power would enable the state to achieve more than half of its 2030 emission reductions goal.

- Expanding solar energy will also reduce emissions of pollutants that contribute to the formation of smog and soot and threaten public health, especially the health of vulnerable populations like children, the elderly and those with respiratory disease.

- Obtaining 25 percent of Arizona's electricity from solar energy would reduce water consumption from power plants dramatically. Using a life-cycle assessment, solar photovoltaics consume 1/500th of the water consumed by coal power plants and 1/80th of the water consumed by natural gas plants per unit of electricity produced.

- Solar energy creates local clean energy jobs that can't be outsourced. Growth in the solar industry from November 2012 to November 2013 was 10 times faster than the national average for employment. Arizona is the state with the second-greatest number of solar jobs – more than 8,500 Arizonans worked in the solar energy industry in 2013.

A future in which Arizona gets at least 25 percent of its electricity from the sun is within reach. Leadership in Arizona will help America generate 10 percent of its electricity from solar power by 2030. The tools to build this vision are available and the momentum exists – now federal, state and local governments should adopt aggressive goals for solar integration and implement policies that encourage the adoption of solar power.

To achieve Arizona's full solar potential:

- **Arizona's state government** should commit to obtain at least 25 percent of its electricity from solar power by 2025 and adopt policies to achieve that goal. Arizona should also maintain strong net metering and interconnection standards, promote community solar and virtual net metering that can deliver the benefits of solar power to low income communities, facilitate third-party sales of solar power to provide access to successful solar leasing programs, and make smart investments to move toward a more intelligent electric grid in which distributed sources of energy such as solar power play a larger role. The state should utilize solar energy wherever possible on public buildings and properties. Arizona should adopt a strategy for complying with the Clean Power Plan, and solar power should play a significant role in the state's plans to meet or exceed the emission reduction targets.

- **The federal government** should commit to a baseline goal of obtaining at least 10 percent of the nation's electricity from solar energy by 2030. The federal government should utilize solar energy on government buildings and also continue successful solar policies, including federal incentives, programs to responsibly site solar energy on public lands, and research, development and deployment efforts designed to help

local and state governments reduce the cost of solar energy and smooth the incorporation of large amounts of solar energy into the electric grid. It should consider adopting a baseline standard for net metering. In addition, the federal government should strengthen and finalize the Clean Power Plan and ensure that distributed electricity resources such as rooftop solar panels can be used as a tool for compliance.

- **Local governments** should adopt strong solar goals, utilize solar energy wherever possible on public buildings and properties, ensure that homeowners and businesses can "go solar" easily and with a minimum amount of red tape, implement financing programs, such as property-assessed clean energy (PACE) financing, and adopt bulk purchasing programs for solar installations. Local governments should also establish zoning and building codes that facilitate the use of solar energy. Municipally owned utilities should promote solar energy by providing net metering or other rate structures to compensate solar homeowners fairly, and by making investments in community-scale and utility-scale solar projects.

EXHIBIT NMM-3

EXHIBIT NMM-3

Excerpted pages from Mark Etherton, *Enhancing Arizona's Ability to Export Renewable Energy, A Report to Address the Arizona Corporation Commission's Sixth Biennial Transmission Assessment, Commission Decision No. 72031*, PDS Consulting, PLC, 38 pp. with appendices, 2011. These statements address Arizona's renewable energy export potential and the barriers to exports.

The original document is available from the Arizona Corporation Commission Docket at http://images.edocket.azcc.gov/docketpdf/0000130865.pdf. The substance of the report was also incorporated as Chapter 3 into the *Seventh Biennial Transmission Assessment (2012-2021) Staff Report*, ACC Docket No. E-00000D-11-0017. This report is available at http://www.azcc.gov/Divisions/Utilities/Electric/Biennial/2012%20BTA/20012-7thBTAStaff%20Reportv1-0-FINAL.pdf?d=81. Accessed October 9, 2015.

Enhancing Arizona's Ability to Export Renewable Energy

A Report to Address the Arizona Corporation Commission
Sixth Biennial Transmission Assessment
Commission Decision No. 72031

Prepared by PDS Consulting, PLC

October 2011

EXECUTIVE SUMMARY

The Arizona Corporation Commission's ("ACC" or "Commission") Sixth Biennial Transmission Assessment ("BTA") Decision highlighted Arizona's abundant supply of renewable resources and the potential for the development of these energy resources to be utilized by surrounding states to meet their renewable portfolio obligations.[1] To help advance this potential, the ACC ordered certain Commission-regulated electric utilities to jointly conduct or procure a study and to conduct a stakeholder workshop process to identify the barriers to and solutions for enhancing Arizona's ability to export renewable energy. Arizona Public Service Company ("APS"); Salt River Project Agricultural Improvement and Power District ("SRP")[2]; Southwest Transmission Cooperative, Inc. ("SWTC"); Tucson Electric Power Company ("TEP"); and UniSource Electric, Inc. ("UNS Electric") procured the services of PDS Consulting, PLC to conduct the study.

This report: (1) summarizes the ACC order for which this report was prepared and briefly introduces the Arizona Utilities (*see* Section I of this report); (2) provides an overview of Renewable Energy Standards ("RES") and regional renewable energy assessments, followed by a summary of prior evaluations regarding Arizona's renewable energy resources and related transmission projects (*see* Section II of this report); (3) presents the results of a high level technical evaluation that assessed the deliverability of the existing transmission system, assessed the incremental deliverability with the addition of the renewable transmission projects ("RTPs"), and identified transmission corridors to enhance export capability (*see* Section III of this report); (4) summarizes stakeholder input, including the identification of barriers to and solutions for enhancing Arizona's ability to export renewable energy (*see* Section IV of this report); and (5) provides the current status of the export market environment (*see* Section V of this report).

Background of Regional Opportunities for Development of Renewable Energy

Renewable Energy Standards ("RES") have emerged as a result of state regulatory rules, federal tax policy, technological advances, and changes in public acceptance. Arizona is surrounded by other states in the Southwest (e.g., California, Colorado, Nevada, New Mexico) that also have RES requirements or goals (e.g., Utah). The combined effect of these standards is an increased demand for renewable energy within the region.

Studies that have evaluated Arizona's renewable resources include:

- Western Renewable Energy Zones ("WREZ") Initiative (Phase 1 report dated June 2009,[3] initiative includes on-going studies)
- A Final Report on the Activities of the Finance Subcommittee (report dated October 5, 2009)
- Final Report of the Arizona Renewable Resource and Transmission Identification Subcommittee (report dated September 2009)
- SWAT Renewable Transmission Task Force Report (report dated May 15, 2008)
- Arizona Renewable Energy Assessment (report dated September 2007)

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[1] Commission Decision No. 72031, dated December 10, 2010.

[2] While SRP is not a Commission-regulated utility, SRP has voluntarily participated in this effort.

[3] www.westgov.org/wga/publicat/WREZ09.pdf (Last accessed October 27, 2011)

The results of these studies indicate that Arizona has significant renewable resource potential and has far more supply of renewable resources than demand. The WREZ initiative also indicates that Nevada and New Mexico have supplies that exceed the in-state demand for renewable resources; whereas, California has a greater demand for renewable resources than in-state supply. The Western Electricity Coordinating Council ("WECC") ten-year plan, approved in September 2011, identified California as representing two-thirds of the total renewable energy needed to address RES and Renewable Portfolio Standards ("RPS") in the western United States. Based on this information, California is the most likely market for Arizona renewable energy exports.

In Arizona, as part of the Commission's Fifth BTA,[4] the Commission-regulated utilities were required to identify future renewable transmission projects ("RTPs"), plans and proposed funding mechanisms to construct the top three RTPs in their respective service territories. As such, APS, SRP, SWTC, TEP, and UNS Electric each filed a report with the Commission in 2009. The utilities also identified additional transmission projects of significant interest to the utilities.

Technical Assessment, including Corridor Identification

This report resulted from Commission Decision No. 72031 (the Sixth BTA) that mandated a study to assess Arizona's ability to export renewable energy. A technical evaluation, discussed in Section III of this report, assessed the deliverability of the existing transmission system and the incremental deliverability with the addition of the RTP system to export renewable resources from the Arizona Renewable Energy Zones ("REZ") to Southern California. The assessment used an injection analysis approach to bench mark the existing transmission system and to assess the incremental deliverability of the RTPs to deliver energy to Southern California. This assessment limited its analysis of exporting Arizona's renewable energy supply to Southern California due to the market potential identified by the WREZ and WECC.

The technical assessment concluded that the RTPs as a whole would bring potential incremental export capability between Arizona and Southern California. This incremental export would be greater if existing limitations in the Southern California system on the existing North Gila – Imperial Valley 500kV line were resolved. This line limits the amount of energy that can be scheduled from Arizona to Southern California. With an additional 500kV line from Delaney to the Colorado River the incremental export would increase but would remain limited due to the existing North Gila – Imperial Valley 500kV line. With the addition of the second North Gila to Imperial Valley 500kV transmission line, the incremental export to Southern California could be increased by approximately 2000 MW. Approximately 3000 MW of additional transmission capacity between Arizona and Southern California could potentially be achieved if the proposed RTPs and the addition of Delaney to the Colorado River and the North Gila to Imperial Valley 500kV transmission lines were combined. It should be noted that the incremental export values achieved in this assessment could differ when analyzed in a WECC Path Rating Study, which would analyze the East of River ("EOR") Path at a stressed level and would also consider the simultaneous impacts on other WECC Paths (i.e., West of River Path).

Commission Decision No. 72031 also required the utilities to identify specific corridors to be built to enhance Arizona's ability to export renewable energy to outside markets. The assessment considered the

[4] Commission Decision No. 70635 (December 11, 2008).

need for additional corridors to the Southern California markets because the assessment identified deliveries to Southern California due to the market potential identified by WREZ and WECC. The assessment concluded that additional corridors were not needed and additional transmission capacity within the existing corridors made more sense. Therefore, two existing corridors in Arizona were evaluated for additional transmission: (1) the Palo Verde – Devers corridor; and (2) the Palo Verde – North Gila corridor. Increased transmission capacity on the North Gila – Imperial Valley corridor could significantly increase Arizona's ability to export to California when added in conjunction with the Arizona RTPs; however, this corridor is located primarily outside of Arizona and would require approval by the California Public Utilities Commission.

Stakeholder Involvement

Stakeholders representing renewable energy developers, transmission developers, state agencies, and industry consultants were invited to participate in the process of the identification of barriers to and solutions for enhancing Arizona's ability to export renewable energy. The barriers and solutions identified by the stakeholders have been categorized as they pertain to economic concerns, physical limitations, permitting corridors or right-of-way, and regulatory structure (*see* Section IV of this report). Neither the Arizona Utilities nor PDS Consulting, PLC has conducted an analysis of the barriers or solutions. Further, the barriers and solutions do not represent a consensus of the Arizona Utilities and stakeholders nor does it reflect a prioritization of issues from the stakeholders.

Current Export Market Environment

This assessment limited its analysis of exporting Arizona's renewable energy supply to Southern California due to the market potential identified by multiple sources; however, California has indicated a focus on meeting the state's RPS with in-state resources. Although there are several indications that California will require additional out-of-state resources, mixed messages exist regarding California's desire to meet significant portions of their RPS requirements with out-of-state renewable resources. California's Renewable Energy Transmission Initiative ("RETI"), California State Law that requires utilities to obtain portions of renewable energy requirement from in-state generation, letters in 2009 and 2011 from Southern California Edison to the ACC, and a letter in 2011 from the Office of the California Governor to WECC indicates that California is focusing on meeting their RPS with in-state resources. These factors have provided significant uncertainty related to California's plans and are discussed in more detail in Section V of this report. Additional clarity of California's policy regarding their need and desire for Arizona renewable resources is needed before Arizona invests substantial resources to move toward additional transmission to support the export of Arizona's renewable energy.

IV. STAKEHOLDER INVOLVEMENT

In May 2011, the Arizona Utilities began the stakeholder involvement process with a small group of stakeholders ("Focus Group"), representing renewable energy and transmission developers, to get their views on a preliminary list of barriers to and potential solutions for enhancing Arizona's ability to export renewable energy. That preliminary list laid the foundation for discussion and further evaluation by a larger stakeholder group in a workshop process. The utilities then formed a technical group to direct the consultant, PDS Consulting, PLC, in preparing preliminary technical analysis that was used as the foundation of this report.

On October 5, 2011, the utilities hosted a Stakeholder Workshop, which was attended by individuals representing organizations, including renewable energy developers, transmission developers, state agencies including the Commission, and industry consultants. The attendee list is attached to this report as Attachment D. The primary objective of this workshop was to solicit input from a broad stakeholder group regarding barriers and solutions for enhancing Arizona's ability to export renewable energy, including the potential development of transmission corridors. The workshop included a sampling of the background on Arizona renewable energy studies performed to date, a presentation of RTP export capability based on a typical SWAT 2014 heavy summer time frame, and a review of proposed content of the report. Below is a summary of the comments received from stakeholders. Neither the Arizona Utilities nor PDS Consulting, PLC has conducted an analysis of these comments. Further, the barriers and solutions do not represent a consensus of the Arizona Utilities and stakeholders nor does it reflect a prioritization of issues from the stakeholders.

A. Barriers to Exporting Renewable Energy

The barriers identified through the stakeholder involvement have been categorized as economic concerns, physical limitations, permitting corridors or right-of-way, and regulatory structure.

1. Economic Concerns

- **Insufficient Demand for Arizona Renewables**
  - Regional markets point to California as the most readily available market for Arizona renewables. Most of Arizona's neighbors (Colorado, Nevada, New Mexico, and Utah) are also looking to export energy to southern California. The California "CA SB 2X" will limit how much can be imported from Arizona based on the ability to transact with a California balancing authority (or dynamically transferred to a California balancing authority). In addition, California studies (including the Renewable Energy Transmission Initiative ["RETI"]) have shown that most of the renewable resources for California can be obtained from within California.
  - Transactions to the east or south may also involve multiple transmission contracts from multiple transmission owners to deliver to those markets, resulting in "pancaking" of wheeling fees. These costs have the potential to make total delivered costs uneconomical for renewable projects.

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Attachment B: July 7, 2011 Letter from Southern California Edison to the Arizona Corporation Commission

Attachment C: August 3, 2011 Letter from the Office of the California Governor to the Western Electricity Coordinating Council

Attachment D: Stakeholder List

EXHIBIT NMM-4

EXHIBIT NMM-4

Table 1. Arizona renewable energy facilities with California power purchase agreements

Project	Size	Location	Year in service/power purchaser
Agua Caliente Solar Energy Project	290 MW	Yuma County	PG&E power purchase agreement 2009; permits approved 2010; completed 2014
Arlington Valley Solar Project II	125 MW	Maricopa County	SDG&E power purchase agreement, completed 2013
Mesquite Solar 1 Project	150 MW	Maricopa County	PG&E power purchase agreement; completed December 2012
Total sold capacity	565 MW		

Table 2. Partially permitted but unbuilt Arizona renewable energy projects

Project	Size	Location	Status
Crossroads Solar Energy Project	150 MW	Maricopa County, west of Gila Bend	Approved 11/20/2012. No power purchase agreement
Hualapai Valley Solar Project	340 MW	Mohave County	CEC issued October 21, 2010; interconnection request discontinued 9/16/11.
Hyder Valley Solar Energy Project	325 MW	Palomas Plain, Mojave County	EIS originally expected in 2014; application withdrawn
Maricopa Solar Park	300 MW	Maricopa County	BLM scoping completed; developer no longer developing EIS
Quartzite Solar Energy Project	100 MW	La Paz County	BLM approved 2013; no power purchase agreement
Sonoran Solar Energy Project	300 MW	Maricopa County	BLM approved 12/21/11; CEC issued; no power purchase agreement
Sterling Solar Generating Facility	1200 MW	Mohave County	Begun 2010; waiting on California power purchase agreement 2013; no further activity
Mohave County Wind Farm	500 MW	Mohave County	BLM approved 2012; sold in 2015; no power purchase agreement
Total unsold capacity	3215 MW		

Compiled from various web resources and project websites.

EXHIBIT NMM-5

EXHIBIT NMM-5

Solar applications on Arizona BLM lands as of 2012. Excerpted from Appendix B, Active Solar Applications, *Final Programmatic Environmental Impact Statement (PEIS) for Solar Energy Development in Six Southwestern States* (Solar PEIS), Bureau of Land Management, July 2012. Full document available at http://solareis.anl.gov/documents/fpeis/. Accessed September 24, 2015.

APPENDIX B:

APPROVED AND PENDING SOLAR APPLICATIONS

B.1 BACKGROUND

This appendix presents information on the approved and pending solar applications on U.S. Department of the Interior (DOI) Bureau of Land Management (BLM) administered lands. This information is provided in support of the Final *Programmatic Environmental Impact Statement (PEIS) for Solar Energy Development in Six Southwestern States* (Solar PEIS). This appendix has been completely revised and the information presented here replaces information provided in Appendix B of the Draft Solar PEIS and in Appendix A of the Supplement to the Draft Solar PEIS.

As of May 31, 2012, the BLM had approved 11 utility-scale solar projects on public lands and 5 linear rights-of-way (ROWs) that enabled development of solar energy projects on private lands. The total capacity for the approved solar projects on BLM-administered lands is 4,512 MW, with an associated BLM land area of 44,025 acres (178 km^2). These applications are listed in Table B-1.

The BLM defines "pending" applications as any applications filed within proposed variance and/or exclusion areas before the publication of the Supplement to the Draft Solar Programmatic Environmental Impact Statement (PEIS) (October 28, 2011), and any applications filed within proposed solar energy zones (SEZs) before June 30, 2009. The BLM has cataloged 91 first-in-line solar applications that meet the definition of pending; as of May 31, 2012, 13 of these first-in-line pending applications had been closed (denied or withdrawn). The applications are listed in Table B-2 and summarized in Table B-3.

The total acreage of BLM-administered lands covered by active first in-line pending applications is approximately 626,000 acres (2,533 km^2), with an estimated total capacity of approximately 33,000 MW. This equates to an average land use of about 20 acres/MW (0.08 km^2/MW) for all of the pending applications combined. This land use is greater than the land use requirements assumed in the Solar PEIS (i.e., 5 acres/MW [0.02 km^2/MW] for parabolic trough facilities; 9 acres/MW [0.04 km^2/MW] for all other facilities), reflecting the fact that applicants often request more acreage to allow flexibility in project design and to avoid lands where resource conflicts might exist within the ROW application area.

The BLM will process second-in-line and subsequent applications as pending applications if they otherwise meet the criteria for pending and the corresponding first-in-line application is closed (denied or withdrawn). While the BLM tracks second-in-line and subsequent applications, they are not included in Table B-2 to avoid double counting of acreage and megawatts.

TABLE B-2 First-in-Line Pending Solar Applications on BLM-Administered Lands[a,b]

Serial Number	Customer Name (Project Name and/or Geographic Area)	Application Received	Capacity (MW)	BLM Acreage	Application Closed as of May 31, 2012?	Planned Technology[c]	Field Office
AZA 034184	Boulevard Assoc., LLC (Aguila)	June 26, 2007	500	7,335	No	CSP/trough	Hassayampa
AZA 034186	Boulevard Assoc., LLC (Burnt Mountain/Big Horn)	June 26, 2007	500	5,912	No	CSP/trough	Hassayampa
AZA 034187	NextEra/Boulevard Assoc., LLC (Sonoran Solar)	June 28, 2007	500	2,013	No	PV	Lower Sonoran
AZA 034200	NextEra/Boulevard Assoc., LLC (Mountain Spring)	June 22, 2007	250	6,705	No	CSP/trough	Kingman
AZA 034321	AREVA Solar AZ II, LLC (Ausra Palo Verde)	Oct. 1, 2007	400	1,867	No	CSP/CLFR	Hassayampa
AZA 034335	Boulevard Assoc., LLC (Bouse)	June 8, 2007	500	24,221	No	CSP/trough	Lake Havasu: Yuma
AZA 034357	First Solar (Gila Bend)	Nov. 6, 2007	500	6,003	No	PV	Lower Sonoran
AZA 034358	First Solar (Saddle Mountain)	Nov. 6, 2007	300	5,997	No	PV	Lower Sonoran
AZA 034416	Pacific Solar Invst., Inc. (Iberdrola) (Eagletail)	Dec. 2, 2007	1,500	26,082	No	CSP/trough	Yuma
AZA 034424	Pacific Solar Invst., Inc. (Iberdrola) (Big Horn)	Dec. 4, 2007	300	7,240	Yes (closed March 30, 2012)	CSP	Hassayampa
AZA 034425	Pacific Solar Invst., Inc. (Iberdrola) (Hyder)	Dec. 7, 2007	350	5,795	No	CSP/trough	Lower Sonoran: Yuma
AZA 034426	Pacific Solar Invst., Inc. (Iberdrola) (Ranegras)	Dec. 2, 2007	2,000	25,860	No	CSP/trough	Yuma

TABLE B-2 (Cont.)

Serial Number	Customer Name (Project Name and/or Geographic Area)	Application Received	Capacity (MW)	BLM Acreage	Application Closed as of May 31, 2012?	Planned Technology[c]	Field Office
AZA 034427	Pacific Solar Invst., Inc. (Iberdrola) (La Posa Solar Thermal)	Sept. 6, 2007	2,000	38,212	No	CSP/trough	Yuma
AZA 034540	Horizon Wind Energy, LLC (Horizon Aguila)	March 4, 2008	250	11,535	No	CSP/trough	Hassayampa
AZA 034554	Nextlight Renewable Power, LLC (Quartzite)	March 26, 2008	500	20,699	No	CSP/trough	Yuma
AZA 034560	Nextlight Renewable Power, LLC (Vicksburg)	March 26, 2008	500	15,040	No	CSP/trough	Yuma
AZA 034566	Nextlight Renewable Power, LLC (Centennial)	March 26, 2008	500	13,428	No	CSP/trough	Yuma
AZA 034568	Nextlight Renewable Power, LLC (Palomas)	March 26, 2008	500	20,165	No	CSP/trough	Yuma
AZA 034665	Solar Reserve, LLC (Black Rock Hill)	May 27, 2008	600	5,600	No	CSP/tower	Yuma
AZA 034666	Solar Reserve, LLC (Quartzsite)	May 27, 2008	100	2,013	No	CSP/tower	Yuma
AZA 034668	Solar Reserve, LLC (Agua Caliente)	May 27, 2008	600	5,678	No	CSP/tower	Yuma
AZA 034737	Arizona Solar Invst., Inc. (Haraquahala)	July 10, 2008	250	14,047	No	PV	Hassayampa
AZA 034739	IDIT, Inc. (Little Horn)	July 9, 2008	1,000	12,291	No	CSP/trough	Yuma
AZA 034754	Horizon Wind Energy, LLC (Wenden)	March 4, 2008	250	28,760	No	CSP/trough	Lake Havasu
AZA 034774	IDIT, Inc. (Dendora Valley)	Aug. 12, 2008	250	14,765	No	PV	Lower Sonoran
AZA 034797	LSR Jackrabbit, LLC (LSR Jackrabbit)	Aug. 27, 2008	500	27,036	Yes (closed Jan. 16, 2012)	CSP/tower	Hassayampa

TABLE B-2 (Cont.)

Serial Number	Customer Name (Project Name and/or Geographic Area)	Application Received	Capacity (MW)	BLM Acreage	Application Closed as of May 31, 2012?	Planned Technology[c]	Field Office
AZA 034799	LSR Palo Verde, LLC (LSR Palo Verde)	Aug. 27, 2008	600	5,855	Yes (closed Jan. 16, 2012)	CSP/trough	Lower Sonoran
AZA 034936	Wildcat Quartzsite, LLC (Quartzite)	Jan. 29, 2009	800	11,960	No	CSP/tower	Yuma
AZA 034946	Wildcat Harcuvar South, LLC (Bright Source Energy) (Wildcat Harcuvar SO)	Jan. 28, 2009	800	10,947	No	CSP/tower	Lake Havasu
AZA 035166	IDIT, Inc. (Arlington West)	July 27, 2009	Unknown	5,800	No	PV	Lower Sonoran
AZA 035236	Solar Reserve (Safford Solar Energy Center/ San Simon)	Jan. 4, 2010	250	22,892	No	PV	Safford
CACA 048669	First Solar (Stateline/Ivanpah)	Dec. 14, 2006	300	5,454	No	PV	Needles
CACA 048728	NextEra Energy (McCoy)	Jan. 31, 2007	750	7,754	No	PV	Palm Springs–South Coast
CACA 048808	Chuckwalla Solar 1, LLC (Chuckwalla)	Sept. 15, 2006	200	4,082	No	PV	Palm Springs–South Coast
CACA 048810	Solar Millennium/Chevron (Palen)	March 14, 2007	500	5,160	No	CSP/trough	Palm Springs–South Coast
CACA 048875	DPT Broadwell Lake, LLC (Broadwell SEGS)	Jan. 24, 2007	1,000	8,625	No	CSP/tower	Barstow
CACA 049002	Leopold Company, LLC (Ward Valley)	April 2, 2007	250	35,200	No	CSP/tower	Needles
CACA 049150	Sunpeak Solar, LLC (Superstition Solar I)	July 17, 2007	500	5,587	No	PV	El Centro

TABLE B-3 Summary Table for Pending Applications[a]

State	Pending Applications	BLM Acreage	Capacity (MW[b])
Arizona	28	371,622	16,450
California	22	156,707	8,915
Colorado	0	0	0
New Mexico	2	8,296	700
Nevada	26	89,353	6,649
Utah	0	0	0
Total	78	625,978	32,714

[a] Summary excludes the 13 applications closed (denied or withdrawn) as of May 31, 2012, identified in Table B-2.

[b] Megawatts for three pending applications were not available; acreages for four pending applications were not available.

B.2 REFERENCES

Note to Reader: This list of references identifies Web pages and associated URLs where reference data were obtained for the analyses presented in this Final Solar PEIS. It is likely that at the time of publication of this Final Solar PEIS, some of these Web pages may no longer be available or their URL addresses may have changed. The original information has been retained and is available through the Public Information Docket for this Final Solar PEIS.

BLM and DOE (Bureau of Land Management and U.S. Department of Energy), 2011, *Supplement to the Draft Programmatic Environmental Impact Statement for Solar Energy Development in Six Southwestern States*, DES 11-49, DOE/EIS-0403D-S, Oct.

EXHIBIT NMM-6

EXHIBIT NMM-6

Current and projected use of utility-scale renewable energy by major Arizona utilities

Utility	2014 Use	Planned Additions	Total planned Capacity
APS	767 MW	818 MW by 2029	1,585 MW
SRP	308 MW	No renewable energy target	Sustainable Resource portfolio includes heavy reliance on hydropower and energy efficiency
TEP	208 MW	321 MW by 2028	529 MW
USNE	28 MW	91 MW by 2028	119 MW
Total	**1311**	**1230 MW**	**2233 MW + unknown SRP**

The Salt River Project is not governed by the Corporation Commission and the renewable portfolio standard it has set. SRP is also not required to submit an integrated resource plan as other Arizona utilities are.

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aps

2014 INTEGRATED RESOURCE PLAN

APRIL 2014 | FILED IN COMPLIANCE WITH A.A.C. R14-2-703

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EXECUTIVE SUMMARY

The 2014 Resource Plan at a Glance

The 2014 Integrated Resource Plan (2014 IRP) lays out how APS is planning to meet the projected nearly 13,000 MW resource requirement within its service territory by 2029. When combining load growth with contract expirations and unit retirements, APS anticipates needing over 6,600 MW of additional resources. To meet that need, APS evaluated several combinations of resource options in compliance with the Arizona Corporation Commission (ACC) Resource Planning and Procurement Rules, and Renewable Energy and Energy Efficiency Standards. The 2014 IRP details the inputs that went into the portfolio evaluation process, including a broad array of resources, costs and environmental variables, and the analytical framework used in the evaluation. The conclusion of this process was clear: low natural gas prices combined with the cost of environmental regulations and increases in self-dispatching solar generation will favor highly flexible natural gas resources over traditional baseload resources. Continued investment in advanced grid technologies is expected to provide further flexibility to the APS system.

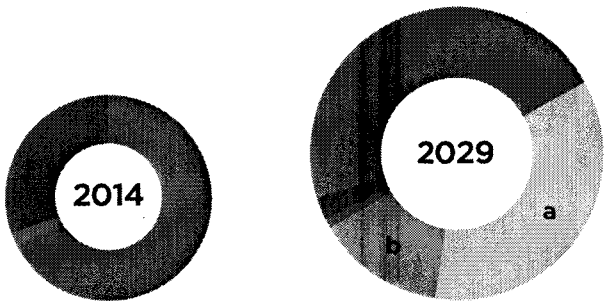
2014-2029 (PROJECTED)

FUTURE ADDITIONAL RESOURCES:
6,613 MW AT PEAK MET WITH

a. New Utility-Scale Resources
   Natural Gas - **4,205 MW**
   Renewable Energy - **425 MW** (818 MW Nameplate Capacity)

b. New Customer Resources
   Energy Efficiency - **1,447 MW**
   Distributed Energy - **261 MW** (722 MW Nameplate Capacity)
   Demand Reponse - **275 MW**

Exisitng Customer Resources
Existing Contracts
Existing Utility-Scale Resources
a New Utility-Scale Resources
b New Customer Resources



8,124 MW
peak requirement
100% met with
existing resources

12,982 MW
peak requirement
50% met with
existing resources

Figure ES-1 - 2014 vs. 2029 Peak Requirements

INVESTING IN ARIZONA'S ENERGY FUTURE

ENERGY PORTFOLIO INVESTMENT

$13.6 billion

Planned to secure sufficient assets to meet requirements under the Selected Portfolio

TRANSMISSION INVESTMENT

$496 million

Needed to support reliability, coordination, aging infrastructure and integration of renewable energy

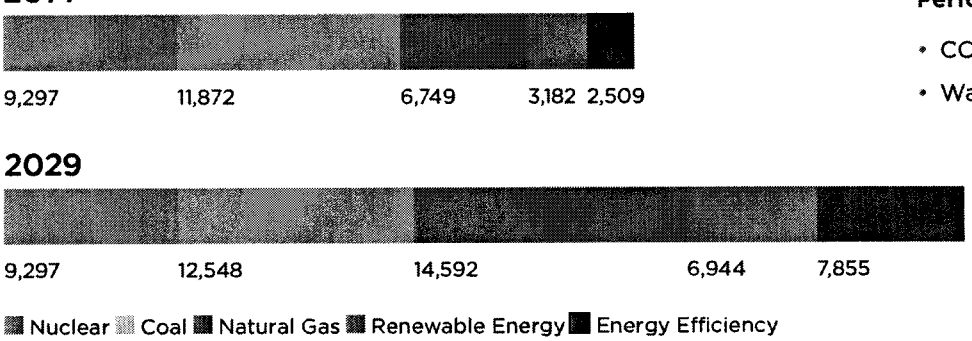
ADVANCED GRID INVESTMENT

$300 million

Planned to support reliability, integrate distributed energy and emerging technologies

HOW THE PORTFOLIO MAY CHANGE

COMPOSITION OF ENERGY MIX BY RESOURCE (GWH)



Improves Environmental Performance:

- CO2 Intensity ▼ **14%**
- Water Intensity ▼ **24%**

Figure ES-2 - 2014 vs. 2029 Energy Mix

Renewable Energy

Renewable resources are clean or "green" energy sources that have a much lower environmental impact than conventional energy sources. Renewable resources are attractive because they are replenished naturally -- which means they will never run out.

SRP has established a goal that by FY20, SRP will meet a target of 20% of its expected retail energy requirements with sustainable resources. Among them are a diversified resource mix of wind, geothermal, large hydro and low-impact hydro, landfill gas and solar.

ALSO ON THIS PAGE:

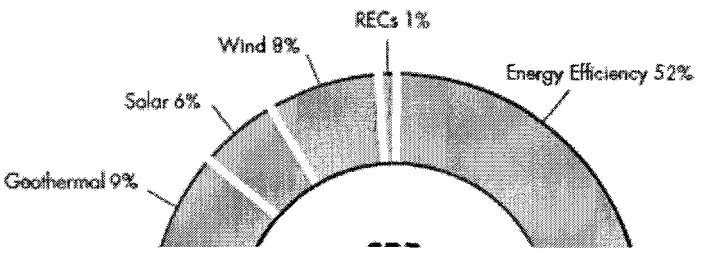
Solar energy
Landfill gas
Hydroelectricity
Low-impact hydro
Wind power
Geothermal
Biomass

Renewable resources at SRP

At SRP, we pursue innovative and effective renewable energy solutions by:

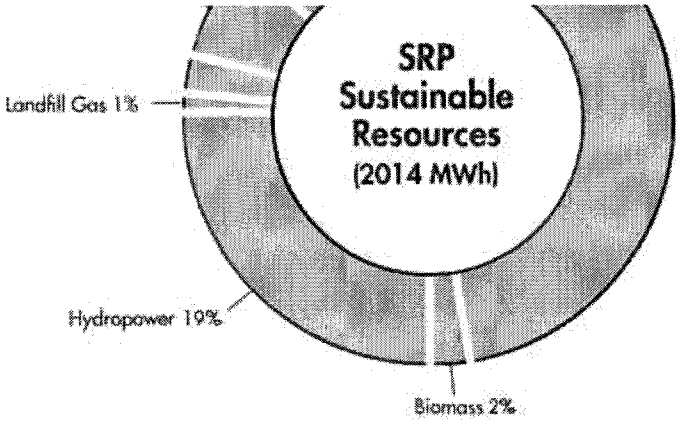
1. Regularly expanding our energy portfolio to include a diverse mix of renewable energy technologies;
2. Tapping the expertise of partners, advisors and environmental leaders to refine our renewable energy pursuits; and
3. Investing in educational programs and events that introduce students to renewable energy solutions.

Sustainable portfolio during FY14



SRP Sustainable Portfolio Principles

SRP's Board of Directors approved a management proposal in the spring of 2011 that directs SRP's future use of renewable energy resources and energy conservation measures. The approved portfolio sets a target of 20% of SRP retail sales to be met through sustainable resources by fiscal year



SRP's total current renewable capacity is 791 megawatts (MW) and includes the following resources:

- Biomass: 14 MW
- Geothermal: 75 MW
- Hydropower: 391 MW
- Landfill gas: 22 MW
- Solar, rooftop: 92 MW
- Solar, utility-scale: 20 MW
- Wind, Dry Lake: 127 MW
- Wind, purchase: 50 MW

Solar power

Solar electric plants use the sun, a free and inexhaustible source of fuel, to produce emission-free electricity.

SRP receives 20 MW of solar energy from the Copper Crossing Solar Ranch in Florence, AZ. This facility produces approximately 54 million kilowatt-hours (kWh) of solar energy annually for SRP Community Solar. That is enough energy to meet the needs of about 3,700 SRP customers' homes each year.

In addition, SRP has a 200 kW solar electric system at the Agua Fria Generating Station in Glendale, as well as two 100 kW solar electric systems at the Rogers Substation in Gilbert. Together, these three plants send close to one million kilowatt-hours (kWh) of

2020.

SRP's Sustainable Energy Portfolio combines renewable energy resources with energy conservation programs to benefit the environment. Our program integrates sound science, customer values and resource preservation strategies.

power to the grid each year, or enough energy to power 72 homes.

SRP has three primary avenues for generating solar power: partnering with communities and businesses, SRP-owned facilities, and SRP subsidized customer-owned systems through the EarthWise Solar Energy program. Some of these projects include solar facilities at community parking garages and schools, and partnering with homebuilders to install innovative solar technology projects.

To find out more, please see our solar energy page.

Landfill gas energy

A landfill is not the place you would expect to find a source of clean energy. But landfill gas is a reliable, renewable energy source that improves the environment.

Landfill gas is about 50% methane, a potent greenhouse gas that, if uncollected, might contribute to global warming. The gas occurs naturally as waste decomposes in a landfill.

SRP's landfill gas project includes:

- **The Tri-Cities landfill gas facility**: Completed in 2001, this 4-MW generation facility captures gas created by the Tri-Cities landfill. The gas is used to fuel five internal combustion engines at the landfill's power generating facility. The Tri-Cities landfill gas facility produces enough clean energy to power more than 2,000 homes each year.

Hydroelectric generation

Hydroelectric generation is an important part of the history of Salt River Project, and a technology that remains core to our power production portfolio.

The water captured by SRP's dams on the Salt and Verde river systems store tremendous potential energy released through hydroelectric generation stations built into five of SRP's seven dams: Theodore Roosevelt, Horse Mesa, Mormon Flat and Stewart

Mountain dams on the Salt River system; and C. C. Cragin Dam on the Verde system.

These generating facilities produce a combined 269 MW of power to serve customers in the Valley.

Low-impact hydroelectric generation

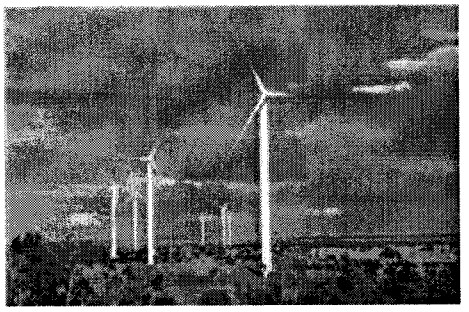
SRP's system of canals also plays a part in utilizing the energy stored in water.

The term "low-impact" refers to hydrogeneration that produces clean power using a canal's natural drop in elevation. Because a dam is not needed to create a drop in elevation, no negative environmental impact is made on the site.

SRP installed a low-impact hydroelectric plant on the Arizona Canal at an historic site known as Arizona Falls (located near 56th St. and Indian School).

Wind power

SRP diversified its renewable energy portfolio in October 2009 by purchasing 100% of the output from the Dry Lake Wind Power Project, located near Heber, Ariz.



SRP receives 100% of 127 MW generated from the wind farm, or enough to power more than 20,000 homes in the metropolitan Phoenix area.

Geothermal energy

Geothermal power is the better energy source in SRP's renewable energy lineup.

Instead of burning a fuel to heat water into steam as seen in

conventional forms of generation, heat from the Earth is used to create the steam that powers the turbines. Geothermal energy is considered renewable energy because no fuel is consumed and the energy is from a naturally occurring source.

The renewable-energy credits are generated by geothermal power plants that produce electricity from naturally occurring geothermal steam. The steam is formed when production wells tap into superheated water reservoirs thousands of feet beneath the Earth's surface.

- **Imperial Valley Geothermal Plants:** SRP has signed a 23-year agreement with CalEnergy, LLC to purchase up to 87 MW of geothermal energy a year from a number of plants located in the Imperial Valley of Southern California.
- **Hudson Ranch 1 Geothermal Plant**: SRP has signed a 30-year agreement to purchase the entire output of the Hudson Ranch 1 project, a 50-MW geothermal power generation project located in the Imperial Valley of Southern California.
- **Cove Fort Geothermal Project**: SRP has signed a 20-year agreement to purchase the entire output of the Cove Fort Geothermal Project, a new 25-MW geothermal power generation project located in Beaver County, Utah.

Biomass energy

Biomass energy is generated from the combustion of fuel, which is typically sourced from wood. SRP has 14 MW of biomass energy in our portfolio through June 2023. The energy is generated from the Novo BioPower Plant located in Snowflake, Ariz. The plant is required to obtain the majority of its fuel from forest thinnings, which helps promote healthy forests. Learn more about SRP's forest health initiatives.

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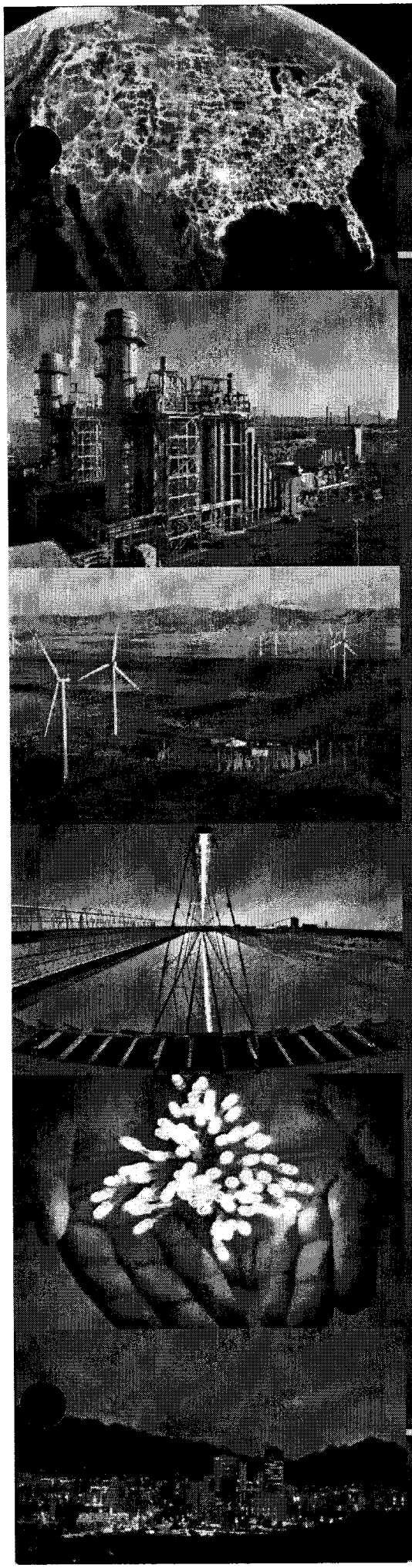

TUCSON ELECTRIC POWER

2014 Integrated Resource Plan

April 1, 2014

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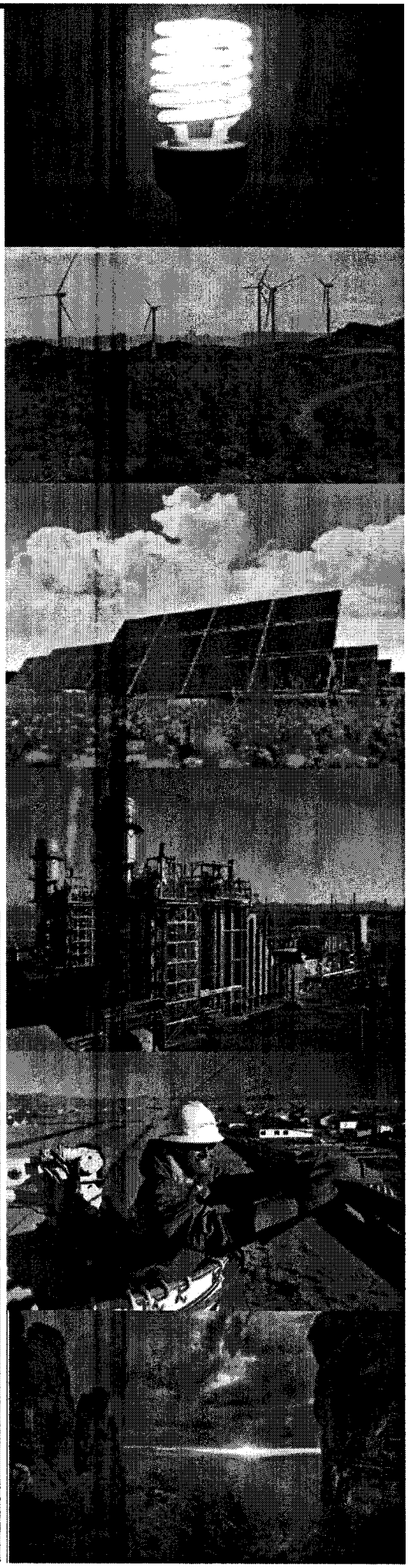
2014 Integrated Resource Plan

April 1, 2014

UNS Electric, Inc.



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Kevin Avila-Robinson, "SunZia's $2B dream still a gamble," *Albuquerque Journal*, June 21, 2015. Available at http://www.abqjournal.com/601834/news/sunzias-2b-dream-still-a-gamble.html. Accessed September 19, 2015.

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ALBUQUERQUE JOURNAL

SunZia's $2B dream still a gamble

These wind turbines are located west of N.M. 42 on Mesa del los Jumanos, between Willard and Cedarvale, N.M. (Dean Hanson/Albuquerque Journal)

By Kevin Robinson-Avila / Journal Staff Writer

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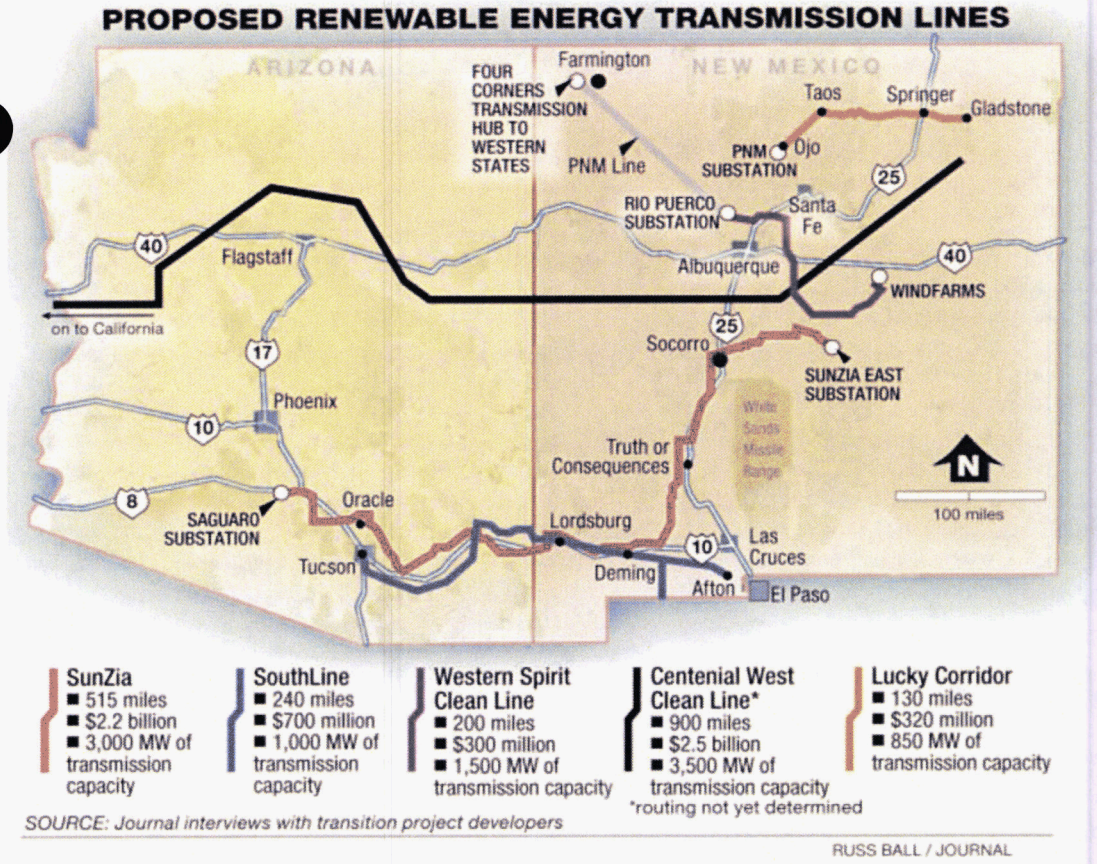

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After seven years of trying, the SunZia transmission project finally received government approval this year to run parts of its planned 515-mile clean energy line across federal lands in New Mexico and Arizona, but whether the $2.2 billion project will ever get built remains an open question.

Its future hinges on whether developers can find utilities in other western states – primarily California – to buy the 3,000 megawatts of renewable energy the project would transport from wind farms and other clean generation sources in central New Mexico and elsewhere.

Without first signing "power purchase agreements" that commit utilities to buy the electricity, lenders will never approve the funding needed for energy developers to build the wind farms needed to provide power, much less for SunZia's promoters to actually build the transmission line itself.

SunZia Project Manager Tom Wray says California's ambitious renewable energy and carbon reduction goals – which could soon include meeting 50 percent of electric demand with clean generation and reducing greenhouse gas emissions to 40 percent below 1990 levels by 2030 – will force utilities there to procure huge amounts of renewable generation from suppliers in New Mexico and elsewhere. Some of those suppliers would then, in turn, become SunZia customers seeking to transport their electricity to California.

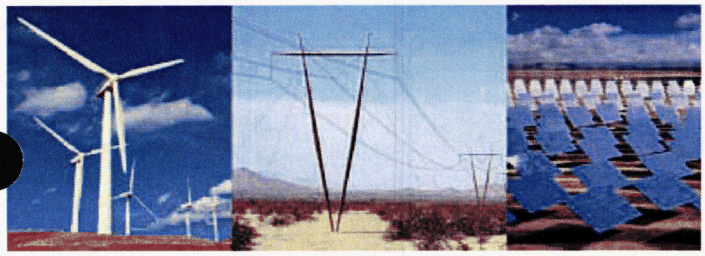
"It's reasonable to expect there will be power purchase agreements in place with utility customers somewhere in the early part of next year to put transmission agreements in place for us to get the financing to start construction," Wray told the **Journal**.

"It's a chicken and egg situation. Our customers have to consummate power purchase agreements with their customers for us to consummate agreements with them, but I believe those agreements will be in place by next year."

Such optimism runs counter to what key California renewable energy officials and industry experts say about evolving renewable markets in the short to medium term.

And it seems particularly optimistic given that SunZia will potentially compete for business with other clean line transmission developers in New Mexico that, taken together, are proposing to build a total of nearly 10,000 MW of capacity to export wind power to California and other western markets.

"To put that in perspective, we have 21,000 MW of renewable energy in California now," said Kevin Barker, chief of staff for the chairman of the California Energy Commission. "So, 10,000 MW of wind – that's a lot of generation."



Pictured are renewable energy components used by SunZia. (Courtesy of SunZia)

The competition

SunZia and New Mexico's other developers will also be competing against other states that want to sell renewable energy to California, Barker said. Those include Wyoming and Montana, which have even more abundant wind resources than New Mexico.

In general, transmission and wind developers want to cash in on New Mexico's gusty central and eastern plains, where a 2008 study by the Western Governors Association identified more than 11,000 MW of developable wind resources.

For that energy to be tapped, New Mexico needs transmission capacity to transport electricity to western markets, since the state's wind potential represents about 75 times more wind-generated electricity than New Mexico alone can consume, according to the National Renewable Energy Laboratory in Colorado.

Apart from SunZia, local and national developers are proposing other big transmission projects. They include the 240-mile "Southline" through southern New Mexico and Arizona, the 900-mile Centennial West Clean Line through central New Mexico and Arizona, the 200-mile Western Spirit Clean Line to carry electricity from central New Mexico to the Four Corners transmission hub, and the 130-mile Lucky Corridor line from northern New Mexico to the Four Corners.

SunZia and the other projects combined would require more than $6 billion to build, plus about $20 billion more to develop all the wind farms needed to fill transmission capacity, said Jeff Mechenbier, Public Service Company of New Mexico's director of transmission and distribution planning and contracts.

"Will all that get built? Probably not," Mechenbier said. "All these folks would need to have some type of signed agreements with electric customers in place to borrow money to go forward."

All the developers are pursuing federal and state permits, and negotiating rights of way with private land owners. SunZia is the furthest along, having received U.S. Bureau of Land Management approval in January for its line to cross federal lands.

It's also the best known, in large part because of high-profile disputes with the U.S. Department of Defense over sections of line just north of White Sands Missile Range that the military feared would interfere with missile tests. That conflict ended when the Pentagon signed off on an agreement that required SunZia to bury some sections.

SunZia says its project would create thousands of construction and hundreds of permanent jobs while generating new state revenue through wage and property taxes. But for such promises to become reality, potential wind developers must first sign up utility customers in California and elsewhere, and that may prove difficult.

Trends feed optimism

Renewable energy developers are counting on forthcoming federal carbon regulations, and renewable portfolio standards in California and other western states to generate huge demand for clean energy in coming years.

Indeed, many coal-fired power plants are now curtailing operations in New Mexico, Arizona and elsewhere to meet environmental regulations, and many are expected to shut down in the near future.

"As coal plants close, it creates opportunities for New Mexico exports," Wray said. "My belief is New Mexico's wind resources are so good and reliable that it will replace a lot of lost generation."

SunZia and others are considering the Arizona market, which has historically relied heavily on coal. But California is the primary target, given that state's mammoth demand and its aggressive renewable goals.

California's drought, which has severely reduced hydroelectric production, plus a new trend by huge industrial companies, such as Apple, to seek renewable electricity independent of utilities, are also feeding optimism about that market, said Sen. Martin Heinrich, D-N.M., who aggressively advocates renewable development at the federal level and is a strong supporter of SunZia and other transmission projects.

"There's a large growth market in the renewable space with enormous potential," Heinrich said. "Making sure we can get our wind resources to market can open up a lot of opportunities. And this is private investment coming into New Mexico, so it adds real value to the state."

California take

Kevin Barker of the California Energy Commission said more opportunities are on the horizon for renewable suppliers. Efforts, for example, to convert much of California's transportation system to electric vehicles to lower carbon emissions could become a "game changer," he said.

But those are long-term trends that remain highly uncertain for now. And, in the short to medium term, California generally has enough renewable energy to meet both its current renewable portfolio standard of 33 percent by 2020 and its carbon-reduction goals into the early 2020s.

In addition, although California Gov. Jerry Brown has proposed raising the portfolio standard to 50 percent by 2030, that change must yet be approved by the state legislature.

"We feel we have enough renewables contracted now for investor-owned utilities to meet or exceed the 33 percent goal," Barker said. "There's potential for more demand in the long term, but with long-term scenarios there are a lot of uncertainties. … It's difficult to see the future 15 years out."

Moreover, even as new demand appears, California laws require its utilities to procure 75 percent of their renewables from in-state sources. And New Mexico producers face intense competition from renewable suppliers in other states.

"Hundreds and hundreds of projects that are already on the table in neighboring states are just sitting there because California doesn't need the power right now," said Norm Meader, a geologist with the Cascabel Working Group in Arizona, which opposes SunZia because of the project's potential environmental impacts. "In 2011 alone, California utilities received 1,000 bids for renewable energy projects totaling 91,000 MW of capacity. Even Arizona developers who are right next door have only been able to sell two solar projects to California utilities for 440 MW."

Other markets

The Arizona market could offer some demand for New Mexico wind and transmission services, but not nearly enough to fill SunZia's 3,000 MW lines, much less the combined capacity offered by New Mexico's other transmission projects.

Carmine Tilghman, director of renewable resources and programs at Tucson Electric Power – which is a minority participant in the SunZia project – said his utility would likely procure some New Mexico wind energy if it became available. But the future of SunZia and other New Mexico transmission projects depends on the California market, he said.

"We're not big enough in Arizona to justify those lines, even with all of Arizona's renewable energy needs combined," Tilghman said.

SunZia and New Mexico's other developers are betting on long-term growth in demand. But the short-term crunch could be a problem for SunZia, which aims to begin construction in 2018 and launch commercial operations by 2020 or 2021.

As New Mexico's projects inch forward, it remains to be seen which will emerge as winners or losers. Lucky Corridor CEO Lynn Greene believes her project, which will cost only $320 million and sell into 11 different western states through the already developed Four Corners transmission hub, has a competitive advantage over SunZia and others.

"The folks who can deliver product to market at the lowest cost are the ones who will be bought first," Greene said. "It will be very difficult to sell 3,000 MW with SunZia. With us, we're only marketing 800 MW and we're selling into a lot more states."

Business Links

- ABQ Economic Development Stories
- ABQJournal's Business Insider newsletter
- City of ABQ Business Registration
- City of ABQ Economic Development Dept.

EXHIBIT NMM-8

EXHIBIT NMM-8

Future cost comparisons by Arizona Public Service Company of various generation technologies. Arizona solar energy is more economic as a renewable resource than wind because maximum generation synchs well with peak demand. Wind energy requires more back-up generation to compensate for its lower output at those times.

Full reference: Arizona Public Service Company, *2012 Integrated Resource Plan*, March 2012, 372 pp. with appendices. Available at http://www.aps.com/library/resource%20alt/2012ResourcePlan.pdf. Accessed September 20, 2015.

2.2.3.2 Cost and Value

Managing the economic cost of delivering electric services is a key objective of resource planning. In the utility industry, the delivered cost analysis is a screening tool that has been commonly used for decades. Essentially, delivered cost is levelized cost plus the cost of transmission. Levelized cost analysis is an evaluation of energy costs comparing capital, operations and maintenance, performance, and fuel costs across several supply-side technologies. An overview of the total delivered cost ($/MWh-delivered) and the cost to construct ($/kW-installed) APS's major resource options are included in Figure 13.[19]

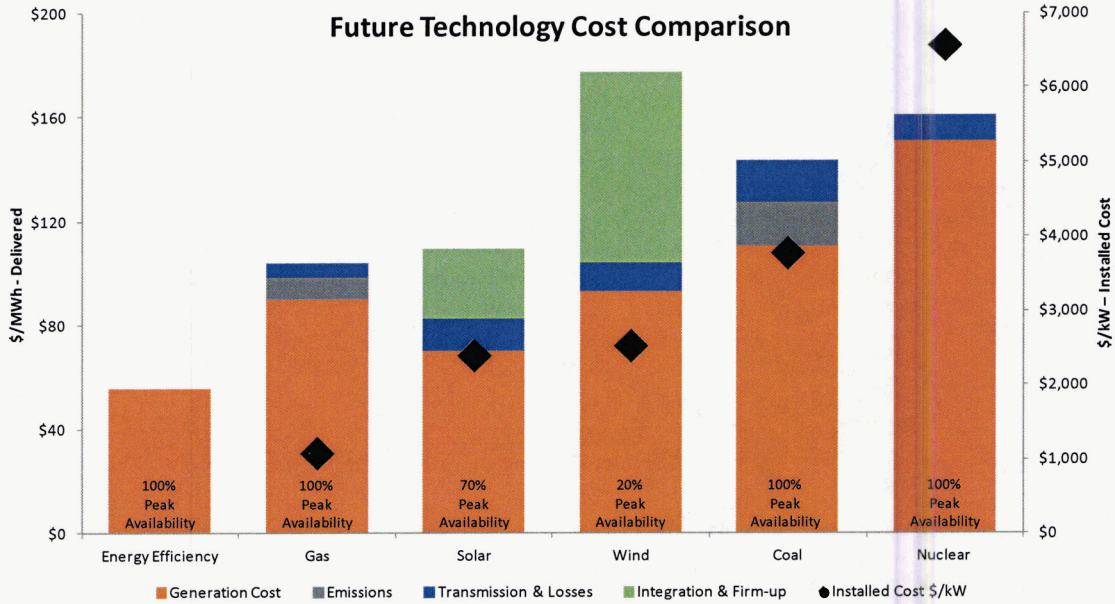


Figure 13 - Technology Cost Comparison: Delivered Cost and Installed Cost

The major components of the delivered cost analysis are capital cost, fuel cost, operation and maintenance (O&M) expenses, power plant fuel efficiency (heat rate), capacity factor, and transmission cost and losses. The resulting average delivered cost is a levelized cost over the estimated economic life of each technology and includes an estimate of the transmission costs that would be required to implement the particular resource. To illustrate the sensitivity of the costs to changes in assumptions, the average delivered cost is "stressed" by estimating the impact of a change in a single input assumption to the average delivered cost. Actual costs will vary for specific projects and sites. APS is including the assumption of hypothetical CO_2 emission costs directly in its delivered cost analysis.

In addition, system integration costs may be imposed by operation of some non-dispatchable resources such as wind and solar. Due to their intermittent nature, additional operating reserves may be needed on the rest of the system to effectively follow APS load and meet WECC reliability requirements. Based on a study performed by Northern Arizona University under the direction of Dr. Tom Acker, a system

[19] Values depicted are in 2015 dollars, including Allowance for Funds Used During Construction (AFUDC).

ARIZONA PUBLIC SERVICE COMPANY

2012 INTEGRATED RESOURCE PLAN

FILED IN COMPLIANCE WITH A.A.C. R14-2-703

MARCH 2012

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Resource Conservation and Recovery Act: The Resource Conservation and Recovery Act (RCRA) gives EPA the authority to control hazardous waste from the "cradle-to-grave". RCRA also regulates the management of non-hazardous solid wastes, as well as environmental problems that could result from underground tanks storing petroleum and other hazardous substances.

Coal Combustion Residuals – In June 2010, EPA proposed new rules to regulate coal combustion residuals (CCRs) to prevent contaminants from leaching into ground water. EPA's final rule, expected in 2012, will affect the manner in which coal-fired power plants manage their ash disposal in surface impoundments and landfills.

Congress: None of the attempts to pass comprehensive climate change legislation in the 111th Congress were successful. As for the 112th Congress, a number of bills introduced are aimed at delaying, eliminating, defunding, or overseeing EPA's authority to regulate GHGs. Such legislation includes delaying any action by EPA to regulate GHG emissions from stationary sources for a fixed number of years, stripping EPA of any CAA authority to regulate GHG emissions, and cutting off funding for the implementation of the agency's GHG rules by prohibiting the use of funds to implement or enforce rules relating to the regulation of GHG emissions from stationary sources. Although the ultimate outcome of these numerous legislative efforts remains uncertain, these actions seem to indicate that it is unlikely any legislation aimed at further regulating GHG emissions will materialize over the next year.

Arizona Department of Environmental Quality: The ADEQ is Arizona's primary environmental regulatory agency, with the responsibility for developing and enforcing state regulations that implement Arizona environmental laws, and also for helping ensure that businesses and facilities operate according to federal environmental laws and regulations. Three programmatic divisions – Air Quality, Water Quality, and Waste Programs – carry out ADEQ's core responsibilities. In some areas, Arizona environmental laws go beyond the federal laws. Examples include the Arizona State Hazardous Air Pollutant (HAP) Program and the Arizona Aquifer Protection Permit Program.

Similar to EPA delegation authority, ADEQ may delegate some permitting and enforcement responsibilities to counties. As discussed in Section 2.2.4.4, ADEQ has delegated CAA permitting and enforcement authority to Pima, Pinal, and Maricopa counties.

2.2.3 Cost

2.2.3.1 Capital Investment

An investment of nearly $9 billion will be required during the Planning Period to meet future customer needs. This investment, projected regardless of whether APS constructs and owns new generation resources or whether resources are developed by market participants and sold to APS under long-term PPAs, does not include: (1) financial commitments to energy efficiency and distributed energy initiatives; (2) transmission investments that will be required to satisfy future customer demands or transmission projects already identified in the last 10-year transmission plan filing; and, (3) ongoing capital investment for existing owned generation.

2.2.3.2 Cost and Value

Managing the economic cost of delivering electric services is a key objective of resource planning. In the utility industry, the delivered cost analysis is a screening tool that has been commonly used for decades. Essentially, delivered cost is levelized cost plus the cost of transmission. Levelized cost analysis is an evaluation of energy costs comparing capital, operations and maintenance, performance, and fuel costs across several supply-side technologies. An overview of the total delivered cost ($/MWh-delivered) and the cost to construct ($/kW-installed) APS's major resource options are included in Figure 13.[19]

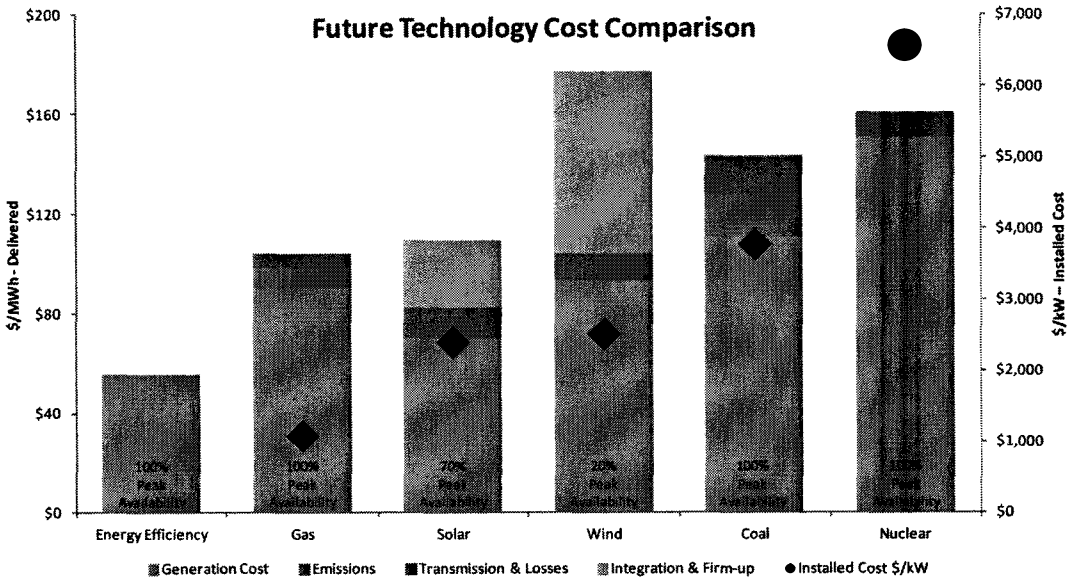


Figure 13 - Technology Cost Comparison: Delivered Cost and Installed Cost

The major components of the delivered cost analysis are capital cost, fuel cost, operation and maintenance (O&M) expenses, power plant fuel efficiency (heat rate), capacity factor, and transmission cost and losses. The resulting average delivered cost is a levelized cost over the estimated economic life of each technology and includes an estimate of the transmission costs that would be required to implement the particular resource. To illustrate the sensitivity of the costs to changes in assumptions, the average delivered cost is "stressed" by estimating the impact of a change in a single input assumption to the average delivered cost. Actual costs will vary for specific projects and sites. APS is including the assumption of hypothetical CO_2 emission costs directly in its delivered cost analysis.

In addition, system integration costs may be imposed by operation of some non-dispatchable resources such as wind and solar. Due to their intermittent nature, additional operating reserves may be needed on the rest of the system to effectively follow APS load and meet WECC reliability requirements. Based on a study performed by Northern Arizona University under the direction of Dr. Tom Acker, a system

[19] Values depicted are in 2015 dollars, including Allowance for Funds Used During Construction (AFUDC).

integration cost of $3.25/MWh is added to wind generation.[20] As solar generation in Arizona is more predictable than wind, though still intermittent, APS assumes a lower integration cost for solar (without storage) of $2.50/MWh, per the Western Governors' Association's Western Renewable Energy Zone Generation and Transmission Model.[21] APS will reevaluate these figures as renewable penetration increases and more experience is gained in dealing with the integration of intermittent or variable generation.

2.2.3.3 Taxes

Production Tax Credit: Section 45 of the Internal Revenue Code provides for a production tax credit (PTC) for the generation of qualified energy from qualified facilities, with terms, including expiration date, specified for each technology type. Eligibility for the credit is contingent upon the generated electricity being sold to an unrelated entity. Qualified energy sources include wind, for which the PTC expires on December 31, 2012, and closed-loop biomass, open-loop biomass, solar, small irrigation solar, municipal solid waste, and marine and hydrokinetic renewable energy, for which the PTC expires on December 31, 2013.[22]

Investment Tax Credit: Section 48 of the Internal Revenue Code provides a package of investment tax credits (ITCs) for solar and other renewable energy developers. The amount of the ITC is 30% for solar placed in-service by December 31, 2016, and 30% for wind-energy systems placed in-service by December 31, 2012. Under current law, after December 31, 2012, large wind-energy systems will no longer qualify for ITC. As of January 1, 2017, the ITC will be reduced to 10% for solar technologies.

Since the PTC will expire and the ITC will be reduced (for solar) during the timeframe covered by the 2012 Resource Plan, a sensitivity analysis is included whereby the tax credits are extended beyond their scheduled expiration dates. For the PTC, this applies to all wind projects deployed after 2012 and for geothermal projects deployed after 2013. For the ITC, this applies to solar projects deployed after 2016.

2.2.4 Risk

2.2.4.1 Uncertainty

Recognizing uncertainty as inevitable is integral to the resource planning process. Although values for key variables such as fuel prices and demand can be forecast, they cannot be known with pinpoint accuracy. Also, some conditions are so unique that they simply cannot be modeled decades in advance, such as the magnitude of the current economic downturn and the delay in federal climate change legislation.

To ensure that uncertainty is addressed in a comprehensive fashion, APS is required to incorporate and evaluate the risks inherent in providing electricity.[23] Notwithstanding that much of the planning process is quantitative in nature, there is also a significant

[20] APS/NAU Wind Integration Study, 2007.
[21] Western Governors' Association Generation and Transmission Model Methodology and Assumptions, Version 2.0, June 2009. APS is currently undertaking an effort to update this figure during the first half of 2012.
[22] The PTC expiration dates pertain to the in-service dates of the qualified facility. The tax credits are earned based upon the production of the qualified facility over a period of time.
[23] A.A.C. R14-2-703.

EXHIBIT NMM-9

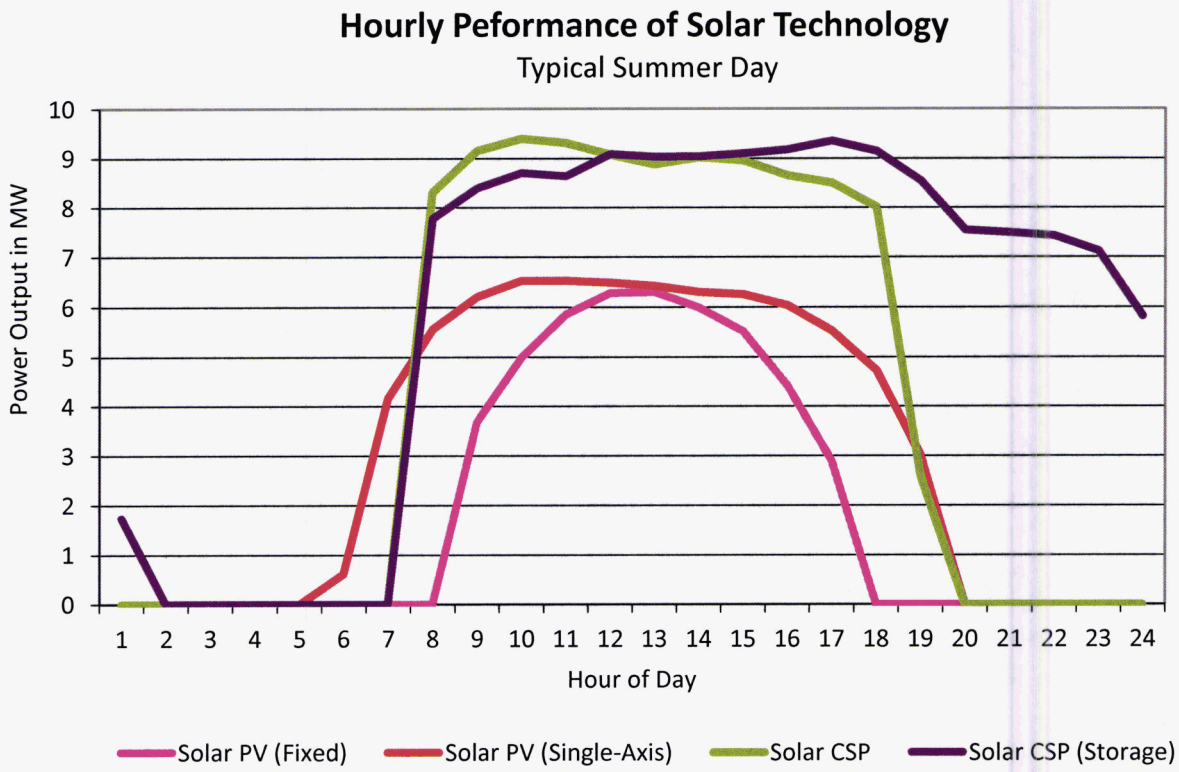
EXHIBIT NMM-9

Comparison of solar resource and wind resource capacity factors by Tucson Electric Power Company. For meeting peak demand in Arizona, solar energy is much more coordinated than wind energy with demand.

Full reference: Tucson Electric Power Company, *2014 Integrated Resource Plan*, April 1, 2014, 387 pp. Available at https://www.tep.com/doc/planning/2014-TEP-IRP.pdf. Accessed October 9, 2015.

SOLAR RESOURCES MODELED

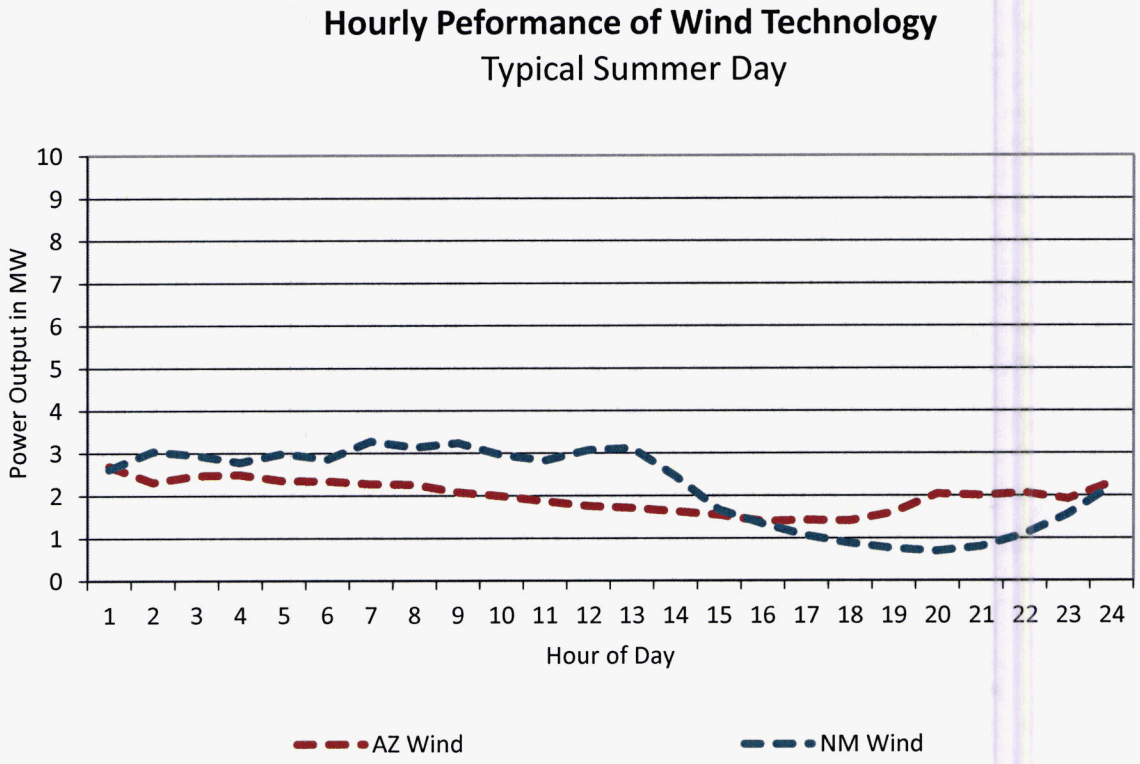
DOE's Solar Advisor Model (SAM) was used to model solar resources based on Arizona sites. SAM's hourly power output was used to estimate annual capacity factors and capacity values.



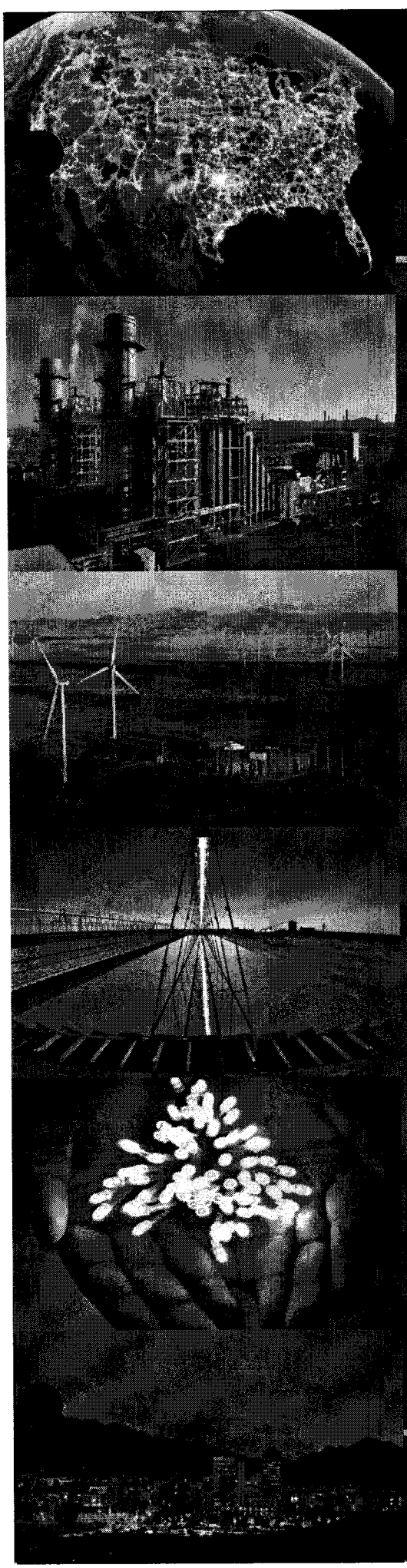
Technology Energy & Capacity Value	Units	Solar PV (Fixed)	Solar PV (Single Axis)	Solar CSP	Solar CSP (Storage)
Typical Capacity Factor	Annual %	17%	24%	30%	38%
Net Coincident Peak Contribution	NCP %	33%	51%	70%	87%

WIND RESOURCES MODELED

NREL's Western Wind Resource Dataset (WWRD) provided hourly wind resource data. This data was used to develop the anticipated coincident peak and expected capacity factors used in the resource planning process.



Cost and Operating Characteristics	Units	NM Wind	AZ Wind
Typical Capacity Factor	Annual %	38%	30%
Net Coincident Peak Contribution	NCP %	13%	9%



TUCSON ELECTRIC POWER

2014 Integrated Resource Plan

April 1, 2014

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EXHIBIT NMM-10

EXHIBIT NMM-10

Full reference for statement that the number of California renewable energy projects scheduled to go online by January 2017 represents more than double the capacity the state needs to achieve a 33 percent renewable portfolio standard.

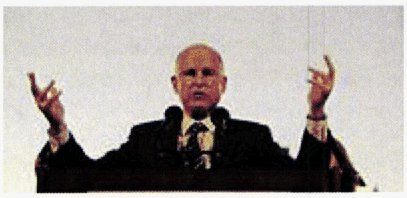
Kaften, C., 2012. California on track to exceed 2020 RE goals, but issues still exist, *PV Magazine–Photovoltaic Markets and Technology*, March 9, 2012. Available at http://www.pv-magazine.com/news/details/beitrag/california-on-track-to-exceed-2020-re-goals--but-issues-still-exist_100006045/#ixzz1ySkTA1cC. Accessed October 9, 2015.

PV Magazine – Photovoltaic Markets and Technology
http://www.pv-magazine.com/

California on track to exceed 2020 RE goals, but issues still exist

09. March 2012 | Top News, Global PV markets, Markets & Trends | By: Cheryl Kaften

The U.S. state of California is well on the way to overachieving its 2020 aim to generate 33 percent of its electricity from renewables, in fact by almost double. Of this, photovoltaics accounts for nearly half. There are issues, however, such as interconnection and grid infrastructure, which still need to be ironed out.



Jerry Brown signed the most ambitious clean energy law in the US last April.
Flickr/Steve Rhodes

At a time when petrol prices are rising faster than we can fill our tanks, Michael Picker, the State of California's Senior Advisor to the Governor for Renewable Energy Facilities, believes that solar generation offers a superior long-term value proposition. "The price for access to the sun is likely to be the same 20 years from now as it is today," Picker told an industry audience, including **pv magazine**, this week, adding, "Remember, we are not competing with the Chinese for the sun, itself."

Picker was the keynote speaker on March 6 at the Solar Energy Symposium, hosted by CleanTECH San Diego and the Solar Electric Power Association (SEPA) at the University of San Diego to discuss the future of solar energy in the region.

Last April, California Governor Jerry Brown signed the most ambitious clean energy law in the nation – requiring that the state obtain 33 percent of its electricity from renewable sources, such as wind and solar energy, by the year 2020. To meet his objectives, Brown intends to:

- Build 12 gigawatts (GW) of localized (distributed) electricity generation;
- Construct eight GW of large-scale renewables;
- Approve plans and permits for new necessary transmission within three years;
- Deal with peak energy needs and develop energy storage;
- Create a timeline to make new homes and commercial buildings zero net energy;
- Make existing buildings more efficient;
- Adopt stronger appliance efficiency standards; and
- Increase combined heat and power production by 6.5 GW

Picker reported that, in many respects, California already has exceeded its own expectations. Of the 12 GW of distributed electricity generation the state is targeting, 7.99 GW of power currently is online, pending, or authorized.

What's more, over 16 GW of renewable energy generation was "permitted" during the 12 months between 2010 and 2011 – nearly half of that (7.67 GW), is to be supplied by photovoltaic projects.

In fact, the queue of projects scheduled to go online by January 2017 represents more than double the capacity the state needs to achieve a 33 percent renewable portfolio standard (RPS). In California, he explained, projects are deemed compatible with renewable portfolio standards if they are sized up to 20 megawatts (MW); and either are located within a low-voltage distribution grid or supply power directly to the consumer.

"There's an imbalance of solar PV," Picker commented, with respect to the permitting. "It is over-weighted compared to, for example, solar thermal (with permits for 2.76 GW)," he noted, admitting, "I thought solar thermal would have a greater percentage of the market by now – but, with the rapid drop in the price of PV, that technology has been able to reach manufacturing capacity more quickly than thermal."

In terms of rooftop and on-site solar, San Diego generates more power from distributed energy – specifically, grid-connected solar panels on residential, commercial, and government buildings – than any other city in California. A study conducted recently by the Environment California Research & Policy Center found that there were more than 4,500 solar installations within San Diego's city limits as of August 2011, ahead of runners-up Los Angeles and San Jose. Most of the San Diego-based distributed energy projects have been funded by the California Solar Initiative (CSI), followed by the Self-Generation Incentive Program (SGIP), and the Emerging Renewables Program (ERP).

Noting that early adopters of solar generation also are apt to be early electric vehicle (EV) adopters, Picker said it was important to develop the infrastructure for demand response, transmission, energy storage, and the smart grid. "San Diego continues to be a real test bed and arena for EVs, and we will need to supply the power they demand, as well as the energy storage they need."

Another major issue on the horizon will be interconnection, as more rooftop systems become grid-connected. "By 2017, we will be able to hook all of these projects to the grid," predicted Picker. "All of the ingredients are there."

Utility scale

In terms of utility scale, Picker pointed out that nearly half of the projects permitted from 2010 to 2011 were sited in Kern County, California – an area in the southern part of the state that is nearly the size of New Jersey. The county extends east, beyond the southern slope of the Sierra Nevada range into the Mojave Desert and includes parts of Indian Wells Valley and Antelope Valley. Until the recent arrival of solar projects, Kern County had earned a reputation as a large

agricultural base; and a significant producer of oil, natural gas, hydro-electric power, wind turbine power, and geothermal power.

Project permits for Kern County at year-end 2011 included 44 MW for biogas, 2.77 GW for photovoltaics, 250 MW for solar thermal, and 4.1 GW for wind.

"Kern County is now the center of [utility-scale] renewable energy in California," Picker stated. "A number of years ago, the town supervisors had a discussion with local oil producers and learned that oil was getting harder to extract; the oil companies had to keep drilling deeper to find it. The supervisors started to worry about losing jobs in the area, once oil 'went away'. Then, one of the supervisors took a drive and saw a wind turbine at work. He came back and, from then on, Kern was determined to be an energy county."

From that case in point, Picker said, the rest of the state and country should learn a lesson: ""You don't have to just drift toward the future. Set a big goal and develop power to meet that goal." He singled out two counties that are not getting with the program yet – Riverside, in the southern part of the state, forming part of the border with Arizona; and San Bernadino, in southeast California, an area characterized by thinly populated deserts and mountains.

However, as an energy professional, he is adamant that conservation in these desert and mountain locales must be considered. "We want to help species such as the tortoises and big horn sheep to survive." The biggest roadblock to saving endangered animals, he noted, was the number of agencies involved, "and the difficulty of getting everybody in the same room."

Finally, Picker was optimistic about the pricing of solar projects. "We are starting to see large (and even, smaller) PV projects coming in at 'price parity', he said, adding, "In theory, the utilities should be agnostic to what type of energy they buy, whether it's fossil fuel or solar, so long as it's cost-efficient."

Edited by Becky Stuart.

Read more: http://www.pv-magazine.com/news/details/beitrag/california-on-track-to-exceed-2020-re-goals--but-issues-still-exist-_100006045/#ixzz1ySkTA1cC

EXHIBIT NMM-11

EXHIBIT NMM-11

Full reference for statement that developers proposed 1,000 renewable energy projects in California in 2011 totaling 91,000 megawatts of capacity.

W. Todd, "California reveals price it pays for renewable energy," *Forbes Green Tech*, February 7, 2012. Available at http://www.forbes.com/sites/toddwoody/2012/02/07/california-reveals-price-it-pays-for-renewable-energy/.

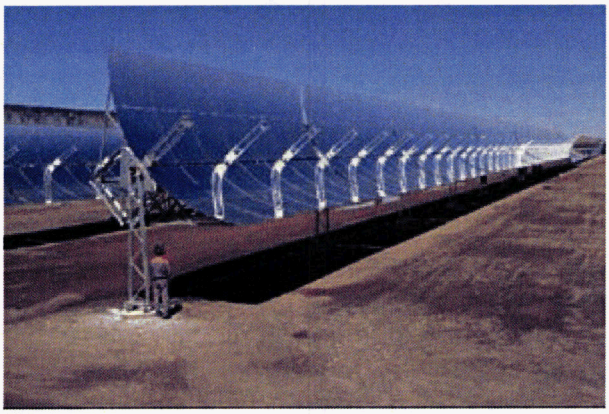
http://www.forbes.com/sites/toddwoody/2012/02/07/california-reveals-price-it-pays-for-renewable-energy/

Feb 7, 2012 @ 12:35 PM **7,727** views

California Reveals Price It Pays For Renewable Energy

Todd Woody, Forbes Staff

I cover environmental and green technology issues from San Francisco. Opinions expressed by Forbes Contributors are their own.



California has one of the nation's most ambitious renewable energy mandates – 33% of its electricity must be carbon free by 2020 – yet the price of that power had long remain locked in a black box, kept confidential by state regulators.

Not any longer. Forced by a new law to publish the electricity rates of utility contracts it has approved, the California Public Utilities Commission on Friday issued a report detailing what green energy costs consumers.

Prices paid for renewable energy ranged between 5.4 cents per kilowatt-hour in 2003 to and 13.3 cents in 2011, with an average cost 11.9 cents. However, the commission said that for contracts signed in 2011 but not counted in the report, prices fell about 30% from 2009 contract prices. Many of those contracts promise to supply electricity below the cost of energy produced by natural-gas fired power plants.

(The increase in renewable energy prices from 2003 to 2011 is a result in part earlier contracts that tied the price paid for renewable energy to prevailing natural gas costs, which spiked in 2008. Green energy prices also rose as utilities – Pacific Gas & Electric, San Diego Gas & Electric and Southern California Edison –rushed to sign contracts to meet the mandate to obtain 20% of their electricity from renewable sources by 2010 – the called the renewable portfolio standard, or RPS – a target not yet achieved.)

The steep drop in the 2011 contracts comes from the plunge in photovoltaic panel prices over the past two years, largely due to competition from China. Tellingly, about two-thirds of bids for solar energy contracts last year (by electricity generated) were for photovoltaic projects and only a third were for solar thermal power plants, which deploy vast arrays of mirrors to heat liquids and produce steam to drive an electricity-generating turbine. Photovoltaic solar, or PV, also represented the bulk of contracts short-listed by utilities, followed by wind energy bids.

"Results from the 2011 RPS Solicitation indicate that the market, especially for solar PV, has matured meaningfully over the last two years, as measured by an increase in experienced market developers, an increase in projects with high viability and a significant decrease in bid prices," the report's authors stated.

Still, high-priced renewable energy contracts continue to be approved. For instance, in November the utilities commission green-lighted utility Pacific Gas & Electric's contract with Spanish developer Abengoa for a 250-megawatt solar thermal power plant over staff and some commissioners' objections that it would cost customers twice as much as other renewable energy projects.

The report shows there's no shortage of interest by developers in building renewable energy projects in California. Last year, they submitted 1,000 bids that, if all were accepted and built, would have generated 91,000 megawatts of electricity – far above the state's power demand.

Though only a fraction of those bids end up being built, California last year installed a record 839 megawatts of renewable energy – from solar and wind – a 28% jump over 2010. To date, California has built 2,541 megawatts of renewable energy under the renewable portfolio standard program.

EXHIBIT NMM-12

EXHIBIT NMM-12

Subject: SunZia
From: Michael Picker <Michael.Picker@GOV.CA.GOV>
Date: 6/14/2012 11:35 AM
To: nmeader@cox.net <nmeader@cox.net>

I was surprised to get your letter regarding SunZia, and the suggestion that the purpose of the power line might be to sell power into California. That seems like a risky business bet.

Most California utilities report that they are already oversubscribed for renewable power generation (see, for example, the article in Renewablesbiz on the link below). Although there's no requirement that they share all their business relationships with me, I'm not aware that any of the California utilities have contracts for power from renewable generators in New Mexico.

http://www.renewablesbiz.com/article/12/05/pge-says-it-will-meet-california-s-renewable-energy-goals

In fact, the California Public Utilities Commission reports that the state's investor-owned utilities have enough contracts from renewable power projects to supply 40% of the state's electricity needs. Much of that will come from the 151 projects, representing some 16 GW of wind, solar and geothermal that were permitted within California during 2010 and 2011.

In fact, California has become an exporter of renewable power to neighboring states. The Hudson Ranch 1 geothermal plant in California's Imperial County recently completed construction and has begun selling power to the Salt River Project.

We've made this point to regional transmission bodies in the past, urging caution on planning regional transmission solely for bulk power sales of renewables to help meet California's 33% Renewable Portfolio Standard. See my letter to WECC of August 3, 2011, which is also attached.

Please feel free to check in if you have further questions.

Michael Picker
Senior Advisor to the Governor for Renewable Energy Facilities
Office of the Governor
State Capitol
Sacramento, CA 95814
(916) 445-7665
Michael.Picker@gov.ca.gov

Attachments:
Final WECC letter 6-21-11.pdf 1.5 MB

EXHIBIT NMM-13

EXHIBIT NMM-13

Full reference for the statement that the California BLM has received 375 applications for renewable energy since 2007 and has approved only 18 of them.

Julie Cart, "Gov. Brown's renewable energy plan could boost solar, wind industries," *Los Angeles Times*, January 8, 2015. Available at http://www.latimes.com/local/california/la-me-renewable-goals-20150108-story.html. Accessed September 19, 2015.

http://www.latimes.com/local/california/la-me-renewable-goals-20150108-story.html

Gov. Brown's renewable energy plan could boost solar, wind industries

Wind turbines in the Tehachapi Mountains; Gov. Jerry Brown's proposal to significantly boost the amount of energy California derives from renewable sources could reinvigorate the state's utility-scale solar and wind industries. (Irfan Khan, Los Angeles Times)

Julie CartContact Reporter

The initial surge of interest in large-scale wind and solar has stalled; Gov. Brown's plan could change that.

January 7, 2015, 5:05 pm

Gov. Jerry Brown's proposal this week to significantly boost the amount of energy California derives from renewable sources could reinvigorate the state's utility-scale solar and wind industries, as well as launch another land rush in the Mojave Desert.

In his inaugural address, Brown didn't say how the state's Renewables Portfolio Standard could be raised to 50% by 2030 — the previous benchmark was 33% by 2020 — but his commitment was clear:

"This is exciting, it is bold, and it is absolutely necessary if we are to have any chance of stopping potentially catastrophic changes to our climate system," the governor said.

He also outlined a plan to reduce petroleum use in cars and trucks by 50% and double the energy efficiency of new buildings in the state.

The reverberation was instantaneous.

"Is it significant? Absolutely. Will it stimulate the market? Absolutely," said Jerry R. Bloom of the Los Angeles law firm Winston & Strawn, who guides renewable energy developers through the financing and permitting processes.

Meeting the governor's goal is easily achievable. But making it fit and work together in terms of [the] grid is the difficulty.

- V. John White, executive director of the Center for Energy Efficiency and Renewable Technologies

Because utilities already are on track to meet California's 2020 goal, they have shown little interest in signing new contracts with large wind and solar firms, Bloom said. Without contracts to sell power, it's been difficult for clean-energy developers to cobble together financing for large-scale projects.

As a result, the initial flurry of interest in permitting solar and wind projects in the state has stalled.

"There has been a dramatic slowdown — or almost freezing out," Bloom said. "There are no utility-scale contracts. There's no real market. The utilities' position is: 'We've reached the 33% and we're done.'

"Fifty percent is a game-changer."

And Brown could make the 50% standard happen simply by issuing an executive order.

The California Public Utilities Commission has the authority to compel the state's three big utilities — Southern California Edison, Pacific Gas & Electric and San Diego Gas & Electric — to procure 50% of their energy through renewables. But such an edict would not apply to large municipal companies like the Los Angeles Department of Water and Power.

Should the governor ask the Legislature to craft a far-reaching bill, it probably would pass the Democrat-controlled Assembly and Senate.

California already has shown that generating large amounts of renewable energy is possible. The next phase — coordinating the new power with the needs of the electrical grid — will be much more complicated, said V. John White, executive director of the Sacramento-based Center for Energy Efficiency and Renewable Technologies.

"Meeting the governor's goal is easily achievable," he said. "But making it fit and work together in terms of [the] grid is the difficulty. The more we add renewables to the system, the more we have to think about how they fit with what we have."

Wind and solar plants deliver power intermittently, making it difficult to align supply with demand. Developing efficient power storage technologies is the next major hurdle, White said.

For a variety of reasons — including the difficulty of obtaining financing and federal subsidies for the construction of billion-dollar plants — utility-scale solar and wind development has fallen off significantly even as small-scale solar power is burgeoning.

California currently ranks third in the nation in wind power production and is first in installed solar capacity.

If developers take Brown's speech as a signal to start gearing up, they probably will look to the vast tracts of federal land available for solar leasing from the Bureau of Land Management. Mike Sintetos, who heads the BLM's renewable energy program in California, said the initial frenzy of renewable applications has cooled in the last few years.

"We have eight pending solar applications. That number was three or four times that much in 2010," he said.

Amid that slowdown, even some inside the industry feared that the mega-plants operating in the California desert were destined to become white elephants.

BrightSource Energy — which built the massive Ivanpah power plant in the Mojave, near the Nevada border — praised Brown this week as a champion of renewables.

"We are pleased Gov. Brown continues his strong support for renewable energy as an essential policy that benefits California's environment and economy," Joe Desmond, a senior vice president at the Oakland company, said in an emailed statement. "As renewable penetration increases, policymakers and utilities have shown growing interest in technologies that can ensure long-term reliability without increasing emissions."

Siting renewable energy facilities on public lands in the West is a priority for the Obama administration, which has set aside 22 million acres in California to support renewable energy and pledged to generate 20,000 megawatts of power from federal land by 2020, enough to power about 6 million homes.

Companies have submitted 375 applications for renewable energy-related projects in California since 2007, BLM State Director Jim Kenna said recently. The agency has approved 18.

Brown's new goals could change that.

"Many thought the initial 33% goal was too challenging, yet California will readily surpass that number," said Martín Múgica, president and chief executive of Iberdrola Renewables, which is

developing wind and solar projects in the state. "The governor's plan will spark innovation across the electricity sector and clearly encourage large-scale renewable energy development."

julie.cart@latimes.com

Twitter: @julie_cart

EXHIBIT NMM-14

EXHIBIT NMM-14

California utility websites that provide information and bid instructions on current requests for renewable energy procurement or future plans for use of renewable energy.

PACIFIC GAS AND ELECTRIC

http://www.pge.com/en/b2b/energysupply/wholesaleelectricsuppliersolicitation/renewables2012/index.page
http://www.pge.com/en/b2b/energysupply/wholesaleelectricsuppliersolicitation/renewables2013/index.page
http://www.pge.com/en/b2b/energysupply/wholesaleelectricsuppliersolicitation/RFO/RPS2014.page

SOUTHERN CALIFORNIA EDISON

https://scerps.accionpower.com/_scerps_1301/home.asp
https://scerps.accionpower.com/_scerps_1401/home.asp

SAN DIEGO GAS AND ELECTRIC

http://www.sdge.com/request-proposals

LOS ANGELES DEPARTMENT OF WATER AND POWER

https://ladwp.com/ladwp/faces/ladwp/aboutus/a-power/a-p-renewableenergy/a-p-re-rpsprogram
https://ladwp.com/ladwp/faces/wcnav_externalId/a-p-doc

SACRAMENT MUNICIPAL UTILITY DISTRICT

https://www.smud.org/en/business/environment/solar-for-your-business/RFO-and-unsolicited-offers.htm

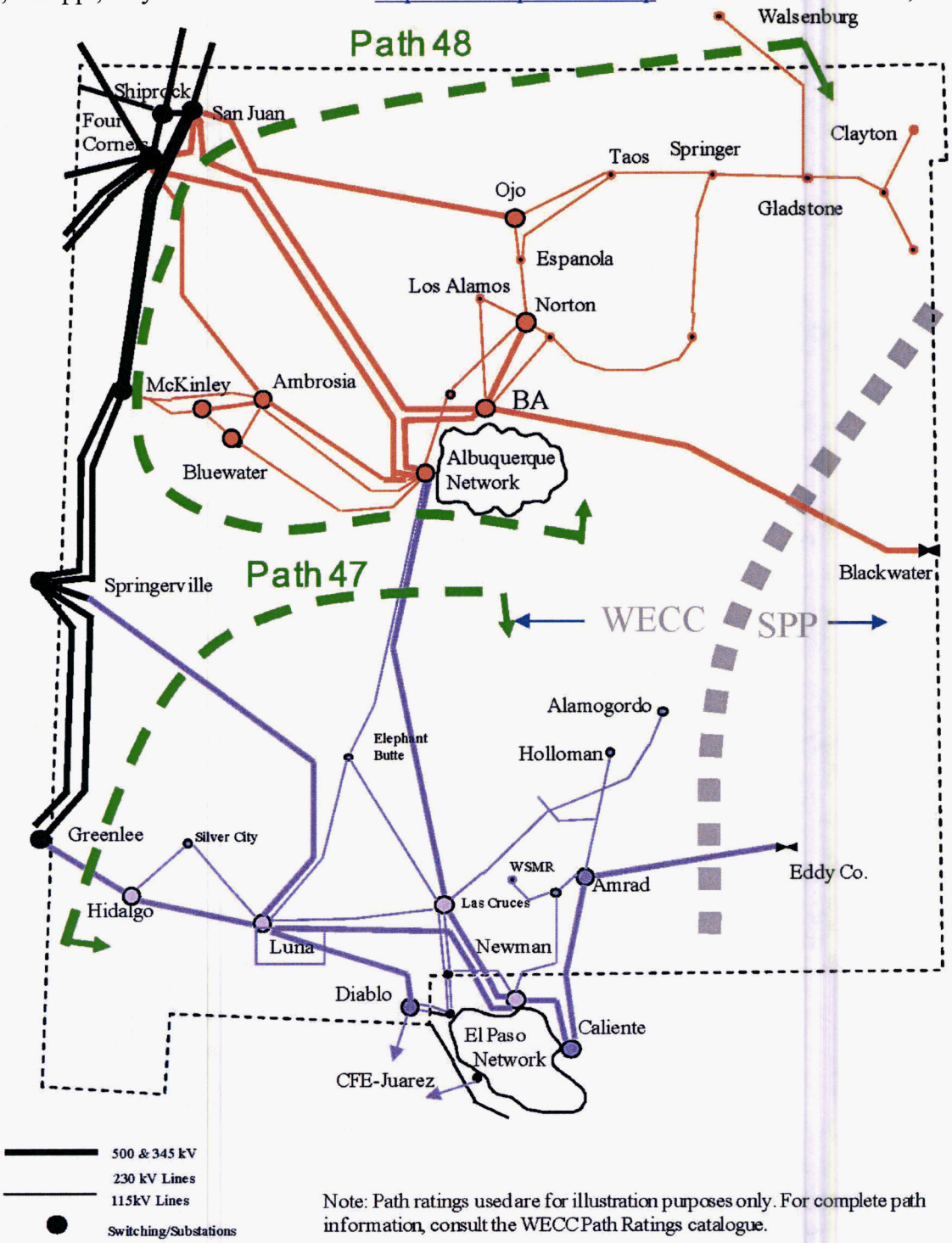
TOPIC 2

RELIABILTY, CONGESTION, AND TRANSFER CAPABILITY NEEDS IN SW NEW MEXICO AND SE ARIZONA

EXHIBIT NMM-15

EXHIBIT NMM-15

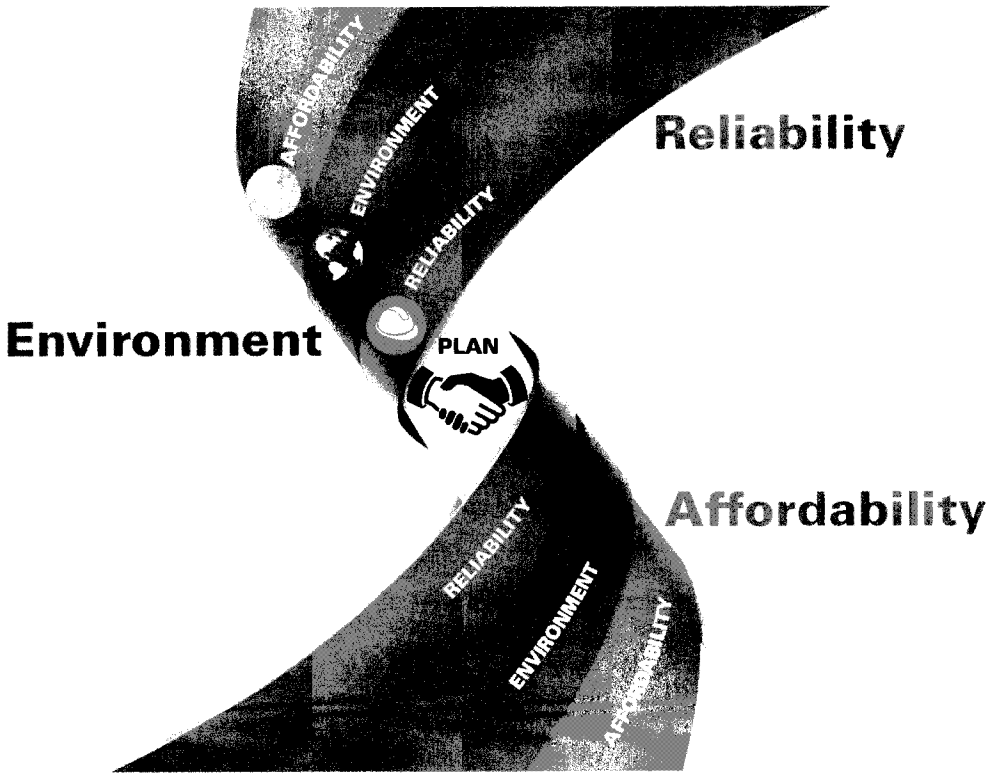
Transmission Path 47 in southwestern New Mexico. The heavier red and purple lines are 345-kilovolt transmission lines, while the thin red and purple lines are 115-kilovolt transmission lines. From page 31, Public Service Company of New Mexico, *PNM Integrated Resource Plan, 2014-2033*, 203 pp., July 2014. Available at https://www.pnm.com/irp. Accessed October 11, 2015.



Note: Path ratings used are for illustration purposes only. For complete path information, consult the WECC Path Ratings catalogue.

PNM
Integrated Resource Plan

2014 – 2033 July 2014



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NETWORK INTEGRATION TRANSMISSION SERVICE CUSTOMERS

Network customers include: Tri-State, Los Alamos County (LAC), Navajo Tribal Utility Authority (NTUA), Western Area Power Administration (WAPA) for Kirtland Air Force Base, City of Gallup, Jicarilla Apache Nation, Navopache Electric Cooperative (NEC), and PNM-Wholesale Power Marketing (WPM) (for PNM retail and City of Aztec).

POINT-TO-POINT TRANSMISSION SERVICE CUSTOMERS

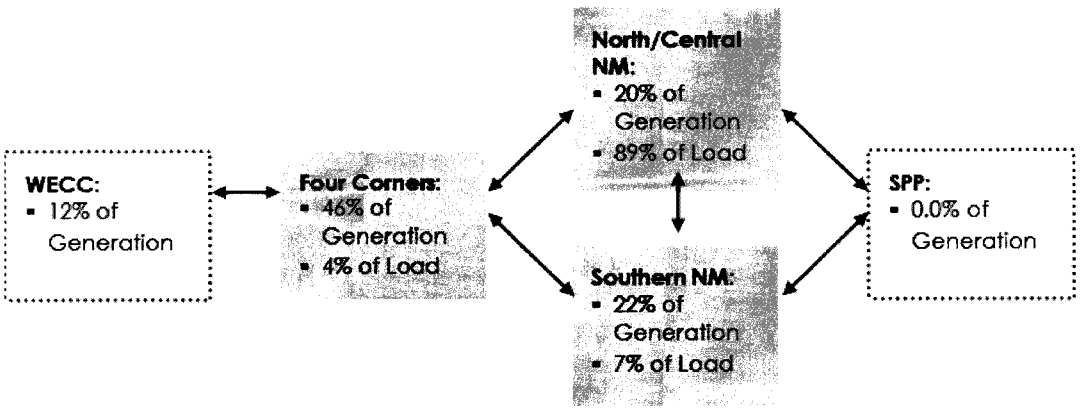
Point-to-point customers include: El Paso Electric Company (EPE), High Lonesome Mesa, Argonne Mesa, NextEra, WAPA, and WPM.

EXISTING TRANSMISSION CAPABILITIES

At a high level, the PNM system can be described by the block diagram in Figure 2-P, which shows the relative generation and load diversity of the PNM system. This diagram illustrates where load and resources (L&R) are located and where loads are served. It illustrates that the majority of the PNM load (89%) is located in North/Central New Mexico. Similarly, more than 50% of PNM's resources are located at Four Corners or beyond and transmitted, or wheeled, to load centers in North/Central New Mexico. Although physical connections exist between PNM and the Southwest Power Pool (SPP) to the east, no supply side resources are currently being imported from the SPP grid to serve PNM load due to the lack of identified available firm economic resources with firm delivery capability to the PNM interconnection point with SPP.

The major transmission lines owned by PNM were primarily developed to deliver remote resources from the Four Corners area of New Mexico to retail and wholesale customers near the load centers in northern and southern New Mexico. A list of Transmission facilities are included in Appendix B.

Figure 2-P: Overview of Existing System Representation During Peak Load



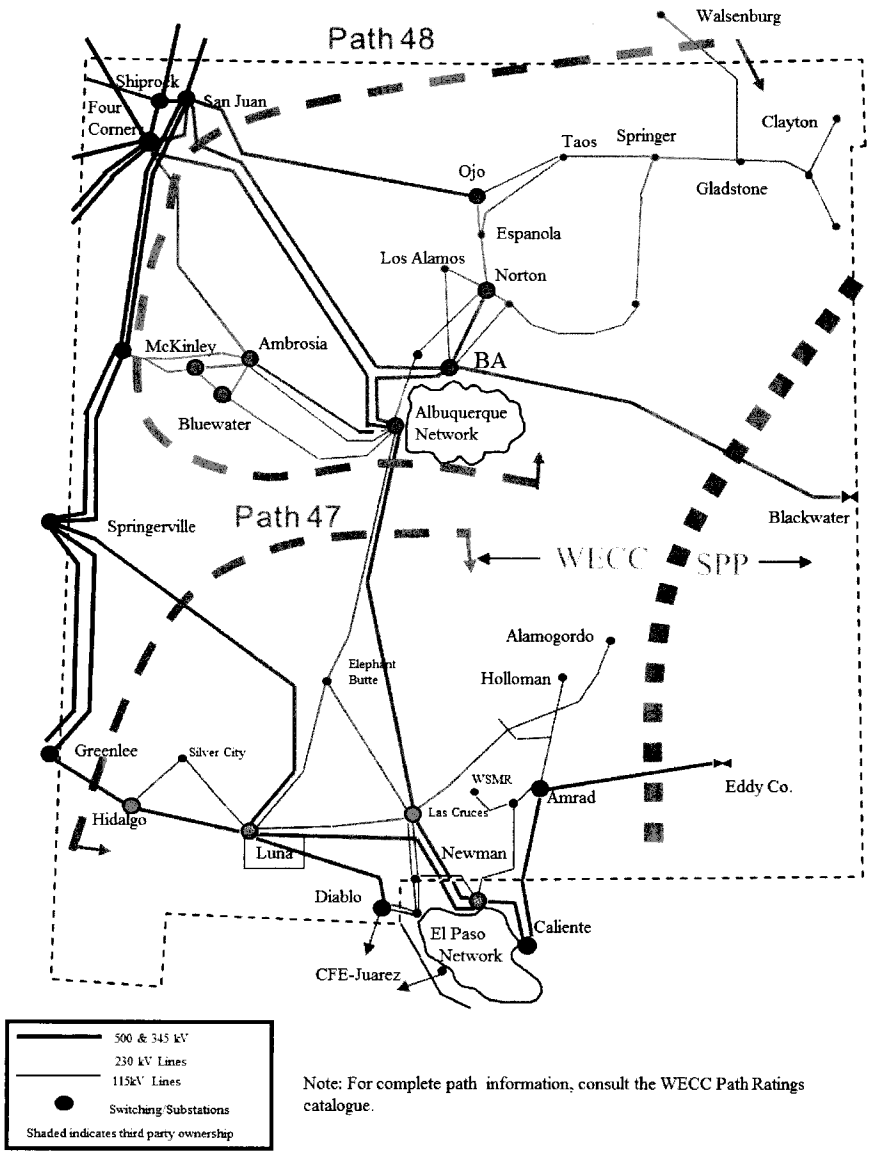
PNM monitors key transmission paths to insure the transmission system is operated in a safe and reliable way. Path limits are established that identified maximum flow levels for safe and reliable operation such that the loss of a major element (e.g., line, transformer, and tie point) can occur without affecting the quality of service delivered by the transmission system. In most cases, customers never know when an element is out of service because the system is operated in a manner that minimizes the effects on customers.

In New Mexico, there are two key paths that define the planning and operation of the transmission system. Path 48 controls the operation of the northern part of the state, and Path 47 controls the operation of the southern part of the state as illustrated in Figure 2-Q. Orange lines represent transmission lines in Path 48. Purple lines represent transmission lines in Path 47. Black and grey colored lines represent transmission that is external to that of Path 47 or Path 48. Assets within each path comprise a combination of PNM and non-PNM owned lines and/or stations. Any transaction that takes place on the PNM system with neighboring systems is bound by the operation of these paths.

PNM's capacity in Path 47 and Path 48 is fully committed to existing firm resources and expansion of the transmission system must be factored into the siting of additional remote resources. Resources located on the load side within Path 47 or Path 48 usually help or enhance the operation of these paths by providing a local resource at the load center. When the load increases and Path 48 approaches its import limit, these additional resources can be dispatched to support the system from within a path.

Siting, permitting, cost and construction timelines for new transmission line projects will continue to be a challenge. The use of load-side generation will continue to play a role in supporting the system and alleviating transmission constraints barring any future barriers to this type of operating practice.

Figure 2-Q: WECC Path 47 and 48



Note: For complete path information, consult the WECC Path Ratings catalogue.

NORTHERN NEW MEXICO TRANSMISSION SYSTEM

The northern New Mexico transmission system includes the WECC rated Path 48. This system delivers power to serve PNM's customer loads in northern New Mexico including the Albuquerque, Santa Fe, and Las Vegas areas, as well as load areas in Valencia County south of the city of Albuquerque. As previously mentioned, 89% of

EXHIBIT NMM-15A

EXHIBIT NMM-15A

Statements showing that SunZia will not now interconnect with Path 47 and the electrical grid in southwestern New Mexico. Also, SunZia will build only a single transformer at its interconnection point with Tucson Electric Power Company's 345-kilovolt lines at the Willow substation. The second line will not be interconnected. From *SunZia Path Rating Re-Study Report Due to the Modified Plan of Service, Volume 1 – Main Report, Final Version*, Prepared by the Western Electricity Coordinating Council SunZia Project Review Group, September 25, 2014. Redacted version provided by SunZia.

SunZia Path Rating Re-Study Report

I. EXECUTIVE SUMMARY

SunZia Southwest Transmission Project (SunZia or the Project) is a major new 500 kilovolt (kV) participation transmission project that is envisioned to provide additional transmission interconnections and 3,000 MW of transmission capacity between central New Mexico and central Arizona. SunZia would enable the development of renewable energy resources by creating access to the interstate power grid across the Southwest.

On December 15, 2006, SouthWestern Power Group (SWPG) submitted a notification letter to WECC Planning Coordination Committee (PCC) and Technical Studies Subcommittee (TSS) formally initiating the Regional Planning Project Review (now known as the Project Coordination Review process) process for SunZia. To achieve Phase 1 status in accordance with the WECC Three Phase Path Rating Process, a Regional Planning Compliance Report was submitted to PCC and TSS on May 17, 2007. On July 12, 2007, PCC accepted the SunZia regional planning compliance report as complete.

In compliance with the WECC Procedure for a Project Rating, a Comprehensive Progress Report (CPR) was submitted to WECC on April 22, 2009 and subsequently Phase 2 status was granted by PCC and TSS on July 27, 2009.

On August 27, 2009, SWPG formed a WECC SunZia Project Review Group (PRG) to proceed and review the Phase 2 Path Rating Study. The study included validation of the plan of service (POS) for non-simultaneous transfer conditions and evaluation of the possible interactions with other WECC major paths. In addition, the assessment of SunZia transmission alternatives and various system variables were included. The PRG prepared the final SunZia Accepted Path Rating Phase 2 Study Report (Report) and submitted it on February 22, 2011 to WECC PCC, TSS and OC for a 30-day review. On March 25, 2011, the SunZia Project was granted Phase 3 status and a 3000MW rating by the PCC Chair.

The BLM Final Environmental Impact Statement (FEIS) was issued during June 2013. A change in the BLM's Preferred Alternative changed the interconnection opportunities in New Mexico and necessitated a reexamination of the technical aspects of the Project. Subsequently in September, Southline and El Paso Electric Company (EPE) raised an issue related to a potential POS change (i.e. Luna interconnection) and concerns of the Path 47 simultaneous impacts and other potential WECC path simultaneous impacts. The original POS included an interconnection at the Luna Substation. Due to the changes in the BLM Preferred Alternative and concerns expressed by EPE and other SunZia PRG members with direct connections to the Luna or Hidalgo substations, the revised POS does not include any intermediate interconnections in NM at this time and one intermediate interconnection station in southeast Arizona:

Willow 500 kV Substation would be located near the planned Willow 345 kV Substation, with one 500/345 kV transformer (Normal Rating=725MVA and Emergency Rating=835MVA).

Owing to this SunZia Path modification based on the interconnection changes, in particular for a modified interconnection plan and facilities that are not part of WECC Path 47 which result in the simultaneous impact on Path 47 different to the original Plan of Service (POS) included in

REDACTED

SunZia Southwest Transmission Project

SunZia Path Rating Re-Study Report Due to the Modified Plan of Service

Volume 1- Main Report

Final Version

Prepared By

The Western Electricity Coordinating Council
SunZia Project Review Group

September 25, 2014

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SunZia Path Rating Re-Study Report

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Owing to this SunZia Path modification based on the interconnection changes, in particular for a modified interconnection plan and facilities that are not part of WECC Path 47 which result in the simultaneous impact on Path 47 different to the original Plan of Service (POS) included in

the WECC Accepted Rating Report, it is necessary to evaluate whether the Project's modified plan of service can achieve a 3,000 MW on the SunZia Path simultaneously with the existing WECC Path 47 at its maximum rating of 1,048 MW, or whether the modified POS would cause incremental impacts on other Accepted WECC Paths not examined with the original POS.

As a result, on November 14, 2013 SunZia reconvened the PRG and held Meeting #1. The last PRG meeting was held previously on November 16, 2010. The purpose of PRG Meeting #1 was to discuss the need for Path 47 and other WECC paths' simultaneous impact studies due to SunZia's modified POS that no longer required an interconnection to Path 47. There was a general consensus to revisit and conduct a necessary SunZia path rating study to reaffirm the rating that was established in 2011. PRG Meeting #2 was held on February 13, 2014 to present and discuss the Project's status and preliminary Path 47 simultaneous study results.

To perform the Re-Study, a 2017 heavy summer pre-project benchmark base case reviewed by the PRG and at the Accepted Path 47 maximum level was developed to establish the base line. SunZia performed selected technical analyses to recalibrate and determine the modified SunZia Path Rating. The analysis consists of power flow, transient stability and post-transient studies under PRG guidance while ensuring applicable North American Electric Reliability Corporation (NERC) Reliability Standards, WECC Planning Standards and Performance Criteria and regional Arizona and New Mexico planning requirements (hereafter jointly referred to as the "Criteria") were met for contingencies.

Summaries of the SunZia modified POS requirements for the non-simultaneous, along with each of the simultaneous analyses are presented in Table 1 below. A non-simultaneous rating study was not included in the original study plan. However, it was included due to the need for the 10% Flow Test reference purpose for supporting information. This was also requested to be included by BPA. The reactive requirements identified in the SunZia POS will be optimized through continued study work to be performed during Phase 3 of the rating process for SunZia. Additionally, an evaluation of the physical feasibility of the renewable generation facilities and the reactive support equipment needs to be performed. Such evaluation involves working with the equipment vendors and the utilities on whose system the new facilities will be installed. This evaluation will be conducted in parallel with the Phase 3 study. It should be noted that a 400MVAR reactive requirement at SunZia East previously identified in the non-simultaneous analysis is required for all the simultaneous analyses. No additional reactive support other than this 400MVAR dynamic VAR compensator in the non-simultaneous analysis is required in order to meet dynamic stability criteria. This requirement will continue to be examined as the planned resources directly connected to SunZia are more defined.

Table I-1

Modified SunZia Plan of Service Summary [A]

Analysis	Total-Reactive Support (MVAR) [B]	Nomogram	Operating Procedure	SPS
Non-Simultaneous	400	No	Yes [C]	Yes [C]
Path 47	400	No	Yes [C]	Yes [C]
Path 66	400	Yes [D]	Yes [C]	Yes [C]
Path 14	400	Yes [D]	Yes [C]	Yes [C]
Path TOT2B+2C	400	Yes D	Yes C	Yes C

A: All analyses assume the following core POS elements:

1. Construct two new SunZia East-Willow500 kV-Pinal Central 500 kV lines with series compensation
2. One 500/345 kV transformer at the Willow 500 kV Substation

B: The reactive support level (SVC at SunZia East Substation) shown represents the total amount required with the assumed resources modeled at SunZia East.

C: An integrated mitigation plan is required involving nomograms, operating procedures and/or an SPS (to reduce or trip generation connected to SunZia to relieve limitation problems for certain N-1 and/or N-2 outages). The project was assumed to add 3,000 MW of generation resource at SunZia East Substation as a part of the planned facilities. Up to 3,000 MW of generation connected to SunZia may be required for tripping due to the double line outage. Load shedding is not required.

D: An operating nomogram and operating procedures are developed due to an extreme outage of SunZia double 500 kV lines to overcome the simultaneous interaction effects on Path 66 (COI) and Path 14 without utilization of the Northwest FACRI scheme; no nomogram was required with the utilization of the FACRI scheme.

For a comparison, the Original and the Modified POS are described below. Tables 2A and 2B show a summary of non-simultaneous and simultaneous transfer levels that are achievable and the necessary power flow, transient stability and post-transient nomogram limits were compared with the SunZia Original and the Modified POS.

TABLE I-2A: Summary of Achievable Transfers with the Original SunZia POS

Category B N-1	Path Rating (MW)	SUNZIA Path Rating (MW)	SUNZIA Generation Tripping Due to Thermal Nomogram Limits (MW)	SUNZIA Generation Tripping Due to Stability Operating Nomogram Limits (MW)	SUNZIA Generation Tripping Due to Post-Transient Operating Nomogram Limits (MW)
Non Simultaneous		3,000	(1) 400 Trip	(2) 1500 Trip (3) 500 Trip	(2) 1500 Trip (3) 500 Trip
Path 47 Footnote A	1,048	3,000	No Additional	No Additional	No Additional
Path 66	4,800	3,000	No Additional	No Additional	No Additional
Category C N-2 Footnote B	**Path Rating (MW)**	**SUNZIA Path Rating (MW)**	**SUNZIA Generation Tripping Due to Thermal Nomogram Limits (MW)**	**SUNZIA Generation Tripping Due to Stability Operating Nomogram Limits (MW)**	**SUNZIA Generation Tripping Due to Post-Transient Operating Nomogram Limits (MW)**
Non-Simultaneous		3,000	(4) 3000 Trip (5) 2000 Trip (6) 2500 Trip	(4) 3000 Trip (5) 2000 Trip (6) 1500 Trip	(4) 3000 Trip (5) 2000 Trip (6) 1500 Trip

III. PROJECT DESCRIPTION AND MODIFIED PLAN OF SERVICE

The Modified POS (MPOS) as determined from the study is provided below:

- Build the two new SunZia East-SunZia South 500 kV AC lines (230 miles each) with 70% series compensation located at SunZia South, no interconnection to the adjacent 345 kV transmission system.
- Build the two new SunZia South-Willow 500 kV AC lines (124 miles each) with 50% series compensation located at the new Willow 500 kV Substation with one 500/345 kV transformer.
- Build the two new 500 kV AC lines from the proposed Willow 500 kV Substation to the Pinal Central Substation (161 miles each) with 50% series compensation.
- Shunt Compensation as required.

The following discussion points out the differences in SunZia's interconnection to the 345kV system in New Mexico and Arizona between the original plan of service and the modified plan of service:

Original Plan of Service:

- SunZia South 500 kV Substation with two 500/345 kV transformers 8.24% impedance (on a 360MVA base each) (rated at 672MVA normal and 806MVA emergency) to interconnect with the Luna 345 kV substation
- Willow 500 kV Substation with two 500/345 kV transformers 8.24% impedance (on a 360MVA base each) transformers (rated at 672MVA normal and 806MVA emergency) to interconnect to the proposed Willow 345 kV substation
- Shunt Compensation as required.

Modified Plan of Service:

- SunZia South (a.k.a. Midpoint) 500kV Substation series capacitor station only (no interconnection to the underlying 345kV system)
- Willow 500 kV Substation with one 500/345 kV transformers 15.72% impedance (362MVA base) (rated at 725MVA normal and 835MVA emergency) to interconnect to the Willow 345 kV substation
- Shunt Compensation as required.

Figure 1 below provides a geographical and electrical overview of the extra high voltage (EHV) transmission system in the Southeastern Arizona, New Mexico and the SunZia Project Transmission Path, as shown in the dash line.

Figure 1: Arizona and New Mexico EHV system

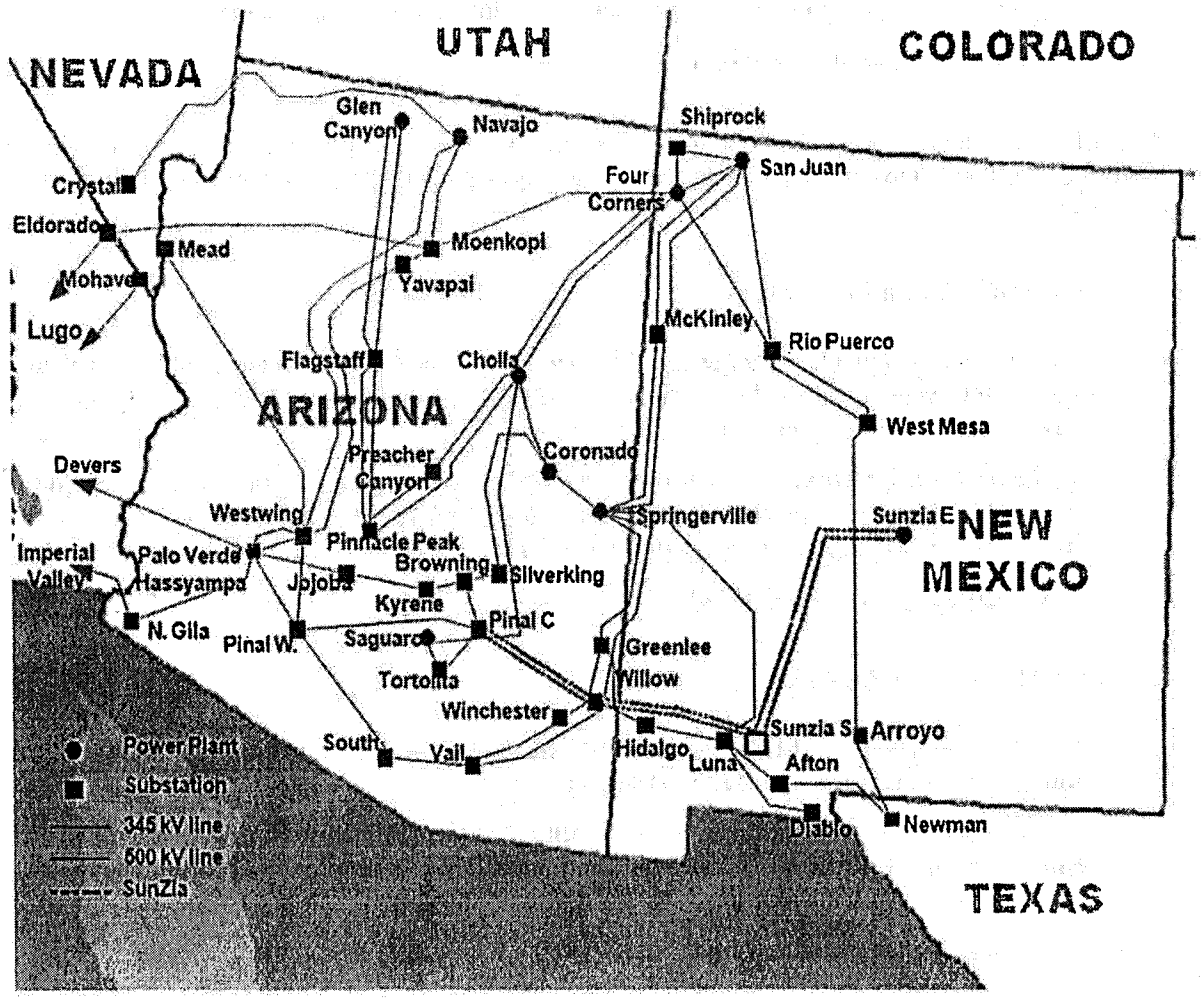


EXHIBIT NMM-16

EXHIBIT NMM-16

A measure of the congestion on Path 47 by using the 75% and 90% utilization levels. Path 47 is not congested or overused in terms of power delivery. Page 18 from Western Electricity Coordinating Council Staff, *2013 WECC Path Reports*, September 4, 2013. Available at https://www.wecc.biz/Reliability/TAS_PathReports_Combined_FINAL.pdf. Accessed October 11, 2015.

Figure 10: 2010 Flow U75 for All Paths - All Hours and Seasonal

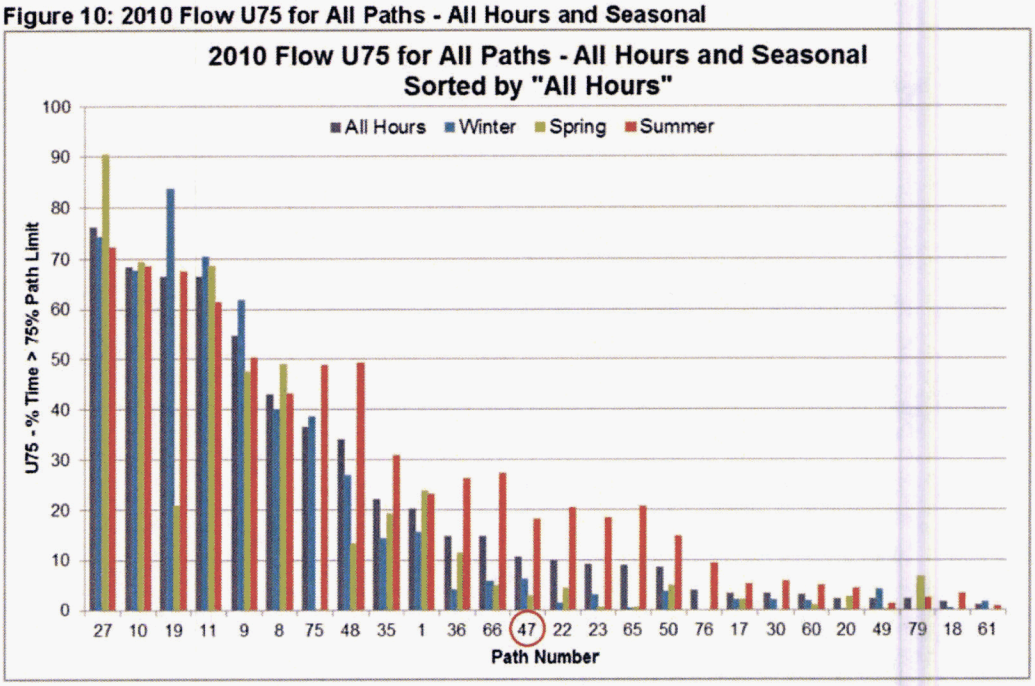


Figure 11: 2010 Flow U90 for All Paths - All Hours and Seasonal

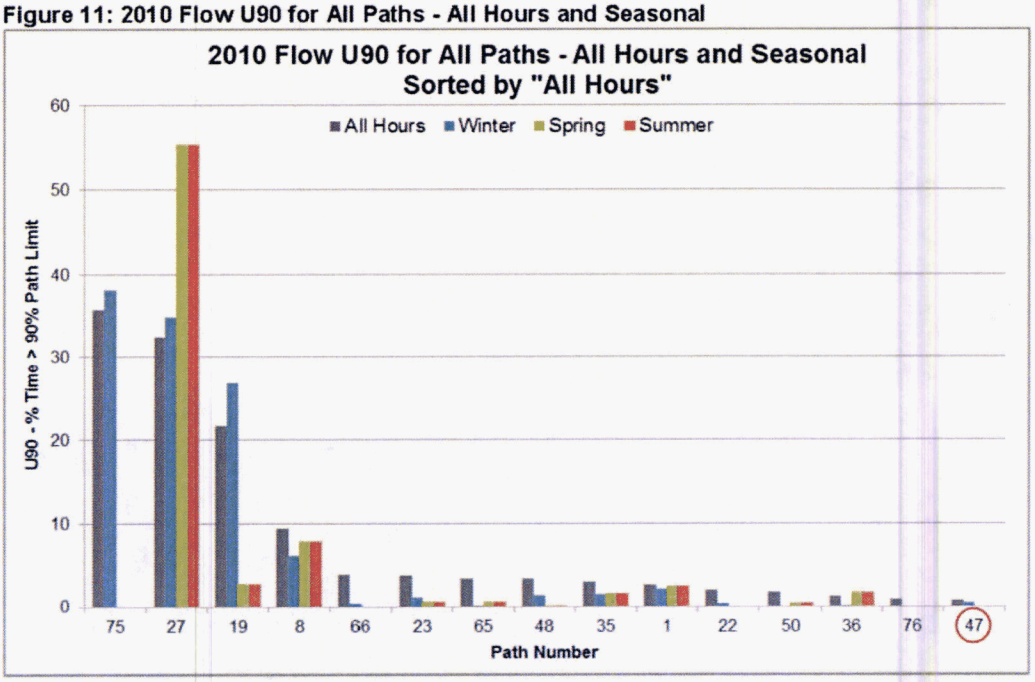


EXHIBIT NMM-17

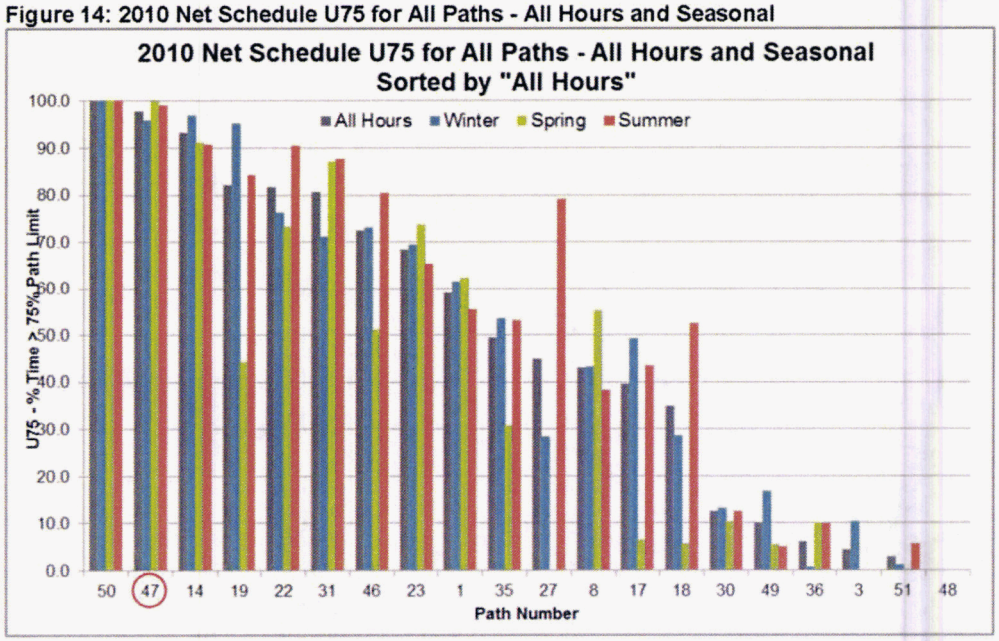
EXHIBIT NMM-17

A measure of congestion on Path 47 in southwestern New Mexico using scheduling. El Paso Electric consistently schedules far more transmission capacity than is needed to meet the El Paso load, which removes capacity that could be freed for the market. The path has no difficulty meeting the actual demand for power, however. Page 21 from *2013 WECC Path Reports*.

Table 9: 2010 Path Congestion Ranking Based on Net Schedule U75 – Sorted by "All Hours"

Path #	Path Name	U75 Net Schedule			
		All Hours	Winter	Spring	Summer
50	Cholla - Pinnacle Peak	100	100	100	100
47	Southern New Mexico (NM1)	98	96	100	99
14	Idaho - Northwest	93	97	91	91
19	Bridger West	82	95	44	84
22	Southwest of Four Corners	82	76	73	90
31	TOT 2A	81	71	87	88
46	West of Colorado River (WOR)	72	73	51	80
23	Four Corners 345/500	68	69	74	65
1	Alberta - British Columbia	59	61	62	55
35	TOT 2C	49	53	31	53
27	IPP DC Line	45	28	0	79
8	Montana - Northwest	43	43	55	38
17	Borah - West	40	49	6	43
18	Idaho - Montana	35	29	6	52
30	TOT 1A	12	13	10	12
49	East of Colorado River (EOR)	10	17	5	5
36	TOT 3	6	1	10	10
3	Northwest - Canada	4	10	0	0
51	Southern Navajo	3	1	0	6
48	Northern New Mexico (NM2)	0	0	0	0

Figure 14: 2010 Net Schedule U75 for All Paths - All Hours and Seasonal



2013 WECC Path Reports

By

WECC Staff

Western Electricity Coordinating Council

September 4, 2013

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Historical Congestion

The utilization metrics were used to compare flow, schedule and ATC on the paths. U75 and U90 values were calculated for all hours of the year and seasonally for flow, schedule and ATC. In addition, U75 and U90 were calculated for flow values based on heavy and light load hours. Where possible, the OTC value was used in the Uxx metric calculation; however, in some cases another value had to be substituted, either the opposite of the primary OTC or the path rating. Table 4 lists each of the paths for which Uxx metrics were calculated and the limit value used for the Uxx calculation. Where used, the path rating value represents the path rating in 2010. It is important to keep in mind the path limit value used for each path when viewing the comparative results because a change in the path limit value used, e.g., from OTC to path rating, can dramatically alter the path Uxx.

Table 4: Limit data Used for Uxx Metric Calculation

	Primary OTC	Secondary OTC
Path 1	OTC	OTC
Path 3	Path Rating	Path Rating
Path 8	OTC	OTC
Path 9	OTC	(-) Primary OTC
Path 10	OTC	(-) Primary OTC
Path 11	OTC	OTC
Path 14	OTC	OTC
Path 16	Path Rating	Path Rating
Path 17	OTC	(-) Primary OTC
Path 18	Path Rating	Path Rating
Path 19	OTC	(-) Primary OTC
Path 20	OTC	OTC
Path 22	OTC	(-) Primary OTC
Path 23	OTC	OTC
Path 27	OTC	OTC
Path 29	OTC	(-) Primary OTC
Path 30	OTC	(-) Primary OTC
Path 31	OTC	OTC
Path 35	Path Rating	Path Rating
Path 36	OTC	(-) Primary OTC
Path 42	Path Rating	Path Rating
Path 46	OTC	(-) Primary OTC
Path 47	OTC	(-) Primary OTC
Path 48	OTC	OTC
Path 49	OTC	(-) Primary OTC
Path 50	OTC	(-) Primary OTC
Path 51	OTC	OTC
Path 52	OTC	(-) Primary OTC
Path 60	OTC	OTC
Path 61	Path Rating	Path Rating
Path 65	OTC	OTC
Path 66	OTC	OTC
Path 75	Path Rating	Path Rating
Path 76	OTC	OTC
Path 78	OTC	OTC
Path 79	OTC	OTC
Path 80	Path Rating	Path Rating

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Flow-Based Congestion Analysis

Table 5 and Table 6 present the 20 most congested paths based on U75 and U90 flow values calculated for all hours in 2010.

Table 5: 20 Most Congestion Paths Based on Flow U75 for All Hours in 2010

Path #	Path Name	U75 All Hours
27	IPP DC Line	76.1
10	West of Coalstrip	68.3
19	Bridger West	66.4
11	West of Crossover	66.4
9	West of Broadview	54.6
8	Montana - Northwest	42.9
75	Midpoint - Summer Lake	36.5
48	Northern New Mexico (NM2)	34.1
35	TOT 2C	22.1
1	Alberta - British Columbia	20.1
36	TOT 3	14.7
66	COI	14.7
52	Silver Peak-Control 55 kV	0.4
47	Southern New Mexico (NM1)	10.7
22	Southwest of Four Corners	9.9
23	Four Corners 345/500	9.1
65	Pacific DC Intertie	8.8
50	Cholla - Pinnacle Peak	8.5
76	Alturas Project	3.9
17	Borah - West	3.3

Table 6: 20 Most Congestion Paths Based on Flow U90 for All Hours in 2010

Path #	Path Name	U90 All Hours
75	Midpoint - Summer Lake	35.7
27	IPP DC Line	32.4
19	Bridger West	21.6
52	Silver Peak-Control 55 kV	0.0
8	Montana - Northwest	9.3
66	COI	3.8
23	Four Corners 345/500	3.8
65	Pacific DC Intertie	3.4
48	Northern New Mexico (NM2)	3.3
35	TOT 2C	3.0
1	Alberta - British Columbia	2.6
22	Southwest of Four Corners	2.0
50	Cholla - Pinnacle Peak	1.7
36	TOT 3	1.2
76	Alturas Project	0.8
47	Southern New Mexico (NM1)	0.6
20	Path C	0.5
9	West of Broadview	0.3
17	Borah - West	0.3
30	TOT 1A	0.3

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Table 7 presents the path ranking according to path U75 values calculated by season. Most of the paths with the highest U75 values in Table 5 also have high values in Table 7; however, the ranking of those values shifts depending on season.

Table 7: 2010 Path Congestion Ranking Based on Seasonal Flows

Winter			Spring			Summer		
Path #	U75	U90	Path #	U75	U90	Path #	U75	U90
19	83.8	26.8	27	90.4	55	27	72.3	55.3
27	74.3	34.9	10	69.3	0	10	68.5	0.0
11	70.4	0.0	11	68.6	0	19	67.4	2.7
10	67.7	0.0	8	49.0	8	11	61.5	0.0
9	61.8	0.2	9	47.7	0	9	50.3	0.1
8	40.1	6.1	1	23.8	2	48	49.3	0.1
75	38.7	38.1	19	20.9	3	75	48.9	0.0
48	27.0	1.4	35	19.2	2	8	43.3	7.9
1	15.6	2.0	48	13.3	0	35	31.0	1.6
35	14.3	1.5	36	11.5	2	66	27.4	0.0
47	6.2	0.4	79	6.6	0	36	26.4	1.7
66	5.8	0.4	50	4.8	0	1	23.1	2.5
36	4.2	0.0	66	4.8	0	65	20.6	0.5
49	4.1	0.0	22	4.3	0	22	20.5	0.0
50	3.7	0.0	47	2.9	0	23	18.3	0.5
23	3.1	1.1	20	2.6	0	47	18.2	0.0
30	2.0	0.2	78	2.3	0	50	14.7	0.4
17	1.9	0.0	17	2.0	0	76	9.3	0.0
60	1.8	0.2	31	1.4	0	30	5.7	0.0
61	1.7	0.0	14	1.2	0	17	5.2	0.4
22	1.4	0.4	60	0.9	0	60	4.9	0.4
3	0.6	0.0	23	0.6	1	20	4.3	0.2
31	0.5	0.2	65	0.6	1	18	3.3	0.0
46	0.4	0.0	29	0.4	0	79	2.5	0.3
65	0.3	0.0	16	0.3	0	49	1.3	0.0
18	0.2	0.0	49	0.1	0	61	0.8	0.0
20	0.1	0.1	75	0.1	0	52	0.7	0.0
52	0.1	0.0	52	0.0	0	31	0.4	0.0
78	0.1	0.1	3	0.0	0	3	0.4	0.0
29	0.0	0.0	18	0.0	0	14	0.3	0.0
14	0.0	0.0	30	0.0	0	29	0.3	0.3
16	0.0	0.0	42	0.0	0	16	0.2	0.0
42	0.0	0.0	46	0.0	0	46	0.0	0.0
51	0.0	0.0	51	0.0	0	42	0.0	0.0
76	0.0	0.0	61	0.0	0	51	0.0	0.0
79	0.0	0.0	76	0.0	0	78	0.0	0.0
80	0.0	0.0	80	0.0	0	80	0.0	0.0

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Figure 10 shows the U75 flow values for all hours and seasonally. Paths with a U75 value of less than one in all four categories (all hours, winter, spring, and summer) are not shown. Figure 11 shows the same analysis for the U90 metric, and paths with a U90 value of zero in all four categories are not shown.

Figure 10: 2010 Flow U75 for All Paths - All Hours and Seasonal

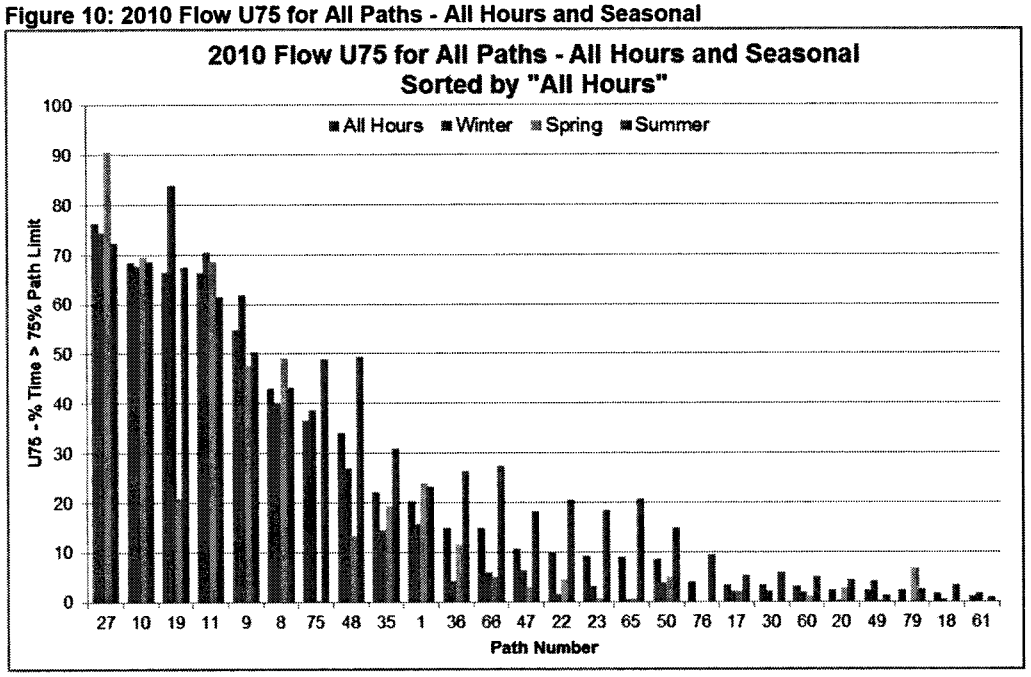

Figure 11: 2010 Flow U90 for All Paths - All Hours and Seasonal

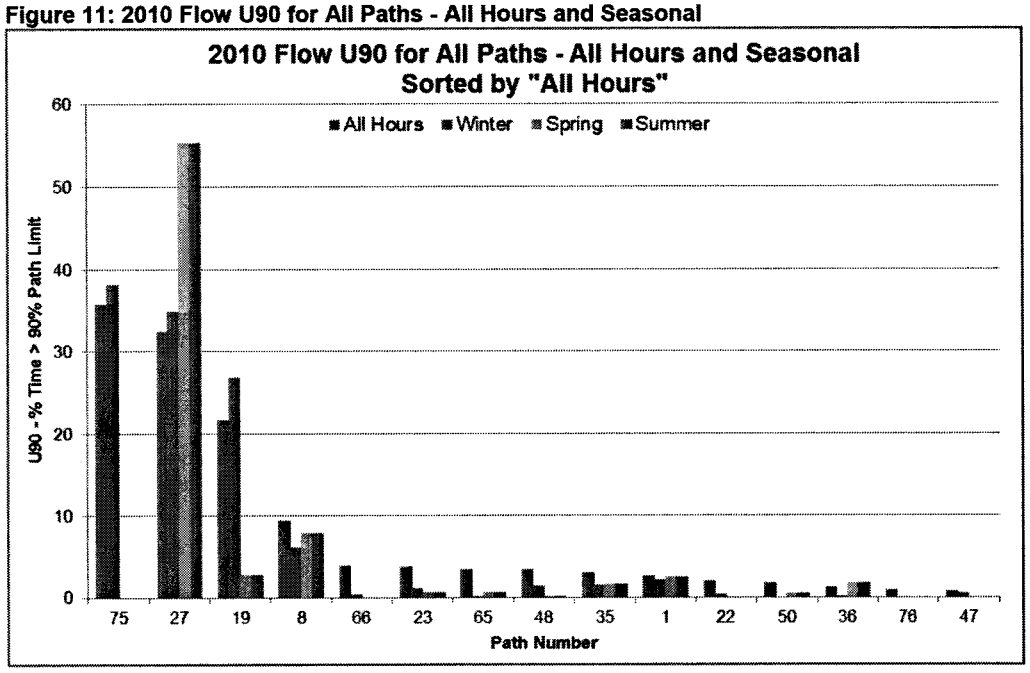

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Table 8 presents the path ranking according to path U75 and U90 values calculated by heavy and light load hour blocks. Like the seasonal analysis, most of the top ranking paths from Table 5 also have high U75 values in the heavy and light load hours analysis in Table 8. The same information is shown graphically in Figure 12 (U75) and Figure 13 (U90). Paths with a U75 or U90 value of zero in all four categories (all hours, winter, spring, and summer) are not shown.

Table 8: 2010 Path Congestion Ranking Based on Flow for Heavy and Light Load Hours

Heavy			Light		
Path #	U75	U90	Path #	U75	U90
27	77.6	33.2	27	74.2	31.4
10	71.9	0.0	19	68.4	25.9
11	67.7	0.0	11	64.6	0.0
19	64.9	18.4	8	64.0	19.4
48	50.1	5.7	10	63.4	0.0
9	49.7	0.1	9	61.2	0.6
75	35.2	34.0	75	38.3	37.8
8	27.2	1.4	35	23.5	3.3
1	24.9	3.2	47	19.2	1.4
35	21.1	2.7	1	15.6	5.6
36	18.8	1.9	48	12.7	0.2
66	18.6	4.9	22	12.0	2.4
65	10.7	4.2	50	10.0	1.6
23	8.6	4.4	23	9.7	2.9
22	8.3	1.7	66	9.5	2.3
50	7.4	1.7	36	9.3	0.3
47	4.2	0.1	65	7.6	3.7
76	3.3	0.4	17	5.9	0.8
20	3.2	0.7	30	4.7	0.4
49	3.2	0.0	76	4.6	1.3
79	2.5	0.1	60	3.8	0.1
18	2.4	0.2	79	1.6	0.0
60	2.3	0.3	20	1.1	0.2
30	2.1	0.1	14	1.0	0.5
61	1.5	0.0	49	0.9	0.0
17	1.4	0.0	61	0.5	0.0
31	1.0	0.2	18	0.2	0.0
3	0.6	0.1	78	0.2	0.0
78	0.6	0.0	16	0.2	0.0
29	0.3	0.3	3	0.1	0.0
14	0.3	0.0	46	0.1	0.0
46	0.2	0.0	31	0.1	0.0
16	0.1	0.0	52	0.0	0.0
52	0.0	0.0	29	0.0	0.0
42	0.0	0.0	42	0.0	0.0
51	0.0	0.0	51	0.0	0.0
80	0.0	0.0	80	0.0	0.0

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Figure 12: 2010 Flow U75 for All Paths - All Hours, Heavy and Light Load

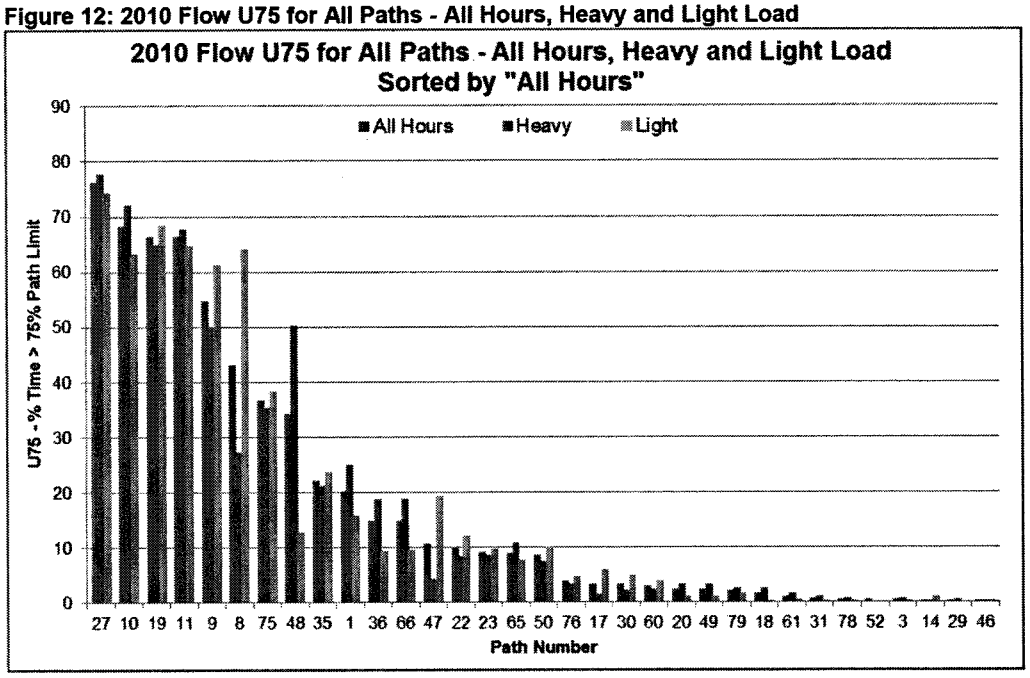
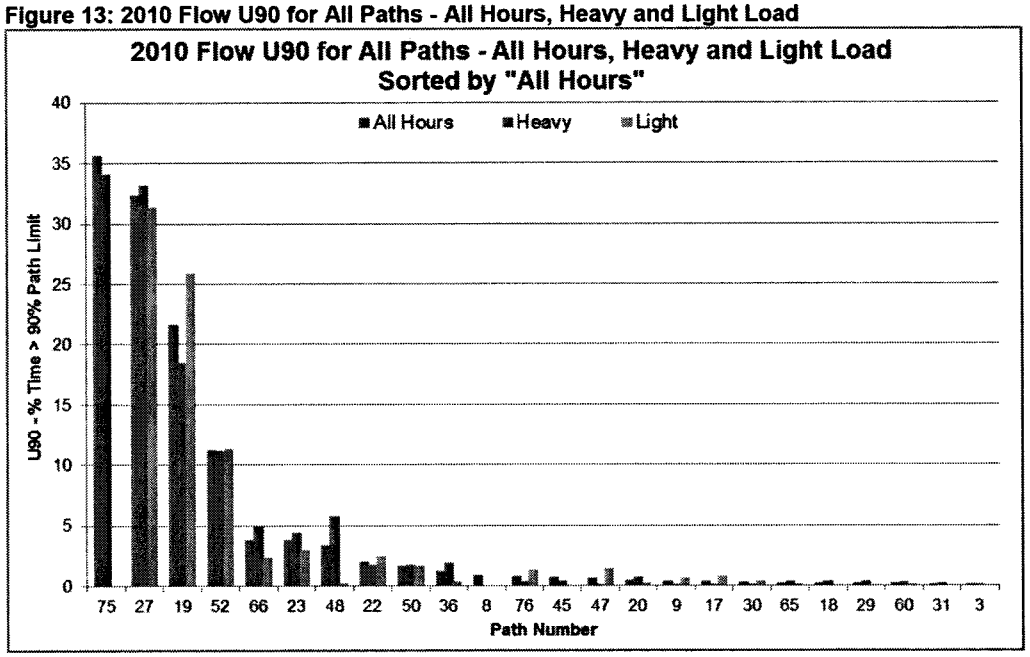


Figure 13: 2010 Flow U90 for All Paths - All Hours, Heavy and Light Load



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Schedule-Based Congestion Analysis

Table 9 presents the path ranking by net schedule U75 value. Schedule data was available for only 20 paths. Figure 14 presents the same data graphically.

Table 9: 2010 Path Congestion Ranking Based on Net Schedule U75 – Sorted by "All Hours"

Path #	Path Name	U75 Net Schedule			
		All Hours	Winter	Spring	Summer
50	Cholla - Pinnacle Peak	100	100	100	100
47	Southern New Mexico (NM1)	98	96	100	99
14	Idaho - Northwest	93	97	91	91
19	Bridger West	82	95	44	84
22	Southwest of Four Corners	82	76	73	90
31	TOT 2A	81	71	87	88
46	West of Colorado River (WOR)	72	73	51	80
23	Four Corners 345/500	68	69	74	65
1	Alberta - British Columbia	59	61	62	55
35	TOT 2C	49	53	31	53
27	IPP DC Line	45	28	0	79
8	Montana - Northwest	43	43	55	38
17	Borah - West	40	49	6	43
18	Idaho - Montana	35	29	6	52
30	TOT 1A	12	13	10	12
49	East of Colorado River (EOR)	10	17	5	5
36	TOT 3	6	1	10	10
3	Northwest - Canada	4	10	0	0
51	Southern Navajo	3	1	0	6
48	Northern New Mexico (NM2)	0	0	0	0

Figure 14: 2010 Net Schedule U75 for All Paths - All Hours and Seasonal

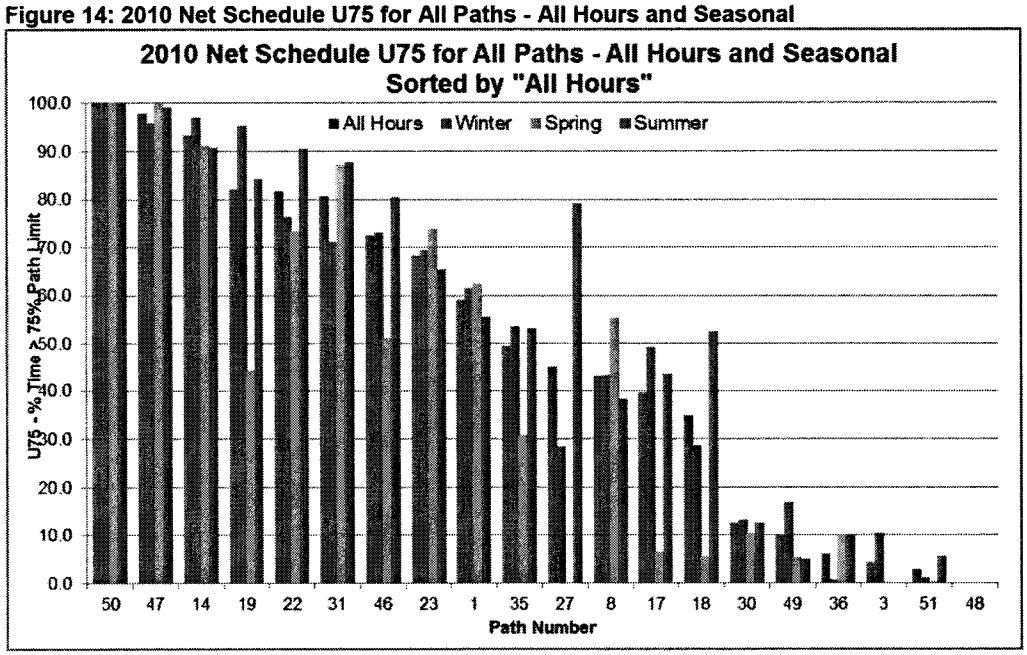

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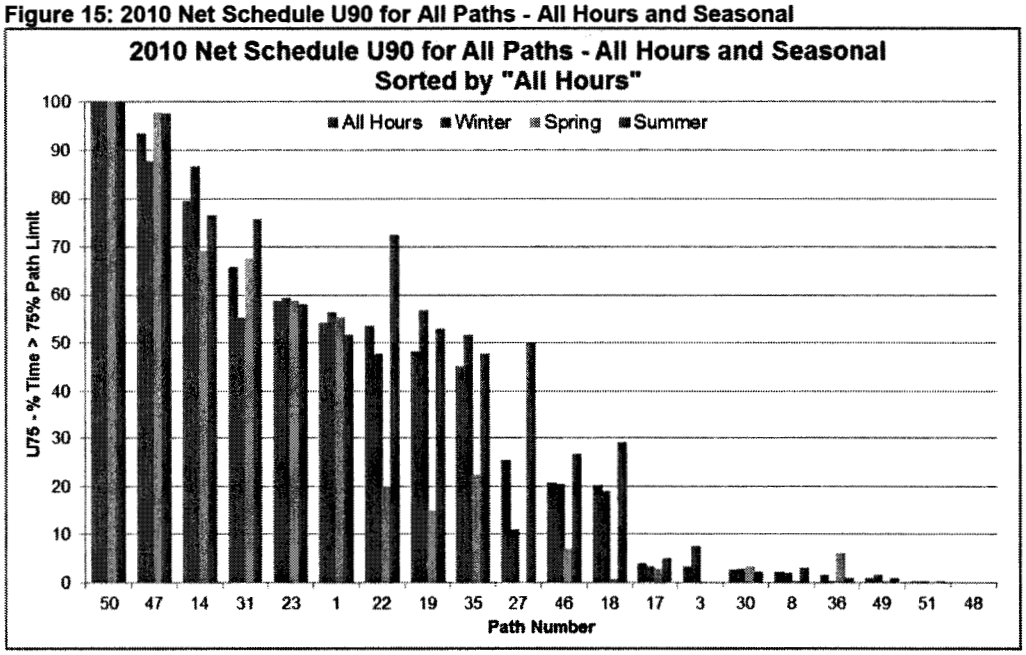
Table 10 presents the path ranking by net schedule U90 value. Figure 15 presents the Net Schedule U90 metric for all paths by all hours and seasonal hours.

Table 10: 2010 Path Congestion Ranking Based on Net Schedule U90 – Sorted by "All Hours"

Path #	Path Name	U90 Net Schedule			
		All Hours	Winter	Spring	Summer
50	Cholla - Pinnacle Peak	100	100	100	100
47	Southern New Mexico (NM1)	93	88	98	97
14	Idaho - Northwest	79	86	69	76
31	TOT 2A	66	55	67	76
23	Four Corners 345/500	59	59	59	58
1	Alberta - British Columbia	54	56	55	52
22	Southwest of Four Corners	53	48	20	72
19	Bridger West	48	57	15	53
35	TOT 2C	45	51	22	48
27	IPP DC Line	25	11	0	50
46	West of Colorado River (WOR)	21	20	7	27
18	Idaho - Montana	20	19	1	29
17	Borah - West	4	3	3	5
3	Northwest - Canada	3	8	0	0
30	TOT 1A	3	3	3	2
8	Montana - Northwest	2	2	0	3
36	TOT 3	1	0	6	1
49	East of Colorado River (EOR)	1	1	0	1
51	Southern Navajo	0	0	0	0
48	Northern New Mexico (NM2)	0	0	0	0

Figure 15: 2010 Net Schedule U90 for All Paths - All Hours and Seasonal



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ATC-Based Congestion Analysis

Table 11 presents the path ranking by ATC U75 value. The utilization metric takes on a slightly different significance when applied to historical ATC data because it represents the amount of ATC offered at least 75 percent of the time. The ATC value includes firm and non-firm ATC in both primary and secondary directions.

Table 11: 2010 Path Congestion Ranking Based on ACT U75 – Sorted by "All Hours"

Path #	Path Name	U75 ATC (total net)			
		All Hours	Winter	Spring	Summer
3	Northwest - Canada	100	100	100	100
18	Idaho - Montana	100	100	100	100
35	TOT 2C	100	100	100	100
48	Northern New Mexico (NM2)	100	100	100	100
50	Cholla - Pinnacle Peak	100	100	100	100
51	Southern Navajo	100	100	100	100
47	Southern New Mexico (NM1)	100	100	100	100
22	Southwest of Four Corners	100	100	100	100
49	East of Colorado River (EOR)	99	100	97	100
65	Pacific DC Intertie	94	98	97	90
1	Alberta - British Columbia	92	91	100	91
19	Bridger West	80	78	95	77
17	Borah - West	80	85	92	69
66	COI	6	12	4	1
8	Montana - Northwest	0	0	0	0
46	West of Colorado River (WOR)	0	0	0	0
14	Idaho - Northwest	0	0	0	0
27	IPP DC Line	0	0	0	0
30	TOT 1A	0	0	0	0
31	TOT 2A	0	0	0	0
36	TOT 3	0	0	0	0

Results of U75 and U90 congestion metric calculations for year 2010 for flow, net schedules, and ATC are shown in the following tables. Table 12 shows the 2010 U75 and U90 flow values for all hours of the year, winter, spring, summer, heavy load, and light load hours. Table 13 shows the 2010 U75 and U90 schedule values for all hours of the year and seasonal hours. Table 14 shows the 2010 U75 and U90 ATC values for all hours of the year and seasonal hours.

Table 12: 2010 Flow U75 and U90 Values - All Hours, Seasonal, and Heavy/Light Load Hours

Path	All Hrs.		Winter		Spring		Summer		Heavy		Light	
#	U75	U90	U75	U90	U75	U90	U75	U90	U75	U90	U75	U90
1	20.1	2.6	15.6	2.0	23.8	2.5	23.1	2.5	24.9	3.2	15.6	5.6
3	0.4	0.1	0.6	0.0	0.0	0.0	0.4	0.0	0.6	0.1	0.1	0.0
8	42.9	9.3	40.1	6.1	49.0	7.9	43.3	7.9	27.2	1.4	64.0	19.4
9	54.6	0.3	61.8	0.2	47.7	0.1	50.3	0.1	49.7	0.1	61.2	0.6
10	68.3	0.0	67.7	0.0	69.3	0.0	68.5	0.0	71.9	0.0	63.4	0.0
11	66.4	0.0	70.4	0.0	68.6	0.0	61.5	0.0	67.7	0.0	64.6	0.0
14	0.3	0.0	0.0	0.0	1.2	0.0	0.3	0.0	0.3	0.0	1.0	0.5
16	0.1	0.0	0.0	0.0	0.3	0.0	0.2	0.0	0.1	0.0	0.2	0.0
17	3.3	0.3	1.9	0.0	2.0	0.4	5.2	0.4	1.4	0.0	5.9	0.8

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18	1.5	0.1	0.2	0.0	0.0	0.0	3.3	0.0	2.4	0.2	0.2	0.0
19	66.4	21.6	83.8	26.8	20.9	2.7	67.4	2.7	64.9	18.4	68.4	25.9
20	2.3	0.5	0.1	0.1	2.6	0.2	4.3	0.2	3.2	0.7	1.1	0.2
22	9.9	2.0	1.4	0.4	4.3	0.0	20.5	0.0	8.3	1.7	12.0	2.4
23	9.1	3.8	3.1	1.1	0.6	0.5	18.3	0.5	8.6	4.4	9.7	2.9
27	76.1	32.4	74.3	34.9	90.4	55.3	72.3	55.3	77.6	33.2	74.2	31.4
29	0.2	0.2	0.0	0.0	0.4	0.3	0.3	0.3	0.3	0.3	0.0	0.0
30	3.2	0.3	2.0	0.2	0.0	0.0	5.7	0.0	2.1	0.1	4.7	0.4
31	0.6	0.1	0.5	0.2	1.4	0.0	0.4	0.0	1.0	0.2	0.1	0.0
35	22.1	3.0	14.3	1.5	19.2	1.6	31.0	1.6	21.1	2.7	23.5	3.3
36	14.7	1.2	4.2	0.0	11.5	1.7	26.4	1.7	18.8	1.9	9.3	0.3
42	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
46	0.2	0.0	0.4	0.0	0.0	0.0	0.0	0.0	0.2	0.0	0.1	0.0
47	10.7	0.6	6.2	0.4	2.9	0.0	18.2	0.0	4.2	0.1	19.2	1.4
48	34.1	3.3	27.0	1.4	13.3	0.1	49.3	0.1	50.1	5.7	12.7	0.2
49	2.2	0.0	4.1	0.0	0.1	0.0	1.3	0.0	3.2	0.0	0.9	0.0
50	8.5	1.7	3.7	0.0	4.8	0.4	14.7	0.4	7.4	1.7	10.0	1.6
51	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
52	0.4	0.0	0.1	0.0	0.0	0.0	0.7	0.0	0.0	0.0	0.0	0.0
60	3.0	0.2	1.8	0.2	0.9	0.4	4.9	0.4	2.3	0.3	3.8	0.1
61	1.1	0.0	1.7	0.0	0.0	0.0	0.8	0.0	1.5	0.0	0.5	0.0
65	8.8	3.4	0.3	0.0	0.6	0.5	20.6	0.5	10.7	4.2	7.6	3.7
66	14.7	3.8	5.8	0.4	4.8	0.0	27.4	0.0	18.6	4.9	9.5	2.3
75	36.5	35.7	38.7	38.1	0.1	0.0	48.9	0.0	35.2	34.0	38.3	37.8
76	3.9	0.8	0.0	0.0	0.0	0.0	9.3	0.0	3.3	0.4	4.6	1.3
78	0.4	0.0	0.1	0.1	2.3	0.0	0.0	0.0	0.6	0.0	0.2	0.0
79	2.1	0.1	0.0	0.0	6.6	0.3	2.5	0.3	2.5	0.1	1.6	0.0
80	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table 13: 2010 Net Schedule U75 and U90 Values - All Hours and Seasonal

Path #	All Hrs.		Winter		Spring		Summer	
	U75	U90	U75	U90	U75	U90	U75	U90
1	59.0	54.1	61.4	56.3	62.4	55.3	55.4	51.6
3	4.2	3.1	10.3	7.6	0.0	0.0	0.0	0.0
8	43.0	2.1	43.1	2.0	55.2	0.1	38.2	3.0
14	93.2	79.4	96.8	86.5	91.0	69.2	90.6	76.5
17	39.6	3.9	49.2	3.2	6.4	2.9	43.3	5.0
18	34.7	20.1	28.6	18.9	5.7	0.8	52.4	29.1
19	82.1	48.1	95.2	56.8	44.2	14.8	84.3	52.8
22	81.6	53.4	76.2	47.7	73.2	19.9	90.4	72.4
23	68.4	58.7	69.4	59.4	73.8	58.6	65.3	58.1
27	44.9	25.5	28.4	11.0	0.0	0.0	79.0	49.8
30	12.4	2.6	13.2	2.9	10.4	3.2	12.5	2.1
31	80.7	65.8	71.1	55.3	87.0	67.3	87.6	75.6
35	49.4	45.1	53.4	51.5	30.7	22.3	53.0	47.8
36	6.0	1.4	0.6	0.1	10.0	6.1	9.8	0.9
46	72.5	20.7	73.1	20.3	51.2	6.8	80.4	26.6
47	97.8	93.4	95.8	87.6	99.9	97.7	98.9	97.5
48	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
49	9.9	0.9	16.8	1.5	5.3	0.1	5.0	0.8
50	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
51	2.8	0.1	1.0	0.1	0.1	0.0	5.7	0.1

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Table 14: 2010 ATC U75 and U90 Values - All Hours and Seasonal

Path #	All Hrs.		Winter		Spring		Summer	
	U75	U90	U75	U90	U75	U90	U75	U90
1	92.3	90.3	90.5	88.8	100.0	99.7	91.0	88.2
3	100.0	99.9	100.0	100.0	100.0	99.8	100.0	99.7
8	0.2	0.0	0.0	0.0	0.0	0.0	0.5	0.0
14	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
17	79.6	36.5	84.9	38.4	92.1	72.3	69.4	20.4
18	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
19	80.5	13.4	78.4	17.2	94.9	28.5	76.7	3.7
22	99.9	93.5	99.9	98.4	100.0	95.0	99.8	88.0
27	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
30	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
31	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
35	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
36	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
46	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.0
47	100.0	100.0	100.0	100.0	100.0	100.0	99.9	99.9
48	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
49	99.3	98.5	99.6	99.6	96.8	93.1	99.9	99.5
50	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
51	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
65	94.4	94.4	98.0	98.0	97.1	97.1	89.8	89.8
66	6.0	3.1	11.8	6.3	4.3	0.8	1.0	0.7

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The same results are also shown geographically on the maps in Figure 16 and Figure 17 for the metrics U75 and U90. In these maps, the upper block beside each path represents the metric magnitude for flow and the bottom block represents the metric magnitude for the schedule in the direction of greatest magnitude.

Figure 16: Map with Path U75 Values

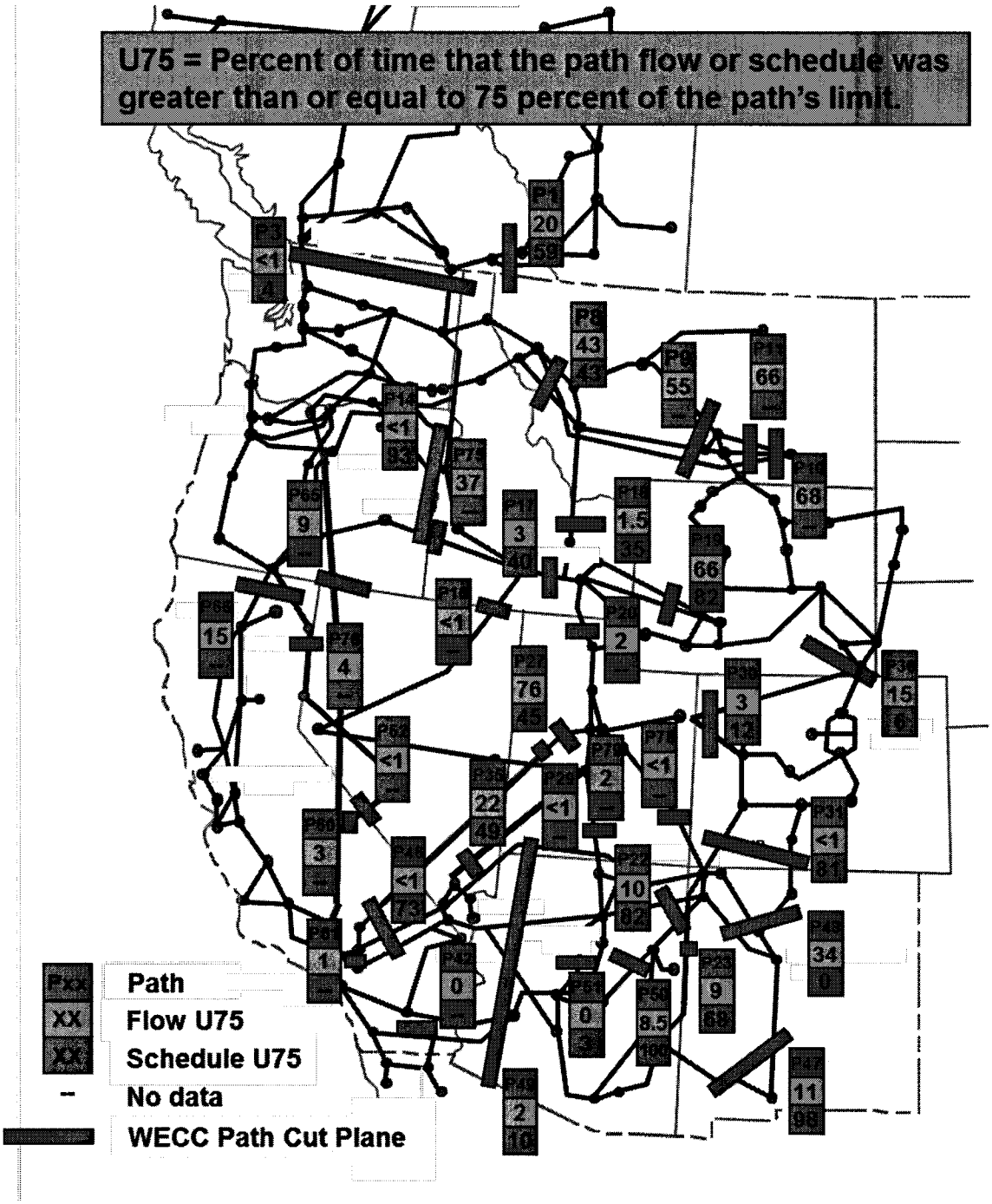

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Figure 17: Map with Path U90 Values

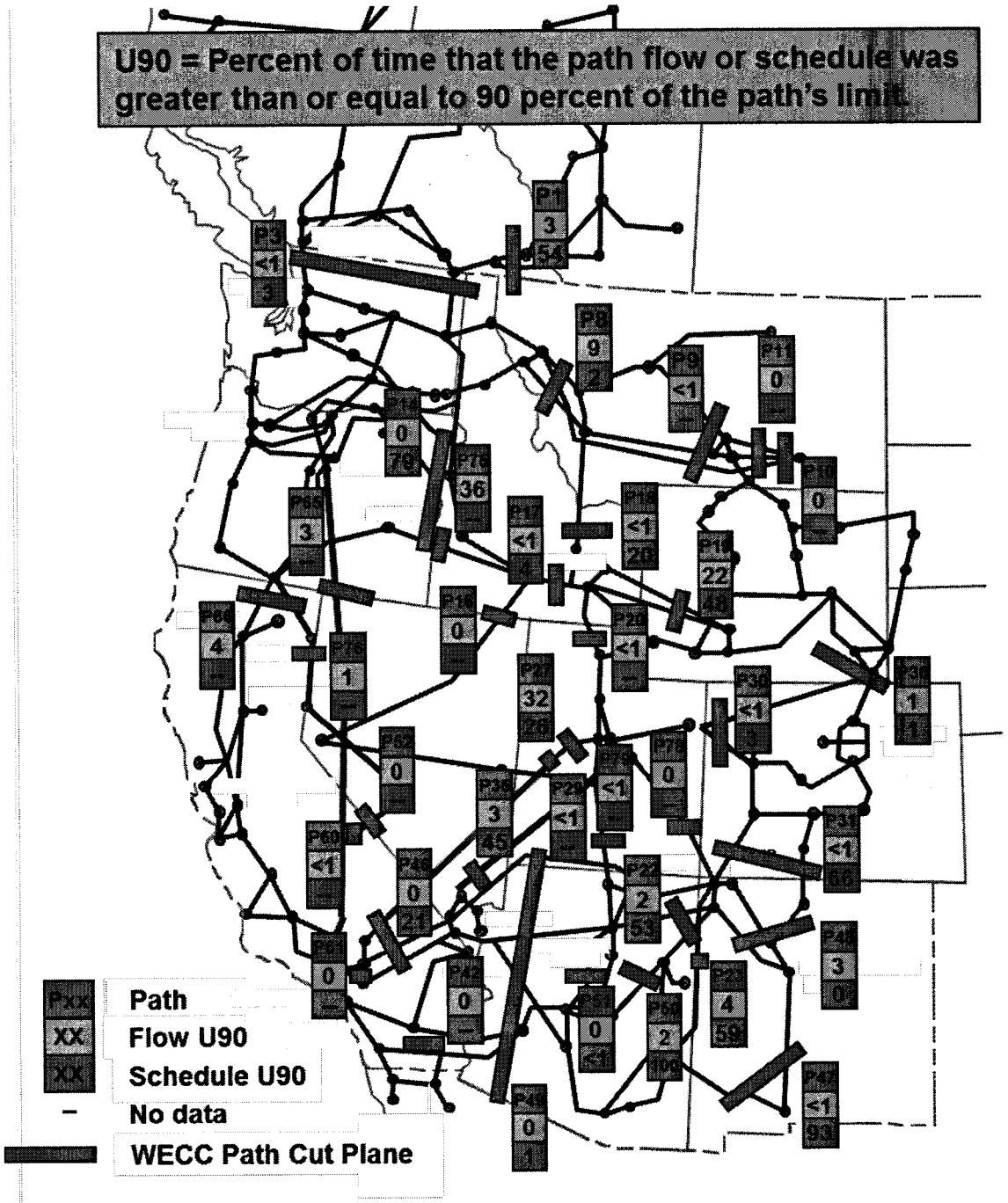

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EXHIBIT NMM-18

EXHIBIT NMM-18

The southeastern Arizona transmission system. The 345-kilovolt lines (green) are owned by Tucson Electric Power Company and deliver power from TEP's Springerville Generating Station and Four Corners power plants to Tucson. The Southwest Transmission Cooperative operates the 230-kilovolt lines shown (orange) and the 115-kilovolt lines between Apache and Hayden and between Pantano and Kartchner. WAPA operates the 115-kilovolt line between Apache and Tucson, and APS operates the 115-kilovolt line from Adams to Mural. Available at http://www.westconnect.com/filestorage/SATS%20EHV_HV%20System_PresentationMap_AlternateProjects.pdf. Accessed October 11, 2015.

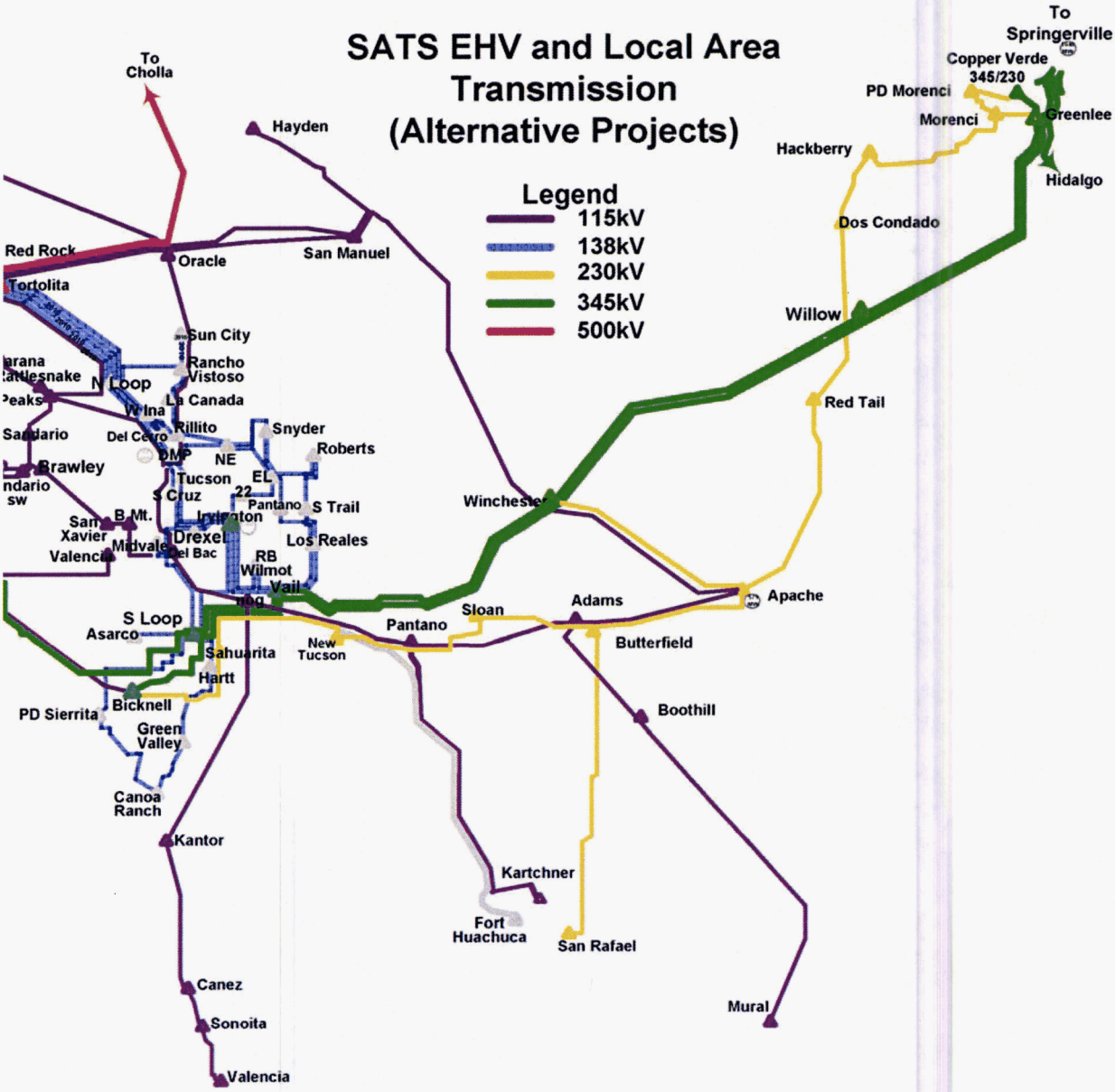

EXHIBIT NMM-19

EXHIBIT NMM-19

General route of the Southline Transmission Project. The stars are substations that will be rebuilt in upgrading the Western Area Power Administration's 115-kilovolt transmission line to two 230-kilovolt transmission lines. If transmission reliability, transfer capability, and congestion are issues across this region, the Southline Project would resolve them as fully as SunZia and would be much more efficient and useful for southeastern Arizona. From http://southlinetransmissionproject.com/files/Southline-Transmission-Project-Fact-Sheet1.pdf. Accessed October 11, 2015.

The Project will have a right-of-way up to 200 feet wide. The Project may include development of a substation in Luna County, New Mexico, with precise location determined when Project route is confirmed.

EXHIBIT NMM-20

EXHIBIT NMM-20

Plans by El Paso Electric Company to cease using its 108-megawatt share of the Four Corners Power Plant in 2016. Page 19, *Integrated Resource Plan for El Paso Electric Company for the Period 2015-2034*, 142 pp., 2015. Available at https://www.epelectric.com/document/integrated-resource-plan-2015-2034-07-16-2015. Accessed September 28, 2015.

A. SUPPLY-SIDE RESOURCES

EPE satisfies the bulk of its customers' electrical demands with power generated from its generating stations fueled by natural gas, coal, and uranium. In addition, EPE purchases varying amounts of firm and non-firm energy through the wholesale markets to meet the needs of its customers. Included in these purchases are Purchased Power Agreements ("PPAs") for renewable energy.

1. EPE's Generating Facilities

EPE owns and operates a fleet of local and remote generating units. The Rio Grande Power Plant ("Rio Grande"), Newman Power Plant ("Newman"), Montana Power Station ("Montana"), and Copper Power Plant ("Copper") are all located in EPE's service area within or near the City of El Paso, Texas. These generating stations are considered EPE's local generation. In addition, EPE owns five small solar photovoltaic ("PV") systems, one located at the Rio Grande Generating Station and another at the Newman Generating Station, the third located near Wrangler Substation in east El Paso, the fourth located at the El Paso Community College - Valle Verde Campus in El Paso's Lower Valley and the fifth system located on the rooftop of EPE's headquarters in downtown El Paso. These volunteer renewable energy projects have no costs allocated to New Mexico.

The Palo Verde Nuclear Generating Station ("PVNGS"), located near Phoenix, Arizona, and the Four Corners Power Plant ("FCPP"), located near Farmington, New Mexico, are considered EPE's remote generation. EPE owns 15.8 percent of the PVNGS' Units 1, 2 and 3; and owns seven percent of FCPP' Units 4 and 5. EPE will not be participating in or receiving power from FCPP after July 6, 2016. . EPE's prior IRPs planned for the end of the 50-year terms of FCPP participation in July 2016. EPE has filed a regulatory proceeding for approval of the sale of EPE's ownership to

EXHIBIT NMM-21

EXHIBIT NMM-21

Future plans by El Paso Electric Company to build 1,195 megawatts of natural gas generating capacity in and around El Paso by 2034. Page 79, *Integrated Resource Plan for El Paso Electric Company for the Period 2015-2034*, 142 pp., 2015. Available at https://www.epelectric.com/document/integrated-resource-plan-2015-2034-07-16-2015. Accessed September 28, 2015.

modeled in the base case. Strategist simulates thousands of resource expansion plans that are ranked based on each plan's total Present Value ("P.V.") Utility Cost. TABLE 28 shows the base case expansion plan results. Results from EPE's Base Case Resource Plan consist of 13 unit additions to be built over the next twenty years. The entire STRATEGIST results for this plan can be found in ATTACHMENT D.

TABLE 28. Base Case Expansion Plan Results

	Base Case	
	Unit	Installed Capacity (MW)
2022	1x1 CC	281
2023		
2024	1x1 CC	281
	10 PV	10
2025	20 PV	20
	LMS100	88
2026	LMS100	88
	10 PV	10
2027	20 PV	20
	WIND	22
2028	1x1 CC	281
2029		
2030		
2031	10 PV	10
2032	LMS100	88
2033		
2034	LMS100	88
	Present Value Utility Cost (k$)	Total Installed Capacity (MW)
	4,463,904	1,287

**Wind resource is 100 MW gross (22MW at peak)

1195 MW total new local natural gas generation

1x1 CC – One by One Combined Cycle
2x1 CC – Two by One Combined Cycle
LMS100 – Gas Turbine
10PV – Solar Photovoltaic (10 MW)
20PV – Solar Photovoltaic (20 MW)
Wind – Wind (22 MW)

INTEGRATED RESOURCE PLAN

OF

EL PASO ELECTRIC COMPANY

FOR THE PERIOD 2015-2034

July 16, 2015

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EXHIBIT NMM-22

EXHIBIT NMM-22

Planned natural gas generation additions by Public Service Company of New Mexico through 2033. Page iii from Public Service Company of New Mexico, *PNM Integrated Resource Plan, 2014-2033*, July 2014. Available at https://www.pnm.com/irp. Accessed October 11, 2015.

- **Emerging Resources:** Continue to monitor and evaluate emerging technologies, particularly battery storage, for application in the future.

The Most Cost-Effective Resource Portfolio

The Most Cost-Effective Portfolio is the portfolio of existing and new resources that meets electric system demand, provides acceptable system reliability and operational flexibility, and meets applicable legal and regulatory requirements, at the lowest reasonable cost to customers.

To identify the Most Cost-Effective Portfolio for the period 2014 through 2033, PNM examined several thousand potential resource portfolios using four different projections of customer demand and three projections of future natural gas and carbon prices. PNM then tested the results of this analysis under alternative assumptions for the price of wind generation, the contribution of solar capacity to peak hour demand, varying levels of energy efficiency, drought conditions and carbon emission costs.

The Most Cost-Effective Portfolio based on this analysis is summarized in Figure E-1 below.

Figure E-1: Summary of Most Cost-Effective Portfolio

Existing Actual Peak: 2008 MW	2018 Peak: 2,048 MW	2033 Peak: 2,890 MW
• San Juan 783 MW • Palo Verde 268 MW • Four Corners 200 MW • Gas 932 MW • Solar 44 MW • Wind 200 MW	• SJGS 443 - 497 MW • Palo Verde 402 MW • Four Corners 200 MW • Gas 1,149 MW • Solar 107 MW • Wind 305 MW	• SJGS 443 - 497 MW • Palo Verde 402 MW • Four Corners 200 MW • Gas 1,676 -1,761 MW • Solar 327 MW • Wind 402 MW

Public Input

The preparation of this IRP Report began in July 2013 with IRP kick-off meetings in Alamogordo, Silver City, Albuquerque and Santa Fe and concluded with a presentation

EXHIBIT NMM-23

EXHIBIT NMM-23

Proposed locations of planned natural gas generation additions by Public Service Company of New Mexico. Pages 55-57 from Public Service Company of New Mexico, *PNM Integrated Resource Plan, 2014-2033*, July 2014. Available at https://www.pnm.com/irp. Accessed October 11, 2015.

5. Future Resource Options

Over the 20-year planning horizon used in this IRP, it is likely that new resource technologies will be developed affecting both supply-side and demand-side resource options. Some of them may already be known, but not yet commercially available or cost effective; some may not yet be known. However, development of a 20-year most cost-effective portfolio cannot be based on speculation of uncertain technology improvements, but rather must take into account what is available and known at the present time. In three years, when the IRP process is again undertaken, the most cost-effective portfolio can be reevaluated taking into account resource options, technologies and costs available at that time. For purposes of this IRP, available resource options for planning the 20-year most cost effective portfolio depend upon technologies and costs at the present time. The following discussion addresses these resource options and resources that currently appear to be on the horizon, but not yet commercially cost-effective. This section of the IRP Report addresses the requirements of Section 17.7.3.9F of the IRP Rule.

Supply Resource Options

The IRP considers all feasible resources including current and developing new resource options. A discussion of each potential resource option, its feasibility of being implemented during the planning horizon, and fuel assessment are presented in this section. Fifteen different generation resources are identified as available to be included in a portfolio over the next 20 years and were allowed to be selected in the portfolio analysis. Costs for each resource included all associated fuel and operating expenses for existing resources and revenue requirements for new resource alternatives. A discussion of the resource alternatives, along with a narrative describing each resource, is provided below. Cost and performance data for new supply side resource options can be found in Appendix D.

250 MW New Combined Cycle Gas Generation

For this option PNM assumes a 1x1 combined cycle gas turbine, which provides a relatively high efficiency rating. The 250 MW size represents a typical manufactured capacity for this type of configuration using high efficiency turbines. The 250 MW combined cycle gas turbine (CCGT) is modeled assuming a $1,545/kW installed capital cost and approximately a 6,950 Btu/kWh heat rate. Unlike gas turbines, combined cycle plants require large amounts of water to condense the steam cycle. To reduce water usage and associated costs, PNM assumed this CCGT will utilize hybrid or dry cooling technology. This additional cost is included in the installed capital pricing above. PNM used the EPRI Technical Assessment Guide (TAG) database as the source of the unit characteristics and adjusted the TAG data for 5,000 feet above sea level.

204 MW New Combined Cycle Gas Generation

PNM models a 1x1 combined cycle gas turbine option, which also provides a relatively high efficiency rating and does not exceed PNM's current largest generation unit at this

size. The 204 MW size represents a typical manufactured capacity. The 204 MW CCGT is modeled assuming a $1,780/kW installed capital cost and about a 7,100 Btu/kWh heat rate. Installing a larger unit may decrease the capacity cost and heat rate, but would increase costs for reliability reserves on PNM's system. Unlike gas turbines, combined cycle plants require large amounts of water to condense the steam cycle. To reduce water usage and associated costs, PNM assumed this CCGT will utilize hybrid or dry cooling technology. This additional cost is included in the installed capital pricing above. PNM used the EPRI TAG database as the source of the unit characteristics and adjusted the TAG data for 5,000 feet above sea level. This resource was assumed to be sited so as not to require any major transmission upgrades by siting it near PNM's largest load center, the Albuquerque/Santa Fe area.

177 & 143 MW New Gas Turbine

The 177 MW and 143 MW gas turbines (GT) are modeled as heavy frame units. The 177 MW option is modeled with 9,790 Btu/kWh heat rate and $979/kW installed capital cost, and the 143 MW option is modeled with 10,142 Btu/kWh heat rate and $1,006/kW installed capital cost. PNM used the EPRI TAG database as the source of the unit characteristics and adjusted the TAG data for 5,000 feet above sea level. The 177 MW and 143 MW sizes represents typical manufactured capacity. This technology can help PNM maintain system voltage, regulation and meet spinning reserve requirements. These resources are expected to require relatively little acreage and minimal amounts of water. Thus, these resources were assumed to be sited so as not to require any major transmission line or upgrades and allowing PNM to site within WECC Path 48 in north central New Mexico.

Additionally, PNM assumed that two more options where these could only be sited at or near SGJS and utilize the available transmission from the San Juan Plant to PNM load centers in north central New Mexico (see the description of PNM's transmission system in Section 3). PNM also assumed a $10 million cost to build a new gas pipeline from an interstate pipeline to the San Juan plant.

93 MW New Reciprocating Engines

The 93 MW of reciprocating gas engines is based upon operating ten smaller sized reciprocating engines at a heat rate of 8,900 Btu/kWh heat rate and $1,521/kW installed capital cost. Reciprocating engines can operate over the full ranges and offer maximum load following flexibility. PNM used the EPRI TAG database as the source of the unit characteristics. This resource was assumed to be sited so as not to require any major transmission upgrades and allow PNM to site it within WECC Path 48 in north central New Mexico.

85 MW New Gas Turbine

The 85 MW GT is based upon a typical manufactured size of aero-derivative hybrid gas turbine with a 9,150 Btu/kWh heat rate and $1,679/kW installed capital cost. Similar

to the 177 MW CT shown above, this unit can provide quick start capability (full operating load in 10 minutes) with a proven track record. PNM used the EPRI TAG database as the source of the unit characteristics and adjusted the TAG data for 5,000 feet above sea level to represent typical siting conditions around New Mexico. **This resource was assumed to be sited so as not to require any major transmission upgrades and allow PNM to site it within WECC Path 48 in north central New Mexico.**

40 MW New Gas Aeroderivative Turbine

The 40 MW option is based upon one 40 MW aero-derivative turbine at a 9,800 Btu/kWh heat rate and $1,644/kW installed capital cost. PNM used the EPRI TAG database as the source of the unit characteristics and adjusted the TAG data for 5,000 feet above sea level. Similar to the 85 MW GT discussed above, this unit can provide quick start capability (full operating load in 10 minutes) to help maintain system reliability. **This resource was assumed to bypass any major transmission upgrades and allow PNM to site it within WECC Path 48 in north central New Mexico.**

100 MW Wind Resource

New Mexico offers abundant and excellent wind resources. This option is assumed to be a new 100 MW wind facility, located in NM and would be procured through a third party entity under a long term power purchase agreement at the rate of 44.41 $/MWh levelized over a thirty year life. Based on previous RFPs, PNM used an average of costs to provide a proxy for this resource. This option assumes minimal interconnection costs and does not assume any transmission upgrade costs as this depends heavily on the location of a new wind facility and access to the PNM transmission system. The wind resource is located on the eastern side of New Mexico and any required transmission upgrades would need to be evaluated on a case by case basis.

20 MW Increment Solar PV Resource

This option based upon a new 20 MW, single axis tracking solar PV facility, located in NM with a $1,981/kW installed capital cost based upon expected costs from developers. PNM used two different cost options to take into account the current federal investment tax credit being reduced from 30% to 10% beginning in 2017. As the penetration of solar increases on PNM's system it will begin to affect the system peak hour during the summer. PNM applies a declining contribution to reserve margin with each successive resource addition made. This option assumes very minimal interconnection costs and does not include transmission upgrade costs as this resource is expected to be located on PNM distribution facilities.

50 MW Solar Trough

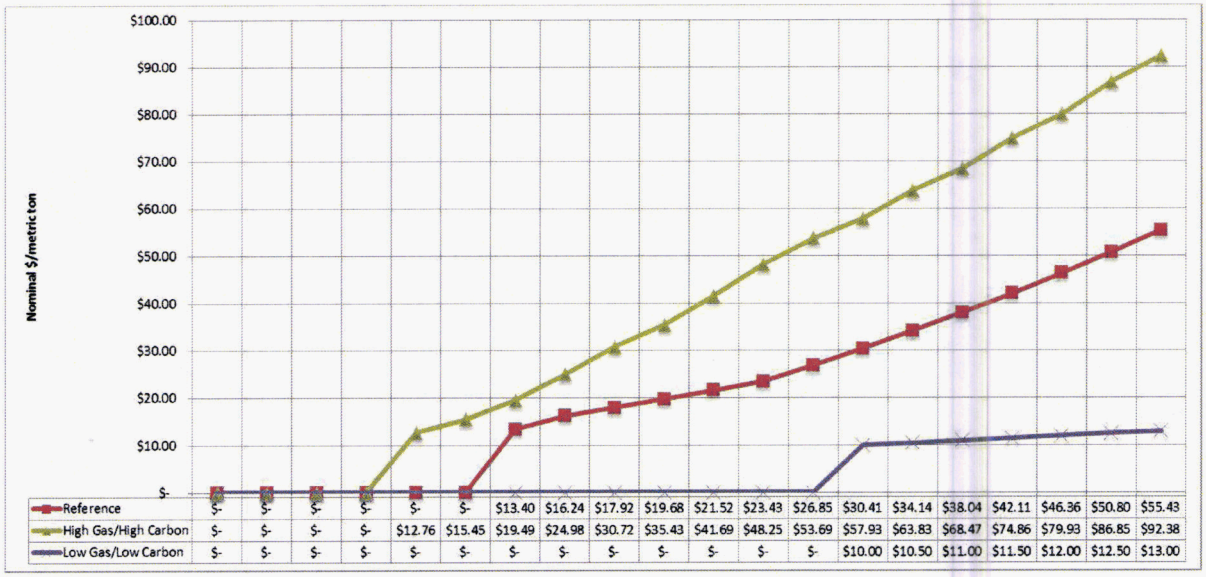
This option based upon a 50 MW parabolic trough technology of which PNM would participate in as part of larger project (>100 MW) to take advantage of larger economies of scale. This proxy alternative would be located in NM with a $4,178/kW

EXHIBIT NMM-24

EXHIBIT NMM-24

Public Service Company of New Mexico's transmission needs through 2033. Page 31 from Public Service Company of New Mexico, *PNM Integrated Resource Plan, 2014-2033*, July 2014. Available at https://www.pnm.com/irp. Accessed October 11, 2015.

FIGURE 5-D – PACE CO2 PRICE CURVES



Reference	$-	$-	$-	$-	$-	$-	$13.40	$16.24	$17.92	$19.68	$21.52	$23.43	$26.85	$30.41	$34.14	$38.04	$42.11	$46.36	$50.80	$55.43
High Gas/High Carbon	$-	$-	$-	$-	$12.76	$15.45	$19.49	$24.98	$30.72	$35.43	$41.69	$48.25	$53.69	$57.93	$63.83	$68.47	$74.86	$79.93	$86.85	$92.38
Low Gas/Low Carbon	$-	$-	$-	$-	$-	$-	$-	$-	$-	$-	$-	$-	$-	$10.00	$10.50	$11.00	$11.50	$12.00	$12.50	$13.00

TRANSMISSION FOR NEW RESOURCES

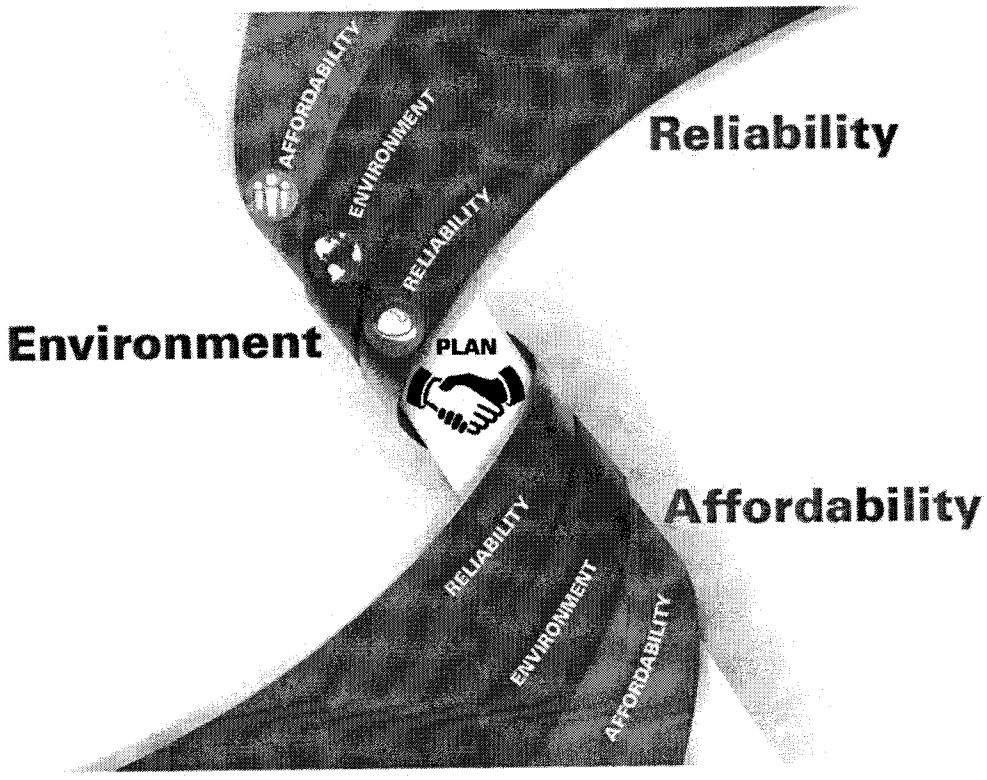
All new potential resources should include costs that reflect transmission improvements required to connect the resources to PNM's system, and transmission service costs required to deliver the power. Since the major assumption for this IRP is that any new resources would be sited within the NNM load pocket; the need for transmission improvements would be limited to station integration costs and require little, if any, newly built transmission facilities. For this IRP, PNM assumed that new transmission would not be built to new resources in remote locations.

DEMAND-SIDE RESOURCES FOR THE FUTURE

Future demand-side resource options are represented by energy efficiency forecasts, DR programs, and demand reductions through rate design. While renewable DG programs are considered demand-side resources, the IRP presents the customer-owned renewable DG program within the discussion of renewable resource options in Section 2 of this report. Amendments to the EUEA in 2013 require utilities to invest 3% of retail sales revenues in energy efficiency and load management programs. This provides consistency in the level of spending that can be expected over the term of the 2014 IRP. The level of savings achieved becomes a function of the effectiveness of each program and rate of increase in cost to procure incremental savings. PNM also assumed a continuation of the general structure of the current demand-influencing rates and tariffs discussed in Section 3 of this IRP Report.

PNM
Integrated Resource Plan

2014 – 2033 July 2014



Talk to us.

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EXHIBIT NMM-25

EXHIBIT NMM-25

Natural gas power plants planned by 2021 by the Salt River Project for Pinal County at the Pinal Central (1,150 megawatts) and Abel (900 megawatts) substations (blue squares on the diagram). In 2011 SRP completed the purchase of the full output of TransCanada's 500-megawatt natural gas power plant in Coolidge. SRP is considering an additional plant location near Eloy. From http://www.pinalenergyprojects.org/projectsoverview.aspx. Accessed October 11, 2015.

http://www.pinalenergyprojects.org/projectsoverview.aspx

Pinal Energy Projects

Projects Background

SRP has an obligation to ensure a reliable and affordable source of electricity for residential, business and industrial customers. To meet the growing needs of SRP's customers, we are planning new generation resources.

In 2008, SRP identified the need for 2,500 megawatts (MW) of new summer peaking and intermediate generation to meet electricity demands. Changing economic conditions in Arizona slowed the project's timeline. However, we are evaluating a number of options to meet this need and will most likely adopt a multi-faceted approach.

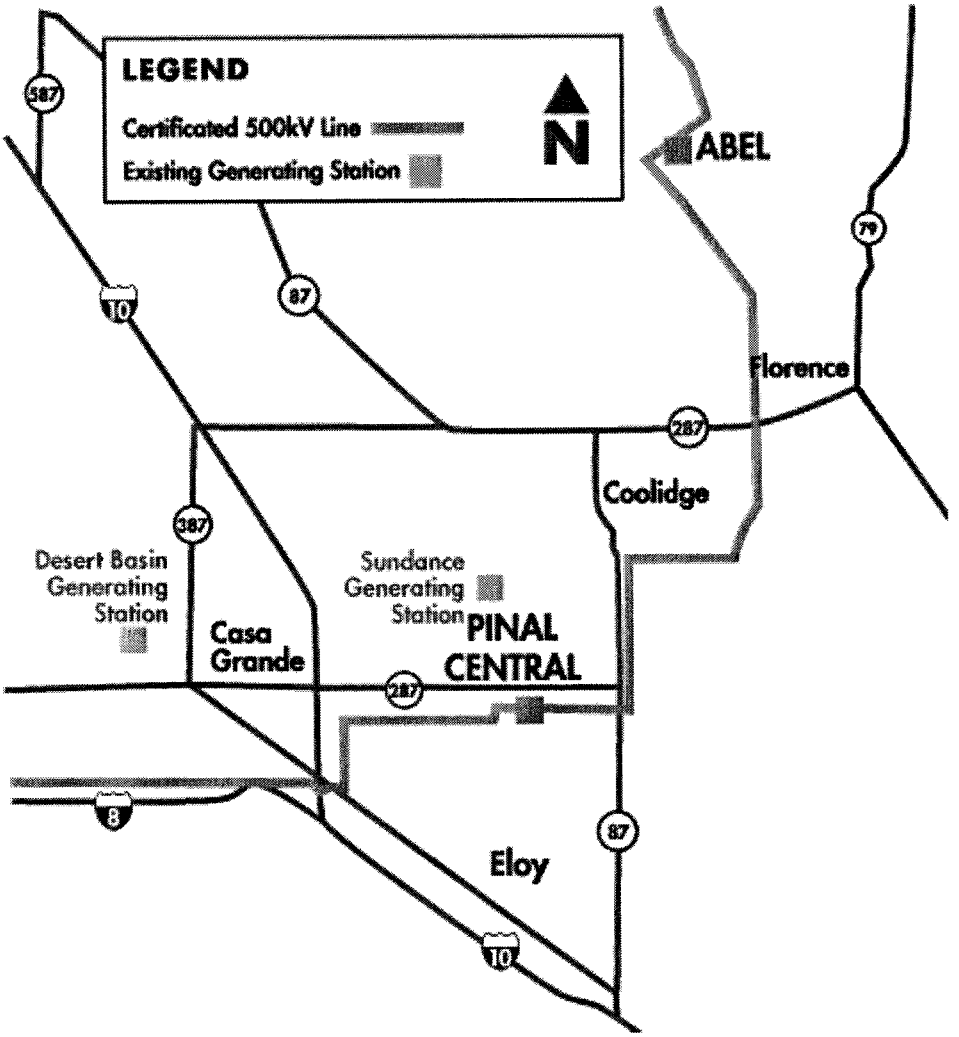
The first step was SRP's power purchase agreement for the output of the TransCanada project near Coolidge, which will meet approximately 500 MW of the 2,500 MW summer need.

The next steps will be to purchase additional output from others and/or build new generation at new or existing SRP sites, as may be determined through SRP's evaluative process.

Selected sites for generating facilities

SRP has selected two sites in Pinal County, as depicted in the map below:

- The **"Abel" site** is near the SRP Abel Substation in Florence
- The **"Pinal Central" site** is near the Pinal Central Substation south of Coolidge.



A third site was considered, near Eloy. While the Eloy site is a good one, SRP decided to proceed with Pinal Central and Abel based upon economic criteria and public acceptance of the Abel and Pinal Central sites. **A third site near Eloy** could be pursued at a later time.

How SRP selected the sites

SRP selected the sites though a comprehensive siting study. The proposed sites offer the necessary access to transmission lines and natural gas resources, and generally meet the siting criteria of the study.

The sites identified for possible power plant development are near the communities of Florence, the Gila River Indian Community, the SanTan Valley, Coolidge, Casa Grande and Eloy.

The proposed sites are located in industrial planning areas. SRP anticipates between 160 and 200 acres of land will be adequate to address the needs of each of the projects.

The electricity produced by any SRP generation is used to meet our customers' electricity needs, including our customers in Pinal County.

About the facilities

The Abel site will be developed to come online in stages in 2018. SRP plans to construct a simple-cycle peaking plant consisting of eight to nine natural-gas-fueled generating turbines of up to approximately **900 megawatts (MW).** In addition to the turbines, the plant sites will have limited fuel storage tanks, water treatment equipment, water storage facilities and a plant control building.

The Pinal Central site is projected to be developed by approximately 2019. It is expected to be a combined-cycle, natural-gas-fueled plant of up to approximately **1150MW.**

Find out about the environmental considerations.

Permitting process and construction schedule

Prior to construction, each project will complete the process to receive a Certification of Environmental Compatibility that must be approved by the Arizona Power Plant and Transmission Line Siting Committee and the Arizona Corporation Commission.

Multiple environmental requirements apply to the construction and operation of such a facility. Two significant permits are the air quality permit and the Aquifer Protection Permit. The air quality permit is issued by the Pinal County Air Quality Department, and the Aquifer Protection Permit is issued by the Arizona Department of Environmental Quality. There are public comment periods in both instances.

The **Abel site** will be developed as an approximately 900MW simple-cycle peaking plant consisting of eight to nine natural-gas-fired turbines. The plant will be constructed in phases, to match load growth as the economy recovers. Initial capacity will be operational in 2019 and additional capacity will be added as needed, with the full plant operational by 2021.

The **Pinal Central site** will be developed as determined by resource need.

System benefits

There are two benefits to these sites. The first is that they are either in or close to the southeast portion of SRP's load center. The proximity to SRP customers **utilizes recently-sited transmission lines** and substations.

The second is that the electric system needs some generation that is local to the load to provide necessary voltage support. Each of these sites provides some voltage support. The Abel site is particularly valuable in this regard, as it is located within the SRP load center.

EXHIBIT NMM-26

EXHIBIT NMM-26

Planned resource additions by Arizona Public Service through 2029. APS plans to add more than 4,000 megawatts of natural gas generating capacity, starting first with upgrades at the Ocotillo and Cholla generation stations. Page viii, Executive Summary, *Arizona Public Service 2014 Integrated Resource Plan*, 449 pp, April 2014. Available at https://www.aps.com/en/ourcompany/ratesregulationsresources/resourceplanning/Pages/resource-planning.aspx. Accessed September 27, 2015.

The 2014 Resource Plan at a Glance

The 2014 Integrated Resource Plan (2014 IRP) lays out how APS is planning to meet the projected nearly 13,000 MW resource requirement within its service territory by 2029. When combining load growth with contract expirations and unit retirements, APS anticipates needing over 6,600 MW of additional resources. To meet that need, APS evaluated several combinations of resource options in compliance with the Arizona Corporation Commission (ACC) Resource Planning and Procurement Rules, and Renewable Energy and Energy Efficiency Standards. The 2014 IRP details the inputs that went into the portfolio evaluation process, including a broad array of resources, costs and environmental variables, and the analytical framework used in the evaluation. The conclusion of this process was clear: low natural gas prices combined with the cost of environmental regulations and increases in self-dispatching solar generation will favor highly flexible natural gas resources over traditional baseload resources. Continued investment in advanced grid technologies is expected to provide further flexibility to the APS system.

2014-2029 (PROJECTED)

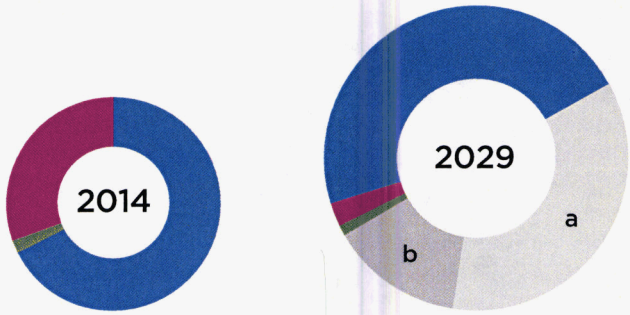
FUTURE ADDITIONAL RESOURCES: 6,613 MW AT PEAK MET WITH

a. New Utility-Scale Resources
   Natural Gas - **4,205 MW**
   Renewable Energy - **425 MW** (818 MW Nameplate Capacity)

b. New Customer Resources
   Energy Efficiency - **1,447 MW**
   Distributed Energy - **261 MW** (722 MW Nameplate Capacity)
   Demand Reponse - **275 MW**

Exisitng Customer Resources
Existing Contracts
Existing Utility-Scale Resources

a New Utility-Scale Resources
b New Customer Resources



8,124 MW peak requirement **100%** met with existing resources

12,982 MW peak requirement **50%** met with existing resources

Figure ES-1 - 2014 vs. 2029 Peak Requirements

INVESTING IN ARIZONA'S ENERGY FUTURE

ENERGY PORTFOLIO INVESTMENT

$13.6 billion

Planned to secure sufficient assets to meet requirements under the Selected Portfolio

TRANSMISSION INVESTMENT

$496 million

Needed to support reliability, coordination, aging infrastructure and integration of renewable energy

ADVANCED GRID INVESTMENT

$300 million

Planned to support reliability, integrate distributed energy and emerging technologies

HOW THE PORTFOLIO MAY CHANGE

COMPOSITION OF ENERGY MIX BY RESOURCE (GWH)

2014

9,297 11,872 6,749 3,182 2,509

2029

[illegible]97 12,548 14,592 6,944 7,855

Nuclear Coal Natural Gas Renewable Energy Energy Efficiency

Figure ES-2 - 2014 vs. 2029 Energy Mix

Improves Environmental Performance:

- CO2 Intensity ▼ **14%**
- Water Intensity ▼ **24%**

EXHIBIT NMM-27

EXHIBIT NMM-27

APS's first step in expanding its natural gas generation is to upgrade its Ocotillo (natural gas) and Cholla (coal) generating stations to newer technology. Page ix, Executive Summary, *Arizona Public Service 2014 Integrated Resource Plan*, April 2014, 449 pp. Available at https://www.aps.com/en/ourcompany/ratesregulationsresources/resourceplanning/Pages/resource-planning.aspx.

Portfolio Selection

APS analyzed four portfolios before arriving at the Selected Portfolio as the most reasonable mix of resources for the 2014 IRP. The analysis focused on flexibility, reliability, cost, environmental impact and risk, among others.

The following table summarizes the analysis of the portfolios, including criteria considered for each. All portfolios include modernizing the Ocotillo power plant to support Valley reliability and renewable energy integration.

TABLE ES-1 - 2014 IRP PORTFOLIO SELECTION

2014 IRP PORTFOLIOS CONSIDERED	SELECTED PORTFOLIO	ENHANCED RENEWABLE PORTFOLIO	COAL REDUCTION PORTFOLIO	COAL-TO-GAS CONVERSION PORTFOLIO
Description	Modernize Ocotillo; continue coal operations; EE and RE compliance	Modernize Ocotillo; continue coal operations; EE compliance; RE well above compliance	Modernize Ocotillo; replace Cholla with gas and renewable generation; EE compliance; RE slightly above compliance	Modernize Ocotillo; convert Cholla to gas operation; EE and RE compliance
RESOURCE CONTRIBUTIONS (2029 PEAK CAPACITY CONTRIBUTION / % ENERGY MIX)				
Nuclear	1,146 MW / 18.1%	1,146 MW / 18.1%	1,146 MW / 18.1%	1,146 MW / 18.1%
Coal	1,932 MW / 24.5%	1,932 MW / 23.4%	1,285 MW / 16.9%	1,285 MW / 16.9%
Natural Gas	7,137 MW / 28.5%	6,933 MW / 21.9%	7,749 MW / 35.0%	7,784 MW / 36.1%
Renewable Energy & Distributed Energy	1,088 MW / 13.6%	1,298 MW / 21.3%	1,117 MW / 14.7%	1,088 MW / 13.6%
Energy Efficiency & Demand Response	1,722 MW / 15.3 %	1,722 MW / 15.3%	1,722 MW / 15.3%	1,722 MW / 15.3%

WHY THE SELECTED PORTFOLIO WAS CHOSEN

Resource planning does not establish a guarantee of future conditions or develop a transactional roadmap. Rather, the IRP process enables APS to develop long-term plans and evaluate which resource options may be appropriate given today's forecasts of future energy needs, resource costs and associated uncertainties. In the formulation of the 2014 IRP, uncertainties regarding environmental regulation and the evolving nature of the electric industry significantly influenced the selection process. The Selected Portfolio was chosen because it provides the most reasonable combination of overall economic performance, and flexibility in the generation fleet to support grid reliability, integrate renewable energy and manage uncertainties. Moving through the Planning Period, circumstances governing current assumptions and forecasts will undoubtedly change and will be updated in future resource plans, potentially shifting the preferred portfolio.

aps

2014 INTEGRATED RESOURCE PLAN

APRIL 2014 | FILED IN COMPLIANCE WITH A.A.C. R14-2-703

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EXECUTIVE SUMMARY

The 2014 Resource Plan at a Glance

The 2014 Integrated Resource Plan (2014 IRP) lays out how APS is planning to meet the projected nearly 13,000 MW resource requirement within its service territory by 2029. When combining load growth with contract expirations and unit retirements, APS anticipates needing over 6,600 MW of additional resources. To meet that need, APS evaluated several combinations of resource options in compliance with the Arizona Corporation Commission (ACC) Resource Planning and Procurement Rules, and Renewable Energy and Energy Efficiency Standards. The 2014 IRP details the inputs that went into the portfolio evaluation process, including a broad array of resources, costs and environmental variables, and the analytical framework used in the evaluation. The conclusion of this process was clear: low natural gas prices combined with the cost of environmental regulations and increases in self-dispatching solar generation will favor highly flexible natural gas resources over traditional baseload resources. Continued investment in advanced grid technologies is expected to provide further flexibility to the APS system.

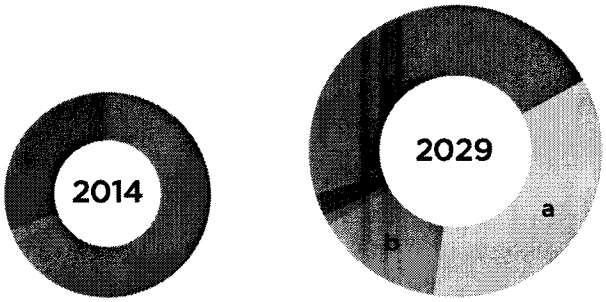
2014-2029 (PROJECTED)

FUTURE ADDITIONAL RESOURCES:
6,613 MW AT PEAK MET WITH

a. New Utility-Scale Resources
   Natural Gas - **4,205 MW**
   Renewable Energy - **425 MW** (818 MW Nameplate Capacity)

b. New Customer Resources
   Energy Efficiency - **1,447 MW**
   Distributed Energy - **261 MW** (722 MW Nameplate Capacity)
   Demand Reponse - **275 MW**

Exisitng Customer Resources
Existing Contracts
Existing Utility-Scale Resources
a New Utility-Scale Resources
b New Customer Resources



8,124 MW
peak requirement
100% met with
existing resources

12,982 MW
peak requirement
50% met with
existing resources

Figure ES-1 - 2014 vs. 2029 Peak Requirements

INVESTING IN ARIZONA'S ENERGY FUTURE

ENERGY PORTFOLIO INVESTMENT

$13.6 billion

Planned to secure sufficient assets to meet requirements under the Selected Portfolio

TRANSMISSION INVESTMENT

$496 million

Needed to support reliability, coordination, aging infrastructure and integration of renewable energy

ADVANCED GRID INVESTMENT

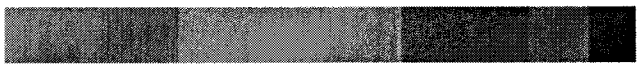
$300 million

Planned to support reliability, integrate distributed energy and emerging technologies

HOW THE PORTFOLIO MAY CHANGE

COMPOSITION OF ENERGY MIX BY RESOURCE (GWH)

2014



9,297 11,872 6,749 3,182 2,509

2029

9,297 12,548 14,592 6,944 7,855

Nuclear Coal Natural Gas Renewable Energy Energy Efficiency

Figure ES-2 - 2014 vs. 2029 Energy Mix

Improves Environmental Performance:

- CO2 Intensity ▼ **14%**
- Water Intensity ▼ **24%**

Portfolio Selection

APS analyzed four portfolios before arriving at the Selected Portfolio as the most reasonable mix of resources for the 2014 IRP. The analysis focused on flexibility, reliability, cost, environmental impact and risk, among others.

The following table summarizes the analysis of the portfolios, including criteria considered for each. All portfolios include modernizing the Ocotillo power plant to support Valley reliability and renewable energy integration.

TABLE ES-1 - 2014 IRP PORTFOLIO SELECTION

2014 IRP PORTFOLIOS CONSIDERED	SELECTED PORTFOLIO	ENHANCED RENEWABLE PORTFOLIO	COAL REDUCTION PORTFOLIO	COAL-TO-GAS CONVERSION PORTFOLIO
Description	Modernize Ocotillo; continue coal operations; EE and RE compliance	Modernize Ocotillo; continue coal operations; EE compliance; RE well above compliance	Modernize Ocotillo; replace Cholla with gas and renewable generation; EE compliance; RE slightly above compliance	Modernize Ocotillo; convert Cholla to gas operation; EE and RE compliance
RESOURCE CONTRIBUTIONS (2029 PEAK CAPACITY CONTRIBUTION / % ENERGY MIX)				
Nuclear	1,146 MW / 18.1%	1,146 MW / 18.1%	1,146 MW / 18.1%	1,146 MW / 18.1%
Coal	1,932 MW / 24.5%	1,932 MW / 23.4%	1,285 MW / 16.9%	1,285 MW / 16.9%
Natural Gas	7,137 MW / 28.5%	6,933 MW / 21.9%	7,749 MW / 35.0%	7,784 MW / 36.1%
Renewable Energy & Distributed Energy	1,088 MW / 13.6%	1,298 MW / 21.3%	1,117 MW / 14.7%	1,088 MW / 13.6%
Energy Efficiency & Demand Response	1,722 MW / 15.3 %	1,722 MW / 15.3%	1,722 MW / 15.3%	1,722 MW / 15.3%

WHY THE SELECTED PORTFOLIO WAS CHOSEN

Resource planning does not establish a guarantee of future conditions or develop a transactional roadmap. Rather, the IRP process enables APS to develop long-term plans and evaluate which resource options may be appropriate given today's forecasts of future energy needs, resource costs and associated uncertainties. In the formulation of the 2014 IRP, uncertainties regarding environmental regulation and the evolving nature of the electric industry significantly influenced the selection process. The Selected Portfolio was chosen because it provides the most reasonable combination of overall economic performance, and flexibility in the generation fleet to support grid reliability, integrate renewable energy and manage uncertainties. Moving through the Planning Period, circumstances governing current assumptions and forecasts will undoubtedly change and will be updated in future resource plans, potentially shifting the preferred portfolio.

EXHIBIT NMM-28

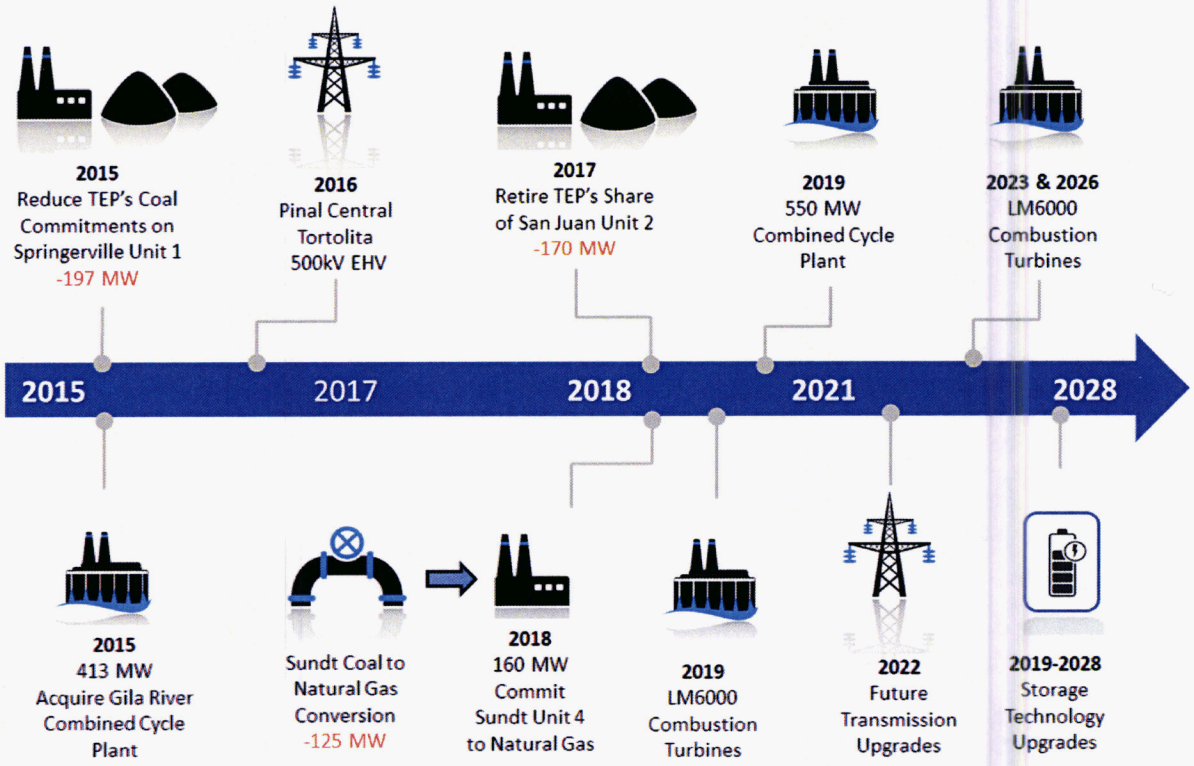
EXHIBIT NMM-28

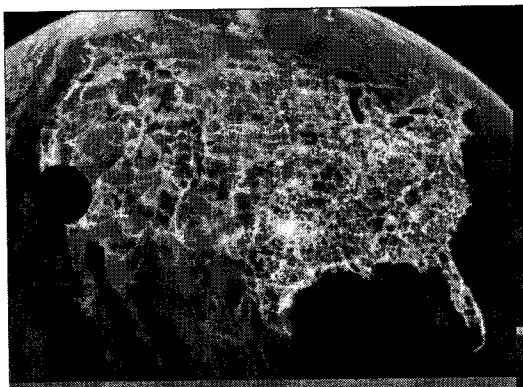
Planned natural gas generation additions by Tucson Electric Power Company through 2026. Page 15 from Tucson Electric Power Company, *2014 Integrated Resource Plan*, April 1, 2014, 387 pp. Available at https://www.tep.com/doc/planning/2014-TEP-IRP.pdf. Accessed October 9, 2015.

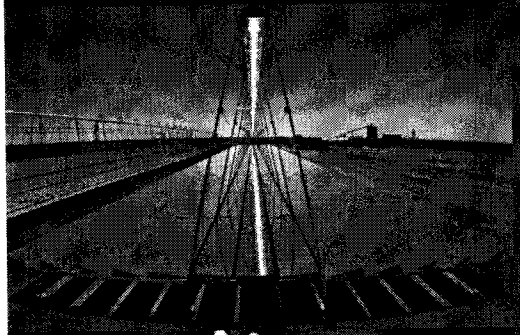
Overview of the 2014 IRP Reference Case Plan

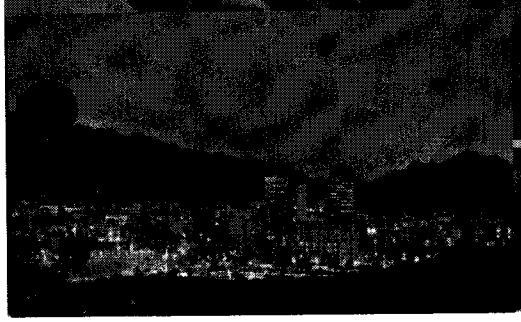
Figure 2 below details the significant resource planning decisions assumed for the 2014 IRP Reference Case plan. As part of TEP's Resource Diversification Strategy, TEP plans to make the following coal capacity reductions as part of the 2014 IRP Reference Case plan. In 2015, it is assumed that TEP reduces it capacity commitment on Springerville Unit 1 from 387 MW to 190 MW. By 2018, TEP will reduce its coal capacity at the San Juan Generation Station from 340 MW to 170 MW. This assumes that the EPA approves the revised New Mexico State Implementation Plan (SIP) and that Selective Non-Catalytic Control (SNCR) technology is installed on San Juan Unit 1, and Unit 2 is retired by the end of 2017. Finally, TEP anticipates permanently eliminating coal as a fuel source at Sundt Unit 4 and operating the unit on natural gas starting in 2018. As a result of this conversion, TEP will gain approximately 40 MW in additional capacity on Unit 4. To replace this lost coal capacity, TEP plans to acquire approximately 413 MW from Power Block 3 at the Gila River Power Station in 2015. This natural gas combined cycle resource will cover the capacity reductions that are planned to occur at Springerville Unit 1 in 2015 and San Juan Unit 2 in 2018. For new resources beyond 2018, it is assumed that TEP acquires or constructs approximately 820 MW of natural gas fired resources from 2019 through 2026. Of the 820 MW of future potential capacity additions, approximately 550 MW is assumed to be combined cycle technology while the remaining 270 MW is assumed to be natural gas peaking resources. These future capacity additions may be a combination of firm long-term purchase power agreements, plant acquisitions, or construction of new local area generating facilities.

Figure 2 – 2014 IRP Reference Case Plan Timeline









TUCSON ELECTRIC POWER

2014 Integrated Resource Plan

April 1, 2014

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TOPIC 3

CONFLICTS WITH CENTRAL AND WESTERN ARIZONA'S TRANSMISSION SYSTEM

EXHIBIT NMM-29

EXHIBIT NMM-29

Electrical District 4 Petition to Intervene in SunZia Petition for a Declaratory Order to the Federal Energy Regulatory Commission, submitted February 5, 2010 by Dennis Delaney of K. R. Saline & Associates, PLC. Use by permission of Mr. Delaney.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

SunZia Transmission, LLC	Docket No. EL10-39-000

MOTION TO INTERVENE

Pursuant to Rule 214 and the Notice of Filing issued by this Commission dated February 5, 2010, Electrical District No. 4 of Pinal County, Arizona hereby moves to intervene in this docket.

I. ELECTRICAL DISTRICT NO. 4

Electrical District No. 4 ("ED4" or "the District") is an electrical district established in 1928 by the Board of Supervisors of Pinal County pursuant to the provisions of Chapter 3 of Title 30 of the Arizona Revised Statutes. ED4 was organized to provide, and has provided since 1930, electrical power and energy primarily for producing water for irrigation. ED4 obtained its original power purchase certificate from the Arizona Power Authority in 1960.

ED4 is located in Pinal County, Arizona, with a service area of approximately 108,000 acres. ED4 owns two distribution substations that are centrally located within its service territory. ED4 provides electrical service to agricultural irrigation pumping, industrial, commercial and residential consumers.

ED4 is governed by a five-member Board of Directors elected annually by freeholders of property within ED4's boundaries. The District is operated by the Central Arizona Irrigation and Drainage District through a Management Services Agreement.

II. CORRESPONDENCE AND COMMUNICATIONS

Correspondence and communications concerning this submission should be directed to:

Ron McEachern
District Manager
Electrical District No. 4 of Pinal County
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Eloy, AZ 85131
ron@caidd.com

Dennis L. Delaney, P.E.
Engineering Consultant
K. R. Saline & Associates, PLC
160 N. Pasadena, Ste. 101
Mesa, AZ 85201
dld@krsaline.com

III. STATEMENT OF ISSUES

ED4's service area is in the immediate vicinity of the planned Pinal Central Substation at which the Project will terminate. ED4 believes that Petitioner's request is premature.

1) Petitioner asserts that "[o]ther federal and state permitting activity also is underway, including the permitting processes necessary in the counties in Arizona and New Mexico that the Project will traverse."

   a) The Project will "terminate at the proposed Pinal Central Substation in Pinal County, Arizona"; and, while Petitioner indicates that "SunZia has made efforts to inform the Arizona Corporation Commission (ACC) and the New Mexico Public Regulation Commission (NMPRC) on critical Project development issues," Petitioner has failed to describe contacts with local agencies and utilities.

   b) Rather than describe the impacts that will most certainly occur by injecting up to 4,500 MW into the grid at the Pinal County location or how SunZia plans to mitigate those impacts, Petitioner simply refers to the Project's inclusion "in the WECC Regional Planning Project Review and Project Rating Process" as being sufficient to conclude that "no adverse reliability impacts to the existing transmission system" will occur. There is no evidence of this assertion.

2) As described, the Project would inject up to 4,500 MW of power at a future station in Pinal County with no specific identified markets or contracts. The Petitioner asserts that "[t]hrough strategic interconnections, utilities in New Mexico, Arizona, Nevada, and

California will have grid access to these new renewable resources to help meet their local power needs."

a) In reference to the Project's purpose, the Petitioner relies heavily on the Southwest Area Transmission Subregional Planning Group ("SWAT"), stating that in 2006 SWAT "originally identified the need for significant transmission expansion between New Mexico and Arizona to serve load growth, increase system power transfer limits and import capability requirements, and provide service for the growing demand for renewable energy resources, particularly from remote renewable energy zones." However, as late as January 2009, the SWAT Renewable Transmission Task Force had identified resource locations for 29,904 MW of potential renewable generation, including 23,572 MW in New Mexico and Arizona.[1] Although the Project has been announced at SWAT, it is not accurate that "[t]he Project originated out of SWAT" (emphasis supplied).

b) At its terminus, the Project is still remote from the referenced Nevada and California markets, and will require additional unidentified facilities and upgrades to deliver to the California market.

c) The same capacity rights sought in the petition will need to be extended to the Palo Verde Hub, or further. ED4 is concerned that Petitioner has not adequately addressed potential market power issues.

d) It is doubtful that the then existing grid in the Pinal Central area ("late 2013 or early 2014") can accommodate anything close to 4,500 MW. Without additional definition of how Project power will reach market, including additional transmission elements and/or contractual arrangements, the Project is not sufficiently defined.

---

[1] The SWAT Renewable Transmission Task Force presented a Power Point presentation dated January 13, 2009 (see Renewable Transmission Task Force) which compared load growth versus renewable generation potential in New Mexico, Arizona and Nevada.

3) Finally, ED4 is concerned over the implied need for "fast tracking" under the renewables mantra. There is considerable potential for renewable generation projects in Arizona and New Mexico, including as much as 5,000 to 7,000 MW renewable generation potential in the general vicinity of Pinal Central, which will also require additional transmission upgrades. There is no adequate justification for the preferences being requested.

IV. CONCLUSION

For the foregoing reasons, ED4 respectfully requests that its Motion to Intervene be granted and that the request to expedite be denied.

Respectfully submitted,

/s/ Dennis L. Delaney, P.E.

Dennis L. Delaney, P.E.
For Electrical District No. 4

February 19, 2010

CERTIFICATE OF SERVICE

I hereby certify that I have this day caused the foregoing document to be served upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated on this 19th day of February, 2010.

/s/ *Jennifer M. Torpey*

K. R. Saline & Associates, PLC

EXHIBIT NMM-30

EHIBIT NMM-30

Statement by David Getts of SunZia about the level of pre-build transmission purchases needed to finance SunZia. Excerpted from David Getts presentation to the AzCPA 2011 Energy Conference, Independent Transmission in and out of Arizona, March 18, 2011. Available from http://www.sunzia.net/presentation_pdfs/azcpa_2011_energy_conference_getts_mar_18_2011.pdf. Accessed October 11, 2015.

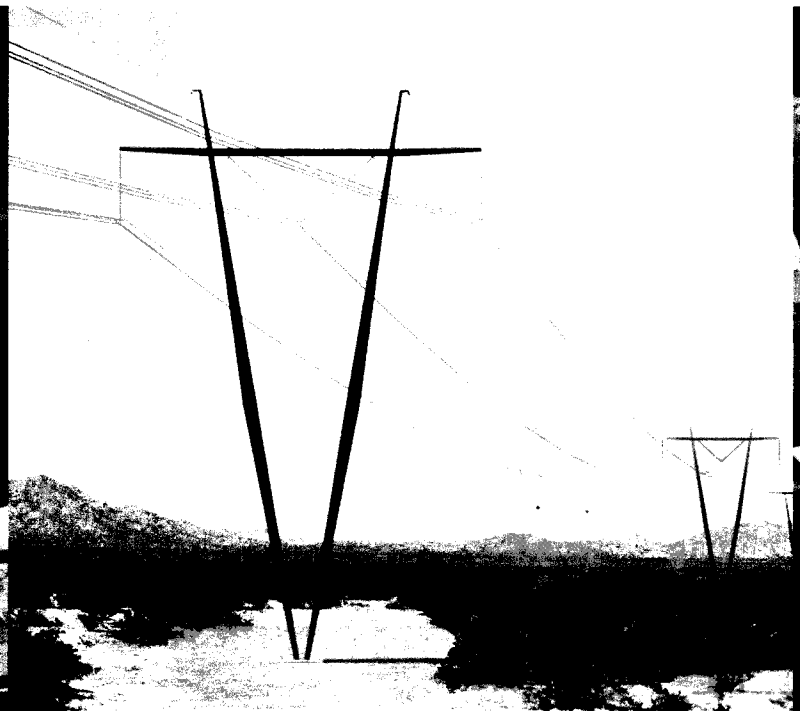
More Possible Remedies

- Independent negotiates up to 100% of ATC with Anchor Tenants (not currently acceptable to the FERC)
  - Projects need greater certainty of acquiring creditworthy customers
  - Generally, projects need 75% to 80% "contract cover" to satisfy lenders
  - Owners and lenders likely want several anchor tenants to spread risk
  - Competition for customers in AC systems is greater & more complex
  - Development risk of long-line projects is significant:
    - NEPA process can take 5 years or more
    - Multiple state jurisdictions and regulatory commissions (NEPA overlap)
    - Numerous, important environmental and land use issues to resolve
    - Possible conflicts with military missions
    - Acquisition of rights-of-way without eminent domain adds risk & time
  - Why risk spending 5% to 10% of total project cost to develop?

SunZia Southwest Transmission Project

AzCPA 2011 Energy Conference

Independent Transmission in and out of Arizona



David Getts

General Manager,

SouthWestern Power Group

March 18, 2011

SOUTHWESTERN POWER GROUP

Independent developer of utility-scale generation and transmission in the Desert Southwest

Project Manager/Developer for SunZia

Staff of 10, based in Phoenix, in business for 10 years

Major References:

- 2,400 MW CCGT Panda Gila River power plant (in operation)
- 1,000 MW CCGT Bowie Power Station (permitted)
- 600 MW Lignite CFB Rockdale Power Plant (in operation)
- 150 MW Solar PV power project (in development, support to affiliate)

Owned by MMR Group in Baton Rouge, LA

Transmission Issues between AZ & CA

Market restrictions reduce choice and increase price

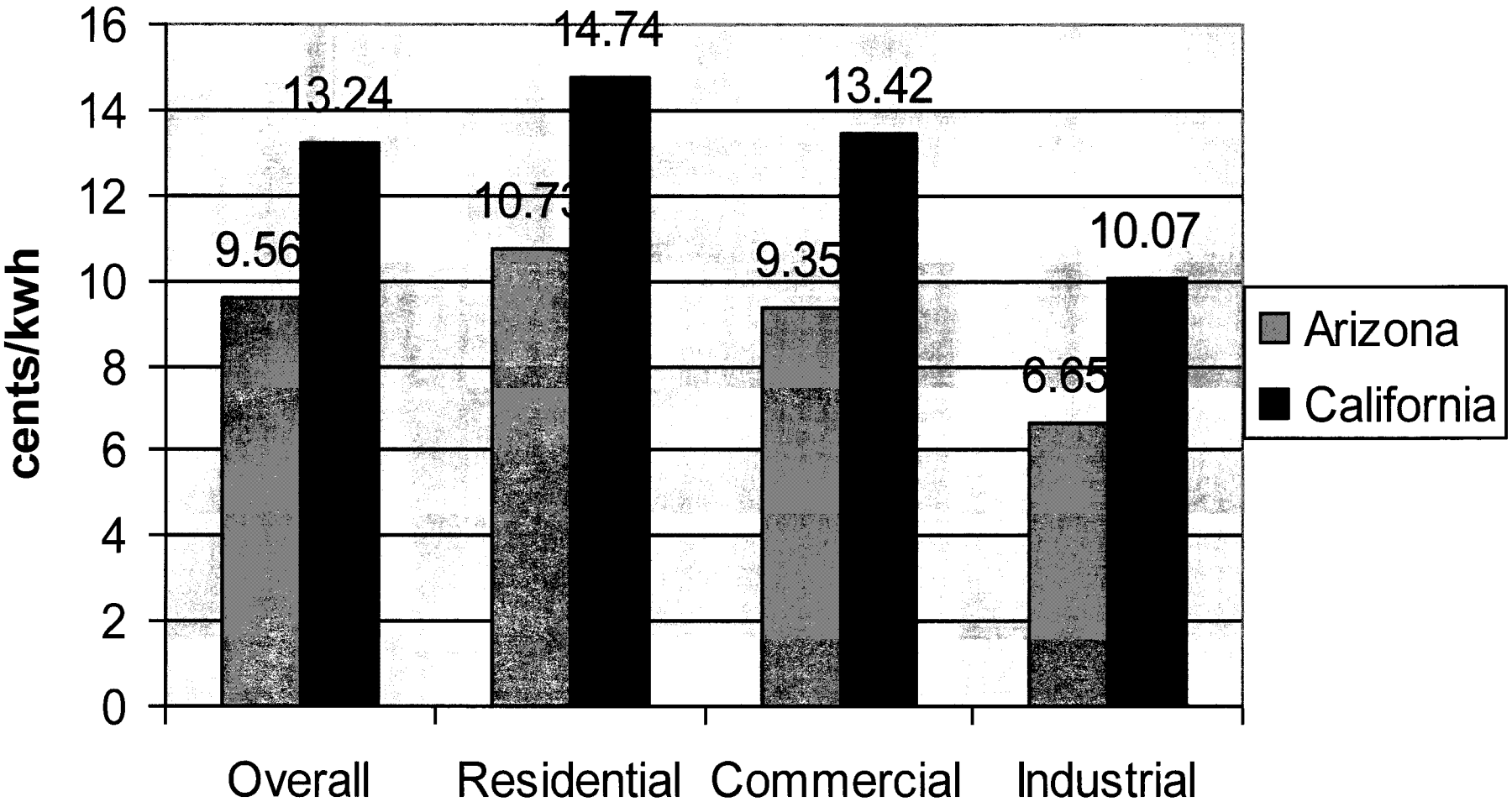
- PV congestion costs + (SP15 less PV price) shows need for more wire
- CA build cost is much > AZ build cost (EHV wire and generation)
- CA political desire to limit imports (e.g., bundled vs TREC's, SB 722)
- CAISO limits on dynamic transfers and pseudo ties
- Past ACC decision on DPV2
- Interstate Balancing Area Authority battles

CA utilities need more resource choices: competition is good

CA ratepayers are the victims of "multiple barriers to entry"

Solution: Supportive policies that let Markets work

Average 2009 Retail Electricity Prices



Data Soure: EIA

Key Challenges for Independent Transmission Projects

In Organized Markets

- Gaining project "approval" by the ISO/RTO
- Barriers to approval = Incumbent ROFR, biased transmission planning processes, closed/unofficial groups (e.g., CTPG)

In Unorganized Markets

- Absence of assured cost recovery mechanism
- Securing investment-grade customers willing to commit early
  - There are few investment-grade generators (and some want to own)
  - There are many investment-grade utilities (but they expect to own)
- Securing utility commitments to purchase ownership
  - They need an incentive to take risk

The Independent Cost Recovery Circle

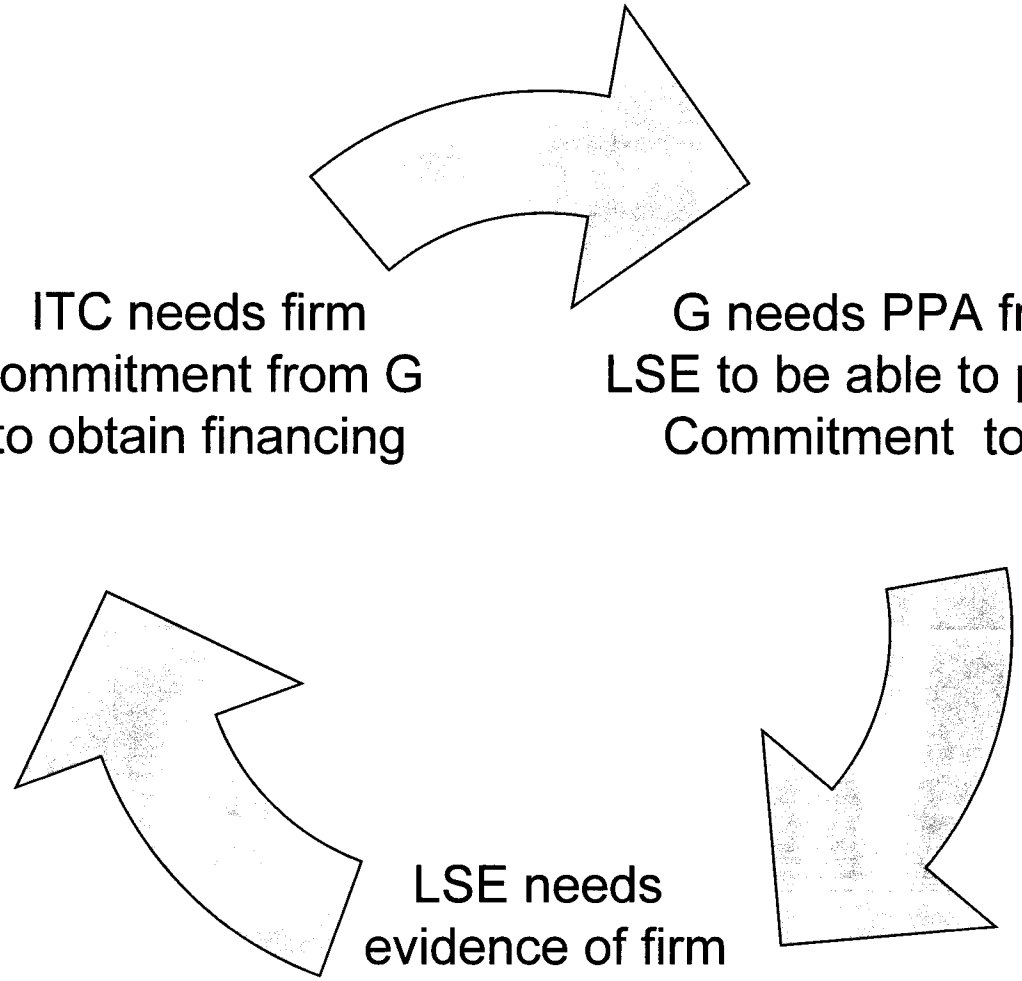
For commercial success, an Independent Transmission Company needs to resolve the inter-related circle:

1. Most ITCs need creditworthy, firm commitments from Generators to obtain construction financing for the project

2. Most Generators will only provide a firm commitment to an ITC after they have a PPA from a Load-Serving Entity

3. Most Load Serving Entities will only award a PPA to a Generator after the Generator has firm transmission rights

The Independent's Cost Recovery



Possible Remedies to the Conundrum

Independent sells developed transmission project to Utility (not attractive to most Independents)

Independent sells developed transmission project to Generator(s) (allowed only if 100% is a gen-tie line and FERC approves)

Independent uses own transmission capacity for own generation (allowed only if 100% is a gen-tie line and FERC approves)

Independent uses its balance sheet to finance construction (few Independents have the necessary balance sheet and are willing to do so)

More Possible Remedies

Independent negotiates up to 100% of ATC with Anchor Tenants (not currently acceptable to the FERC)

- Projects need greater certainty of acquiring creditworthy customers
- Generally, projects need 75% to 80% "contract cover" to satisfy lenders
- Owners and lenders likely want several anchor tenants to spread risk
- Competition for customers in AC systems is greater & more complex
- Development risk of long-line projects is significant:
  - NEPA process can take 5 years or more
  - Multiple state jurisdictions and regulatory commissions (NEPA overlap)
  - Numerous, important environmental and land use issues to resolve
  - Possible conflicts with military missions
  - Acquisition of rights-of-way without eminent domain adds risk & time

Why risk spending 5% to 10% of total project cost to develop?

Additional Ideas

Encourage Utility + Independent partnerships

- Approve higher ROE's on investments made by utilities in Independent projects (that are not BAU).
- Promote inclusion of development risk premium/fee paid to the developer and those that provide development capital in the project's cost basis.

Allow combined Generator + Transmission ownership

- Establish ATC threshold of say 50% that could be used by Generator for its own generation with the balance going to open season.
- Establish maximum own-capacity ownership of say 20% that is deemed to be de minimis (i.e., min. 5 own-capacity owners).
- Relax 100% requirement for gen-tie lines to say 50% or less in conjunction with anchor tenants or an open season.

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(602) 808-2004

Appendix

Cost Recovery Options for Independent Transmission Projects

Within organized markets (e.g., CAISO):

1. Cost-of-service recovery through approved transmission rates of ISO/RTO
   - Examples: Path 15 and Trans Bay Cable
2. Merchant model via long-term contracts with customers

Outside organized markets (e.g., most of the WECC):

1. Market based rates in open season via long-term contracts with customers
   - Example: Montana Alberta Tie Line
2. Cost-of-service rates via long-term contracts with customers
3. Combination of market based rates in open season and negotiated contracts via long-term contracts with customers
   - Examples: Chinook/Zephyr and SunZia
4. Sell project to Electric Utility who recovers through cost-of-service & retail rates
5. Qualify as a "gen tie line" with FERC and recover via associated generation project PPAs
   - Example: Milford Project

PROPOSED FACILITIES

Double-circuit 500 kV interstate transmission project between central New Mexico and Metro-Phoenix

Purpose is to deliver primarily renewable energy from NM and AZ to western markets

Route will be ~500 miles long (with many alternatives)

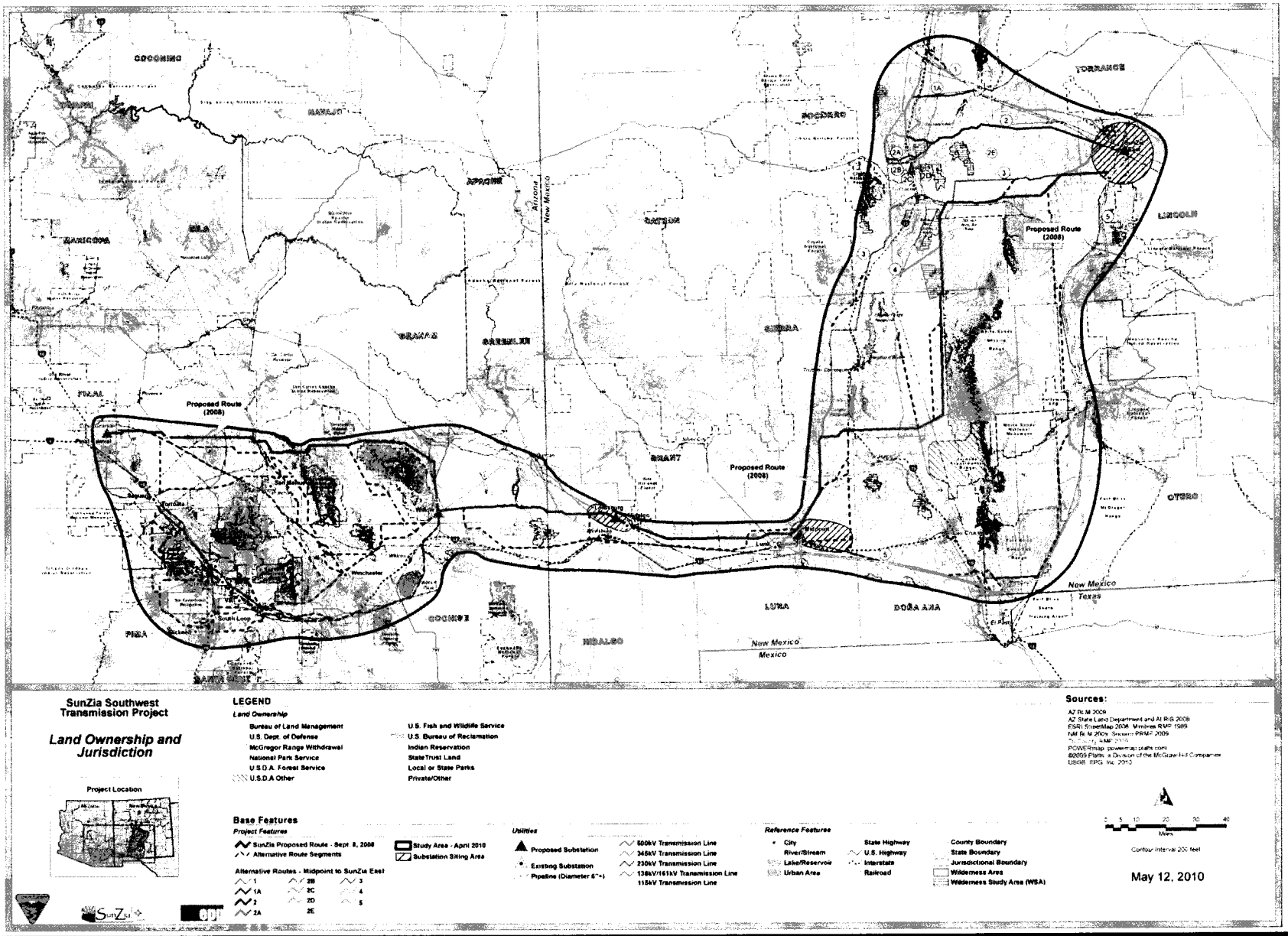
Configuration Options:

- Two 500 kV AC lines (in WECC Phase 2 review)
- One 500 kV AC and one 500 kV DC line (hybrid option)

Expected power transfer capacity of 3,000 MW or 4,500 MW with AC/DC hybrid option

Interconnects with up to five substations (two in AZ; three in NM)

SunZia Study Area as of December 2010



EIS Schedule as of December 2010

PROJECT TIMELINE

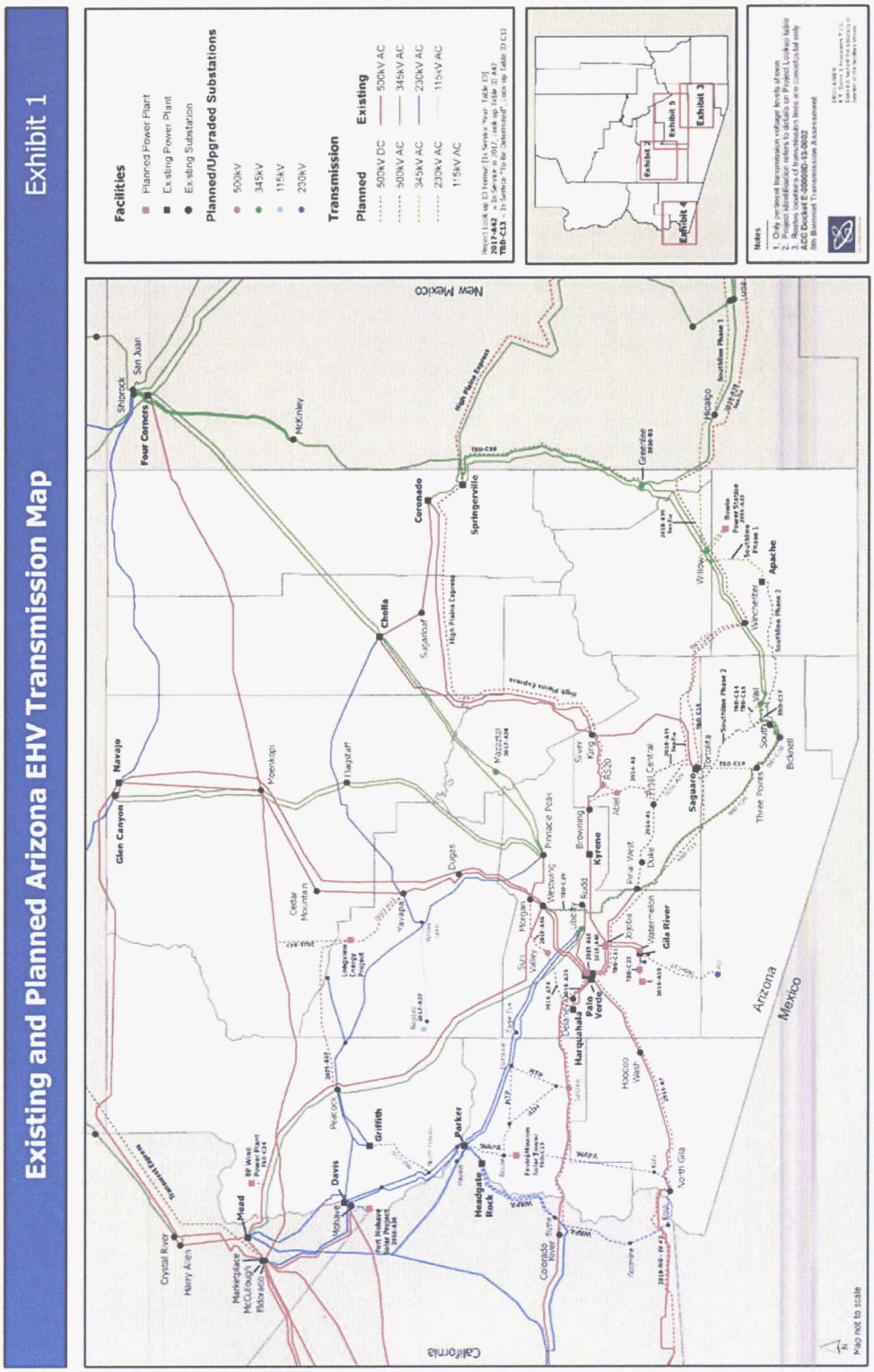
SUMMER 2009/SUMMER 2010	SPRING 2011	SUMMER 2012	FALL 2012	2015
Scoping Comment Periods Public Meetings	Draft Environmental Impact Statement	Final Environmental Impact Statement	Record of Decision Right-of-Way Permit	Construction & Operation

Jun - Aug 2009	Oct - Nov 2009	Apr - May 2010			
Initial Study Area 90 Days	Expanded Study Area in NM 45 Days	Expanded Study Area in AZ and NM 45 Days	Public Review Period 90 Days	Public Review Period 30 Days	

EXHIBIT NMM-31

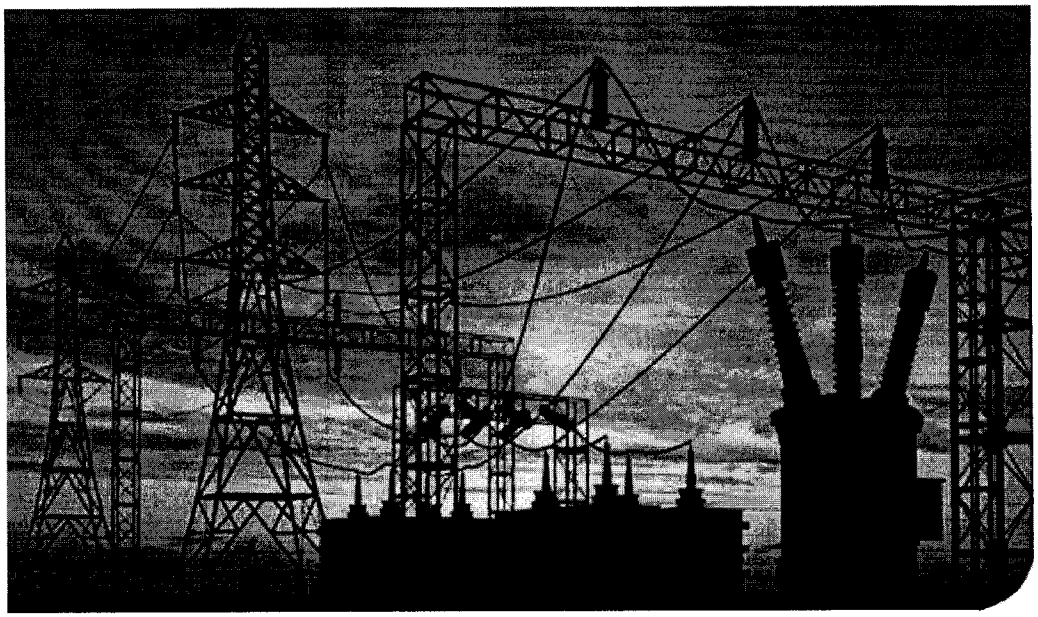
EXHIBIT NMM-31

Components of Arizona's extra-high-voltage transmission system and 230-kilovolt lines outside the Phoenix metropolitan area. Exhibit 1, page 79, from Arizona Corporation Commission Staff and K.R. Saline and Associates, P.LC., *Eighth Biennial Transmission Assessment 2014-2023*, Docket No. E-00000D-13-0002, Decision No. 74785, October 29, 2014, 191 pp. Available from http://www.azcc.gov/divisions/utilities/electric/biennial.asp. Accessed October 11, 2015.



Seventh Biennial Transmission Assessment (2012-2021) Staff Report

Docket No. E-00000D-11-0017.



December 12, 2012

EXHIBIT NMM-32

EXHIBIT NMM-32

DEFINITIONS

Available Transfer Capability (ATC) is a measure of the transfer capability remaining in the physical transmission network *for further commercial activity* over and above already committed uses. It is defined as Total Transfer Capability (TTC) less existing transmission commitments, less a Capacity Benefit Margin (reserved for load-serving entities), less a Transmission Reliability Margin.

Total Transfer Capability (TTC) is the amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions.

Transmission Reliability Margin (TRM) is defined as that amount of transmission transfer capability necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions.

Capacity Benefit Margin (CBM) is defined as that amount of transmission transfer capability reserved by load serving entities to ensure access to generation from interconnected systems to meet generation reliability requirements.

EXHIBIT NMM-33

EXHIBIT NMM-33

Detailed view of high-voltage transmission lines in central Arizona. Red = 500 kilovolts, green = 345 kilovolts, and blue = 230 kilovolts. The 230-kilovolt system within the Phoenix metropolitcan area is not shown. Some of those lines would form part of the path between Pinal Central and Palo Verde. The ATC values measured to assess capacity are from the Pinal West substation to Palo Verde (southerly route) and from the Abel substation to Palo Verde (northerly route). TBD-C11 is from Line Siting Case 11, which was a 500-kilovolt line proposed 40 years with the construction of the Palo Verde Nuclear Generating Station but never used.

From Exhibit 1, page 79, Arizona Corporation Commission Staff and K.R. Saline and Associates, P.LC., *Eighth Biennial Transmission Assessment 2014-2023*, Docket No. E-00000D-13-0002, Decision No. 74785, October 29, 2014, 191 pp. Available from http://www.azcc.gov/divisions/utilities/electric/biennial.asp. Accessed October 11, 2015.

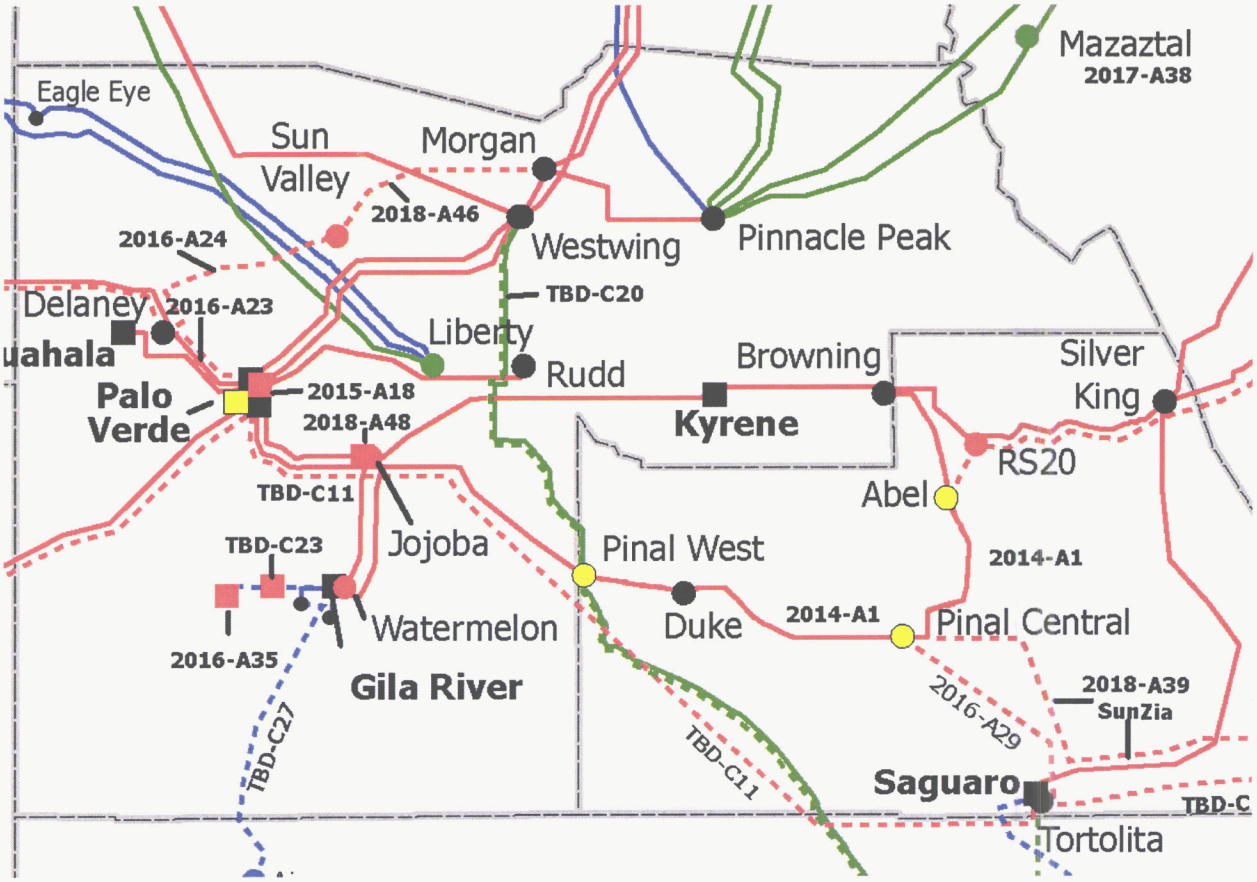
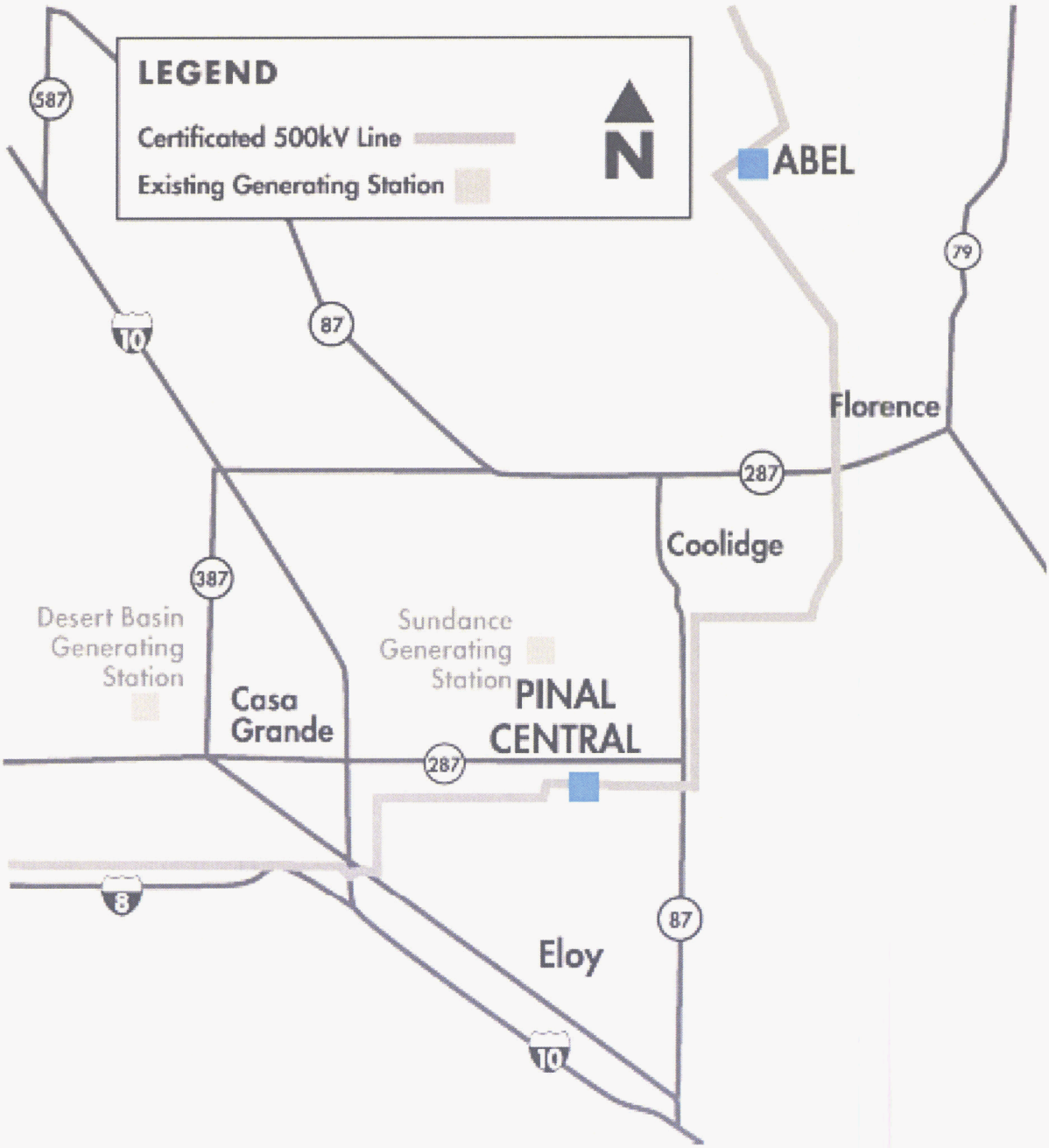


EXHIBIT NMM-34

EXHIBIT NMM-34

Locations of new natural gas power plants proposed for construction by the Salt River Project at Pinal Central and Abel by 2020. The Pinal Central plant would be 1,150 megawatts, while the Able plant would be 900 megawatts. Construction of these plants follows the purchase of all output from TransCanada's Coolidge 570-megawatt natural gas power plant in 2011. SRP has currently postponed building an additional plant at Eloy because of lower-than-expected demand. From Salt River Project website http://www.pinalenergyprojects.org/projectsoverview.aspx. Accessed October 11, 2015.



TOPIC 4

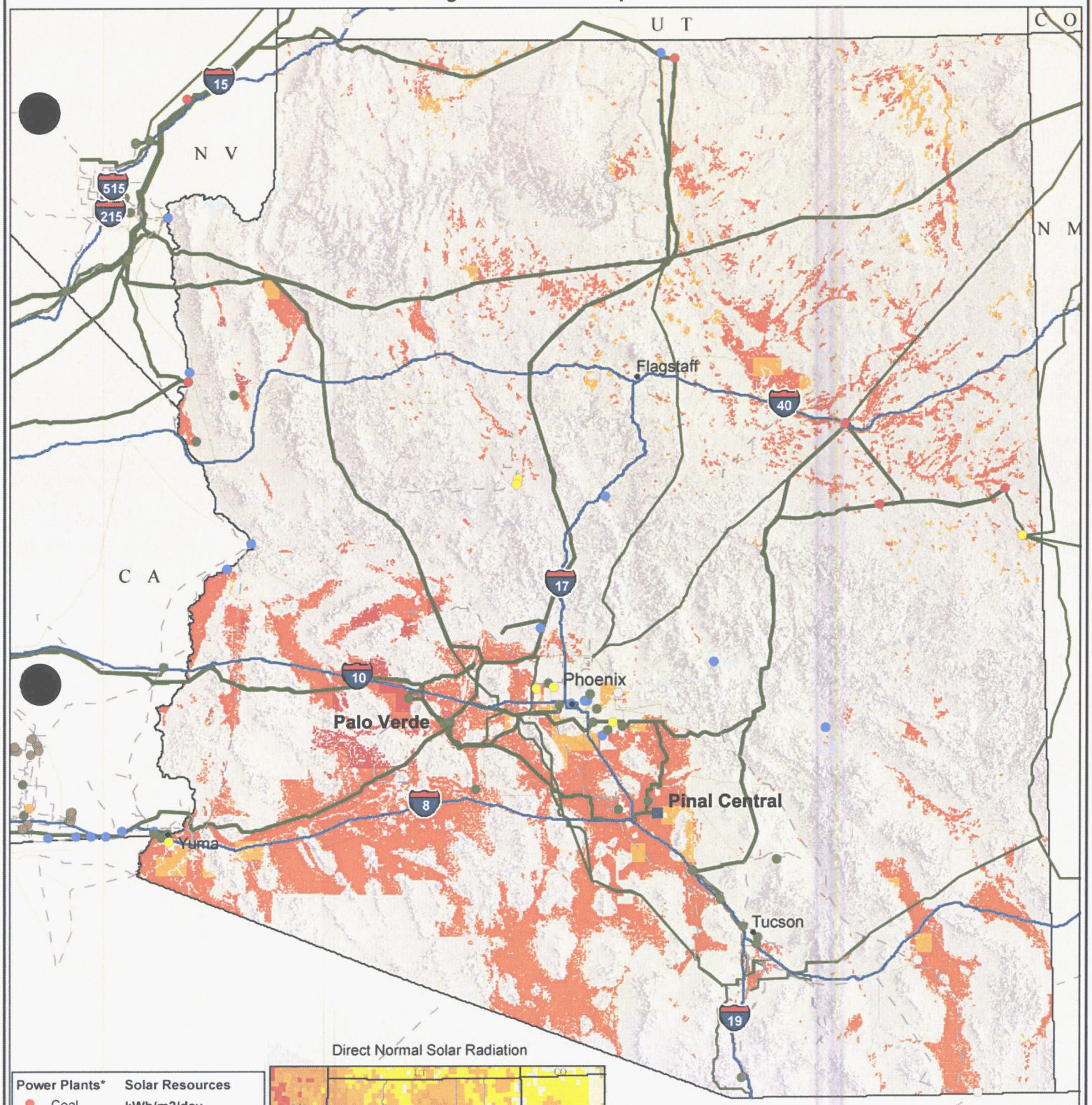
CONFLICTS WITH ARIZONA'S SOLAR ENERGY DEVELOPMENT

EXHIBIT NMM-35

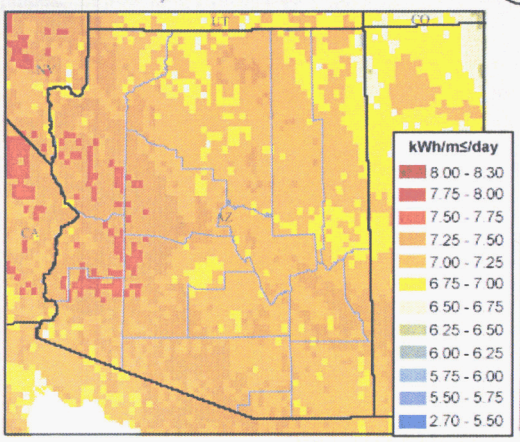
EXHIBIT NMM-35

Concentrating solar prospects for Arizona defined by the National Renewable Energy Laboratory for areas of 1% slope or less. The areas have been high graded by selected for the flatness of terrain in order to accommodate this solar technology. Available from http://www.nrel.gov/csp/images/1pct_csp_az.jpg.

Concentrating Solar Power Prospects of Arizona



Direct Normal Solar Radiation



Power Plants*	Solar Resources
Coal	kWh/m2/day
Natural Gas	8.0 - 8.2
Solar	7.5 - 8.0
Uranium	7.0 - 7.5
Water	6.5 - 7.0
Wind	6.0 - 6.5
Geothermal	**Transmission Lines***
Biomass	735kV - 999kV
Other	500kV - 734kV
	345kV - 499kV
	230kV - 344kV
	Below 230kV

NREL

July 2007

* Source: POWERmap. ©2007 Platts, a Division of the McGraw-Hill Companies

Potentially sensitive environmental lands, major urban areas, water features, areas with slope > 1%, and remaining areas less than 1 sq.km were excluded to identify those areas with the greatest potential for development.

The direct normal solar resource estimates shown are derived from 10 km SUNY data, with modifications by NREL.

EXHIBIT NMM-36

EXHIBIT NMM-36

The status of renewable energy interconnection requests on Arizona transmission lines through 2010. Solar energy interconnection requests total 14,726 megawatts. Wind energy interconnection requests total 7,964 megawatts. Note that 3,400 megawatts of wind energy interconnection requests are from New Mexico, while 50 megawatts of solar energy are.

Slide 3 from Peter Krzykos, *SWAT RTTF Technical Committee Report* (PowerPoint Presentation), SWAT Oversight Committee Meeting, August 17, 2010. Available at http://www.energy.ca.gov/reti/steering/2010-10-07_meeting/documents/03%20-%202010-10-07%20Krzykos%20SWAT%20RTTF.pdf Accessed October 5, 2015.

Generation Interconnection Requests

< 21 MW not shown but included in totals

APS
Solar 7294MW
Wind 3464MW

SRP
Solar 2820MW
Wind 1700MW

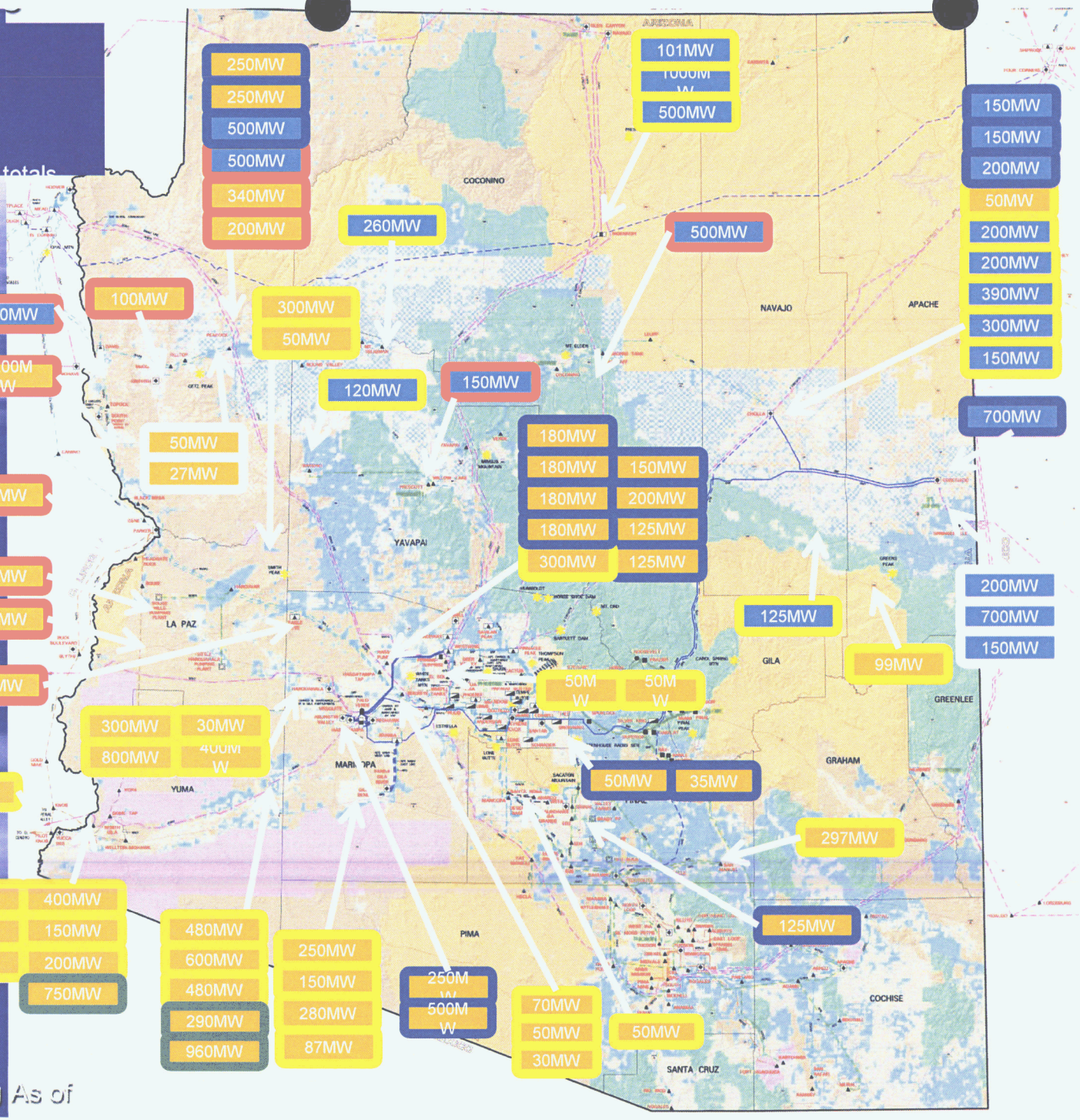
TEP
Solar 117MW
Wind 1050MW

WAPA
Solar 2495MW
Wind 1750MW

CAISO
Solar 2000MW

Totals
Solar 14726MW
Wind 7964MW

Interconnection Queue Listing As of



Outline

- Nevada, New Mexico and Arizona Queue Update (2010)
- Recommendations from the 6th BTA
- RTTF next step
  - SWAT Steering Committee meeting
  - Coordination with other subrigional groups (CATS , SATS, CRT,NM)
  - Study Plan

Generation Interconnection Requests

< 21 MW not shown but included in totals

APS

Solar

Wind 3464MW

SRP

Solar

Wind 1700MW

TEP

Solar

Wind 1050MW

WAPA

Solar

Wind 1750MW

CAISO

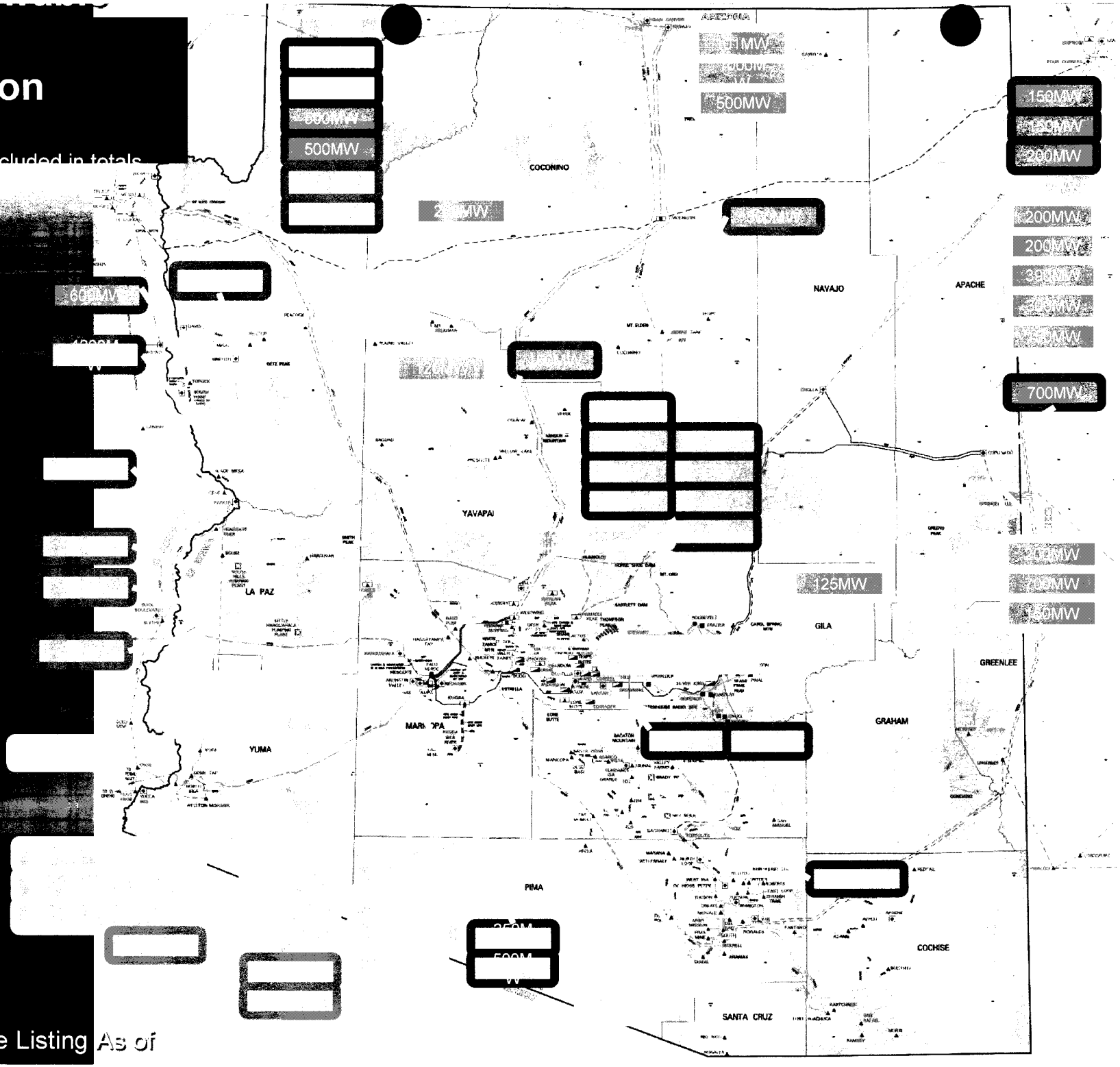
Solar

Totals

Solar

Wind 7984MW

Interconnection Queue Listing As of

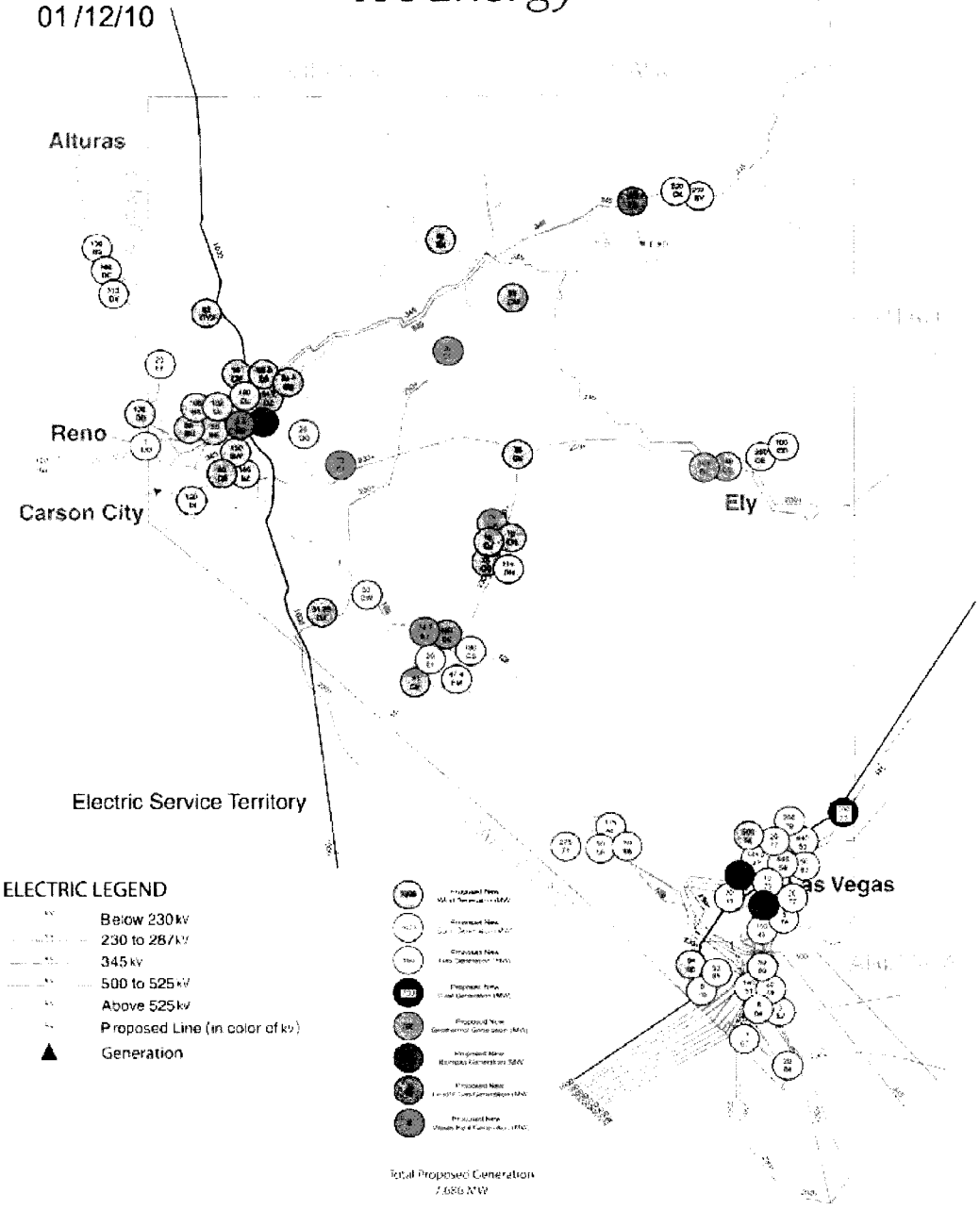


OASIS
NVE Proposed Interconnections
01/12/10

NVEnergy

Renewable resource locations are based upon public information from the NV Energy OASIS queue.

These do not represent the actual location of the plants.

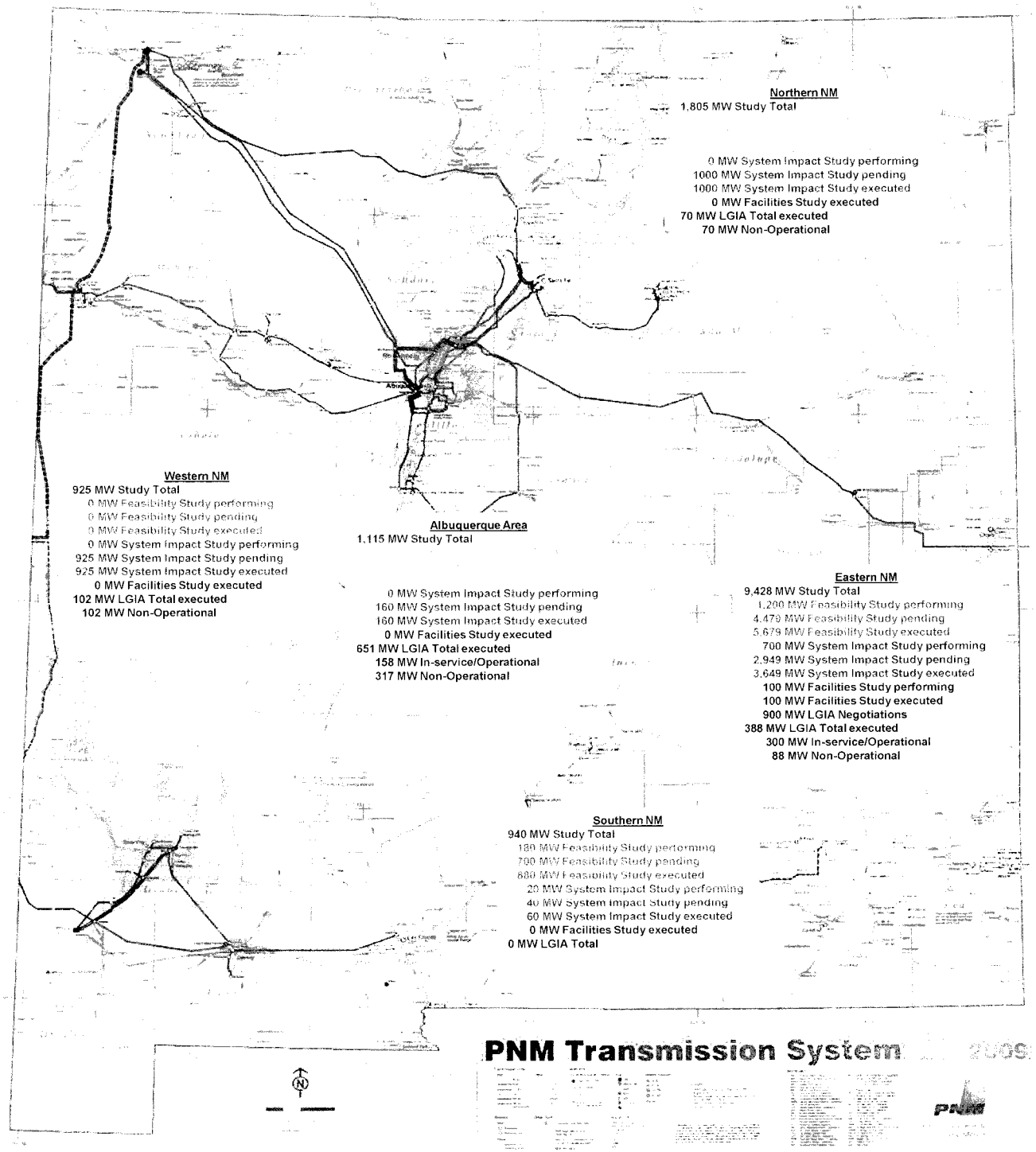


ELECTRIC LEGEND

- Below 230kV
- 230 to 287kV
- 345kV
- 500 to 525kV
- Above 525kV
- Proposed Line (in color of kV)
- ▲ Generation

Total Proposed Generation
7,686 MW

© NV Energy 01/12/10

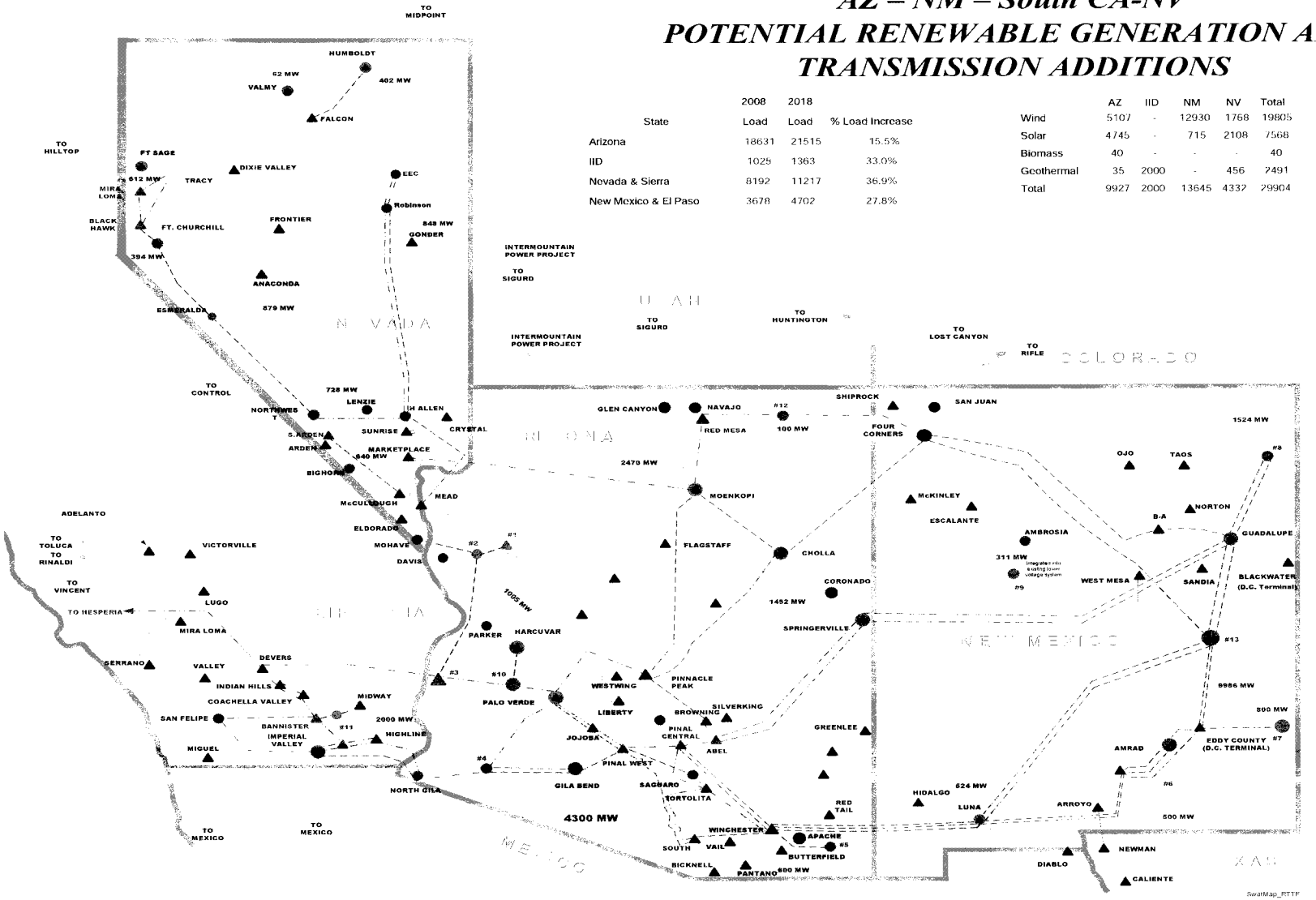

Northern NM
1,805 MW Study Total
0 MW System Impact Study performing
1000 MW System Impact Study pending
1000 MW System Impact Study executed
0 MW Facilities Study executed
70 MW LGIA Total executed
70 MW Non-Operational
Western NM
925 MW Study Total
0 MW Feasibility Study performing
0 MW Feasibility Study pending
0 MW Feasibility Study executed
0 MW System Impact Study performing
925 MW System Impact Study pending
925 MW System Impact Study executed
0 MW Facilities Study executed
102 MW LGIA Total executed
102 MW Non-Operational
Albuquerque Area
1,115 MW Study Total
0 MW System Impact Study performing
160 MW System Impact Study pending
160 MW System Impact Study executed
0 MW Facilities Study executed
651 MW LGIA Total executed
158 MW In-service/Operational
317 MW Non-Operational
Eastern NM
9,428 MW Study Total
1,200 MW Feasibility Study performing
4,479 MW Feasibility Study pending
5,679 MW Feasibility Study executed
700 MW System Impact Study performing
2,949 MW System Impact Study pending
3,649 MW System Impact Study executed
100 MW Facilities Study performing
100 MW Facilities Study executed
900 MW LGIA Negotiations
388 MW LGIA Total executed
300 MW In-service/Operational
88 MW Non-Operational
Southern NM
940 MW Study Total
180 MW Feasibility Study performing
700 MW Feasibility Study pending
880 MW Feasibility Study executed
20 MW System Impact Study performing
40 MW System Impact Study pending
60 MW System Impact Study executed
0 MW Facilities Study executed
0 MW LGIA Total
PNM Transmission System
2005
N
PNM

Potential Transmission Additions

AZ – NM – South CA-NV
POTENTIAL RENEWABLE GENERATION AND TRANSMISSION ADDITIONS

State	2008 Load	2018 Load	% Load Increase
Arizona	18631	21515	15.5%
IID	1025	1363	33.0%
Nevada & Sierra	8192	11217	36.9%
New Mexico & El Paso	3678	4702	27.8%

	AZ	IID	NM	NV	Total
Wind	5107	-	12930	1768	19805
Solar	4745	-	715	2108	7568
Biomass	40	-	-	-	40
Geothermal	35	2000	-	456	2491
Total	9927	2000	13645	4332	29904



EXISTING TRANSMISSION ELEMENTS

- POWER PLANT
- SUBSTATION
- +500KV DC
- 500KV
- 345KV
- 230KV

10 YEAR PLAN TRANSMISSION ELEMENTS

- POWER PLANT
- SUBSTATION
- 500KV
- 345KV
- 230KV

POTENTIAL RENEWABLE ENERGY TRANSMISSION ELEMENTS

- BULK RENEWABLE POWER PLANT AT A NEW SUBSTATION
- BULK RENEWABLE POWER PLANT AT AN EXISTING SUBSTATION / POWER PLANT
- SUBSTATION
- 500KV
- 230KV

SOLAR RESOURCE

WIND RESOURCE

BIOMASS RESOURCE

GEOTHERMAL RESOURCE

EXHIBIT NMM-37

EXHIBIT NMM-37

Statements of Interest for solar energy development received for Western's (WAPA's) new 230-kilovolt line from Electrical District 5 northwest of Tucson to Pinal West and by extension to the Palo Verde hub.

Top image, slide 4 from Western Area Power Administration, *SPPR Group Proposal* (presentation), October 6, 2010. Available from https://www.wapa.gov/regions/DSW/PowerMarketing/Documents/SPPR%20Meeting%20(10-06-10)%20Final.pdf. Accessed October 11, 2015.

Bottom image, project map from page 13, Western Arizona Power Administration, *Draft Environmental Assessment, Electrical District 5 – Palo Verde Hub Project*, Western No.: DOE/WA-1864, June 2011, 203 pps. Available at http://energy.gov/sites/prod/files/nepapub/nepa_documents/RedDont/EA-1864-DEA-2011.pdf. Accessed October 12, 2015.

Renewable Nexus Statements of Interest

1. Federal Register Notice requesting Statements of Interest (SOI) issued July 26, 2010, seeking interest in long-term firm transmission to deliver renewable energy from south of Phoenix to Palo Verde Hub
2. Western received 8 SOIs from 5 entities submitted by renewable resource developers
   - SOI's vary between 40 MW – 1,000 MW of transmission service
   - The 8 SOI's total approximately 2,000 MW
   - The renewable resources include Wind, Solar, Photovoltaic, Flash Geothermal

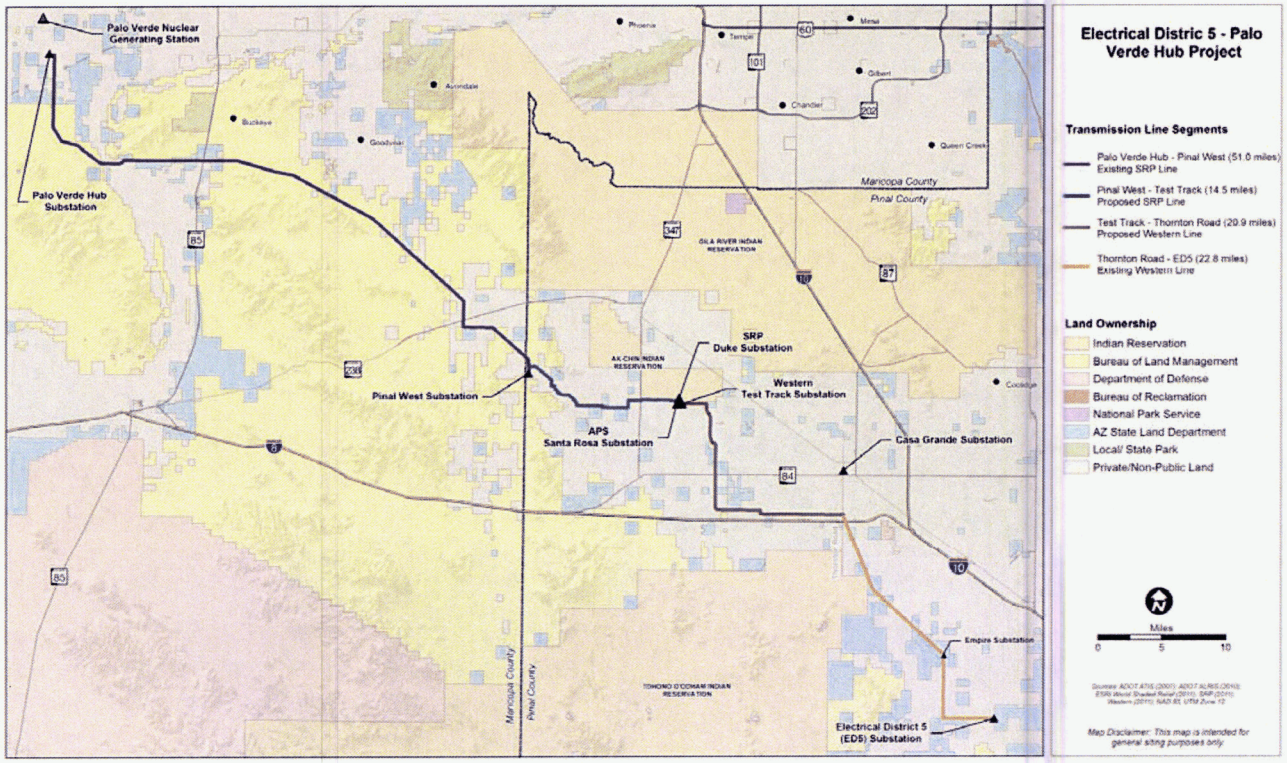


Figure 2-1 Vicinity and Jurisdiction Map

SPPR Group Proposal

Should Western pursue a TIP-financed project to enhance the Parker-Davis Project transmission system South of Phoenix?

October 6, 2010

Recap from June 23, 2010, Customer Meeting

June 23rd Presentation and Comments can be found at:

http://www.wapa.gov/dsw/pwrmkt/Ed5

Next Steps identified at June meeting:

- Determine Renewable Nexus
- Analysis of Alternatives
- Initiate Transmission Planning Studies
- Refine the Project Proposal
- Follow up with customers on Revised Proposal

Today's Agenda

1. **Next Steps from June 23rd:**
   - Renewable Nexus ..... Todd Rhoades
   - Analysis of Alternatives/Project Descriptions .. Todd Rhoades
   - Transmission System Planning Studies ..... Josh Johnston
2. **Business Needs Discussion** ..... Todd Rhoades
3. **Revised ED5-Palo Verde Hub Project Proposal** ..... Todd Rhoades
   - Marketability ..... John Steward
   - Cost and Financing ..... Jack Murray
   - Rate Treatment ..... Jack Murray
   - Benefits of Proposed Project ..... Todd Rhoades
   - Summary ..... Todd Rhoades
4. **Proposed Timeline** ..... Todd Rhoades
5. **Discussion / Comments**

Renewable Nexus Statements of Interest

1. Federal Register Notice requesting Statements of Interest (SOI) issued July 26, 2010, seeking interest in long-term firm transmission to deliver renewable energy from south of Phoenix to Palo Verde Hub
2. Western received 8 SOIs from 5 entities submitted by renewable resource developers
   - SOI's vary between 40 MW – 1,000 MW of transmission service
   - The 8 SOI's total approximately 2,000 MW
   - The renewable resources include Wind, Solar, Photovoltaic, Flash Geothermal

Renewable Nexus Transmission Service Request

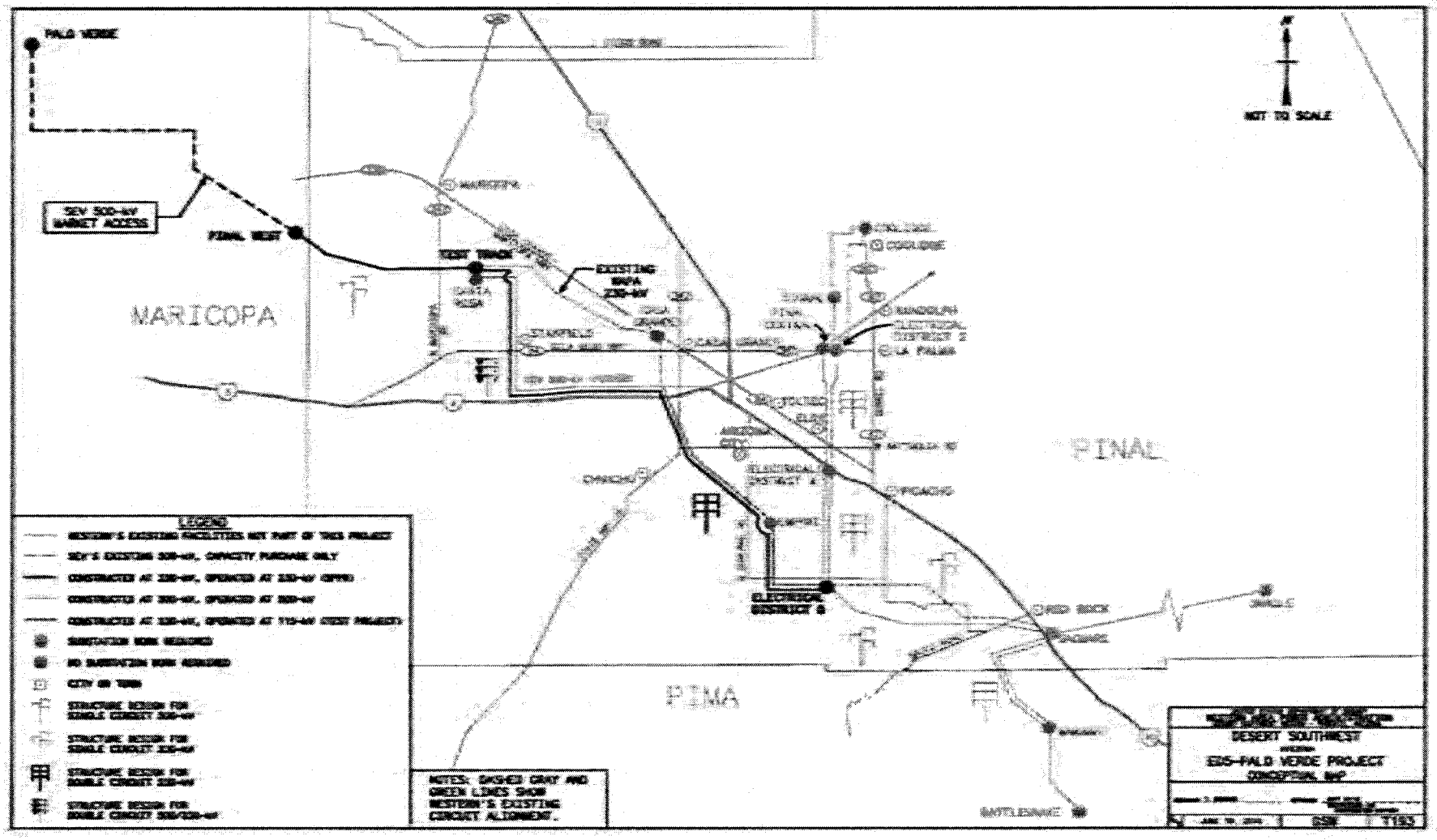
Additionally, Western has received a transmission service request for 300 MW from ED-5 to Palo Verde Hub.

This request is associated with a renewable generation project.

Analysis of Project and Alternatives

1. ED5- Palo Verde Hub (SPPR Proposal)
2. ED5-Casa Grande – Palo Verde Hub
3. Test Track – Palo Verde Hub (OATT Alternative)

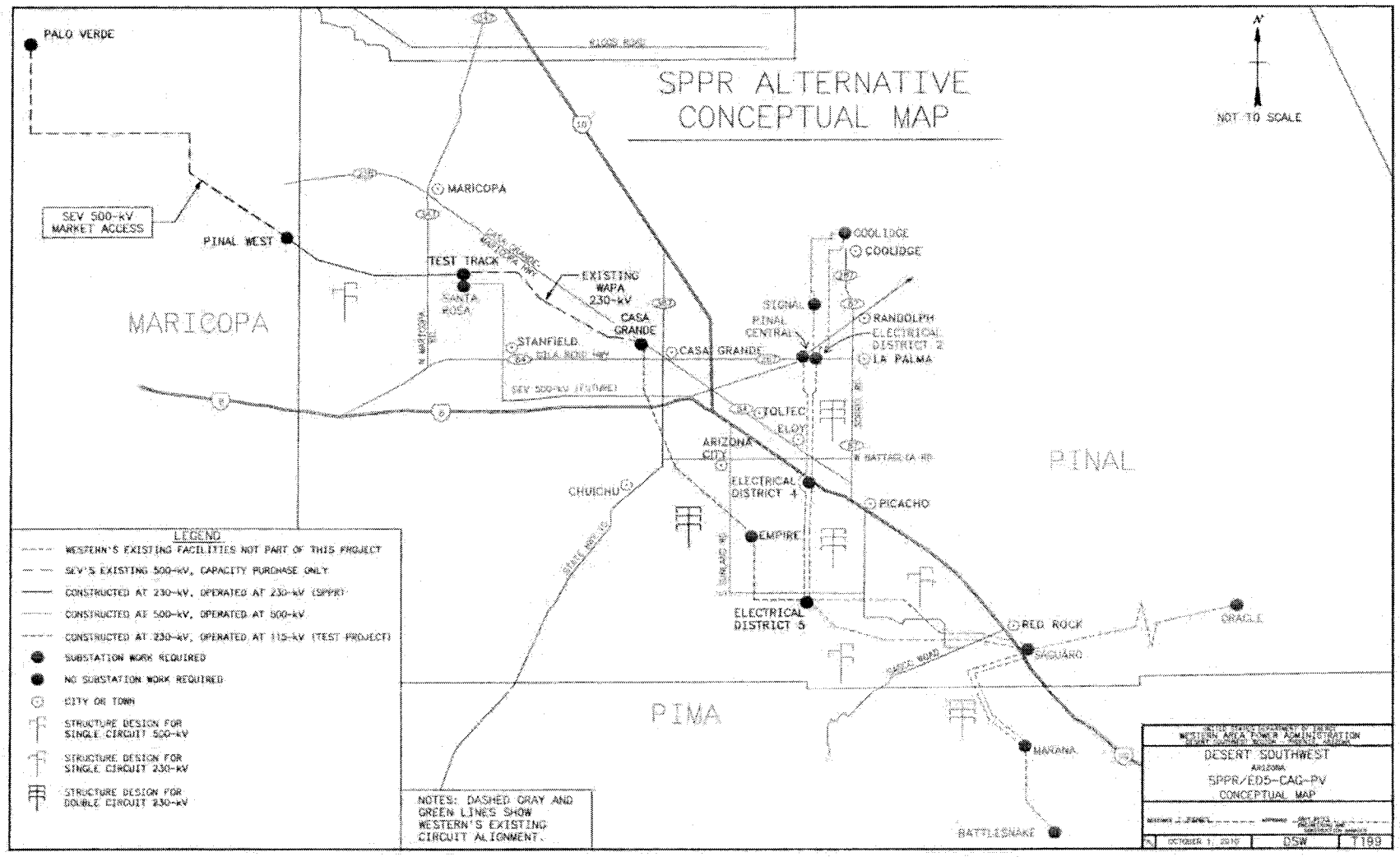
ED5-Palo Verde Hub Project



ED5-Palo Verde Hub Project Description

1. The major elements of the project are:
   - Participation in 500-kV Southeast Valley Project from Hassayampa to Santa Rosa/Test Track
   - Conversion of 230-kV switchyard at Test Track Substation from Ring Bus to Breaker-and-One-Half configuration and addition of new bays
   - Construction of a new 230-kV ED5-Test Track Line; this line is under built on the SEV 500-kV Pinal Central-Santa Rosa Line, and double circuited with Western's CAG-EMP-ED5 115-kV Line
   - Conversion of the ED5 115-kV Tap to a Breaker-and-One-Half switchyard (built to 230-kV standards) and interconnection of a new 230/115 transformer
2. Estimated Construction Cost: $75.4M; does not include financing and overhead costs

ED5-CAG-Palo Verde Hub Project Alternative

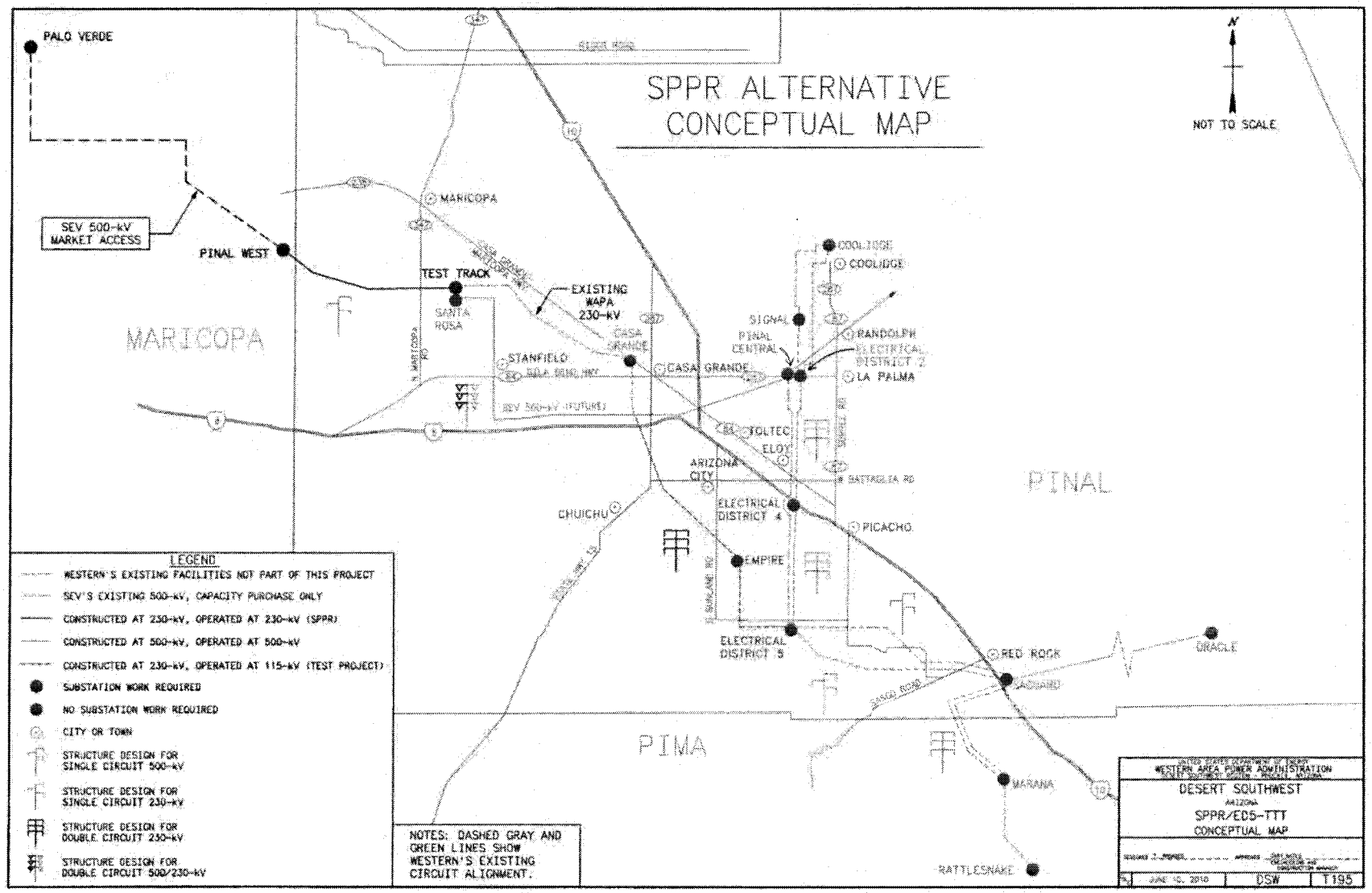


ED5-CAG-Palo Verde Hub Alternative Description

1. The major elements of this alternative are:
   - Participation in 500-kV SE Valley Project from Hassayampa to Santa Rosa/Test Track
   - Conversion of 230-kV switchyard at Test Track Substation from Ring Bus to Breaker-and-One-Half configuration and addition of a new bay
   - Construction of a new 230-kV CAG Switchyard (ring bus); removal of the existing 230/115 transformer and replacement of 115/12.5 transformers with 230/12.5
   - Conversion of the ED5 115-kV Tap to a Breaker-and-One-Half switchyard (built to 230-kV standards) and interconnecting a new 230/115 transformer
2. Estimated Construction Cost: $65.9M; does not include financing and overhead costs

NOTE: Requires participation by ED-4 for upgrades at Empire Substation

TTT-Palo Verde Hub Project Alternative



TTT-Palo Verde Hub Alternative Description

1. The major elements of this alternative are:
   - Participation in 500-kV SE Valley Project from Hassayampa to Santa Rosa/Test Track
   - Conversion of 230-kV switchyard at Test Track Substation from Ring Bus to Breaker-and one-Half configuration and addition of a new bay

2. Estimated Construction Cost: $29.9M; does not include financing and overhead costs

TTT-Palo Verde Hub Alternative Description (continued)

If TIP financing is not pursued, this alternative's configuration may proceed under Western's OATT.

- The Transmission Service Request of 156 MW serving load from PVH to various delivery points on P-DP will require Western to evaluate the Test Track-PVH project segment under the tariff.
- Some or all of the project segments could qualify as network upgrades for which the customer may be eligible for transmission service credits.

Transmission System Planning Studies

Western performed high-level power flow studies for the three alternatives, with these results:

1. ED5-PV Hub Project
   - Capable of supporting over 400 MW of renewable generation
   - Could support up to 700 MW of renewable generation when ED5-Saguaro 115-kV Line upgraded (in TYP)

2. ED5-CAG-PV Hub Project
   - Capable of supporting up to 350 MW of renewable generation

3. TTT-PV Hub Project
   - Capable of supporting up to 250 MW of renewable generation

Transmission System Planning Summary

- All three alternatives capable of serving the 156MW request for load serving
- The Test Track – PVH option not capable of supporting an additional 300MW of generation
- The ED5 – PVH option provides the greatest load-serving capability for future customer load growth
- The amount of renewable generation able to be supported and the path ratings are dependent on:
  - Where generation is sited
  - Where generation output is delivered
- Western currently working on technical studies to establishing path rating(s)

Business Needs Met by the Proposed ED5-PV Hub Project

- Responsive to customer request to accommodate future load growth
- Provides necessary upgrade to transmission system South of Phoenix
- Enhances reliability and improves safety
- Supports renewable generation development
- Enhances opportunity for additional transmission sales
- Creates additional market access

ED5-PV Hub Project Proposal

- Proposal resulted from SPPR Group's Statement of Interest on May 14, 2010
- Proposed project would support members' load growth and development of renewable generation in the area south of Phoenix
- Proposal includes use of borrowing authority under Western's Transmission Infrastructure Program

ED5-Palo Verde Hub Project Proposal

(continued)

Federal Assets Resulting from the Project:

- New Transmission Rights on PVH-Test Track
  - PV to Test Track – 156 MW of capacity
  - Test Track to PV – 300 MW of capacity
- New 230-kV ED5-Test Track Transmission Line
- Additions and upgrades at Western's 230-kV Test Track Switchyard
- Additions and upgrades at Western's 230/115-kV ED5 Substation

ED5-Palo Verde Hub Project-Marketability

New transmission services between Palo Verde Hub-Test Track-ED5:

- 156 MW have been requested for load serving
- 300 MW have been requested for renewable generation
- SOIs received for ~2,000 MW of transmission supporting delivery of renewable energy

ED5-Palo Verde Hub Project-Marketability (continued)

- New transmission capacity may attract generation/transmission Interconnection requests and the purchase of additional capacity
- Western would be able to market unscheduled firm capacity as non-firm, resulting in downward pressure on P-DP transmission rate
- Provides accessibility to Palo Verde Hub for all P-DP customers
- Customers will be able to continue using P-DP to meet their transmission needs instead of exploring alternatives

ED5-PV Hub Project Cost & Financing

Estimated Construction Costs (in millions)	
New Transmission Rights (SEV Project)	$26.4
New 230-kV Transmission Line (ED5-Test Track)	27.6
Additions/Upgrades at Substations (ED5 & Test Track)	21.4
Total	$75.4
Level Annual Payment for TIP Financing	$4.1

- **TIP financing structured using a series of loans with multiple maturity dates**
- **Level annual payment based on interest rates as of Sept. 2, 2010**
- **Effective financing rate of 3.89% (PMA rate is 4.00%)**

ED5-PV Hub Project Proposed Rate Treatment

- All costs associated with the ED5-PV Hub Project will be included in the P-DP rate formulation, but kept separate through a *Facilities Use Charge*
- Revenue from the ED5-PV Hub Project capacity upgrades will also be included in the P-DP rate formulation, but kept separate through a *Facilities Use Charge* to offset costs
- The Beneficiaries and Participants of the ED5-PV Hub Project share the costs and benefits via a Facilities *Use Charge*
- This approach uses an existing cost recovery mechanism and shields current customers from adverse rate impacts, in the event transmission reservations using the new capacity decrease from current forecasts

ED5-PV Hub Project
Facilities Use Charge Concept

P-DP Rate Base

Revenue Requirement
÷ Reservations
= Transmission Rate

+

Project Costs

Annual Payment
for TIP Financing
+ O&M

Offsetting

−

Offsetting

Revenue

Facilities Use
Charge

=

P-DP w/Project

Revenue Requirement
+ Project Costs
- Facilities Use Revenue
÷ Reservations
= Transmission Rate

Facilities Use Charge

+ TIP Payment
+ Project O&M
÷ Usage Level
= Unit Cost

ED5-PV Hub Project
Facilities Use Charge Concept (continued)

- The Facilities Use Charge will be the usage level, multiplied by the unit cost
- Depending on usage levels, the unit cost may be more or less than the transmission rate
- Preliminary analysis indicates that a usage level of ~ 228 MW is required for the unit cost to equal the projected FY 2015 transmission rate
- A usage level above ~ 228 MW results in a unit cost lower than the projected FY 2015 transmission rate

ED5-PV Hub Project
Facilities Use Charge Concept (continued)

- Existing customers can elect to become a Beneficiary and participate in the ED5-PV Hub Project Facility Use Charge
- Customers that do participate must continue participation through the term of their transmission service agreement
- The Participants' share of the transmission revenue requirement will be included in the Facilities Use Charge

ED5-PV Hub Project
Facilities Use Charge Concept (continued)

P-DP Rate Base

Revenue Requirement
÷ Reservations
= Transmission Rate

+

Project Costs

Annual Payment
for TIP Financing
+ O&M

Offsetting

−

Offsetting

Revenue

Facilities Use
Charge

=

P-DP w/Project

Revenue Requirement
+ Project Costs
- Facilities Use Revenue
÷ Reservations
= Transmission Rate

Facilities Use Charge

Participants' Share of
Revenue Requirement
+ TIP Payment
+ Project O&M
÷ Usage Level
= Unit Cost

ED5-PV Hub Project
Facilities Use Charge Concept (continued)

- Transmission customers of the newly created capacity must elect to be Beneficiaries of the Project
- Other P-DP customers may elect to be Beneficiaries of the Project by voluntarily opting in, and are referred to as "Participants"
- Beneficiaries must have both a transmission service and a facility use agreement
- Participants will continue to use existing transmission service agreements, and will need Facilities Use Charge agreements

ED5-PV Hub Project
Facilities Use Charge Concept
(continued)

- Beneficiaries and Participants will be charged for transmission service and facilities use
- However, since their share of the costs will be recovered in the Facilities Use Charge, the transmission charge will be fully credited
- As a result, all Beneficiaries will only pay the facilities use charge plus applicable ancillary services
- This allows the use of Project facilities without pancaked transmission rates

Benefits of the Proposed Project

- Facilitate the delivery of renewable generation through transmission service requests and FRN responses
- Respond to customer Request to work with them to serve load South of Phoenix
- Reduce transmission rate pancaking for numerous P-DP customers
- Reduce potential downside risk of current Parker-Davis reservation levels if customers are not able to utilize Parker-Davis system effectively

Benefits of the Proposed Project (continued)

- Provide access to the Palo Verde Hub for P-DP customers
- Insulate existing P-DP customers from project-related rate increases and give them an opportunity to participate
- Provide funding for the Ten Year Plan ED5 Switchyard upgrade scheduled for construction beginning in FY 2014 and in-service in FY 2018.

Summary of ED5-PV Hub Project Proposal

- The ED5-PV Hub Project is currently proposed as a P-DP financed by Western's TIP
- Project Cost: $75.4 million plus financing costs
- Transmission service will be marketed through Western's Tariff
- Current requests in Western's Queue total 456 MW

Proposed Timeline

- P-DP Customer meeting to present proposed plan — Oct. 6, 2010
- Receive comments on Project Proposal — Oct. 22, 2010
- Notify customers of decision on proposal — Nov. 19, 2010
- If sufficient support from customers is received:
  - Begin NEPA Documentation for project — Dec. 1, 2010
  - Submit TIP funding application material to CSO/TIP office — Dec 1, 2010
  - Project update including additional information on Facilities Use Charge — Spring 2011
  - Signed TSR contracts — June 2011
- Signed construction and participation agreements — July 2011
- Receive first TIP funding — October 2011

Discussion / Comments

Please submit your comments by October 22, 2010

E-mail address: DSWPWRMKT@wapa.gov

POC Information:

Project Management: Todd Rhoades

Construction: Gary Bates

Planning & Technical Studies: Josh Johnston

Transmission Marketability: John Steward

Finance and Rates: Todd Statler

TOPIC 5

CONFLICTS WITH THE PLANNED SOUTHLINE TRANSMISSION PROJECT

EXHIBIT NMM-38

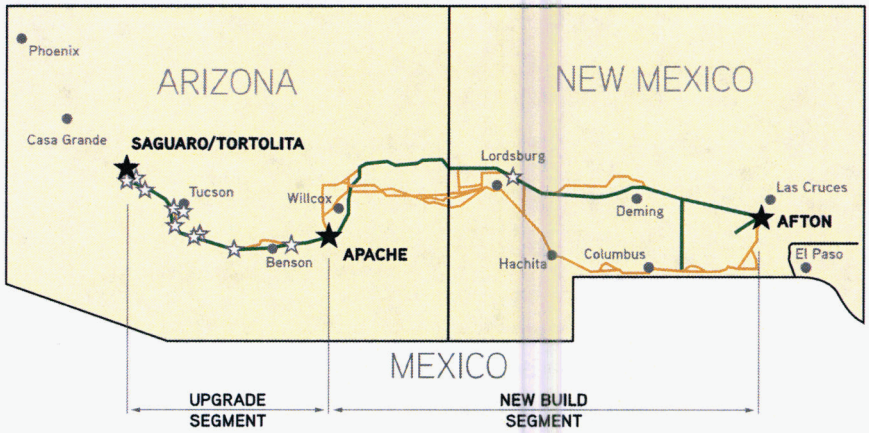
EXHIBIT NMM-38

Southline Transmission Project fact sheet. Available from http://southlinetransmissionproject.com/files/Southline-Transmission-Project-Fact-Sheet1.pdf. Accessed October 11, 2015.

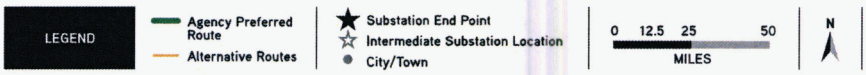
SOUTHLINE TRANSMISSION PROJECT

WHAT IS THE SOUTHLINE TRANSMISSION PROJECT?

The Southline Transmission Project is a proposed transmission line designed to collect and transmit electricity across southern New Mexico and southern Arizona, bringing electric system benefits to the Desert Southwest, one of America's fastest-growing regions. The project is being designed to minimize land and resource impacts by developing a route along existing linear features and by upgrading existing transmission lines where feasible – an innovative approach that respects the region's communities and natural and cultural resources. The project will provide up to 1,000 megawatts of transmission capacity in both directions, and will interconnect with up to 14 existing substation locations. The project consists of two sections:



The Project will have a right-of-way up to 200 feet wide. The Project may include development of a substation in Luna County, New Mexico, with precise location determined when Project route is confirmed.



- Approximately **240 miles of new, 345-kilovolt (kV) double-circuit transmission lines** between the existing substations at Afton (NM) and Apache (AZ); and
- A series of upgrades to approximately **120 miles of existing transmission lines** (from single-circuit 115-kV to double-circuit 230-kV) between the Apache (AZ) and Saguaro (AZ) substations.

The Bureau of Land Management and Western Area Power Administration have published a Draft Environmental Impact Statement for the project. For more information, please visit: www.blm.gov/nm/southline and http://go.usa.gov/3FTPh.

WHY IS IT NEEDED?

- **To improve reliability** – There is limited existing electrical transmission capacity in the region, which causes system reliability risks.
- **To relieve congestion** – Transmission capacity in the region is needed to relieve congestion and help local utilities access the most cost-efficient energy sources.
- **To sustain growth** – The Desert Southwest area is expected to experience substantial long-term growth, creating increased demand for power and therefore a greater need for transmission capacity to provide that power.
- **To facilitate renewable energy** – Satisfying the renewable energy requirements of western states will require access to transmission for renewable resources; a major challenge facing renewable energy development is insufficient transmission access.

WHAT BENEFITS DOES IT BRING?

- **Cost-effective, reliable electricity** – By interconnecting with up to 14 existing substation locations along its route, the Southline Transmission Project will enable local utilities to meet energy demands.
- **Local economic development** – The Southline Transmission Project will facilitate local economic development through project construction, enhanced power reliability, and by enabling additional local renewable energy development.
- **Resource conservation** – The Southline Transmission Project will minimize land use conflicts by working with federal and state energy and land use planning efforts, using existing infrastructure, and developing a route along existing infrastructure corridors.
- **Renewable energy** – The Southline Transmission Project will facilitate the connection of renewable energy projects to the electric system, helping states in the Desert Southwest meet renewable energy requirements.
- **Smart, coordinated approach** – The Southline Transmission Project team has worked closely with local utilities and other transmission providers since 2009 to ensure the Southline Transmission Project meets local needs and improves the region's electric system.

2009-2010 Preliminary feasibility and design

2011-2012 Public outreach and workshops to develop routing alternatives

2013-2016 Federal, state, and local permitting; right-of-way acquisition

2016-2018 Construction expected to occur

2018 Transmission operations expected to begin

WE LOOK FORWARD TO WORKING WITH YOU

Please visit our website to sign up for updates, access the latest information, and find out how to participate.
We strive to respond rapidly to all inquiries, including requests for meetings and presentations.

Website: www.southlinetransmissionproject.com / **Phone:** (888) 752-2822 / **Email:** connect@southlinetransmissionproject.com

September 2015

EXHIBIT NMM-39

EXHIBIT NMM-39

The Southline preferred alternative from the BLM's Draft Environmental Impact Statement. Available at http://southlinetransmissionproject.com/files/Project_Overview_Webmap.pdf. Accessed October 11, 2015.

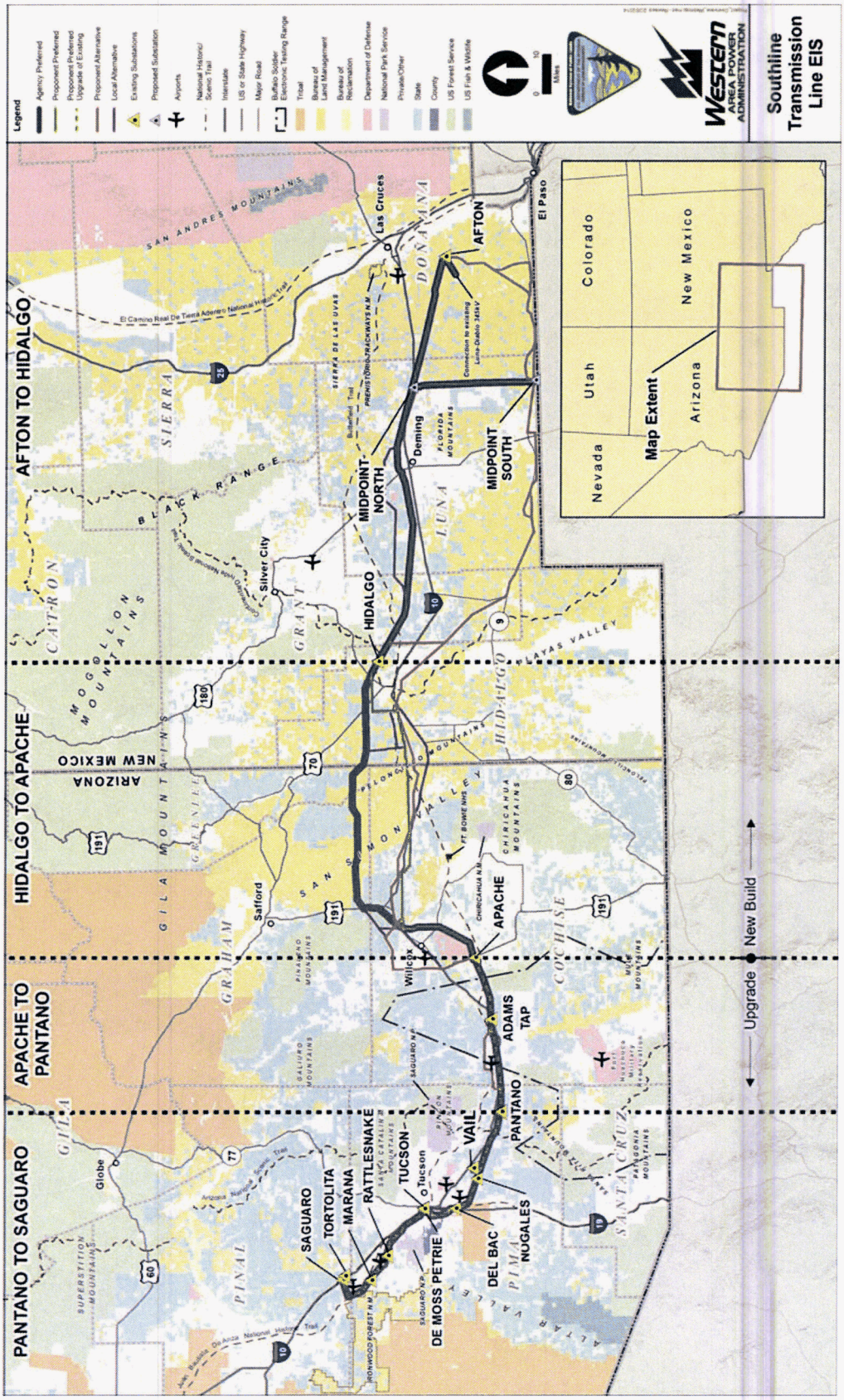


EXHIBIT NMM-40

EXHIBIT NMM-40

The preferred alternatives for the SunZia and Southline projects. From kmz files provided by the SunZia and Southline projects and loaded into Google Earth.

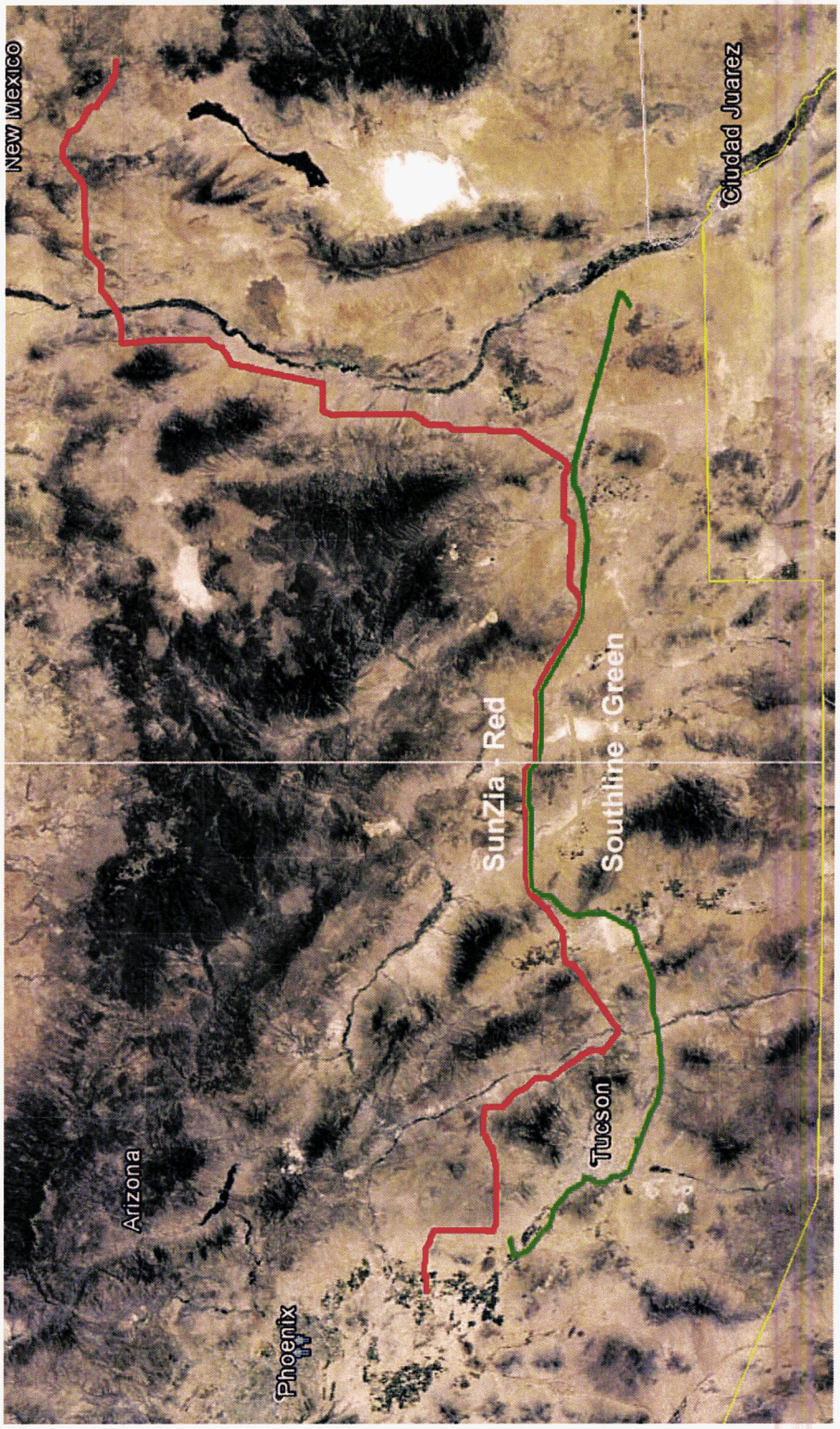
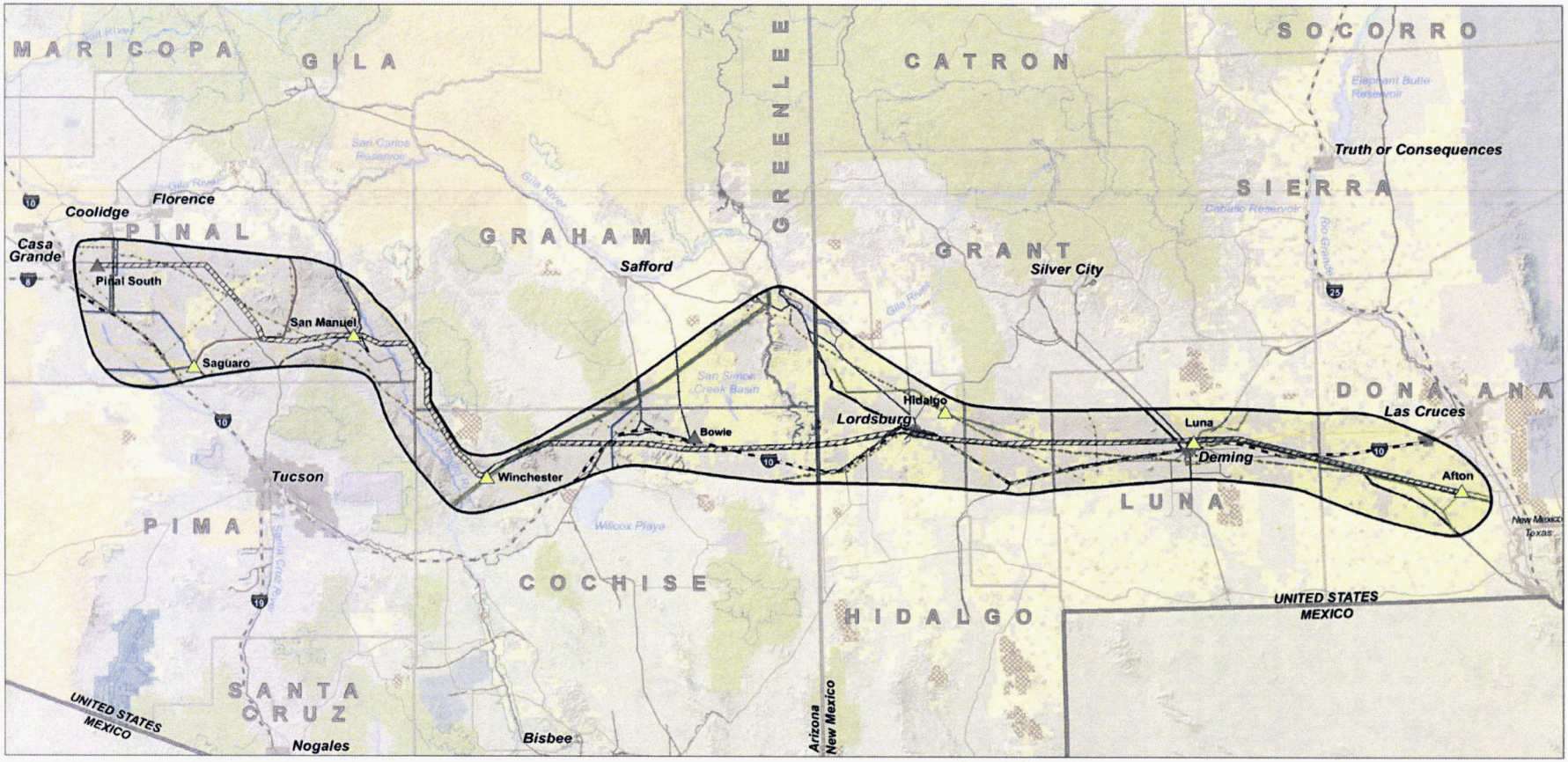


EXHIBIT NMM-41

EXHIBIT NMM-41

The initial SunZia Project showing its similarity to the Southline Project. Slide 3 from SunZia Southwest Transmission Project presentation, Arizona Corporation Commission Biennial Transmission Assessment Workshop, Phoenix, AZ, May 22 & 23, 2008. Available from http://www.azcc.gov/Divisions/Utilities/Electric/Biennial/2008%20BTA/SunZia%20BTA%202008.ppt. Accessed October 11, 2015.



LEGEND

Project Features
- Study Area
- Proposed Transmission Line Corridor
- ACEC
- Wilderness Area

Land Ownership
- Bureau of Land Management
- Indian Reservation/Bureau of Indian Affairs
- U.S. Forest Service
- National Park Service
- Department of Defense
- U.S. Fish & Wildlife Service
- State/Private/Other

Utilities
- Substation (Existing)
- Substation (Proposed)
- 500 kV Transmission Line
- 345 kV Transmission Line
- 230 kV Transmission Line
- 138 kV Transmission Line
- 115 kV Transmission Line
- Pipeline (6" Diameter and Above)

Reference Features
- International Boundary
- State Boundary
- County Boundary
- Interstate
- State Highway/Major Road
- Railroad
- River/Stream
- Lake/Reservoir
- Urban Area

Confidential - Not for Distribution

Note - Substation and transmission line locations are schematic and do not necessarily represent precise locations.

SunZia Southwest Transmission Project

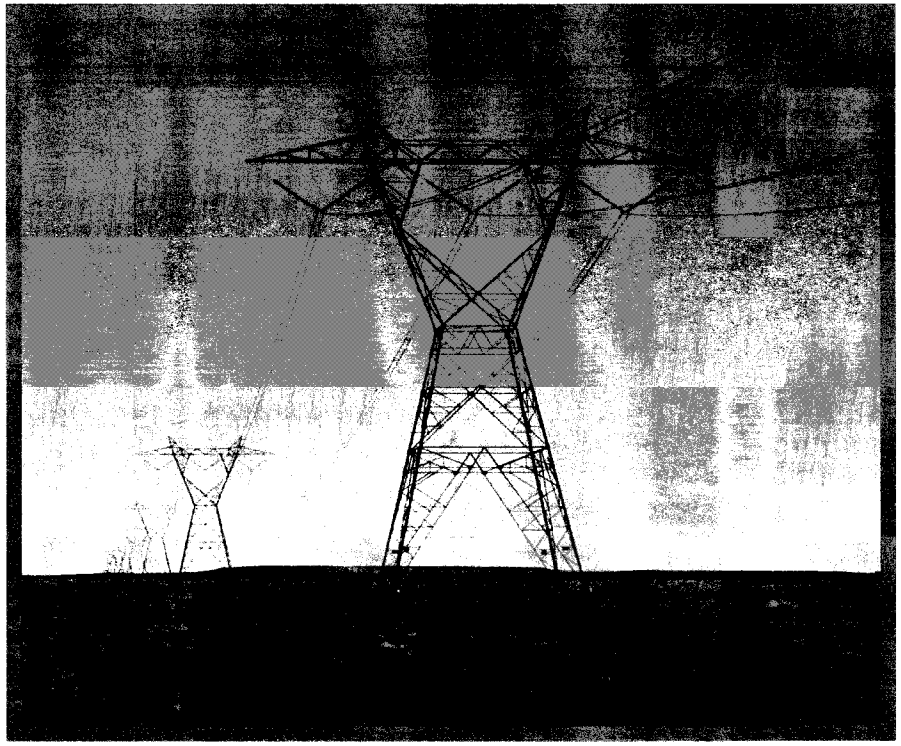
Preliminary Plan of Development

Figure 1

September 2007

Sources:
StreetMapUSA, 2007; BLM, 2004; USGS, 2005; EPG, Inc., 2007

SunZia Southwest Transmission Project



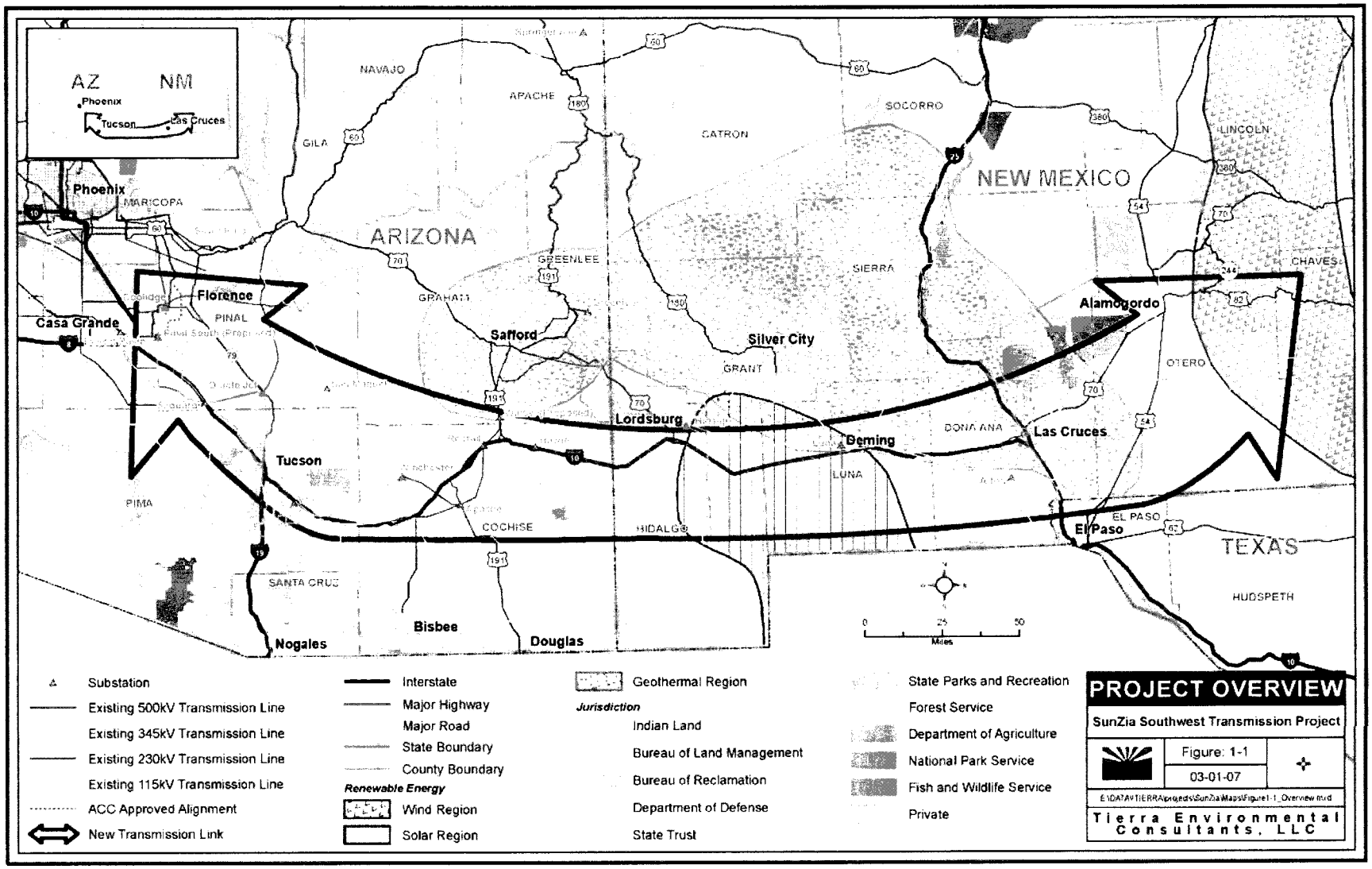
Arizona Corporation Commission Biennial Transmission Assessment Workshop

Phoenix, AZ

May 22 & 23, 2008

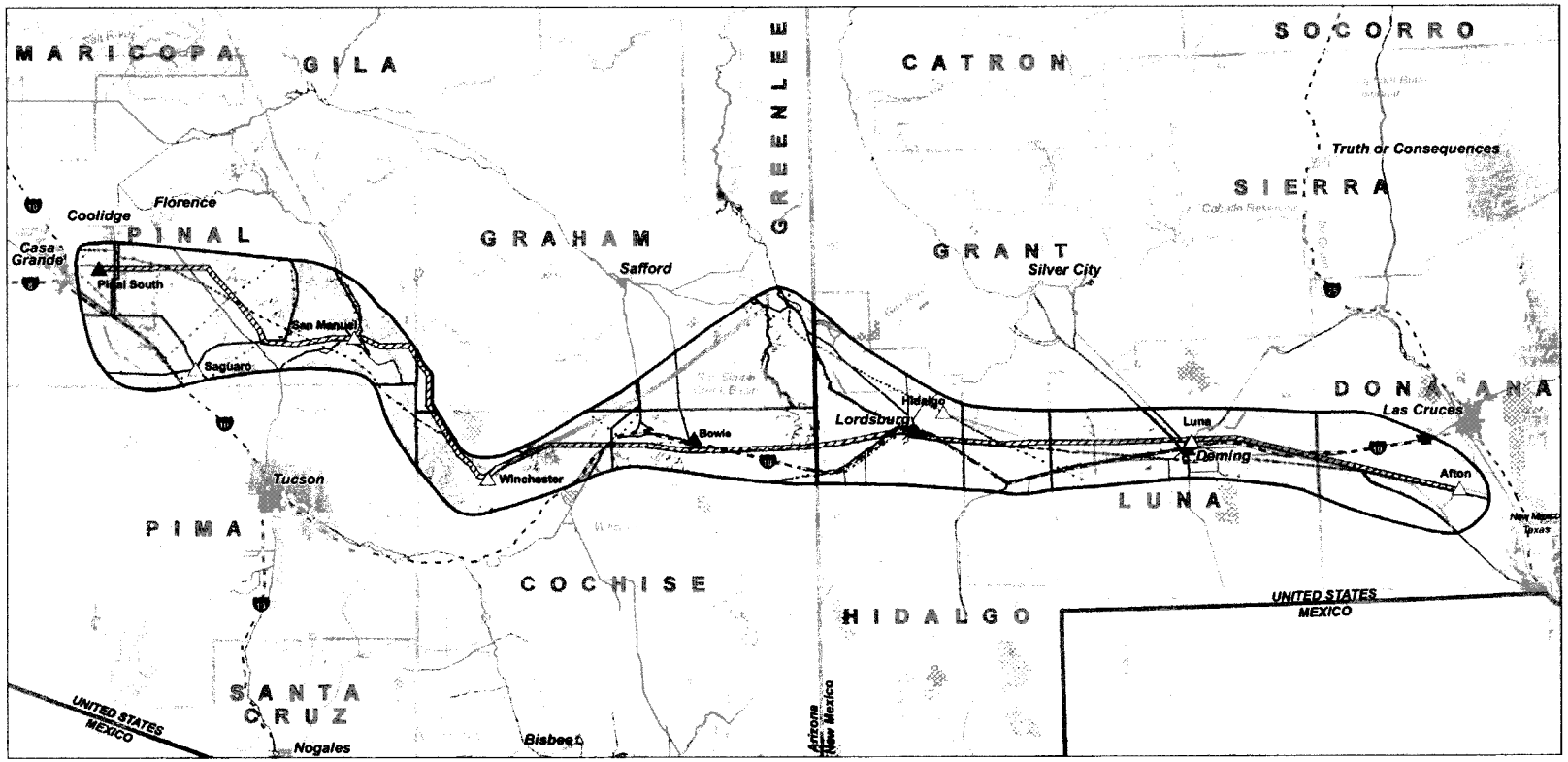
Energy Corridor

SunZia Southwest Transmission Project



Project Study Area

SunZia Southwest Transmission Project



LEGEND

Project Features
- Study Area
- Proposed Transmission Line Corridor
- ACEC
- Wilderness Area

Land Ownership
- Bureau of Land Management
- Indian Reservation/Bureau of Indian Affairs
- U.S. Forest Service
- National Park Service
- Department of Defense
- U.S. Fish & Wildlife Service
- State/Private/Other

Utilities
- Substation (Existing)
- Substation (Proposed)
- 500 kV Transmission Line
- 345 kV Transmission Line
- 230 kV Transmission Line
- 138 kV Transmission Line
- 115 kV Transmission Line
- Pipeline (6" Diameter and Above)

Reference Features
- International Boundary
- State Boundary
- County Boundary
- Interstate
- State Highway/Major Road
- Railroad
- River/Stream
- Lake/Reservoir
- Urban Area

Confidential - Not for Distribution

SunZia Southwest Transmission Project

Preliminary Plan of Development

Figure 1

September 2007

Sources:
StreetMapUSA, 2007; BLM, 2004; USGS, 2005; EPG, Inc., 2007

Project Benefits

SunZia Southwest Transmission Project

- Provides delivery of renewable resources (solar, wind, and geothermal) to markets
- Increases reliability of the existing New Mexico and Arizona EHV transmission systems
- Promotes interconnections of existing and planned transmission facilities in New Mexico and Arizona
- Increases the transmission system transfer capability across the Western Interconnect

- Regular project updates issued to SWAT and its subcommittees
- Initiated Regional Project Planning (December 15, 2006)
- Initiated Open Season (December 15, 2006)
- Attracted thirty interested parties
- Initial Meeting held (February 16, 2007)
- Draft Regional Planning Project Report issued (March 16, 2007)
- Final RPPR issued to WECC (May 17, 2007)
- WECC issued acceptance of RPPR (July 12, 2007)

WECC Project Rating Process

SunZia Southwest Transmission Project

- Entered Phase 1 Project Rating Process July 2007
- Technical Work Group formed August 2007
- Draft Study Plan developed September 2007
- Technical Work Group meetings Sept and Oct 2007
- Suspended Technical Work Group November 2007 meetings to fully take into account Development Partner interests (pending execution of MOA)
- Re-initiate TWG and Update Study Plan June 2008
- Comprehensive Progress Report and potential rating expected to be submitted to WECC by October 2008
- Begin Phase 2 Rating Process January 2009

Schedule

SunZia Southwest Transmission Project

- Project Phases and Target Completion Dates:
  - Phase 0 – Project Feasibility and Execute MOA
    - **Completed April 2008**
  - Phase 1 – Project Development/Permitting
    - **Initiate Q2 2008**
    - **Complete Q4 2011**
  - Phase 2 – Design and Construction
    - **Initiate Q3 2009**
    - **Complete Q4 2013**
  - Phase 3 – Operation
    - **Late 2013**

Websites

SunZia Southwest Transmission Project

For more information on the SunZia Southwest Transmission Project:

www.sunzia.net

www.southwesternpower.com

EXHIBIT NMM-42

EXHIBIT NMM-42

Map showing the three sections of the SunZia Project that the Department of Defense requires be buried across the Northern Call-up Area of the White Sands Missile Range (from the SunZia Record of Decision). From the BLM's Record of Decision for SunZia. Available at http://www.blm.gov/style/medialib/blm/nm/programs/more/lands_and_realty/sunzia/sunzia_docs.Par.94853.File.dat/SunZia_ROD_Record%20of%20Decision%20(1).pdf

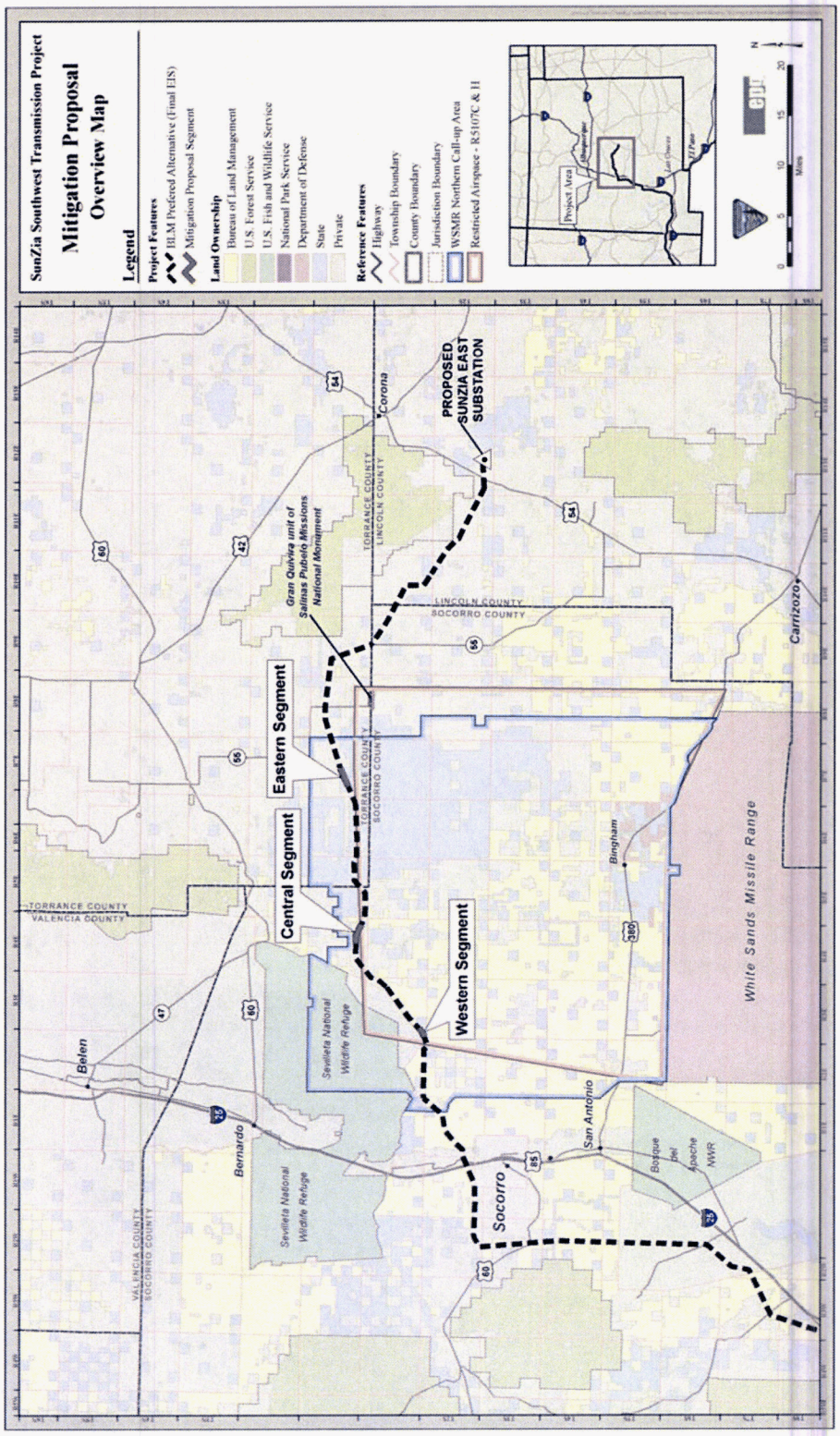


Figure 3. Mitigation Proposal

TOPIC 6

MEETING JOB NEEDS – SUNZIA'S ACTUAL POTENTIAL

EXHIBIT NMM-43

Exhibit NMM-43

Article about SunZia's job potential. Michael Hartranft, staff writer, "Benefits seem overstated for SunZia Project," *Albuquerque Journal*, March 19, 2012. Also available online at http://www.abqjournal.com/94700/biz/benefits-seem-overstated-for-sunzia-project.html.

Benefits seem overstated for SunZia project

▪ *Study questions job projections for transmission system*

Copyright © 2012 Albuquerque Journal

By Michael Hartranft
Journal Staff Writer

The initial rosy economy benefits projected for the two-state SunZia high-voltage transmission project were too rosy.

So asserts Arizona resident Norm Meader, who has been monitoring the project's development as a member of the Cascabel Working Group, a watchdog of the San Pedro River Valley in southeastern Arizona.

To be sure, Cascabel's group is trying to prevent the route of the project — a 500-mile-long transmission system linking New Mexico and Arizona to deliver electricity principally generated by renewable sources — from intruding into the valley because of its environmental uniqueness.

But Meader, a retired University of Arizona geoscience department staff member, says SunZia's widely reported claim — including in the **Journal** — that the project would create 6,200 construction jobs and spin off 36,700 renewable-energy jobs is badly overstated, which he attributes to labeling errors on data tables in the report and misinterpretations of what the label actually means.

One of the report's authors concedes Meader is right.

"Of course, there's an economic upside to it," said Meader of the project. "It just isn't nearly as big as it's been portrayed — maybe a third."

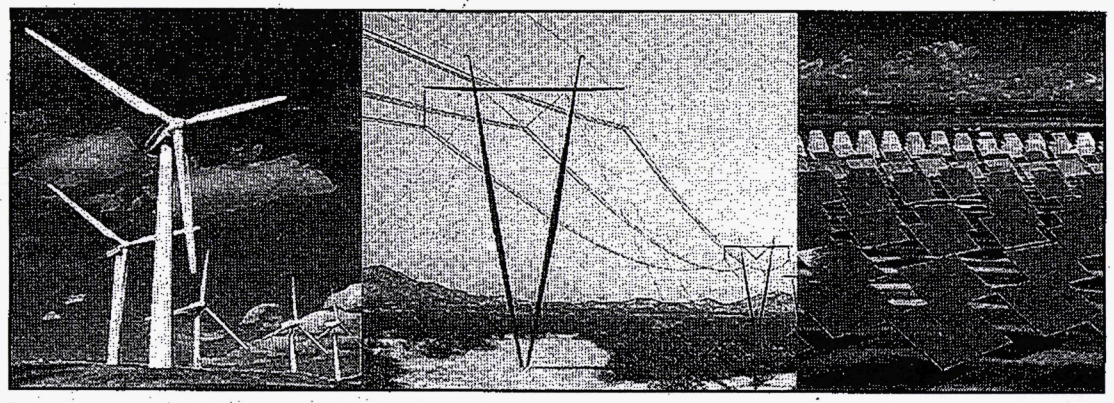
Jobs vs. FTEs

Meader also provided a copy of the critique to report co-author Alberta Charney of the University of Arizona, who confirmed the report intended jobs to mean job- or man-years. She said "jobs" is commonly used in economic reports, but could see how it might be confusing.

"Sometimes people misinterpret jobs to mean, oh, it's going to be 6,000 people working for the full duration of this project," she said. "That is the common usage, so I sympathize with you."

She said man-years are used in economic studies because of uncertainties about the actual jobs.

"If you have three jobs, you don't know for sure whether that's three guys working for one year, or one guy working for three years," she said.



These are renewable energy components that would be in play in SunZia's proposed, 500-mile-long transmission project linking New Mexico and Arizona.

SunZia's logo suggests New Mexico-Arizona linkage.

Meader said the projection of 36,700 "jobs" related to renewable generation development is also inflated, though not as dramatically because construction times are shorter, one to two years. Converting the figure to actual jobs would reduce the number to 31,090, he said.

An unrealistic mix?

He contends the study, however, relies on an unrealistic mix of renewable projects — 10 solar and 12 wind projects, though wind is far more economical and wind-energy producers are likely expecting to use far more than the projected 1,200-megawatt capacity used in the SunZia study. A more realistic mix of four solar, one geothermal and 19½ wind farms to match the amount of renewable generation in the economic study would reduce the job numbers to 17,547, Meader said.

But the number shrinks even more because of the high number of job-years projected to complete solar PV projects. While the model said it would take 890 job-years to complete a 100-megawatt plant, Meader said a survey showed it would actually be in the range of 200 to 300 job-years, making the SunZia number a factor of three to 4.5 too high. Decreasing the photovoltaic numbers by a factor of three would reduce the number of renewable-generation jobs to 13,878, he said.

A draft of the environmental impact statement identifying the preferred route is due out in April.

EXHIBIT NMM-44

EXHIBIT NMM-44

Number of construction workers needed to build the full project across *both* Arizona and New Mexico. Building one line would require 206 workers. If two lines are built simultaneously, or if two crews are used to build a single line, the total number of workers would be 412. It would require 55 workers to build a substation for 1 line, 51 workers to expand the substation to accommodate 2 lines. Pages 2-83 to 2-86 of the SunZia Final Environmental Impact Statement.

Table 2-8. Estimated Personnel and Equipment for Transmission Line Construction					
		500 kV AC Line		500 kV AC or DC Line	
Activity	Equipment Type	Quantity of Equipment	Personnel (per line)	Quantity of Equipment	Personnel (per line)
Material Yard/ Receiving/Distribution	¾-ton Pickup	4	14	4	14
	10,000 lb. Forklift	2		2	
	50-ton Crane	2		2	
	Tractor Trailer (flatbed)	6		6	
	20-ton Boom Truck	3		3	
	100-ton Crane	0		0	
Survey (Construction Staking)	½-ton Pickup	2	4	2	4
	ATVs	4		4	
Soil Borings	¾-ton Pickup	2	6	2	6
	Drill Rig	2		2	
Right-of-Way Clearing	¾-ton Pickup	3	4	3	4
	Chainsaw	2		2	
	Hydro Axe	1		1	
Roads and Access	1-ton Pickup	2	6	2	6
	Cat D-6	1		1	
	Grader	1		1	
	Semi w/Dump Trailer	1		1	
	Water Truck	3		3	
Foundations (3 crews)	½-ton Pickup	3	36	3	36
	1-ton Pickup	6		6	
	Drill Rig	3		3	
	Loader/Backhoe	3		3	
	Boom Truck	3		3	
	Concrete Truck	6		6	
	Generator	3		3	
	Cat D-6	3		3	
Structure Assembly Lattice (3 crews)	½-ton Pickup	3	30	3	30
	1-ton Line Truck	3		3	
	20-ton Boom Truck	3		3	
	Air Compressor	3		3	
	30-ton R/T Crane	3		3	
Structure Assembly Tubular (1 crew)	½-ton Pickup	1	10	1	10
	1-ton Flatbed Truck	1		1	
	Air Compressor	1		1	
	30-ton R/T Crane	1		1	

Table 2-8. Estimated Personnel and Equipment for Transmission Line Construction					
		500 kV AC Line		500 kV AC or DC Line	
Activity	**Equipment Type**	**Quantity of Equipment**	**Personnel (per line)**	**Quantity of Equipment**	**Personnel (per line)**
Structure Erection (Lattice – 1 crew)	½-ton Pickup	1	10	1	10
	1-ton Flatbed Truck	1		1	
	200-ton Crane	2		2	
	20-ton Boom Truck	2		2	
	Air Compressor	1		1	
Structure Erection (Tubular – 1 crew)	½-ton Pickup	1	10	1	10
	1-ton Flatbed Truck	1		1	
	200-ton Crane	1		1	
	20-ton Boom Truck	1		1	
	Air Compressor	2		2	
Wire Pulling (Conductor, OHGW, OPGW)	1-ton Line Truck	2	20	2	20
	200-ton Crane	2		2	
	20-ton Boom Truck	2		2	
	Air Compressor	0		0	
	Cat D-8	3		3	
	Puller	2		2	
	Tensioner	2		2	
Conductor Clipping and Dead-ending (3 clip, 1 dead-end)	½-ton Pickup	4	32	4	32
	1-ton Line Truck	6		6	
	Bucket Truck/ Boom w/Basket	4		4	
Restoration	½-ton Pickup	2	4	2	4
	Tractor with Disc	1		1	
	Cat D-4	1		1	
	Hydro Seed Truck	1		1	
Contractor Management/ Compliance Monitors	½-ton Pickup	20	20	20	20
	ATV (Inspection)	2		2	
Total Personnel[1]			**206**		**206**

[1] Maximum total personnel required during the construction period, considering all tasks (actual personnel at any one time would be up to 824 if two contractors are working simultaneously).

Table 2-9. Estimated Personnel and Equipment for Substation Construction							
		500 kV Transmission Line (AC) (per substation)		500 kV Transmission Line (DC) (per substation)		Second 500 kV Transmission Line (AC) (per substation)	
Activity	Equipment Type	Quantity of Equipment	Quantity of Equipment	Personnel	Personnel	Quantity of Equipment	Personnel
Material Yard/ Receiving/ Distribution	¾-ton Pickup	2	2	3	3	2	3
	5-ton R/T Forklift	2	2			2	
	50-ton Crane	1	1			1	
	Tractor Trailer	1	1			1	
	30-ton Boom Truck	1	1			1	
Construction Staking	½-ton Pickup	1	1	2	2	1	2
Soil Borings	¾-ton Pickup	1	1	2	2	1	2
	Drill Rig	1	1			1	
Site Clearing and Grading	¾-ton Pickup	2	2	8	8	2	4
	F-350 Pickup	2	2			2	
	Cat D-6	2	2			2	
	Grader	2	2			2	
	Semi with Dump Trailer	4	4			4	
	Water Truck	1	1			1	
	Scrapers	1	1			1	
	Roller Compactors	2	2			2	
Foundations/ Raceway/Grounding	½-ton Pickup	3	2	10	10	2	10
	¾-ton Pickup	4	2			2	
	Drill Rig	1	1			1	
	Loader/ Backhoe	2	2			2	
	Boom Truck	1	1			1	
	Concrete Truck	1	1			1	
	Excavator	1	1			1	
	Dump Truck	2	2			2	
	5-ton R/T Forklift	1	1			1	
	Mini Excavator	2	2			2	

Table 2-9. Estimated Personnel and Equipment for Substation Construction							
		500 kV Transmission Line (AC) (per substation)		500 kV Transmission Line (DC) (per substation)		Second 500 kV Transmission Line (AC) (per substation)	
Activity	**Equipment Type**	**Quantity of Equipment**	**Quantity of Equipment**	**Personnel**	**Personnel**	**Quantity of Equipment**	**Personnel**
	Air Compressor	2	2			2	
	Trencher	2	2			2	
	Roller Compactor	2	2			2	
	Hand Compactor	3	3			3	
Structure and Equipment Installation	½-ton Pickup	4	4	10	10	4	10
	1-ton Line Truck	2	2			2	
	200-ton Crane	1	1			1	
	30-ton Boom Truck	4	4			4	
	Air Compressor	3	3			3	
	Man Lifts	4	4			4	
	50-ton Crane	2	2			2	
	Generator	2	2			2	
	5-ton R/T Forklift	4	4			4	
Wiring	½-ton Pickup	1	1	12	12	1	12
	1-ton Line Truck	1	1			1	
	Generator	2	2			2	
	5-ton R/T Forklift	1	1			1	
Testing and Cleanup	½-ton Pickup	2	2	5	5	2	5
	Bucket Truck/Boom w/Basket	2	2			2	
Contractor Management	½-ton Pickup	3	3	3	3	3	3
Total per substation			55		55		51
Total for Option A[1]			**220**				**204**
Total for Option B[1]			**220**		**110**		

[1] Maximum total personnel required during the construction period (actual personnel at any one time would be less), considering all tasks for construction of 4 AC substations (Option A) or 4 AC and 2 DC substations (Option B). Multiple crews may be required depending on schedule requirements.

EXHIBIT NMM-45

EXHIBIT NMM-45

Percentage of SunZia construction workers hired in Arizona (30%). Page 4-239 of the SunZia Final Environmental Impact Statement.

support industries such as restaurant and hotel/lodging) typically employ workers who are already present in local economies.

Approximately 30 percent of all construction workers are expected to come from Arizona or New Mexico, with 10 percent of all workers anticipated to be hired locally within the counties where construction will take place (Charney et al. 2012a, Appendix G1). An assumption is made that all local workers and most in-state workers would commute to the construction site from their homes and therefore would not contribute to population growth. The remaining 70 percent of workers would temporarily relocate within proximity of individual construction sites. Because construction employment would be temporary in nature and developed linearly in New Mexico and Arizona, it is unlikely that relocated workers would also relocate their families. Based on these assumptions, including the likelihood that multiple crews along a 500-mile corridor would be in close proximity to one another, no significant impacts related to population increases are expected from temporary population increases of a few hundred people.

Operations

Because operational employment would be minimal and spread between three cities in New Mexico and Arizona, population increases are expected to be negligible. Not including the surrounding metropolitan areas, the Las Cruces, Tucson, and Phoenix populations in 2009 totaled approximately 100,000; 500,000; and 1,500,000 respectively (U.S. Census 2005-2009b).

4.13.4.2 Housing Impacts

Construction

The temporary population increase during the construction of the proposed Project is expected to have little to no impact on housing availability, because the number of construction workers onsite at any one time would not be significant (less than 206 for transmission line construction and 55 for each substation). Construction workers are expected to temporarily locate across the Project study area. Workers would reside in hotels, campgrounds, and other short-term living options (personal communication, Bedillion 2011). In addition, some would commute from their existing residences in nearby counties. Counties within proximity to where construction would take place in New Mexico and Arizona have a high number of vacant housing units, with nearly 28,000 and 86,000 vacancies, respectively.

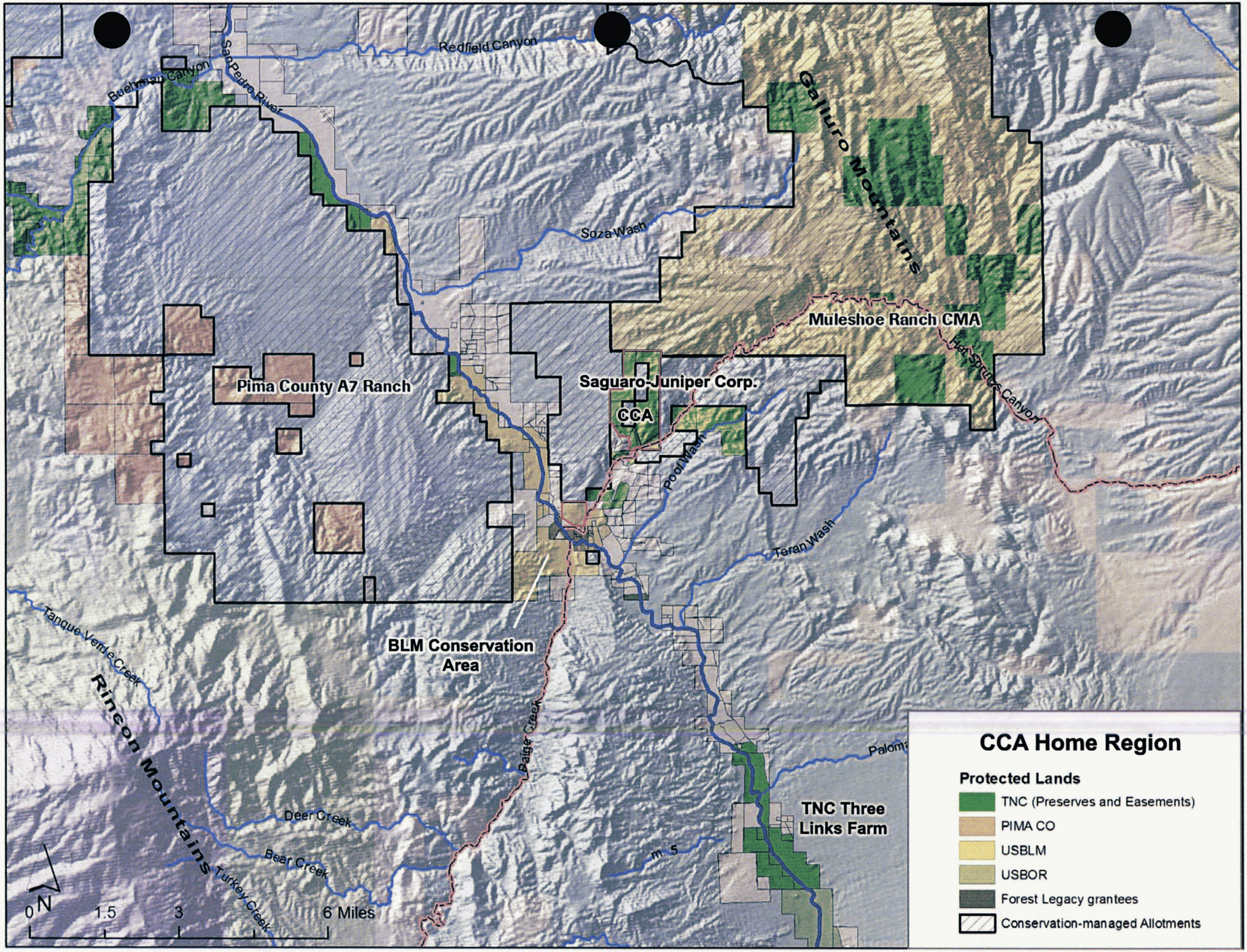
There would be no direct impacts to residences for right-of-way acquisition among any alternatives in Route Group 1 or Route Group 3; subroutes 4A, 4B, 4C1, or 4C2; as well as the BLM preferred alternative subroutes. However, the construction of the Project using Subroute 4C3 could result in significant impacts due to the take of approximately 216 residences (in addition to 48 commercial and industrial properties along links F111 and F112 in South Tucson). Local alternative links F81a-F81b would also result in significant impacts to residential properties, resulting in the take of approximately 120 residences (in addition to 37 commercial and industrial properties). The locations of potential right-of-way acquisition are described in Section 4.10.5.3. Residential displacement could cause homeowners to experience a temporary hardship of having to find new housing; however, residents are expected to receive ample notice

WILLCOX AREA TOUR

EXHIBIT NMM-46

EXHIBIT NMM-46

Conservation lands in the vicinity of Cascabel, Arizona. Map courtesy of The Nature Conservancy.


CCA Home Region
Protected Lands
TNC (Preserves and Easements)
PIMA CO
USBLM
USBOR
Forest Legacy grantees
Conservation-managed Allotments
Redfield Canyon
Buehman Canyon
San Pedro River
Gallure Mountains
Soza Wash
Muleshoe Ranch CMA
Hot Springs Canyon
Pima County A7 Ranch
Saguaro-Juniper Corp.
CCA
Pool Wash
Teran Wash
Tanque Verde Creek
BLM Conservation Area
Rincon Mountains
Paige Creek
Paloma
TNC Three Links Farm
Deer Creek
Bear Creek
Turkey Creek
m 5
0 1.5 3 6 Miles
N