




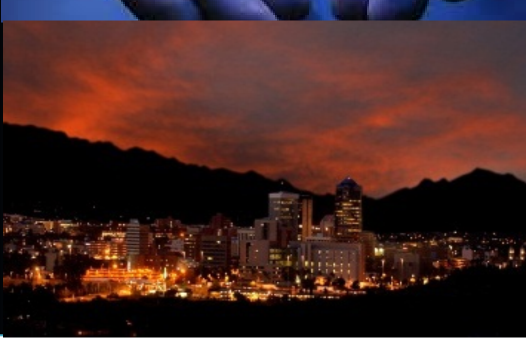

TUCSON ELECTRIC POWER

2014 Integrated Resource Plan

April 1, 2014

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CHAPTER 1

Executive Summary

Introduction

Tucson Electric Power Company's (TEP's or the Company's) 2014 Integrated Resource Plan (IRP) identifies TEP's future capacity requirements through 2028. The plan describes how TEP plans to meet future demand requirements, while providing safe and reliable service to our customers, meeting future regulatory requirements, and reducing environmental impacts at just and reasonable rates. In addition to providing a snapshot of TEP's current loads and resources, the IRP highlights the investment decisions that must be made regarding TEP's existing generation fleet over the next few years.

The 2014 base case (Reference Case) plan strikes a balance between minimizing costs to customers, mitigating environmental impacts, and effectively using TEP's existing infrastructure while protecting Arizona's local economies. The Reference Case plan puts emphasis on a portfolio diversification strategy that will effectively reduce long-term risks to TEP's customers while achieving compliance with future environmental, renewable energy, and energy efficiency (EE) standards.

The Reference Case plan highlights the following goals:

- The 2014 Reference Case plan highlights a long-term portfolio diversification strategy to reduce long term risks associated with investments in coal fired generation. The Reference Case plan details TEP's planned commitments to reduce its overall coal capacity by 492 MW (32% of TEP's existing coal fleet) over the next five years at Springerville, San Juan and Sundt Generating Stations.
- The 2014 Reference Case plan includes a joint acquisition with sister company UNS Electric of a 550 MW combined cycle power plant located at the Gila River Power Station in Gila Bend, Arizona. TEP's planned share of this natural gas resource will be 413 MW and will replace the anticipated capacity reductions that are planned at the Springerville and San Juan Generating Stations.
- The 2014 Reference Case plan details how the Gila River acquisition along with the local area expansion of natural gas combustion turbines and grid supported storage technologies will be a critical piece of TEP's long-term portfolio diversification strategy by supporting the integration of renewable resources.
- The 2014 Reference Case plan confirms TEP's commitment in maintaining its full participation at the Four Corners Power Plant and Navajo Generation Station. These commitments support the proposed "Better-than-BART" alternatives that offer significant costs savings to TEP's customers while protecting the economic welfare of the Navajo and Hopi tribes, and Central Arizona Water (CAP) users.
- The 2014 Reference Case plan highlights TEP's improvements to transmission import capabilities with the build out of the Pinal-Central to Tortolita transmission project. This project supports the on-going

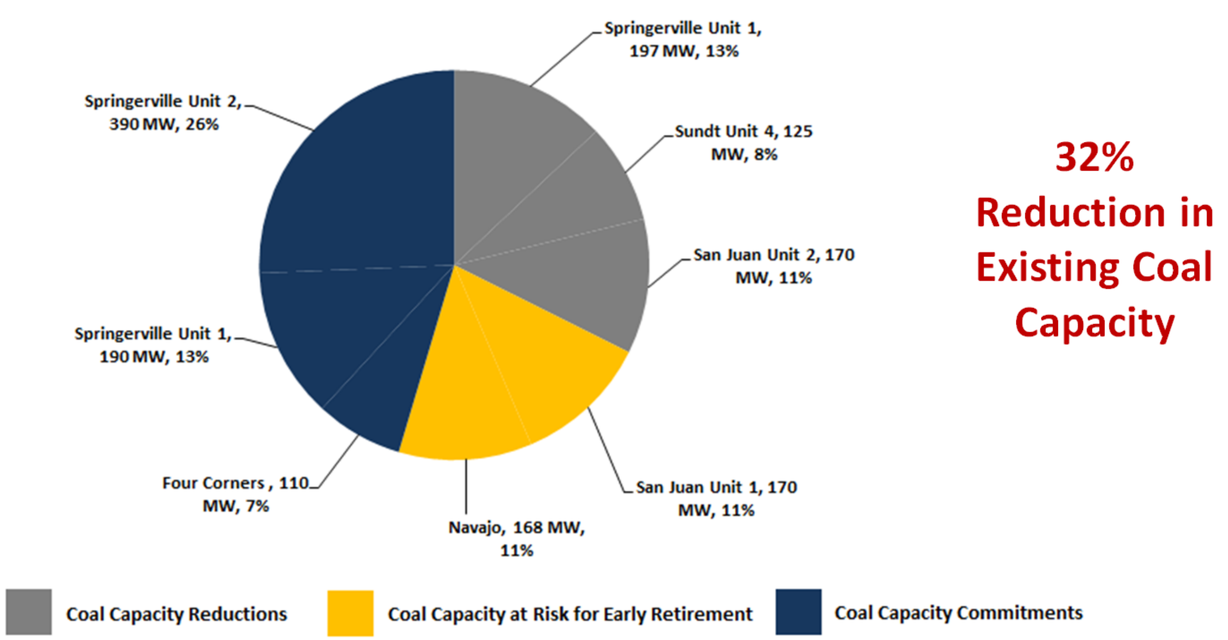
development of a regional transmission infrastructure and maximizes TEP's future load serving capabilities while enhancing access to future renewable and wholesale market resources.

- The 2014 Reference Case plan emphasizes a comprehensive Energy Efficiency portfolio that includes a range of demand response and efficiency programs. The 2014 Reference Case plan assumes TEP is in compliance with the Arizona EE Standard.
- The 2014 Reference Case plan highlights TEP's success with its efforts to develop a well-diversified renewable resource portfolio that meets Arizona's Renewable Energy Standard (RES) requirements. TEP plans to continue its development of low cost renewable projects that minimize both water usage and negative impacts to the environment and provide long-term value to TEP's retail customers.

TEP's Portfolio Diversification Strategy for the 2014 IRP

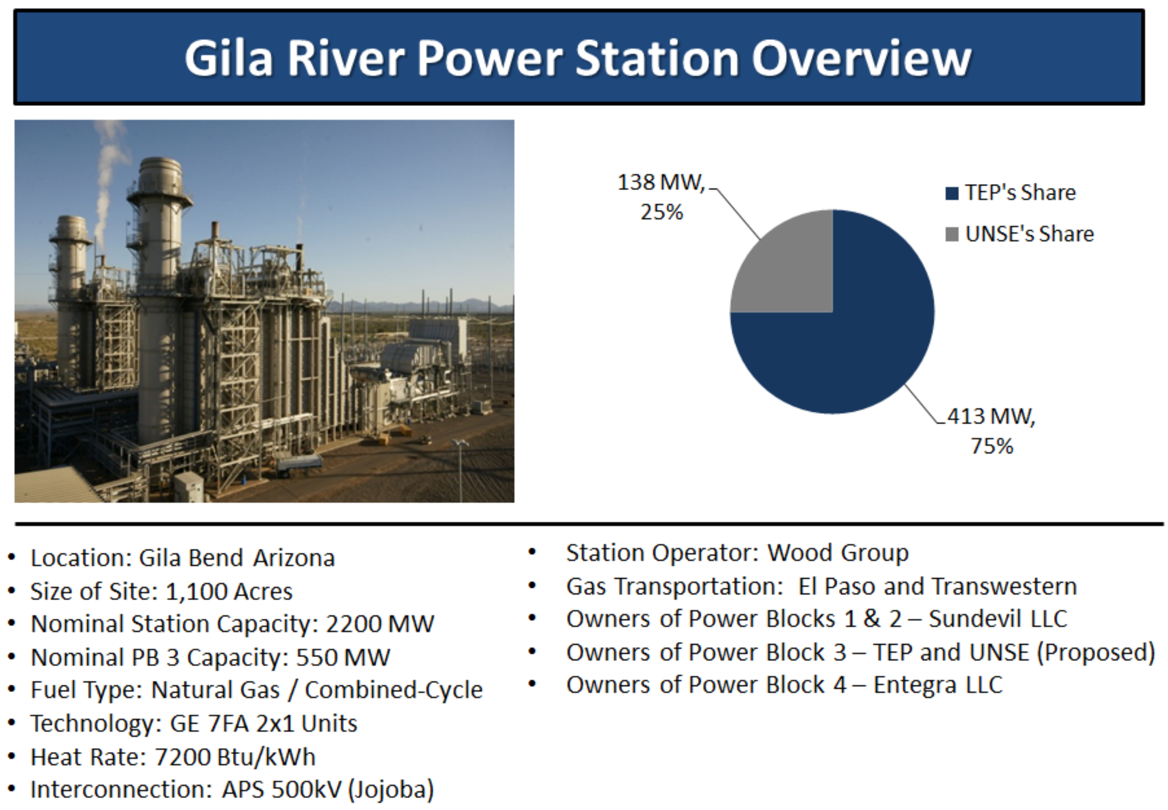
As part of the 2014 Reference Case plan, TEP is committed to moving forward with a portfolio diversification strategy to reduce the risks associated with investments in coal fired generation. This strategy results in lower cost outcomes for TEP's customers while reducing longer term carbon risk in the generation resource portfolio. Chart 1 below shows the current status of TEP's commitments regarding its coal generation resources. The coal resources in grey reflect TEP's planned commitments to reduce its overall coal capacity by 492 MW (32% of TEP's existing coal fleet) over the next five years at Springerville, San Juan and Sundt Generating Stations. The coal resources shown in yellow reflect the proposed "Better than BART" alternatives that are still pending final approval from the EPA. The coal resources shown in dark blue reflect TEP's current commitment to maintain its participation in these generation facilities.

Chart 1 – 2014 IRP Planned Coal Capacity Reductions and Commitments



To replace this lost coal capacity from TEP's existing resource mix, TEP conducted a Request for Proposal (RFP) in May 2013 to evaluate the potential alternatives for the capacity reductions that were being considered at the Springerville and San Juan Generating Stations. As a result, TEP received fourteen different proposals from nine different bidders. Based on TEP's bid analysis, Gila River Unit 3 was chosen as the final bidder due to the economic and operational advantages of their proposal. In December 2013, TEP and its affiliate UNS Electric Inc. (UNS Electric) entered into a purchase agreement with a subsidiary of Entegra Power Group LLC (Entegra) to purchase Power Block 3 of the Gila River Generating Station (Gila River Unit 3). Gila River Unit 3 is a gas-fired combined cycle unit with a capacity rating of 550 MW, located in Gila Bend, Arizona. The purchase price is set at $219 million ($398/kW) subject to adjustments to prorate certain fees and expenses through the closing and in respect of certain operational matters. It is anticipated that TEP will purchase a 75% undivided interest in Gila River Unit 3 for approximately $164 million and UNS Electric will purchase the remaining 25% undivided interest for approximately $55 million, although TEP and UNS Electric may modify the percentage ownership allocation between them. TEP and UNS Electric expect the transaction to close in December 2014.

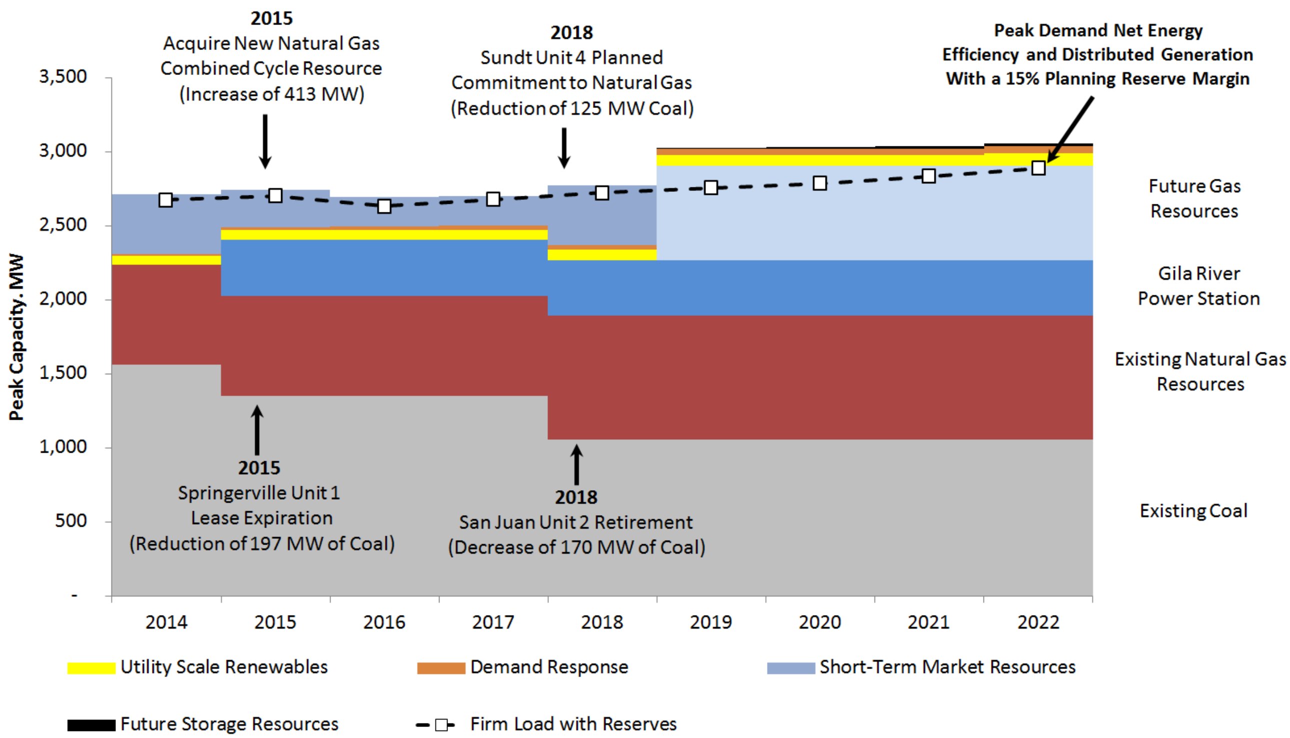
Picture 1 – Gila River Power Station



Reference Case Plan - Coal Capacity Reductions

Figure 1 shows the Reference Case Plan timing of the expected coal reductions as well as the acquisition of the Gila River Power Station that are planned to occur over the next five years.

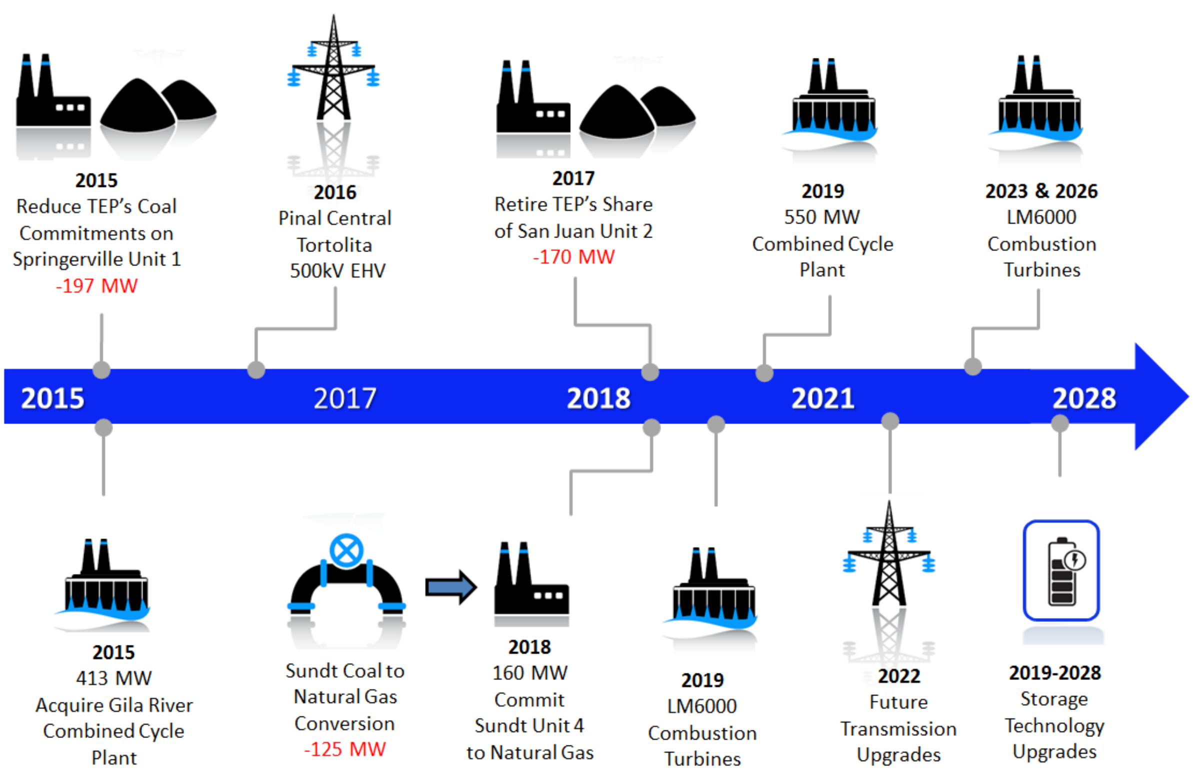
Figure 1 – Reference Case - Plan Coal Capacity Reductions



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



In addition, the 2014 IRP Reference Case plan assumes that two new transmission upgrades will be required over the 15-year timeframe. The Pinal Central - Tortolita 500 kV transmission upgrade is planned for 2016 and will tie the existing Salt River Project (SRP) Southeast Valley transmission project from Pinal Central into Tortolita. This upgrade will provide additional import capacity from renewable resources and wholesale merchant plants located near Palo Verde and will increase TEP's load serving capabilities out through 2022. By 2022 it is expected that additional system upgrades will be required based on current load projections. For purposes of the 2014 IRP Reference Case plan, a conceptual 345kV EHV transmission project was assumed for modeling purposes. However, the exact project or required system upgrades are expected to be determined through the next series of Biennial Transmission Assessments that are coordinated with regional transmission providers and filed with the Arizona Corporation Commission. TEP will update these conceptual project descriptions in future IRP filings as they are determined. Finally, the 2014 IRP Reference Case plan recognizes the need for future storage technologies to support the integration of intermittent resources. For purposes of this filing, TEP assumes that approximately 50 MW of battery storage technology will be required by 2028 to support future ancillary service requirements for the grid.

Utility Scale Renewables and Distributed Generation

Renewable Overview

Over the last several years, TEP has constructed or entered into purchased power agreements (PPAs) for solar, wind and biofuel resources to provide renewable energy for its service territory. This is part of the company's commitment to meeting the Arizona RES. The table below lists TEP's existing and planned renewable resources. Chapter 12 provides an overview of the various renewable technologies and detailed descriptions of the individual projects.

Table 1 – TEP's Existing Renewable Resources

Resource- Counterparty	Owned/PPA	Technology	Location	Operator-Manufacturer	Completion Date	Capacity MW
Fixed PV						
Springerville	Owned	Fixed PV	Springerville, AZ	Various	Dec 10	6.4
Solon UASTP III	Owned	Fixed PV	Tucson, AZ	Solon	January 2012	5
Astrosol UASTP IV	PPA	Fixed PV	Tucson, AZ	Astrosol	June 2012	6
Solon Prairie Fire	Owned	Fixed PV	Tucson, AZ	Solon	Oct 2012	5
NRG Solar Avra Valley	PPA	Fixed PV	Tucson, AZ	First Solar	Oct 2012	35
TEP Warehouse	Owned	Fixed PV	Tucson, AZ	Various	2012	0.5
Ft Huachuca (Planned)	Owned	Fixed PV	Sierra Vista, AZ	Solon	Q4 2014	17.6
Single Axis Tracking						
Solon UASTP I	Owned	SAT PV	Tucson, AZ	Solon	Dec 2010	1.6
E.On UASTP	Owned	SAT PV	Tucson, AZ	Suntech	Dec 2010	6.6
FRV Picture Rocks	PPA	SAT PV	Tucson, AZ	MEMC	Oct 2012	25
E.On/TEP Valencia	PPA	SAT PV	Tucson, AZ	Areva	July 2013	13.2
Pima Mine Rd (Planned)	PPA	SAT PV	Tucson, AZ	Avalon	Q4 2014	28.0
Concentrated PV						
Amonix UASTP II	PPA	CPV	Tucson, AZ	Amonix	Apr 11	2
Wind						
Macho Springs	PPA	Wind	Deming, NM	Element Power	Nov 2011	50.4
Red Horse 2 (Planned)	PPA	Wind	Willcox, AZ	Torch Renewables	Q4 2015	40.0
Biomass						
Sexton Energy	PPA	Landfill Gas	Tucson, AZ	Sexton Energy	Dec 11	2.2

Notes: PPA – Purchase Power Agreement - Energy is purchased from a third party provider.
Fixed PV – Fixed Photovoltaic – Stationary Solar Panel Technology
SAT PV – Single Axis Tracking Photovoltaic
CPV – Concentrated Photovoltaic

Utility Scale Renewables

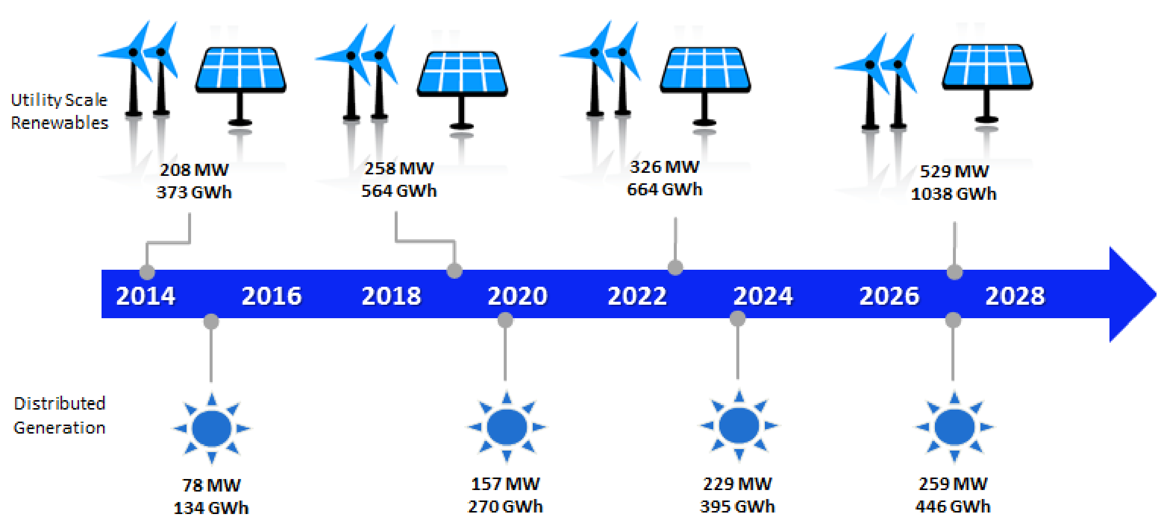
The Reference Case plan also includes a diverse portfolio of renewable resources that complies with the RES. The Reference Case plan meets the renewable energy standard goals. The RES requires TEP to utilize renewable energy resources to serve 4.5% of its 2014 retail load requirement, growing to 15% by 2025. By 2028, the Reference Case plan includes approximately 529 MW of utility scale renewable nameplate capacity. These utility scale renewable resources are expected to supply approximately 373 GWh of energy in 2014 growing to 1,038 GWh by 2028.

The 2014 Reference Case plan places emphasis on in-state solar resources that provide higher coincident peak capacity value to the TEP resource portfolio. In addition, TEP also plans to acquire other renewable technologies such as wind and bio-resources as opportunities become available. TEP's current renewable acquisition strategy focuses on developing a number of small to mid-scale renewable projects diversified across a wide-range of projects and counterparties. Today, TEP's renewable resource portfolio has approximately 157 MW of renewable nameplate capacity. By the end of 2014, this amount should grow to approximately 208 MW and by 2028, TEP's renewable portfolio should have approximately 529 MW of solar, wind, and biogas resources. Chapter 12 of this document details these projects and technologies.

Distributed Generation

The Reference Case plan resource plan meets the distributed generation requirement based on Arizona's RES. The annual distributed generation requirement is 30% of the total renewable energy standard. By the end of 2015, the Reference Case plan will include approximately 78 MW of rooftop solar PV and solar hot water heating capacity. Distributed generation resources are expected to supply at least 134 GWh of energy on an annual basis in 2015 growing to approximately 456 GWh by 2028. Figure 3 below shows the expected cumulative nameplate capacity of distributed generation that will be installed in TEP's service territory from 2014 through 2028.

Figure 3 - Utility Scale Renewables and Distributed Generation Resource Capacity



Energy Efficiency and Demand Response

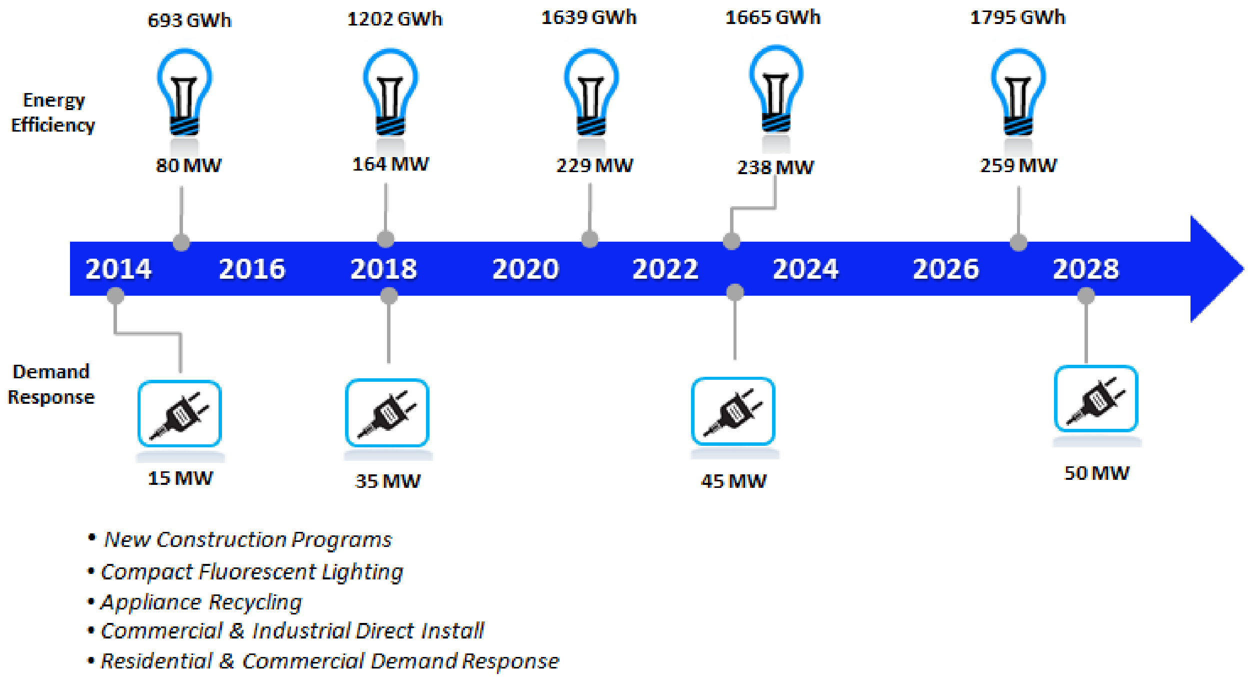
Energy Efficiency

TEP will pursue a range of cost-effective and industry-proven programs to meet future energy efficiency targets. TEP's proposed energy efficiency portfolio is intended to meet compliance with the Arizona EE Standard which ultimately targets cost effective programs that reach a 22% cumulative energy reduction by 2020. By 2028, this offset to future retail load growth is expected to reduce TEP's annual energy requirements by approximately 1,816 GWh and reduce TEP's system peak demand by 312 MW.

Demand Response

The Reference Case plan targets dispatchable demand response programs that reduce TEP's summer peak loads. TEP's future demand response programs are expected to reduce TEP's system peak demand by 50 MW by 2028. Figure 4 shows the equivalent capacity reductions installed under future energy efficiency and demand response programs for the Reference Case plan from 2014 through 2028.

Figure 4 - Energy Efficiency and Demand Response (Equivalent Capacity Reductions)



Reference Case Plan Composition

Table 2 below shows the generation mix by resource type under the Reference Case plan. Today, TEP's resource portfolio is dominated by coal and natural gas resources. The Reference Case plan anticipates future investments in low to zero emission resources to diversify its energy portfolio over the next fifteen years. By 2028, it is projected that TEP's resource portfolio mix will be 43% coal resources, 36% natural gas resources and the remaining 21% will be made up of renewable energy and energy efficiency resources.

Table 2 - Reference Case Plan Portfolio Composition (Percent of Total Resources)

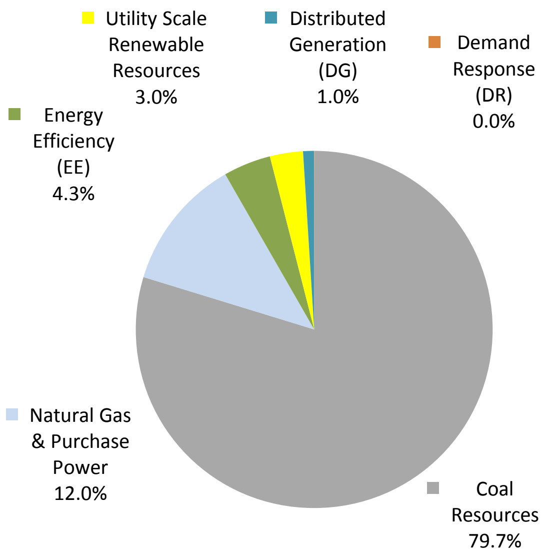
Resource Portfolio (Percent of System Resources)	2014	2019	2023	2028
Coal Generation	79.73%	55.83%	50.50%	43.19%
Natural Gas or Market Purchases	11.98%	27.76%	31.43%	35.73%
Energy Efficiency (EE)	4.29%	10.32%	11.16%	11.47%
Utility Scale Renewable Resources	2.99%	4.24%	4.46%	6.71%
Distributed Generation (DG)	0.99%	1.83%	2.43%	2.88%
Demand Response (DR)	0.03%	0.02%	0.02%	0.02%
Total Resource Portfolio	100.0%	100.00%	100.00%	100.00%

Resource Portfolio (Percent of Net Retail Load)	2014	2019	2023	2028
Renewable Resources (Utility Scale and DG)	4.5%	9.0%	13.0%	15.0%
Energy Efficiency and Demand Response	7.25%	19.50%	22.00%	22.00%

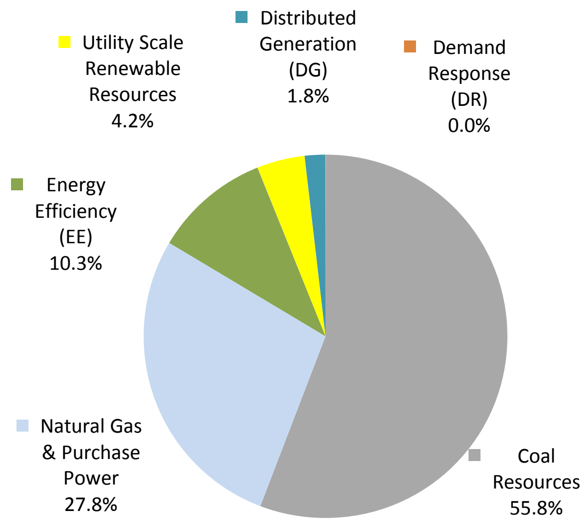
Note: Table 2 is based on TEP's resource portfolio on a stand-alone basis. The top portion of the table represents total energy as a percentage of total system resources. Furthermore, these portfolio statistics do not include third-party sales and purchases transactions that are typically made by TEP as a normal course of business. The bottom portion of the table represents statistics as a percentage of TEP's net retail load.

Chart 2 below shows how the Reference Case plan resource strategy diversifies TEP's portfolio over the next 15 years.

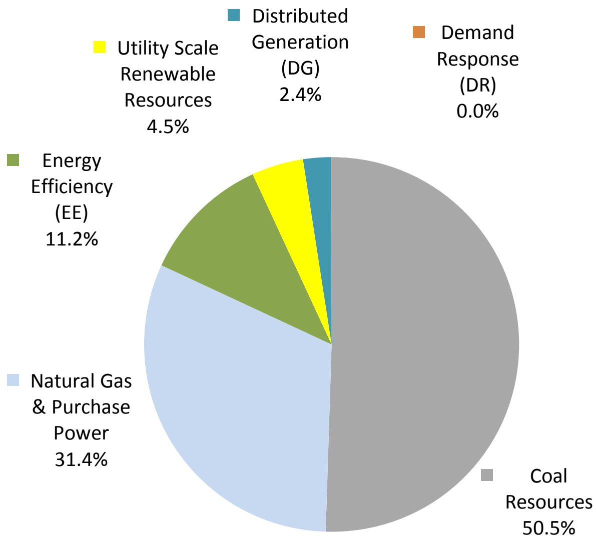
Chart 2 - Reference Case Plan Portfolio Diversification (2014-2028)



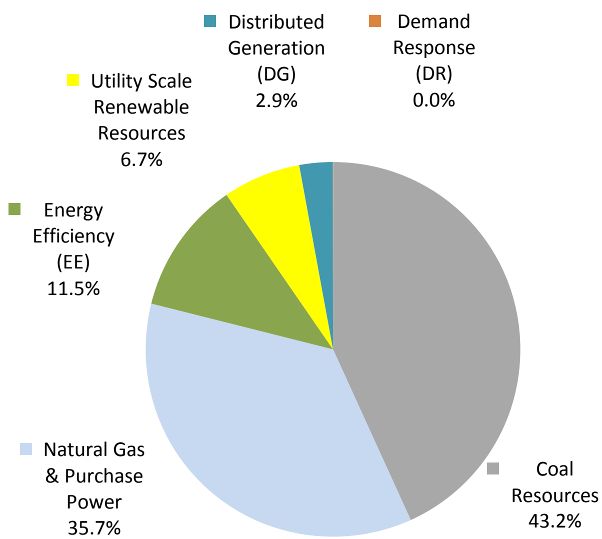
Forecast Year 2014



Forecast Year 2019



Forecast Year 2023



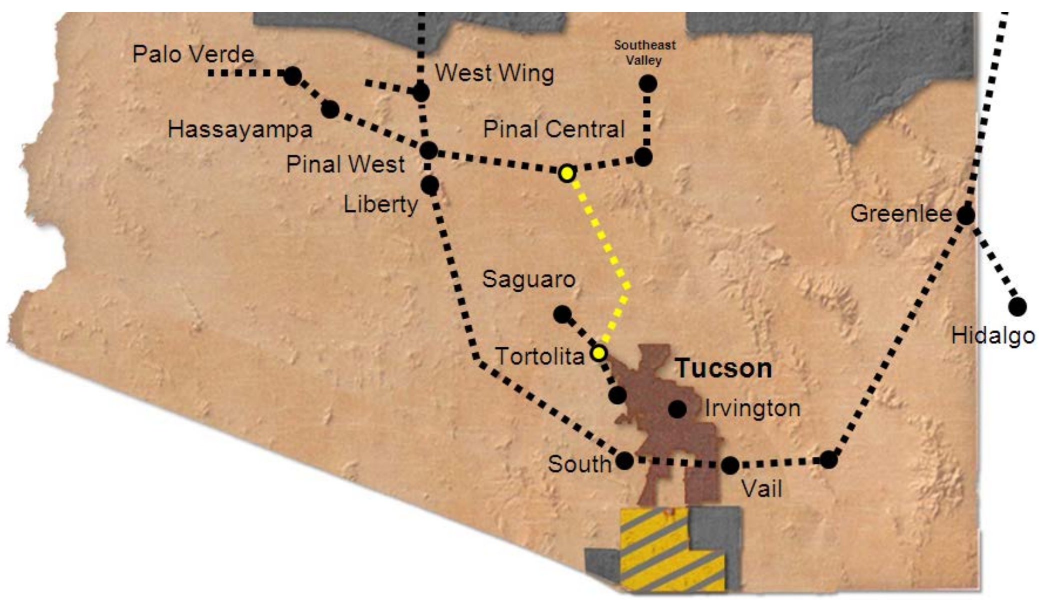
Forecast Year 2028

Local Area Generation and Transmission Upgrades

Pinal Central – Tortolita 500 kV Transmission Project

The Pinal Central - Tortolita 500 kV transmission project is a planned network interconnection that is coordinated with the build out of SRP's Southeast Valley Transmission (SEV) project. This segment of the project will be constructed and operated by TEP. Map 1 below details the planned route which runs from the Pinal Central substation to the Tortolita substation. Based on TEP's future load growth and the SRP construction schedule for the SEV project, it is assumed that construction on the TEP segment will commence in late 2014 with the project going into service by the summer of 2016. The estimated cost for the Pinal West – Pinal Central – Tortolita 500 kV project is $111 million. This new transmission interconnection will further improve TEP's access to a wide range of renewable and wholesale market resources located in the Palo Verde area while improving TEP's system reliability.

Map 1 - Pinal Central - Tortolita 500 kV Transmission Project



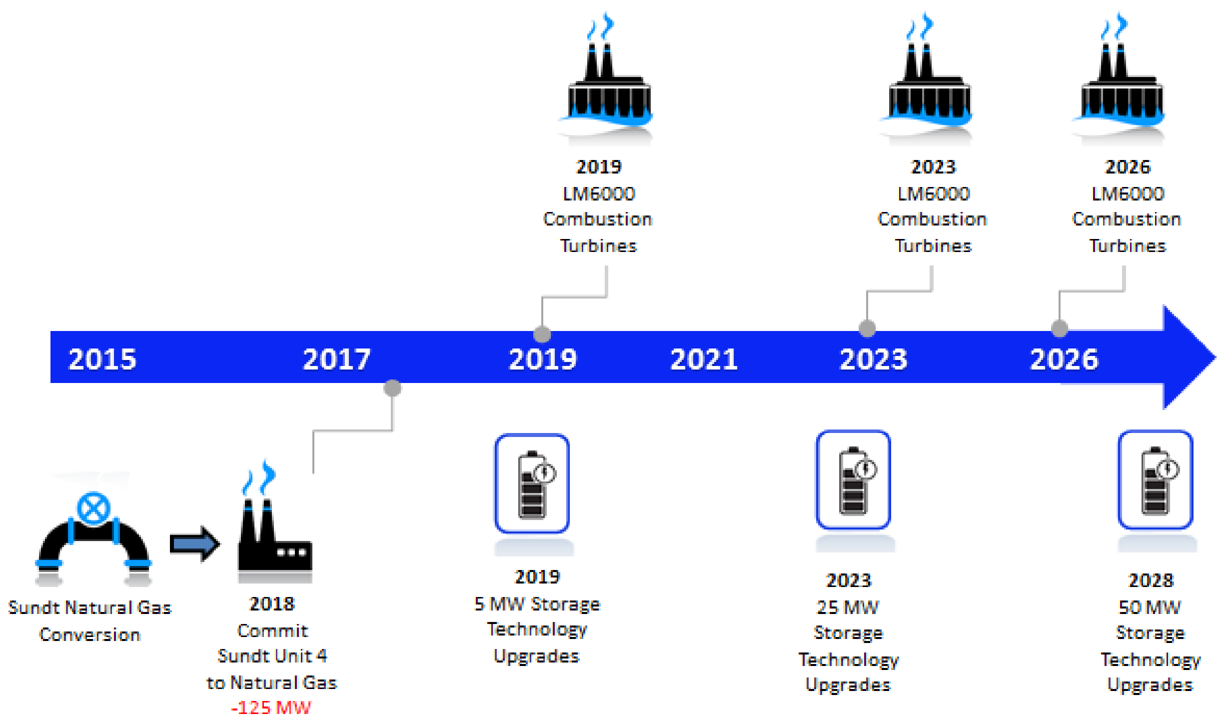
Local Area Gas-Fired Generation

The 2014 Reference Case plan demonstrates the need for additional 270 MW of natural gas resources between 2019 and 2026. These future resources may be a combination of firm long-term purchase power agreements, plant acquisitions, or construction of new local area generating facilities.

The Future of Renewable Resource Integration

As higher percentages of renewable resources are added to TEP's resource portfolio, TEP anticipates the need for future investments in transmission, quick-start combustion turbines, energy storage devices and smart grid technologies in order to maintain reliable grid operations. For purposes of reliability, the 2014 IRP assumes that approximately 50 MW of battery storage technology will be required between 2019 and 2028 to support future ancillary service requirements for the grid. Chapter 13 discusses some of the Research and Development (R&D) initiatives that TEP is involved in to study the effects of intermittent generation resources and provides an overview on some of the strategies and technologies being used by other utilities to integrate renewable resources.

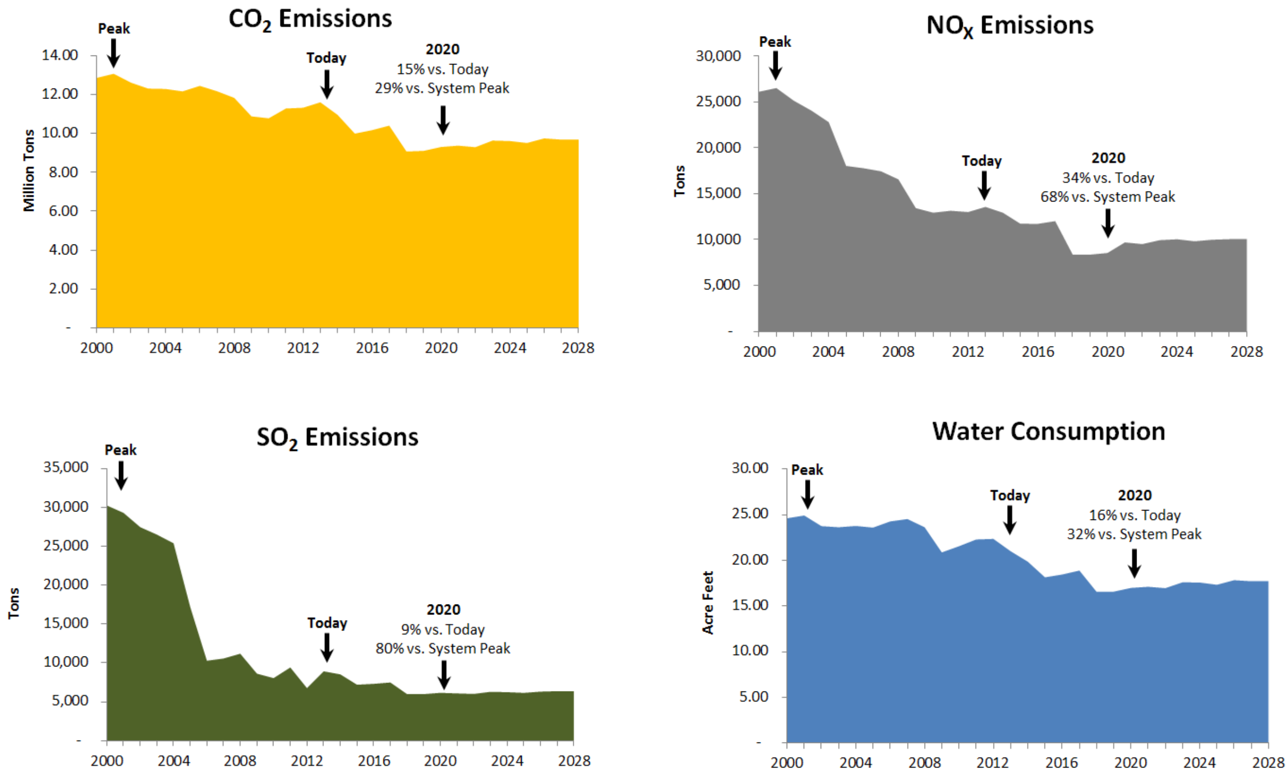
Figure 5 – Local Area Generation and Rewewable Integration



Reference Case CO_2, SO_X, NO_X and Water Consumption Reductions

The 2014 IRP Reference Case plan shows a long-term reduction in CO_2, SO_2, NO_X, and water consumption. For the last decade, TEP's existing generation plants have made significant progress on reducing emissions output. For CO_2 emissions, TEP has dropped from 13.1 million tons per year in the year 2000 to 11.1 million tons in 2012, a 15% reduction. By 2020, TEP's CO_2 emission levels will be reduced by 18% compared to TEP's 2012 emission levels. The Reference Case plan shows that the net decrease from the system peak for CO_2 is 29%. For NO_X emissions, TEP has dropped from 26,124 tons per year in the year 2000 to 13,148 tons in 2012, a 50% reduction. By 2020, TEP's NO_X emission levels will be reduced by 18% compared to TEP's 2012 emission levels. The Reference Case plan shows that the net decrease from the system peak for NO_X is 68%. For SO_2, TEP has dropped from 30,242 tons per year in the year 2000 to 8,929 tons in 2012, a 70% reduction. By 2020, TEP's SO_2 emission levels will be reduced by 10% compared to TEP's 2012 SO_2 emission levels. The Reference Case plan shows that the net decrease from the system peak for SO_2 is 80%. In terms of water consumption, TEP has dropped from 24.9 thousand acre-feet per year in the year 2000 to 21.1 thousand acre-feet in 2012, a 16% reduction. By 2020, TEP's water consumption will be reduced by another 16% compared to TEP's 2012 levels. The Reference Case plan shows that the net decrease from the system peak for water consumption is 32%.

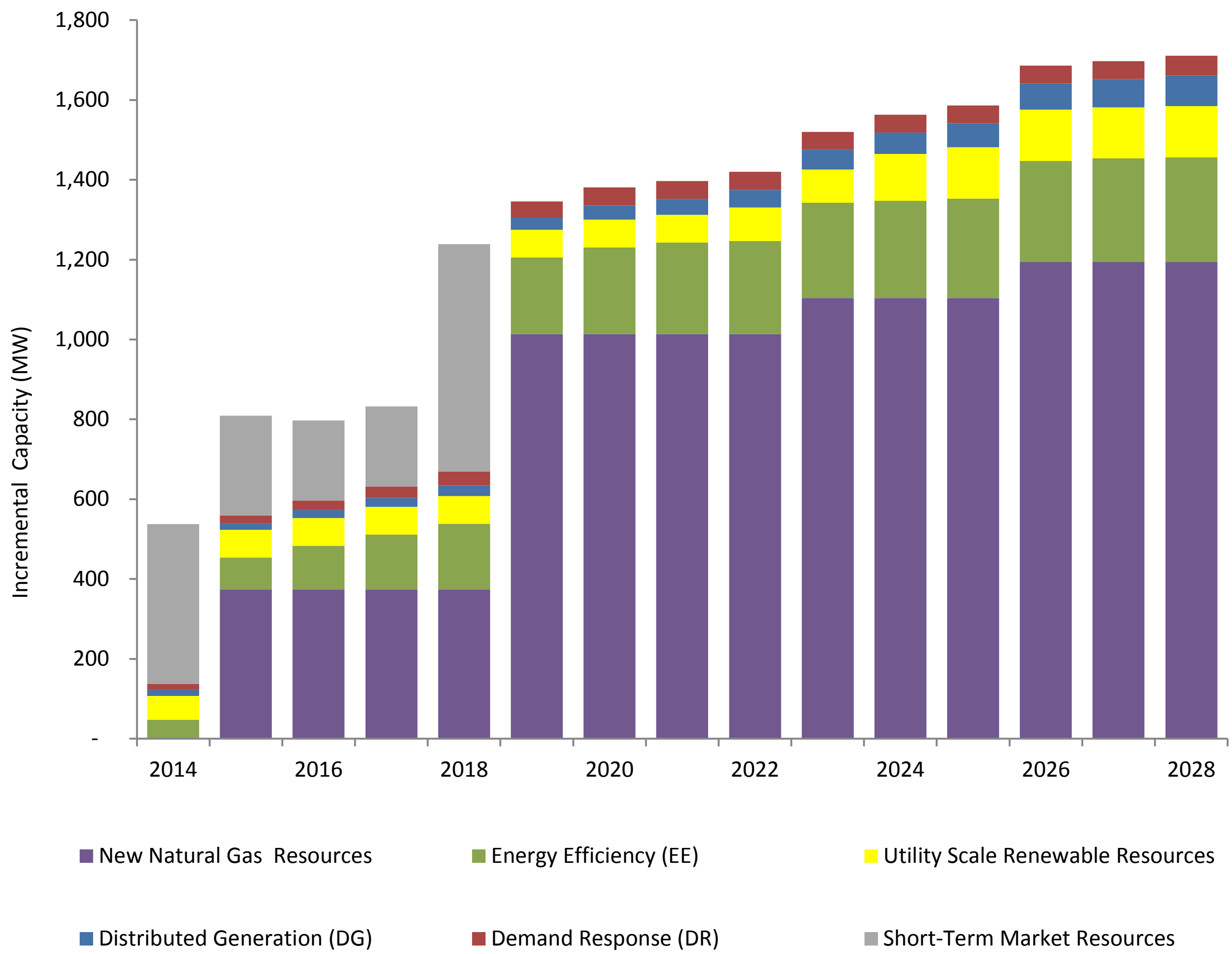
Figure 6 – TEP's Emission Profiles (Historical and 2014 Reference Case Plan)



Reference Case Plan - Capacity Contribution to System Peak

Based on TEP's future load growth and changes to its existing generation fleet, TEP projects that it will need to acquire approximately 1,700 MW of new resource capacity to serve it future load obligations over the next fifteen years. This new capacity is expected to be composed of a mix of new natural gas, renewable and energy efficiency resources. Chart 3 illustrates the Reference Case plan based on a resource's capacity contribution to the coincident system peak.

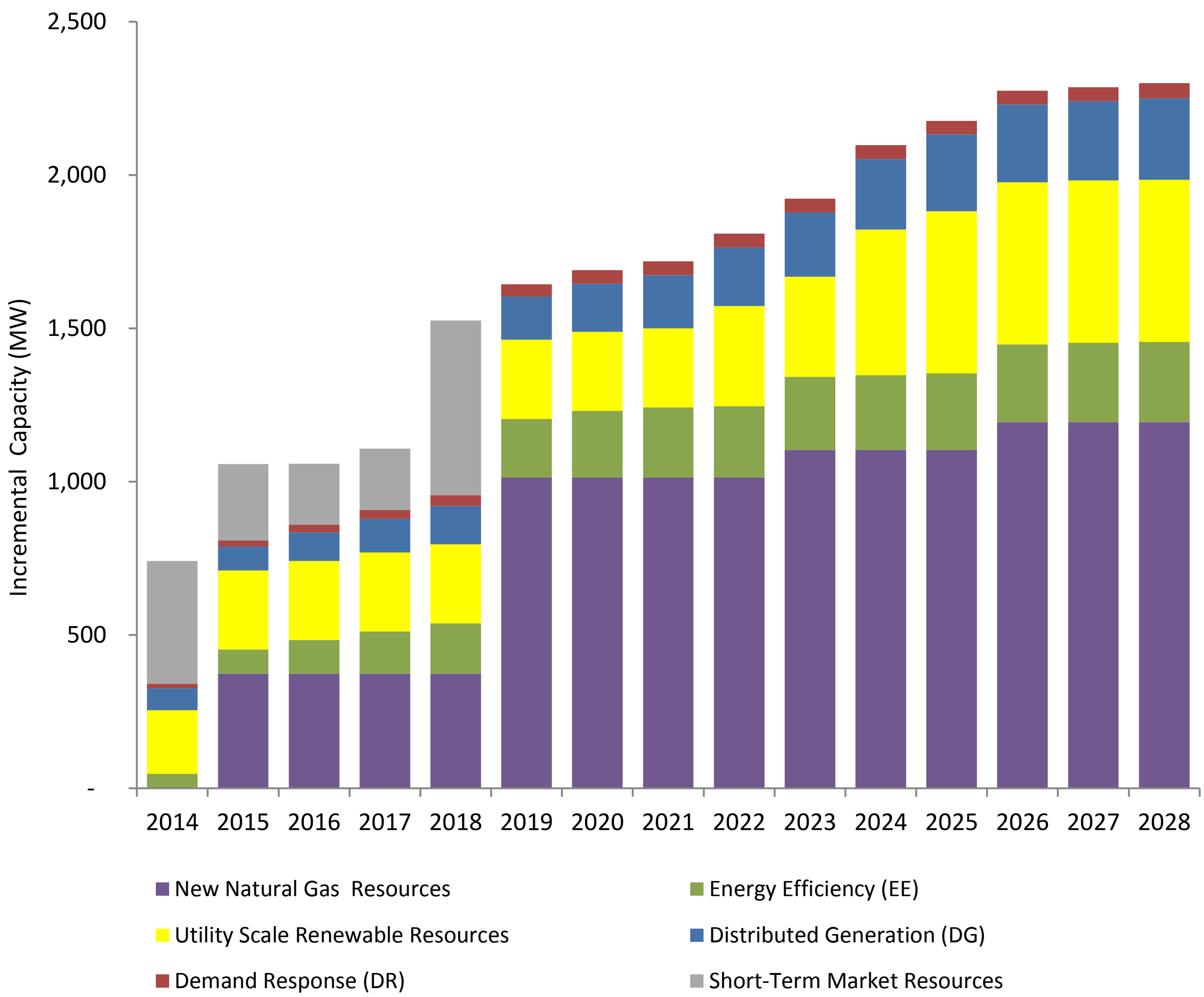
Chart 3 – Reference Case Plan, New Resource Capacity (Coincident to System Peak MW)



Reference Case Plan - Future Capacity Additions

Chart 3 on the previous page displayed the coincident peak capacity for a given resource type. Chart 4 below reflects the installed nameplate capacities for future capacity additions under the Reference Case plan. The Reference Case plan estimates the need for approximately 2,300 MW of new resource capacity based on a 15% planning reserve margin. Chart 4 below shows the incremental nameplate capacities installed by year and resource type.

Chart 4 – Reference Case Plan Capacity Additions, Future Nameplate Capacity (MW)



Reference Case Plan - Future Capacity Additions

Table 3 shows the future resource capacities by year and resource type. This table summarizes the cumulative capacity additions that are expected under the Reference Case plan.

Table 3 – Reference Case Plan Capacity Additions 2012-2027, Cumulative Nameplate Capacity (MW)

Future Resources (Nameplate Capacity MW)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Natural Gas Resources	-	374	374	374	374	1,016	1,018	1,020	1,022	1,114	1,116	1,118	1,210	1,212	1,214
Utility Scale Renewables	208	258	258	258	258	258	258	258	326	326	475	529	529	529	529
Distributed Generation (DG)	71	78	94	110	125	141	157	173	190	210	229	250	254	259	265
Energy Efficiency (EE)	48	80	110	137	164	191	217	229	233	238	244	249	253	259	262
Demand Response (DR)	15	19	24	29	35	40	45	45	45	45	45	45	45	45	50
Total Nameplate Capacity	342	808	859	908	956	1,646	1,695	1,724	1,817	1,933	2,109	2,191	2,291	2,304	2,320
Short-Term Market Resources	400	250	200	200	570	-	-	-	-	-	-	-	-	-	-
Total System Resources	742	1,058	1,059	1,108	1,526	1,646	1,695	1,724	1,817	1,933	2,109	2,191	2,291	2,304	2,320

Future Load Obligations

The tables shown on the next two pages provide a data summary on TEP's loads and resources. Table 4 shows TEP's projected firm load obligations which includes retail, firm wholesale and planning reserves.

Table 4 – Firm Load Obligations, System Coincident Peak Demand (MW)

Firm Load, Demand MW	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Residential	1,089	1,118	1,148	1,182	1,217	1,243	1,270	1,294	1,321	1,352	1,383	1,407	1,440	1,471	1,504
Commercial	454	465	477	491	505	517	528	538	549	562	575	586	597	609	621
Industrial	480	492	505	519	534	547	558	569	581	594	608	619	631	644	657
Mining	200	205	210	216	222	228	232	237	242	247	253	258	263	268	273
Other	49	50	51	53	54	56	57	58	59	61	62	63	64	66	67
Retail Demand	2,272	2,330	2,391	2,461	2,532	2,591	2,645	2,696	2,752	2,816	2,881	2,933	2,995	3,058	3,122
Distributed Generation	-19	-21	-25	-29	-33	-37	-41	-46	-50	-55	-61	-66	-67	-68	-70
Energy Efficiency	-48	-80	-110	-137	-164	-191	-217	-229	-233	-238	-244	-249	-253	-259	-262
Net Retail Demand	2,205	2,229	2,256	2,295	2,335	2,363	2,387	2,421	2,469	2,523	2,576	2,618	2,675	2,731	2,790
Firm Wholesale Demand	120	120	33	33	33	33	36	43	43	0	0	0	0	0	0
Total Firm Load Obligations	2,325	2,349	2,289	2,328	2,368	2,396	2,423	2,464	2,512	2,523	2,576	2,618	2,675	2,731	2,790
Reserve Margin	385	391	406	372	573	625	608	572	544	628	613	588	626	575	526
Reserve Margin, %	17%	17%	18%	16%	24%	26%	25%	23%	22%	25%	24%	22%	23%	21%	19%

Reference Case Plan – System Resource Capacity

Table 5 shows TEP's Reference Case plan based on a resource's capacity contribution to system peak.

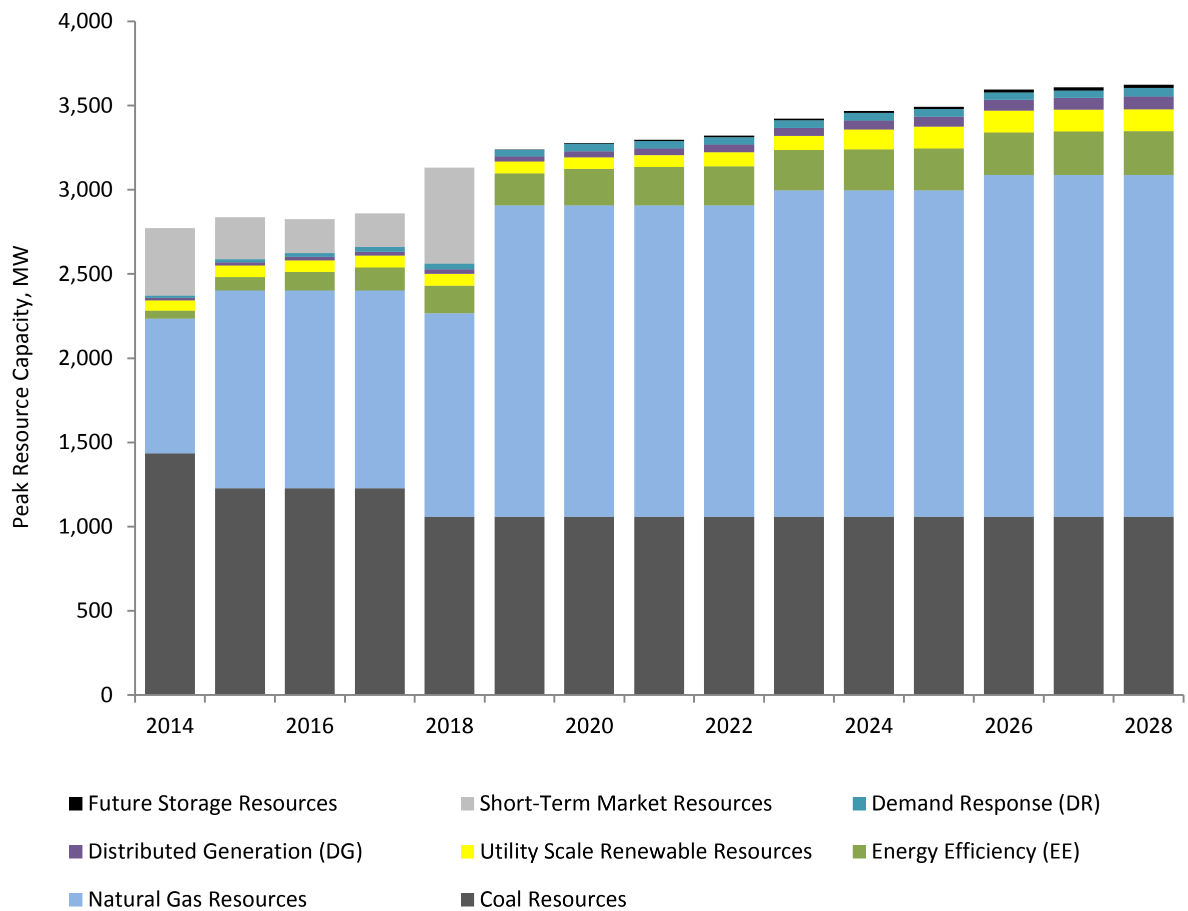
Table 5 – Reference Case Plan - Capacity Resources, System Coincident Peak Demand (MW)

Firm Resource Capacity (MW)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Four Corners	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110
Navajo	168	168	168	168	168	168	168	168	168	168	168	168	168	168	168
San Juan	340	340	340	340	170	170	170	170	170	170	170	170	170	170	170
Springerville	817	610	610	610	610	610	610	610	610	610	610	610	610	610	610
Remote Coal Resources	1435	1228	1228	1228	1058	1058	1058	1058	1058	1058	1058	1058	1058	1058	1058
Sundt 1-4	391	391	391	391	426	426	426	426	426	426	426	426	426	426	426
Luna Energy Facility	190	190	190	190	190	190	190	190	190	190	190	190	190	190	190
Gila River Power Station	0	374	374	374	374	374	374	374	374	374	374	374	374	374	374
DeMoss Petrie CT	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
North Loop CT 1-4	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
Sundt CT 1-2	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49
Future Natural Gas Resources	0	0	0	0	0	640	640	640	640	730	730	730	820	820	820
Total Natural Gas Resources	800	1174	1174	1174	1209	1849	1849	1849	1849	1939	1939	1939	2029	2029	2029
Utility Scale Renewables	60	69	69	69	69	69	69	69	84	84	117	129	129	129	129
Demand Response	15	19	24	29	35	40	45	45	45	45	45	45	45	45	50
Total Renewable Resources	75	88	93	98	104	109	114	114	129	129	162	174	174	174	179
Short-Term Market Resources	400	250	200	200	570	0	0	0	0	0	0	0	0	0	0
Future Storage Resources	0	0	0	0	0	5	10	15	20	25	30	35	40	45	50
Total Firm Resources	2710	2740	2695	2700	2941	3021	3031	3036	3056	3151	3189	3206	3301	3306	3316

Reference Case Plan – System Coincident Peak Capacity

Chart 5 provides an aggregate summary of TEP's resource capacity including its existing generation resources. In 2014, the resource capacity mix is made up of coal, natural gas, renewables, and short term market resources. Based on the 2014 Reference Case Plan, the TEP resource portfolio shows a 32% decline in coal fired capacity over the next five years with increases in natural gas, renewables and energy efficiency resources.

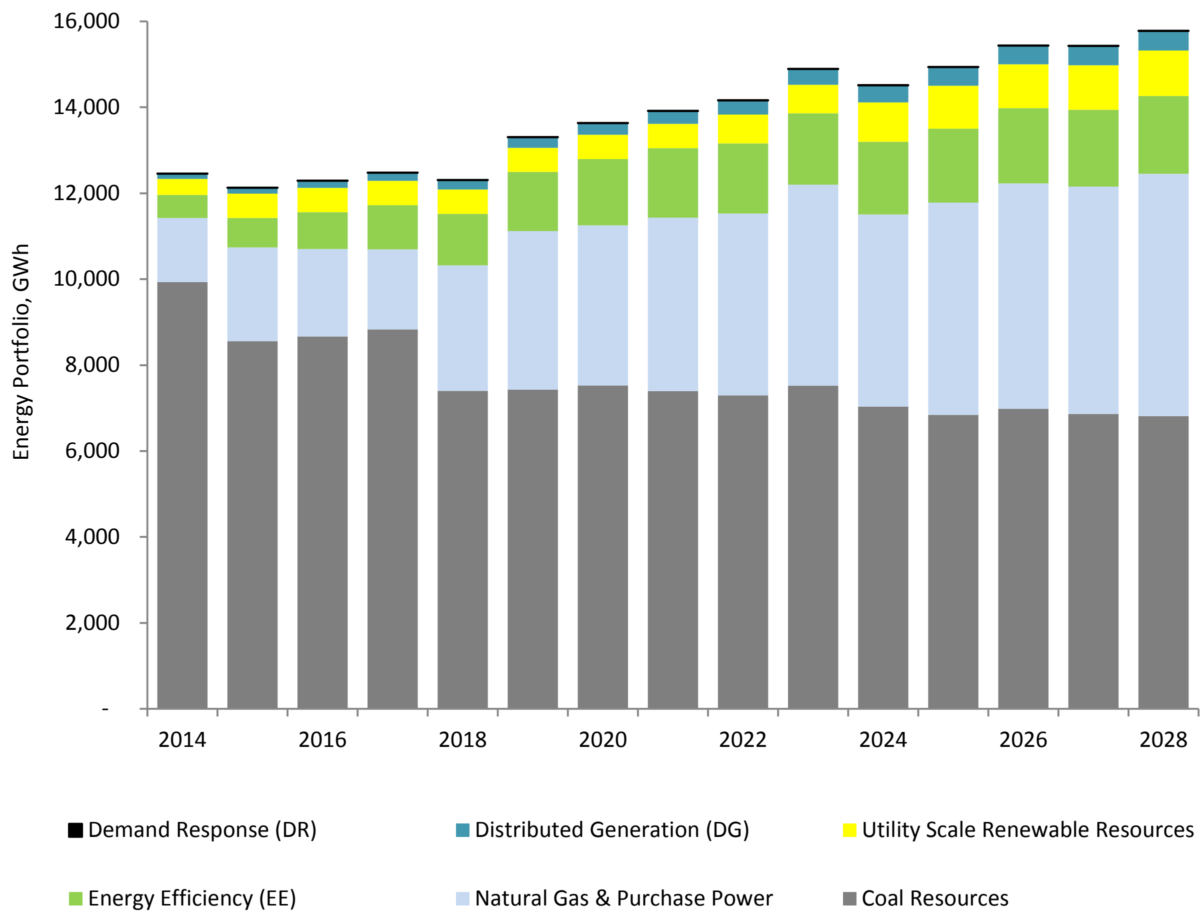
Chart 5 – Reference Case Plan, System Resource Capacity (Coincident to System Peak MW)



Reference Case Plan – Expected Annual Energy

Chart 6 shows the Reference Case Plan expected energy contribution to meet TEP's firm load obligations by year and resource type. In 2014, TEP's energy portfolio is 80% coal and 12% natural gas resources with the remaining 8% will be made up of renewables and demand-side resources. By 2028, it is projected that TEP's energy portfolio will be 43% coal and 36% natural gas resources, while the remaining 21% will be made up of renewables and demand-side resources.

Chart 6 – Reference Case Plan, Expected Annual Energy (GWh)



Action Plan

Overview

The 2014 Reference Case plan was chosen as the preferred portfolio plan based on the current assumptions known at the time of this filing. As a result, TEP has developed a short-term action plan based on the resource decisions that must be implemented in the early phases of this strategy. Under this action plan, additional detailed study work will be conducted to fully validate all technical and financial assumptions prior to any final implementation decisions.

Under the 2014 Reference Case plan, as discussed in more detail herein, TEP's action plan includes the following:

- TEP plans to implement its long-term portfolio diversification strategy to reduce the long term risks associated with investments in coal fired generation. TEP plans to reduce its overall capacity commitments by 492 MW over the next five years at Springerville, San Juan, and Sundt Generating Stations.

- TEP anticipates finalizing its plan to purchase its current leased interests of 35.4% or 135 MW of Springerville Unit 1 for $65 million. As a result of this purchase, TEP will own 49.5% of Springerville Unit 1 for a total of 190 MW.

- TEP plans to finalize the joint acquisition of the Gila River Power Station in December 2014. It is anticipated that TEP will purchase a 75% undivided interest in Gila River Unit 3 for approximately $164 million.

- TEP plans to continue with its utility scale build out of its current RES implementation plans. TEP anticipates that an additional 130 MW of new renewable capacity will be in-service by the end of 2015 raising the total distributed generation and utility scale capacity on TEP's system to approximately 350 MW. By 2016, renewable resources will make up close to 15% of TEP's total nameplate generation capacity. As a result, TEP is currently investing its time and resources into a number of research and development activities that will determine the future need for storage and smart grid technologies to support the grid.

- TEP will continue to implement cost-effective EE programs based on the Arizona EE Standard. TEP will closely monitor its energy efficiency program implementations and adjust its near-term capacity plans accordingly.

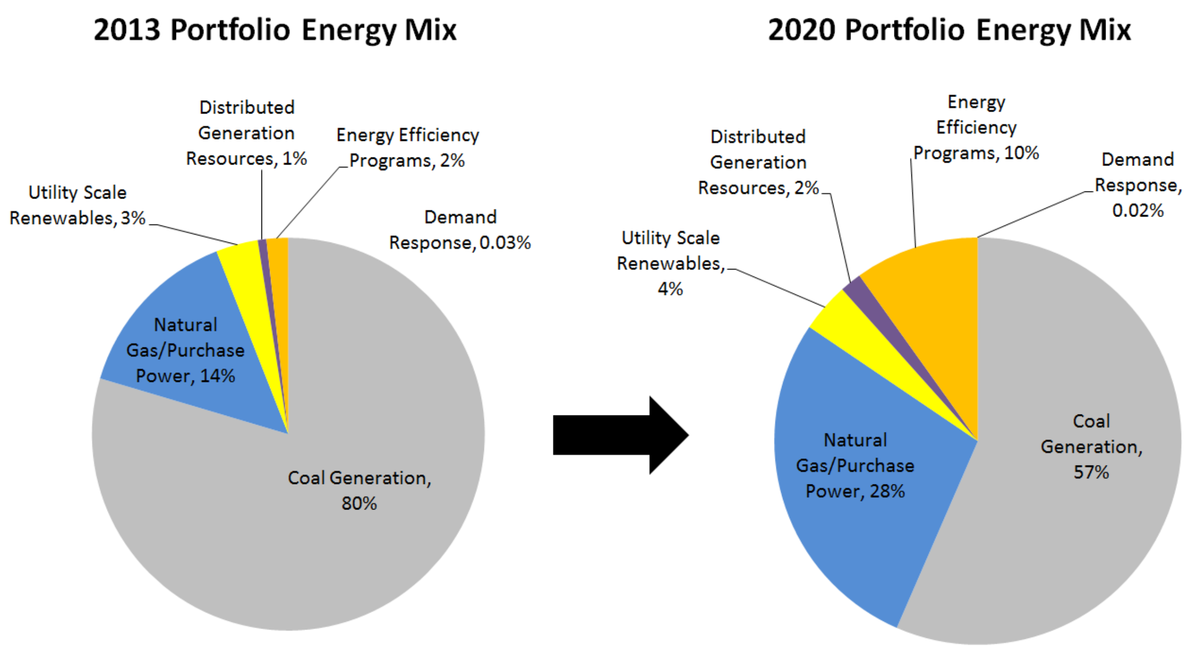
- As part of its near-term portfolio strategy, TEP will continue to utilize the wholesale merchant market for the acquisition of short-term market based capacity products. In addition, TEP will continue to monitor the wholesale market for other resource alternatives such long-term purchase power agreements and low cost plant acquisitions. TEP will also monitor its natural gas hedging requirements as it reduces its reliance on coal based generation in favor of natural gas resources and make recommendations on potential fuel hedging changes if they become necessary.

As with any planning analysis, the 2014 IRP represents a snapshot in time based on known and reasonable planning assumptions. It is important to note that the final acceptance by the EPA regarding the BART alternatives at San Juan, Navajo, and Sundt Generating Stations will be finalized sometime in 2014. Even after the 2014 IRP filing date, TEP anticipates that the plant participants will continue to work through the complex issues surrounding the final EPA rulings, plant operating agreements, fuel contracts, land leases, and environmental impact reviews before the final resource decisions are made. Given the confidential nature of these decisions, TEP plans to communicate any major change in its anticipated resource plan with the Arizona Corporation Commission as part of its ongoing planning activities. TEP hopes this dialog will allow the Commission an opportunity to help shape TEP's future resource portfolio outcomes while providing TEP with greater regulatory certainty with regards to future resource investment decisions. TEP requests that the Commission acknowledge its 2014 Integrated Resource Plan as provided in A.A.C. R14-2-704.B.

CONCLUSIONS

The 2014 Reference Case plan results in significant reductions in both air emissions and cost impacts on TEP's customers. Over the last five years, TEP, along with other regional utilities have worked with the EPA to develop a number of cost saving "Better than BART" proposals for Regional Haze at it existing coal-fired generating stations. In addition, TEP's planned acquisition of a low cost gas-fired combined cycle power plant at Gila River Power Station will enable TEP to save approximately $140 M in capital expenditures related to coal retrofits and replacement generation capacity. In addition to this cost savings, TEP's portfolio diversification strategy results in significant reductions in air emissions as TEP reduces approximately 32% (492 MW) of its existing coal capacity over the next five years. On an energy basis it is expected that TEP will reduce its coal exposure from 80% today to 57% by 2020 as a result of transitioning to more environmental friendly resources such as natural gas, renewables and EE.

Chart 7 – Portfolio Comparisons



CHAPTER 2

INTEGRATED RESOURCE PLANNING METHODOLOGY

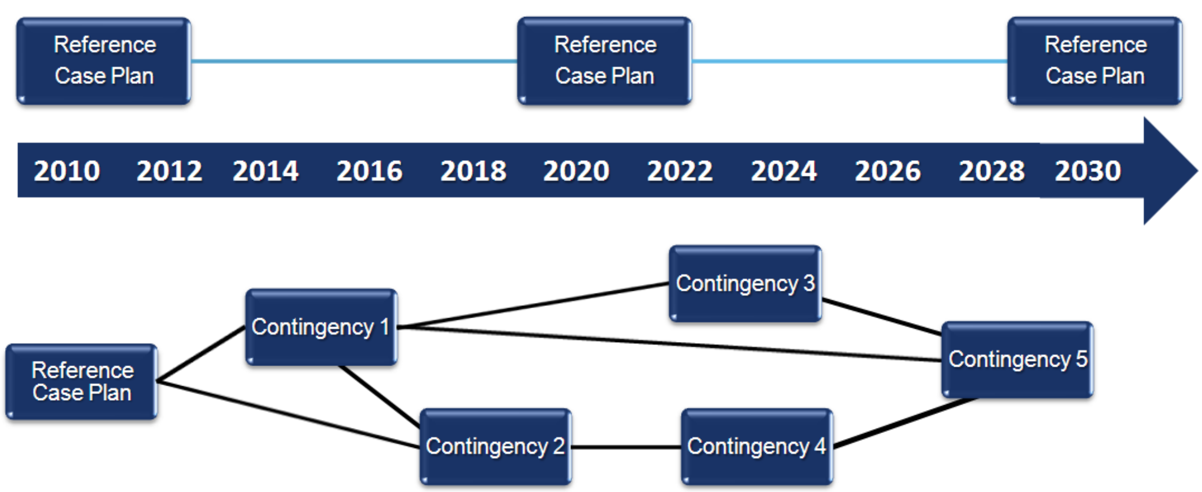
Overview

The purpose of the 2014 Integrated Resource Plan (IRP) is to develop a strategic roadmap for TEP that ensures reliable electric service, meeting renewable and energy efficiency mandates while effectively managing costs and future uncertainty. The IRP also serves to inform regulatory staff, customer interest groups, regulators and other interested stakeholders on the assumptions used to develop the company's long-term resource strategy.

The IRP process is a dynamic business function that helps utility planners narrow the choices on long-term resource procurement. The Reference Case plan is not meant to be a static plan; but rather it is expected to evolve as economic, regulatory, and environmental uncertainties reshape the utility industry.

It is important to realize that the Reference Case plan is considered the current "best view" of future resource possibilities. The Reference Case plan also considers future uncertainties and through the use of simulation and scenario analysis a number of contingency plans are also developed. This approach is similar to a project management exercise where utility planners determine the foreseeable critical path decisions along the resource planning timeline. Figure 7 shows this from a conceptual basis.

Figure 7- Resource Planning Contingency Timelines



Methodology for Analyzing Potential Portfolios

The scope of this IRP is to identify a resource portfolio that meets TEP's projected firm load obligations over the next twenty years. This IRP process identifies a series of resource options that can be used to meet system reliability in a cost effective and environmentally responsible manner.

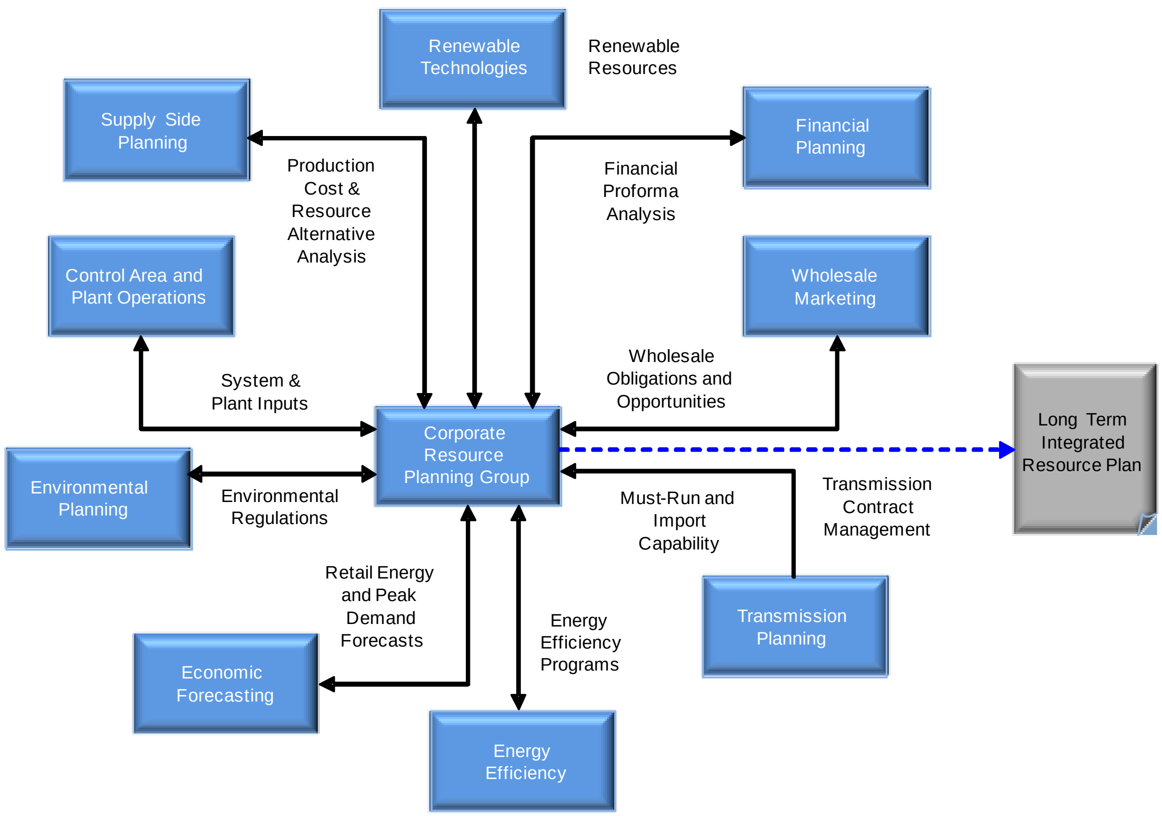
This chapter summarizes TEP's IRP methodology and discusses the following topics related to this integrated planning process.

- Corporate Resource Planning Group
- IRP Process Overview
- Forecast and Scenario Development
- Minimum Planning Requirements
- Public Workshops

Corporate Resource Planning Group

The Corporate Resource group is responsible for overseeing the coordination of the resource planning efforts for TEP. This group, shown in Figure 8, is comprised of representatives from different planning areas that provide the assumptions required to perform this analysis. Planning groups such as Financial Planning, Supply-Side Planning, Transmission Planning, Energy Efficiency and Renewable Programs examine the financial and technical tradeoffs between the numerous resource alternatives. The Reference Case plan presented in this report represents the collaborative efforts of several workgroups.

Figure 8 - Corporate Resource Planning Group



Joint Resource Planning Activities

As part of TEP's on-going resource planning efforts, TEP coordinates it's planning activities with its regional partners to develop potential generation and transmission resource options. Due to locational proximity to southern Arizona TEP, works with companies such as Unisource Electric (UNSE), TRICO, and Freeport McMoRan, Navajo Tribal Utility Authority (NTUA) and Tohono O'odham Utility Authority (TOUA) in coordinating its long-term resources plans. Over the last few years a number of opportunities have developed that will offer potential cost savings for Arizona's retail and wholesale customers.

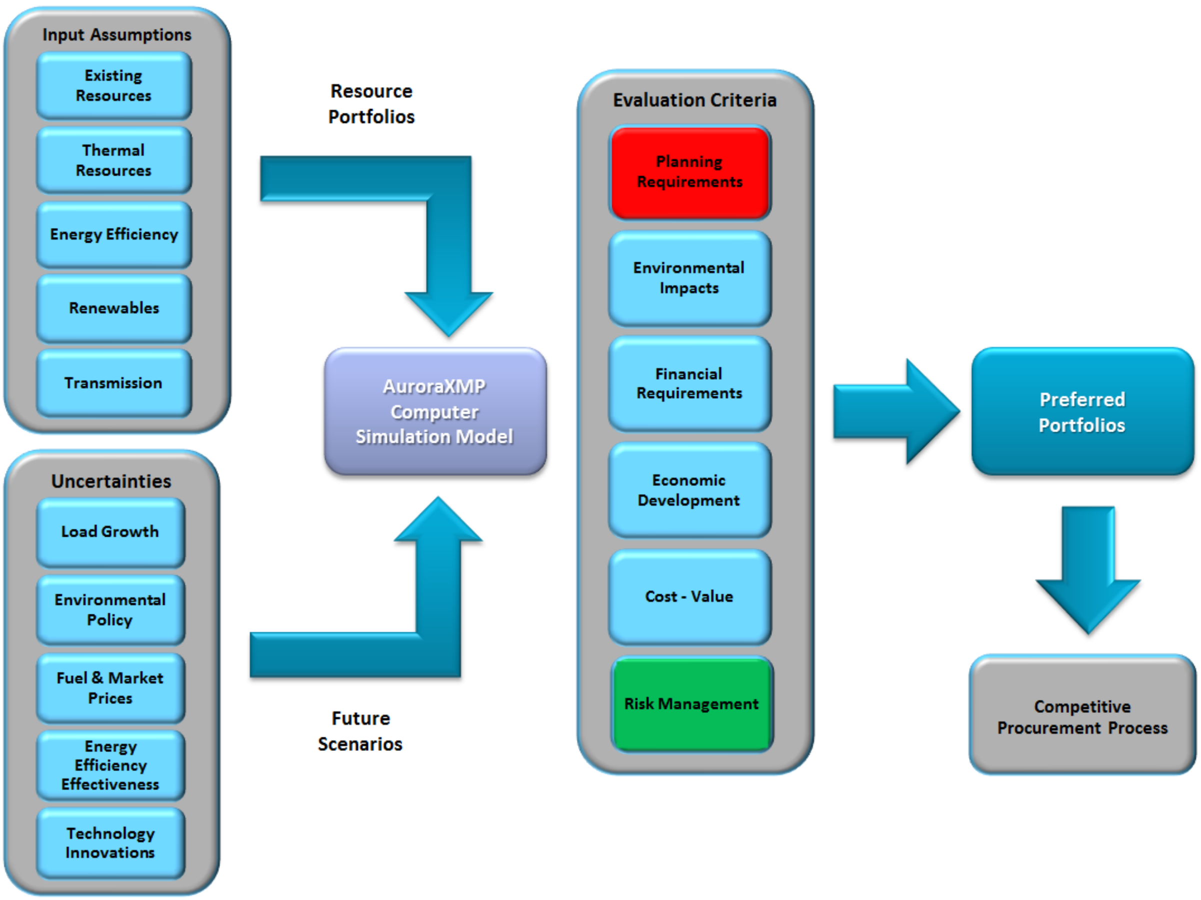
- Today, TEP has in place wholesale contracts with both NTUA and TOUA. TEP has been a partner with both of these wholesale customers for several decades. TEP coordinates its longer term planning activities as well as daily scheduling under the terms of these partial requirements sale contracts.
- In 2006, TEP and Freeport McMoRan partnered with PNM on the acquisition and the construction of the Luna Generating Facility. Today each party holds a 33.3% ownership in the combined cycle facility.
- TEP and UNSE coordinate a number operating activities such as real-time system scheduling and dispatch, portfolio hedging, capacity procurement and long-term resource planning.
- TEP and UNSE have partnered in its efforts to develop both its renewable energy and energy efficiency programs. Currently both TEP and UNSE are working with Torch Renewables to develop Red Horse 2 which is a proposed wind-solar renewable project sited near Willcox, Arizona. This project is currently being developed with 40 MW of wind resources for TEP and 30 MW of solar resources for UNS Electric. This project is expected to be in-service by the end of 2015.
- TEP and TRICO are also working together to coordinate near term portfolio hedging, capacity procurement and long-term resource planning. TEP also services as TRICO's Balancing Authority agent conducting real-time system scheduling and dispatch of its generation and transmission resources.
- In 2014, TEP and UNSE are coordinating efforts to acquire ownership interests in Power Block 3 at the Gila River Power Station. Through this acquisition, both companies will acquire an appropriate share of unit capacity to match its near term resource needs thus minimize rate impacts for its retail customers. In addition, TEP and UNSE will coordinate the operations and maintenance activities as well as the daily scheduling and dispatch of the unit. These efforts will help maximize the efficiency of the unit while reducing costs for both companies.

TEP plans to continue to develop these types of joint partnerships with regional utilities and wholesale customers to maximize resource efficiencies while minimizing rate impacts on its customers.

IRP Process Overview

The section provides a narrative of the data requirements, evaluation criteria and computer simulation models that were used in developing the 2014 resource plan. An overview of the resource planning process is shown in Figure 9 - IRP Process Overview

Figure 9 - IRP Process Overview



Computer Simulation Modeling

Tucson Electric Power currently uses AURORAxmp (version 11.3) for its resource planning production cost modeling. AURORAxmp is a complex generation dispatch simulation model that performs multiple functions throughout the organization. Additional information about AURORAxmp can be found at http://epis.com/

- Price Forecasting
- Resource Valuation
- Risk and Uncertainty Analysis
- Long-Term Capacity Expansion Modeling
- Dispatch Optimization
- Locational Marginal Pricing (LMP) Analysis

Input Assumptions

One of the first steps in developing an integrated resource plan is to define the input assumptions for the Reference Case plan. The details related to future generation and transmission resources are covered in detail throughout this report.

- Future Supply-Side and Demand–Side Resources are summarized in Chapter 6.
- Future transmission resources are summarized in Chapter 7.
- Chapter 11 provides an overview on TEP's energy efficiency programs and modeling assumptions.
- Chapter 12 has an in-depth write-up on TEP's renewable resources.

Forecast and Scenario Development

In developing its fifteen year market forecast, the resource planning time considered forward market projections from a wide variety of reputable economic forecasting services including Wood-Mackenzie, IHS-CERA, and PACE Global. These forward price projections for wholesale power, coal, natural gas and emission prices were based on a comprehensive set of market fundamentals for the WECC Region. The data related to these forecast assumptions are summarized in Chapter 16.

Risk Analysis and Simulation Development

In the development of the Reference Case plan, it is important to consider the performance of each candidate portfolio under a wide range of possible outcomes to understand the risks associated with each choice in addition to the simple expected costs. Traditionally, this uncertainty analysis was conducted using a scenario based approach. While scenario analysis has its advantages and is still utilized, in the 2014 IRP the risk analysis has been expanded to include the use of simulation. Specifically, the performance of each candidate portfolio was compared across the same set of 100 possible futures representing a correlated set of gas prices, power prices, and loads.

Expanding the examination of uncertainty using this approach has a number of advantages including:

- Most importantly, ensures that the selected Preferred Portfolio performs well in a wide range of possible futures (not just the expected case)
- Provides a good understanding of the distributions of possible outcomes
- Provides explicit risk metrics including better understanding of "worst" and "best" cases
- Allows for identification and removal of candidate portfolios that have similar expected costs but significantly higher associated risks than other portfolio options

The 100 iterations (possible futures) were developed using a stochastic model that utilizes parameters such as expected market prices, historical correlations, volatility, and mean reversion, as well as additional constraints to ensure that each iteration is internally consistent.

A detailed discussion of the market iterations and summary statistics is provided in Chapter 15. A risk profile for each candidate portfolio and a summary of simulation outcomes is provided in the discussion of IRP planning results in Chapter 17.

Minimum Resource Planning Requirements

In addition to the market input assumptions TEP has some minimum resource planning criteria that are required under all resource portfolios. In all planning scenarios, TEP assumed compliance with the following criteria:

- Maintain 15% Planning Reserve Margin
- Maintain Adequate Load Serving Capacity
- Meet the Arizona Energy Efficiency Standards
- Meet the Arizona Renewable Energy Standards

Planning Reserve Margin

A planning reserve margin of 15% is used in the resource planning process to compensate for uncertainty surrounding future load forecast changes and resource contingencies such as generation or transmission forced outages. The planning reserve margin is calculated as the amount of firm peak resource capacity in excess of projected retail demand as a percentage of total demand. For purposes of the reserve margin calculation in the IRP, TEP defines system peak demand as the forecasted retail peak demand minus energy efficiency and demand response programs. It is assumed that these demand-side resources will meet the reserve criteria of SRSG, WECC and NERC.

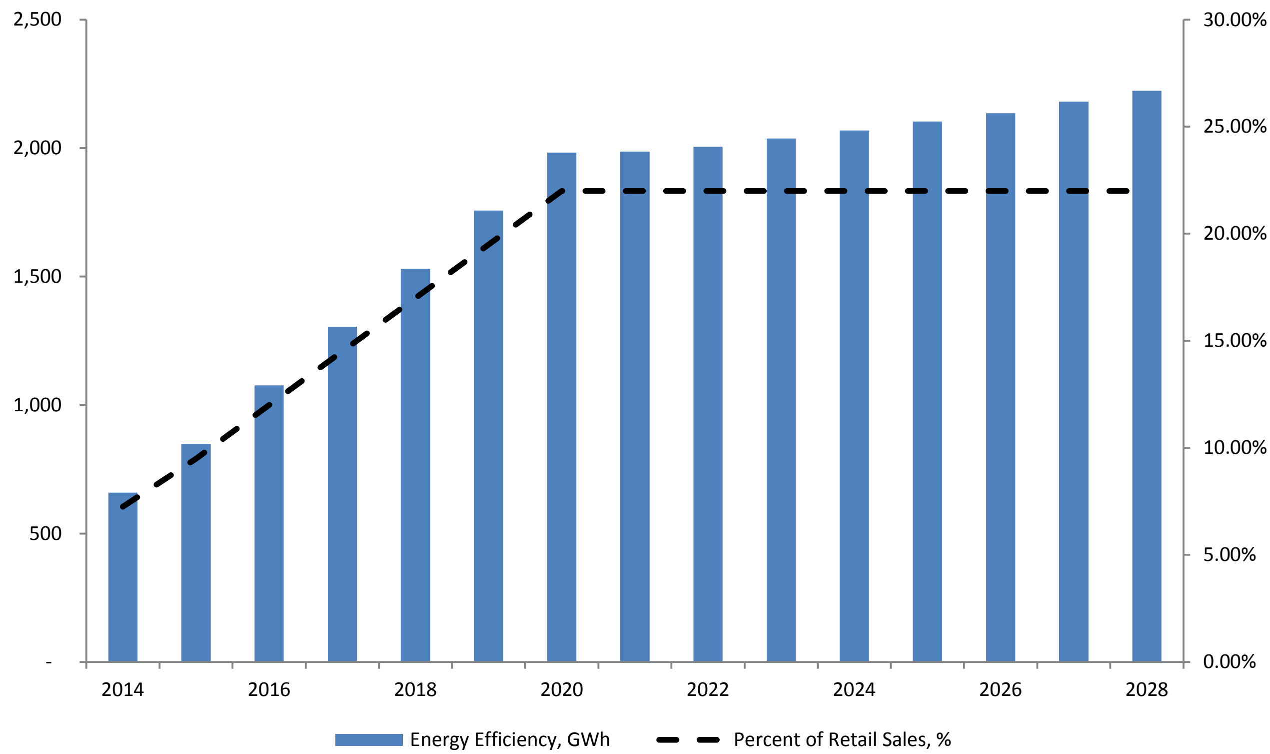
Maintain Adequate Load Serving Capacity

TEP load serving requirement is defined around TEP's ability to adequately serve its retail load obligations within the Tucson metropolitan area. TEP's wholesale load obligations outside of the Tucson area are not factored into this equation. TEP's load serving capability is defined as the sum of local area generation capacity plus TEP's transmission import capacity at system peak. Adequate capacity to meet TEP's load serving capability is one of four mandatory planning requirements in all potential resource portfolios.

Energy Efficiency Standard Compliance

For resource planning purposes, TEP has assumed that it maintains compliance with Arizona Energy Efficiency Standard which targets a cumulative load reduction of 22% by 2020. Chart 8 below shows the expected displacement of customer load by energy efficiency by year through 2028. TEP's projected energy efficiency programs will achieve a cumulative reduction of 640 GWh in 2014 increasing to 2,223 GWh by 2028.

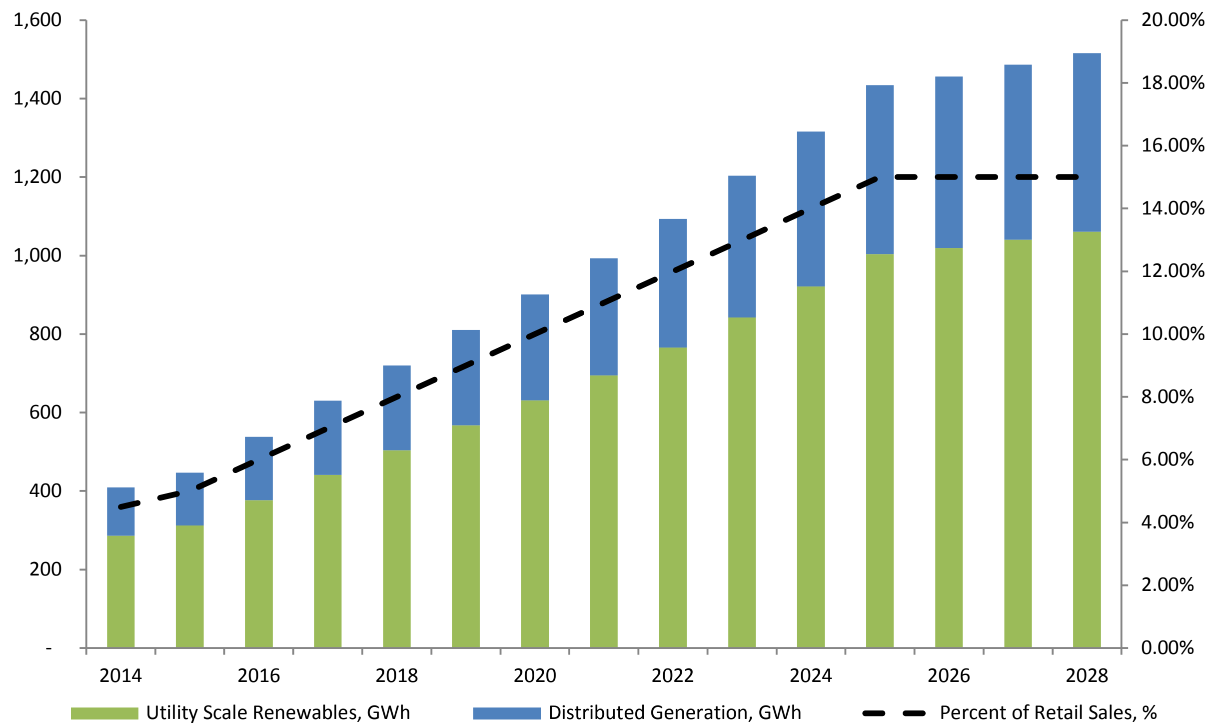
Chart 8 - Projected Energy Efficiency Targets by Year



Renewable Energy Standard Compliance

The Renewable Energy Standard (RES) sets forth the annual renewable energy requirements for TEP. The RES target is 4.5% of the prior year retail sales in 2014 increasing to 15% by 2025. Chart 9 shows the expected renewable energy requirement by year, based on this standard. In order to meet the RES requirements, TEP will need to implement a renewable portfolio of utility scale and distributed generation resources to meet an annual production level of approximately 409 GWh in 2014 reaching 1,515 GWh by 2028.

Chart 9 - Projected RES Requirements by Year



IRP Public Workshops

In developing the 2014 Integrated Resource Plan, TEP conducted a public workshop to inform and solicit feedback from a variety of stakeholders. The goal of the workshops was to provide a public forum where participants could ask questions and provide input into the resource planning process. TEP's resource planning group presented a wide range of resource planning topics.

In addition to members of the general public, workshop attendees included stakeholders from various organizations:

Arizona Corporation Commission	Raytheon
Arizona Public Service Company	Rosemont Copper Company
Arizona's G&T Cooperatives	Sempra Energy
City of Tucson	Sierra Club Grand Canyon Chapter
Copper State Consulting Group	Southwest Gas Corporation
Energy Strategies, LLC	Technicians for Sustainability
Freeport-McMoRan Copper & Gold, Inc.	Tucson-Pima Metro Energy Commission
Pima Association of Governments	

These presentations are currently available on the TEP website in a PDF file format. The TEP resource planning website address is listed below:

http:// https://www.tep.com/Projects/Planning/

IRP Workshop Guest Speakers
Gregg Garfin, The University of Arizona
Assessment of Climate Change in the Southwest U.S. - *www.swcarr.arizona.edu*

Will Holmgren, The University of Arizona
Mike Leuthold, The University of Arizona
Forecasting Renewable Energy Resources

CHAPTER 3

LOAD FORECAST

Introduction

In the IRP process, it is crucial to estimate the load obligations that existing and future resources will be required to meet for both short and long term planning horizons. As a first step in the development of the resource plan, a long term load forecast was produced. This chapter will provide an overview of the anticipated long term load obligations at TEP, a discussion of the methodology and data sources used in the forecasting process, and a summary of the tools used to deal with the inherent uncertainty surrounding a number of key forecast inputs.

The sections in this chapter include:

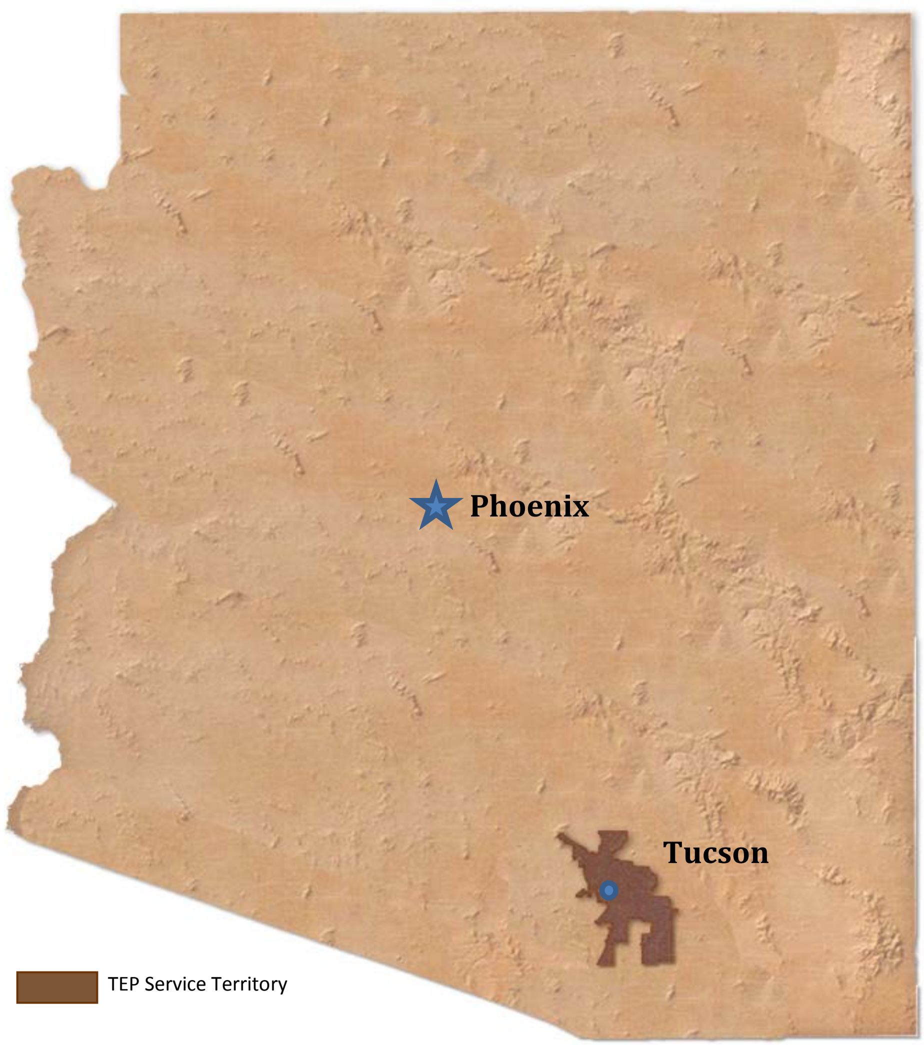
- **Company Overview:** TEP geographical service territory, customer base, and energy consumption by rate class
- **Reference Case Plan Forecast:** An overview of the Reference Case plan forecast of energy and peak demand used in the planning process.
- **Wholesale Obligations:** An outline of the firm system requirements for wholesale electricity sales
- **Summary:** Compilation of results from this analysis

Company Overview

Geographical Location and Customer Base

TEP currently provides electricity to more than 400,000 customers in the Tucson metro area (Pima County). Pima County has experienced rapid growth over the last decade and is now estimated to have a population of approximately 1,000,000 people.

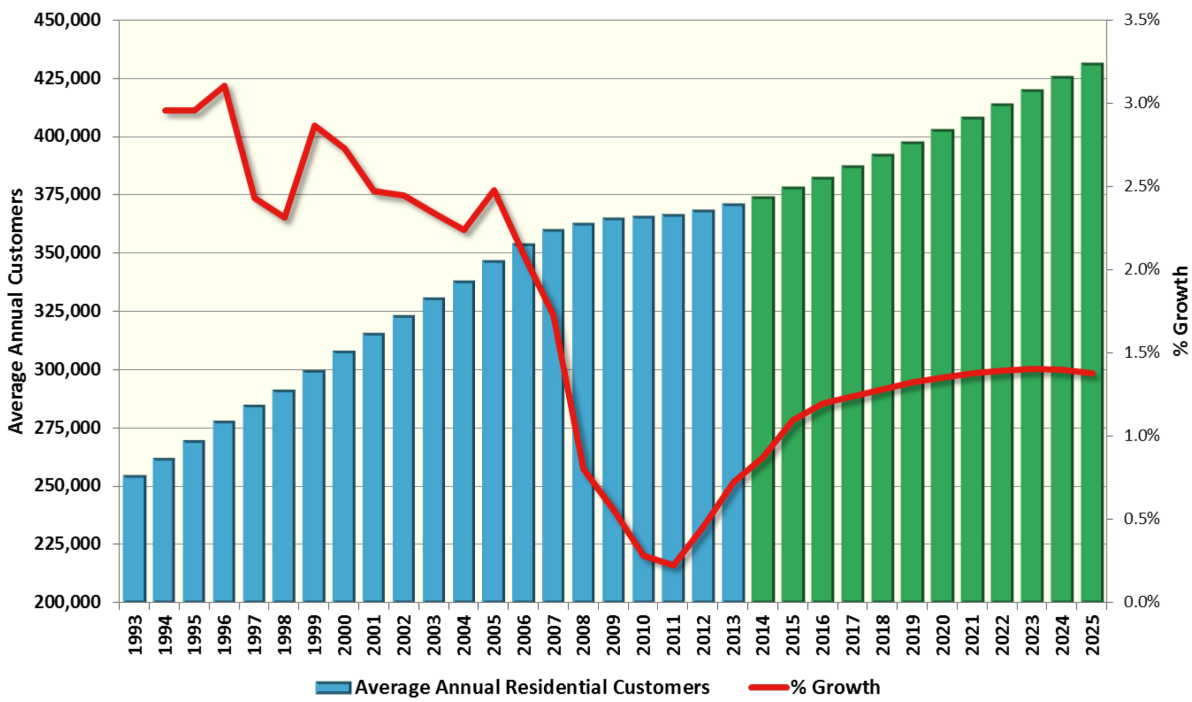
Map 2 - Service Area of Tucson Electric Power



Customer Growth

In recent years, population growth in Pima County and customer growth at TEP have slowed dramatically as a result of the severe recession. While customer growth is currently rebounding from its recessionary lows, it is not expected to return to its pre-recession level. Chart 10 outlines the historical and expected customer growth in the residential rate class from 1993-2025. As customer growth is the largest factor behind growth in TEP's load, the continuing customer growth will necessitate additional resources to serve the increased load in the medium term.

Chart 10 - Estimated TEP Customer Growth 1993-2025

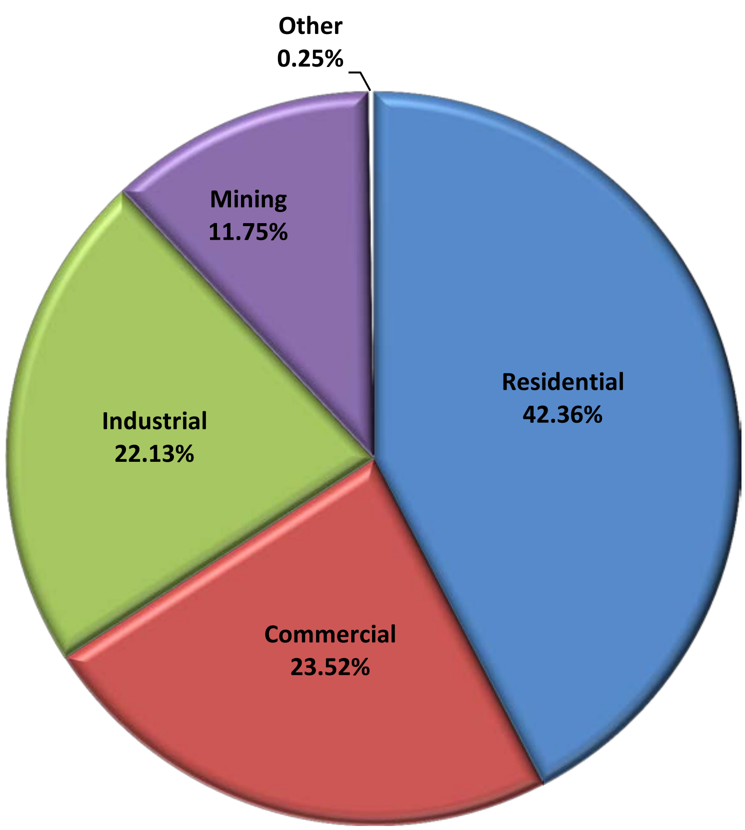


Retail Sales by Rate Class

In 2013, TEP experienced a peak demand of approximately 2,230 MW with approximately 9,279 GWh of retail sales. Approximately 65% of 2013 retail energy was sold to the residential and commercial rate classes, with approximately 34% sold to the industrial and mining rate classes. Customer classes such as municipal street lighting, etc. accounted for the remaining sales.

Chart 11 gives a detailed breakdown of estimated 2014 retail sales by rate class prior to the effects of energy efficiency and distributed generation.

Chart 11 – Estimated 2014 Retail Sales % by Rate Class



Reference Case Plan Forecast

Methodology

The load forecast used in the TEP IRP process was produced using a "bottom up" approach. A separate monthly energy forecast was prepared for each of the major rate classes (residential, commercial, industrial, and mining). As the factors impacting usage in each of the rate classes vary significantly, the methodology used to produce the individual rate class forecasts also varies. However, the individual methodologies fall into two broad categories:

1) For the residential and commercial classes, forecasts are produced using statistical models. Inputs may include factors such as historical usage, weather (e.g. average temperature and dew point), demographic forecasts (e.g. population growth), and economic conditions (e.g. Gross County Product and disposable income).

2) For the industrial and mining classes, forecasts are produced for each individual customer on a case by case basis. Inputs include historical usage patterns, information from the customers themselves (e.g. timing and scope of expanded operations), and information from internal company resources working closely with the mining and industrial customers.

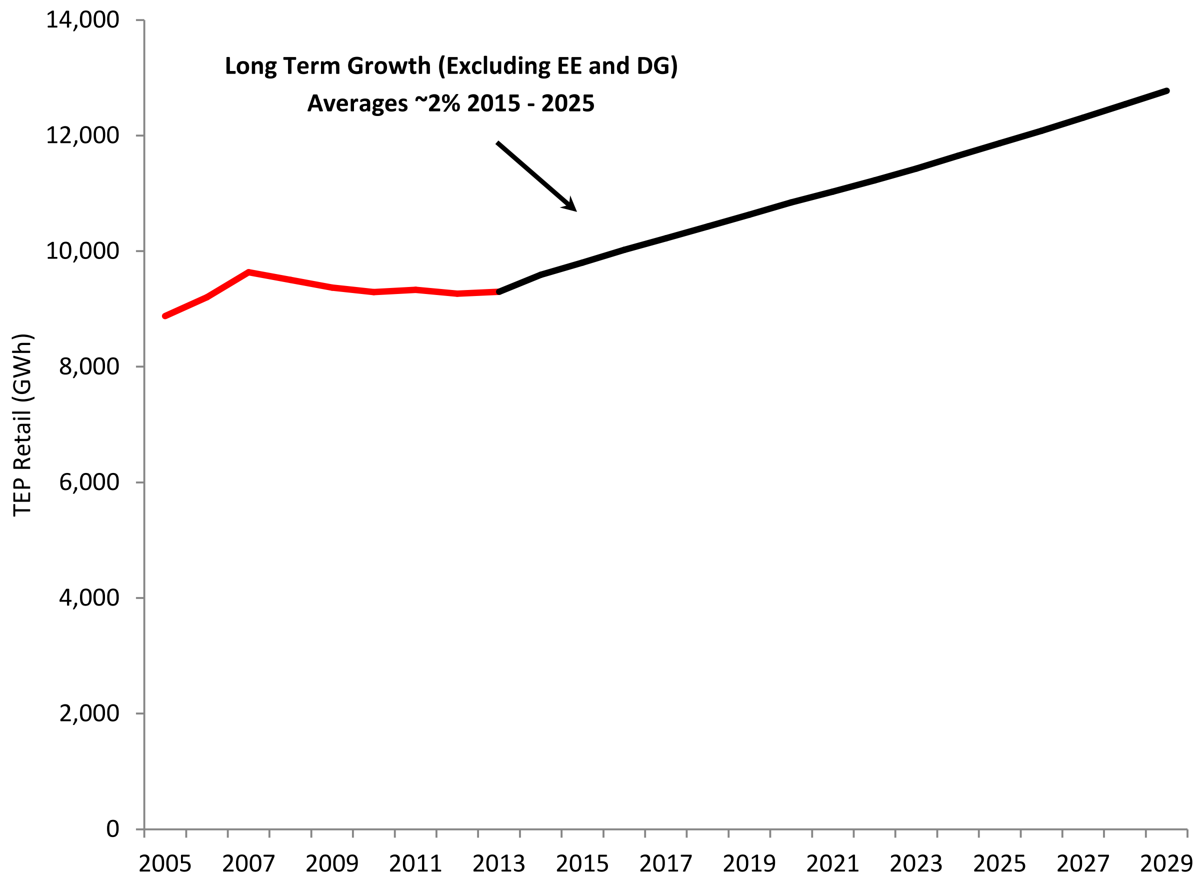
After the individual monthly forecasts are produced, they are aggregated (along with any remaining miscellaneous consumption falling outside the major categories) to produce a monthly energy forecast for the company.

After the monthly energy forecast for the company was produced, the anticipated monthly energy consumption was used as an input for another statistical model used to estimate the peak demand. The peak demand model is based on historical relationship between hourly load and weather, calendar effects, and sales growth. Once these relationships are estimated, 60+ years of historical weather scenarios are simulated to generate a probabilistic peak forecast.

Reference Case Plan Retail Energy Forecast

As illustrated in Chart 12, after a period of relatively rapid growth from 2005 – 2007, TEPs retail energy sales fell significantly from 2008 – 2011 and have remained relatively flat through 2013. As the recessionary environment continues to dissipate, the load is expected to grow significantly in 2014 and beyond as customer growth resumes and customer usage rebounds. Note that forecasted values in Chart 12 exclude the effects of energy efficiency and distributed generation.

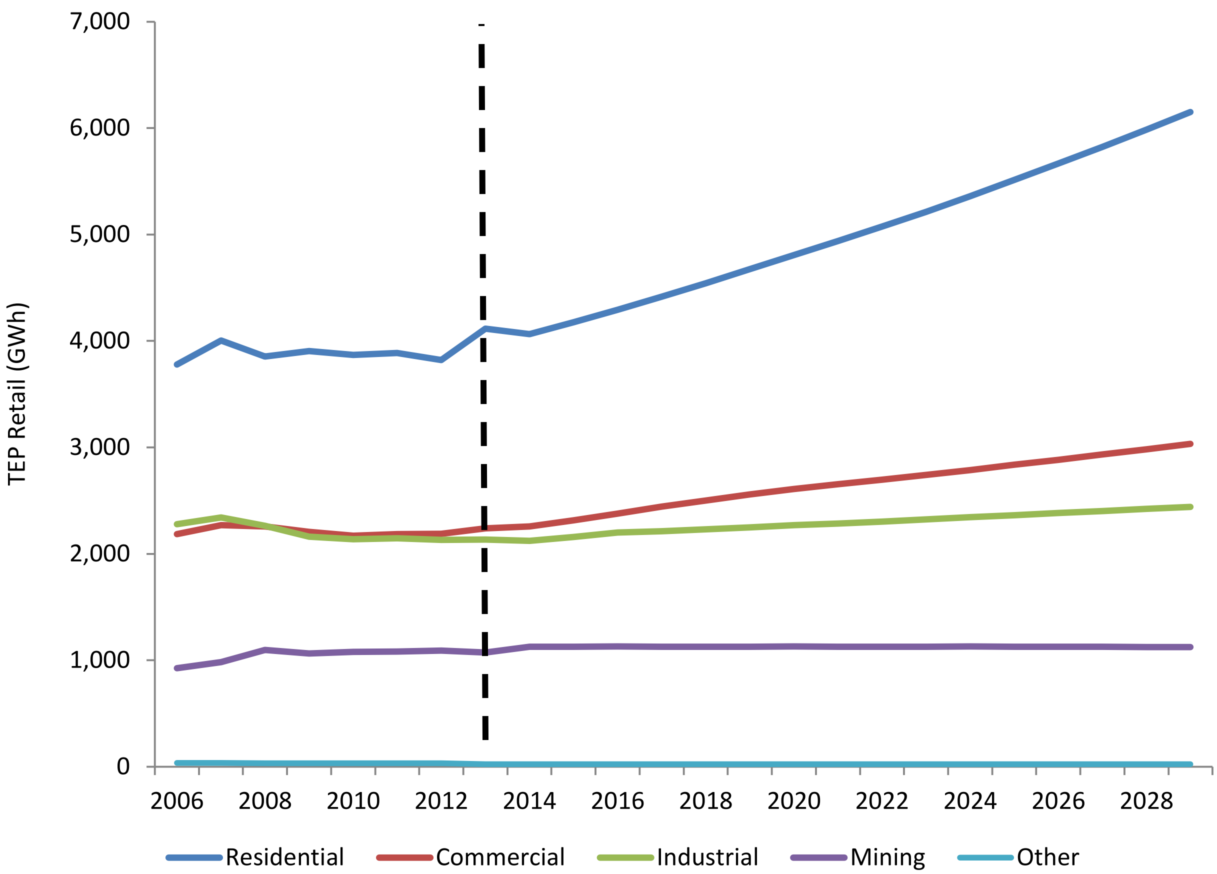
Chart 12 - Reference Case Plan Retail Energy Sales



Reference Case Plan Retail Energy Forecast by Rate Class

As illustrated in Chart 13 the Reference Case Plan forecast assumes steady energy sales growth at TEP throughout the planning period. However, the growth rates vary significantly by rate class. The energy sales trends for each major rate class are detailed in Chart 13. Note that the forecasted values in Chart 13 exclude the effects of energy efficiency and distributed generation.

Chart 13 - Reference Case Plan Retail Energy Sales by Rate Class

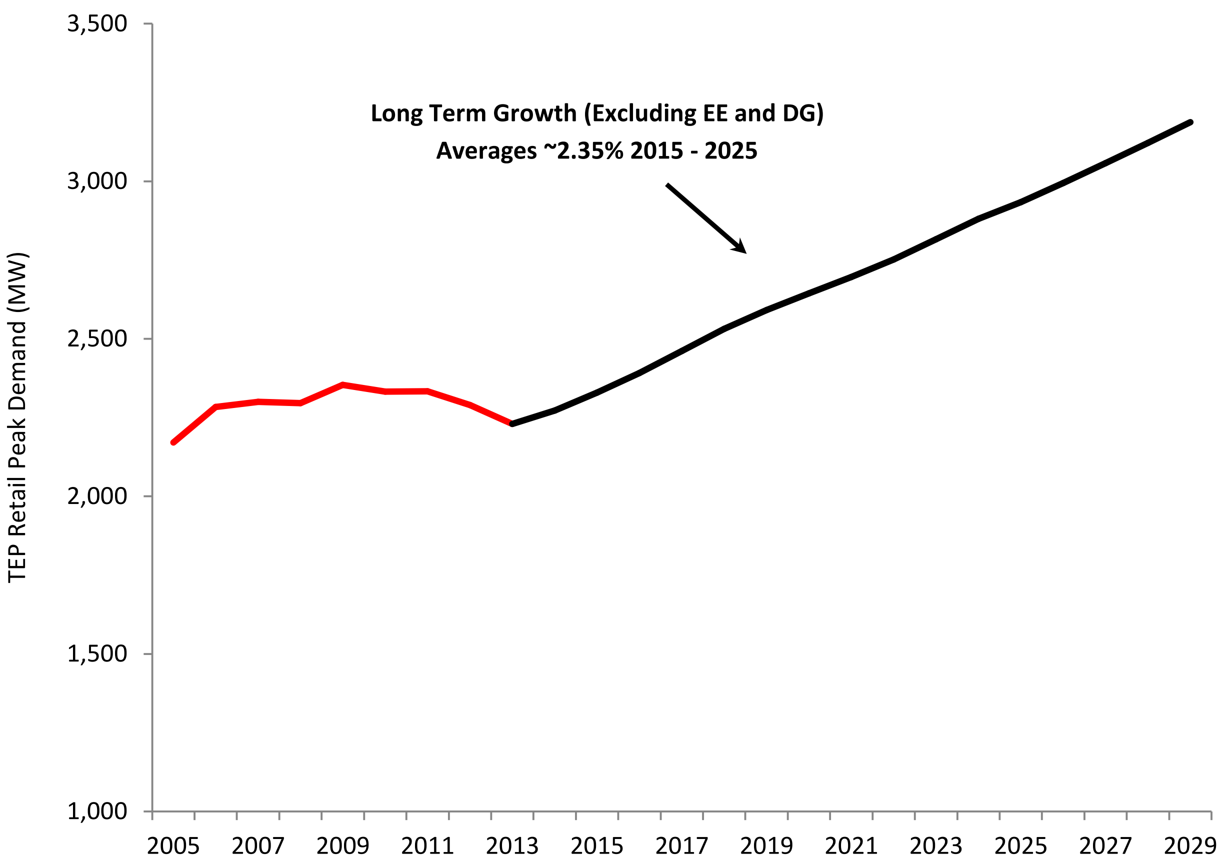


After experiencing consistent year over year growth throughout the recent past, both residential and commercial energy sales fell from 2008-2011 and remained relatively flat until 2013. Both are assumed in the Reference Case Plan to increase steadily after 2014. However, industrial energy sales are assumed to increase much more slowly than those in either the residential or commercial classes. In addition, mining sales are assumed to remain stable at 2008 levels.

Reference Case Plan Peak Demand Forecast

As show in Chart 14 below, after remaining relatively stable from 2007 – 2013, demand is expected to return to steady growth after 2013. Note that forecasted values in Chart 14 exclude the effects of energy efficiency and distributed generation.

Chart 14 - Reference Case Plan Peak Demand



Data Sources Used in Forecasting Process

As outlined above, the Reference Case plan forecast requires a broad range of inputs (demographic, economic, weather, etc.) For internal forecasting processes, TEP utilizes a number of sources for these data:

- IHS Global Insight
- The University of Arizona Forecasting Project
- Arizona Department of Commerce
- U.S. Census Bureau
- National Oceanic and Atmospheric Administration (NOAA)
- Weather Underground Forecasting Service

Risks to Reference Case Plan Forecast and Risk Modeling

As always, there is a large amount of uncertainty with regard to projected load growth. While an exhaustive list would be impossible to produce, some of the key risks to the current forecast include:

- Strength and timing of the economic recovery
- Possible structural changes to customer behavior (i.e. do post recession customers have consumption patterns different from those seen pre-recession?)
- Volatility in industrial metal prices and associated shifts in mining consumption
- Efficacy of energy efficiency programs (i.e. what percentage of load growth can be offset by demand side management?)
- Technological innovations (e.g. plug in hybrid vehicle penetration)
- Volatility in demographic assumptions (e.g. much higher or lower population growth than currently assumed)

Because of the large amount of uncertainty underlying the load forecast, it is crucial to consider the implications to resource planning if TEP experiences significantly lower or higher load growth than projected. For this reason, load growth is one of the fundamental factors considered in the risk analysis process undertaken as part of the 2014 IRP. Specifically, the performance of each potential resource portfolio is considered over 100 iterations of potential load growth (along with correlated gas and power prices in each case.) A more in depth discussion of the risk analysis process is provided in Chapters 2 and 15.

In addition to the simulation analysis, a more specific discussion of how resource decisions and timing would be affected in the case of sustained higher or lower loads is provided at the end of this Chapter.

Firm Wholesale Energy Forecast

In addition to retail sales directly to customers, TEP is currently under contract to provide wholesale energy to three utility customers:

1) Salt River Project (SRP) through May 2016
2) Navajo Tribal Utility Authority (NTUA) through December 2022
3) Tohono O'odham Utility Authority (TOUA) through December 2015

TEP expected firm wholesale obligations are shown in Table 6 below. It is important to note contract extensions have not been assumed. However, there is a possibility that any or all agreements could be extended. This would obviously require current resource plans to be revised to account for the additional energy sales and peak summer load requirements.

Table 6 - Firm Wholesale Requirements

Firm Wholesale, GWh	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
SRP	491	491	205	0	0	0	0	0	0	0	0
NTUA	234	239	249	256	264	272	280	287	294	0	0
TOUA	27	19	0	0	0	0	0	0	0	0	0
Total Firm Wholesale	753	749	454	256	264	272	280	287	294	0	0

Peak Demand, MW	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
SRP	100	100	100	0	0	0	0	0	0	0	0
NTUA	17	17	33	33	33	33	36	43	43	0	0
TOU	3	3	0	0	0	0	0	0	0	0	0
Total Firm Demand	120	120	33	33	33	33	36	43	43	0	0

Summary of Reference Case Plan Load Forecast

Table 7 excludes the effects of distributed generation and energy efficiency.

Table 7 - TEP Reference Case Plan Forecast Summary

Retail Sales, GWh	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Residential	4,064	4,176	4,292	4,415	4,543	4,674	4,808	4,940	5,073	5,213	5,361
Commercial	2,256	2,314	2,378	2,444	2,502	2,557	2,610	2,654	2,696	2,741	2,788
Industrial	2,123	2,159	2,199	2,214	2,230	2,248	2,269	2,285	2,304	2,324	2,346
Mining	1,127	1,127	1,131	1,127	1,127	1,127	1,131	1,127	1,127	1,127	1,131
Other	24	24	24	24	24	24	24	24	24	24	24
Total Retail	9,594	9,799	10,023	10,223	10,426	10,631	10,840	11,029	11,224	11,428	11,649

Residential Sales Growth %	-1.25%	2.76%	2.79%	2.87%	2.89%	2.90%	2.86%	2.74%	2.71%	2.76%	2.83%
Commercial Sales Growth %	0.72%	2.56%	2.77%	2.75%	2.40%	2.21%	2.04%	1.69%	1.58%	1.67%	1.73%
Industrial Sales Growth %	-0.51%	1.69%	1.87%	0.67%	0.73%	0.80%	0.92%	0.72%	0.84%	0.85%	0.95%
Mining Sales Growth %	4.92%	0.00%	0.29%	-0.29%	0.00%	0.00%	0.29%	-0.29%	0.00%	0.00%	0.29%
Other Sales Growth %	0.00%	0.00%	0.08%	-0.08%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Total Retail Sales Growth %	0.07%	2.14%	2.29%	2.00%	1.98%	1.96%	1.97%	1.74%	1.77%	1.82%	1.93%
Customer Count, 000	413	418	422	428	433	438	444	450	456	462	469

Firm Wholesale, GWh	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
SRP	491	491	205	0	0	0	0	0	0	0	0
NTUA	234	239	249	256	264	272	280	287	294	0	0
TOUA	27	19	0	0	0	0	0	0	0	0	0
Total Firm Wholesale	753	749	454	256	264	272	280	287	294	0	0

Peak Demand, MW	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Retail Demand	2,272	2,330	2,391	2,461	2,532	2,591	2,645	2,696	2,752	2,816	2,881
Retail Demand Growth %	1.90%	2.52%	2.65%	2.91%	2.88%	2.33%	2.07%	1.95%	2.08%	2.32%	2.29%

Peak Demand, MW	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
SRP	100	100	100	0	0	0	0	0	0	0	0
NTUA	17	17	33	33	33	33	36	43	43	0	0
TOU	3	3	0	0	0	0	0	0	0	0	0
Total Firm Demand	120	120	33	33	33	33	36	43	43	0	0

Total Retail & Firm	2,392	2,450	2,424	2,494	2,565	2,624	2,681	2,739	2,795	2,816	2,881

Load Growth Scenarios

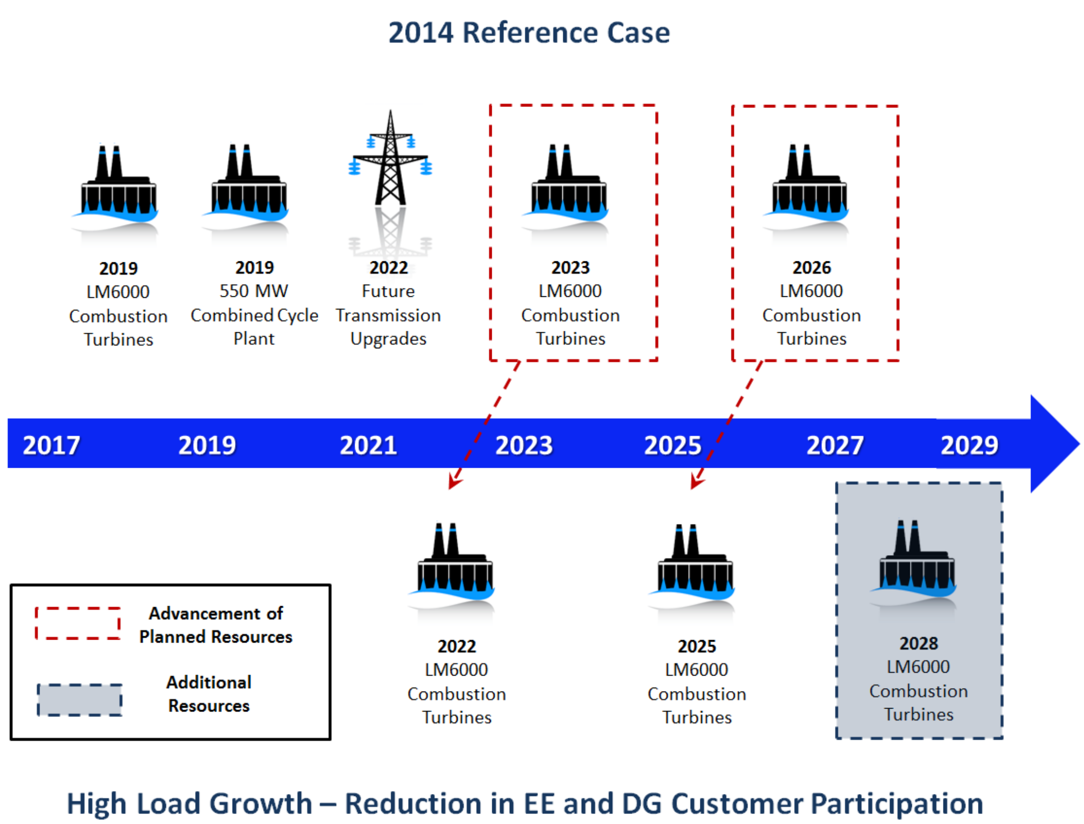
The 2014 Reference Case plan projects TEP peak demand growing between 1.0% and 1.5% per year. This change in growth assumes no significant expansions in TEP's large industrial and mining customers and assumes that targets for energy efficiency (22% by 2020) and distributed generation (30% of 15% by 2025) are realized per Arizona state standards.

For purposes of the 2014 IRP, TEP modeled two additional load growth scenarios that reflect two potential scenarios that may affect TEP's long-term expansion plans. The first scenario considers the potential reductions in customer participation in TEP's energy efficiency and distributed generation programs. The second scenario contemplates a new large industrial customer or a facility expansion at an existing mining customer within TEP's service territory.

Reduction in Energy Efficiency or Distributed Generation

For purposes of this scenario, it is assumed that TEP only realizes about 50% of the energy efficiency and distributed generation targets. Under this scenario, TEP's peak demand grows between 1.5% and 2.0% per year. This change in the forecast has only moderate impacts on TEP's 2014 Reference Case plan. As shown in Figure 10 below, TEP would have to advance the installation of its planned combustion turbines in 2023 and 2026 by one year. In addition, by the end of the 15-year planning period, TEP would need to install additional combustion turbines in 2028 as the result of this increased load growth.

Figure 10 – Reduction in EE or DG Load Scenario



Large Industrial / Mining Expansions

Given TEP's geographic proximity to Southern Arizona mining operations, TEP coordinates it planning strategies around potential mine shutdowns or expansions. Rosemont and Twin Buttes mines are two potential mining projects that may expand operations in the near future.

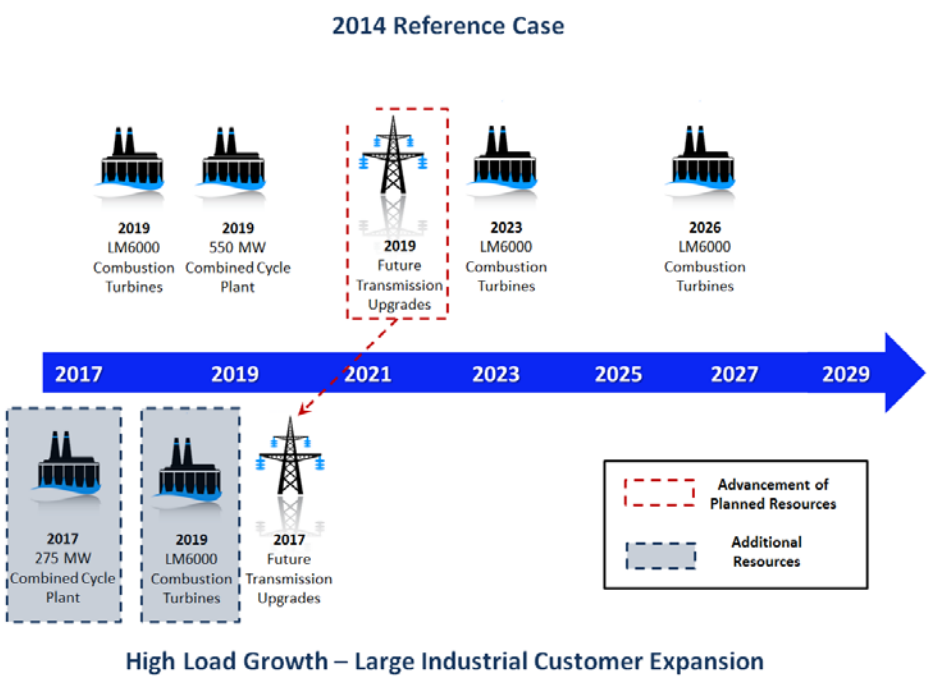
Rosemont Mine – The proposed copper mine is located 30 miles south of Tucson in the Santa Rita Mountains. Augusta Resource Corporation, a Vancouver, BC-based mining company is hopeful to begin building the mine in the near future.

Twin Buttes Mine – TEP is also monitoring the Twin Buttes mine project. In late 2009, Freeport-McMoRan bought the Twin Buttes mine site, near Sahuarita. The Twin Buttes Mine adjoins Freeport's existing Sierrita Mine, which is seven miles west of Green Valley. Freeport needs to conduct studies to determine the property's best use, but the purchase gives Freeport-McMoRan the potential to expand their current operations.

Large Industrial Customer Expansion

For purposes of this scenario, it is assumed that TEP's peak demand increases significantly over the next five years due to an expansion of a new or existing large industrial customer. Under this scenario, TEP's peak demand increases by 125 MW in 2017 and again in 2019 by 125 MW (for a total of 250 MW, a 10% increase in retail demand). This change in the forecast would result in the advancement of both transmission and generation resources in the near term. As shown in Figure 11 below, TEP would have to advance work on future transmission and system upgrades by two years from 2019 to 2017. In addition, TEP would have to procure additional generation resources starting in 2019 to cover the load and reserve margin requirements under this scenario. Given the high load factors associated with these types of customers, this scenario shows the need for additional combined cycle and combustion turbines resources as early as 2019.

Figure 11 – Large Industrial Customer Expansion



CHAPTER 4

EXISTING RESOURCE CAPACITY

TEP's Existing Resource Portfolio

This section provides an overview of TEP existing thermal resources and provides details on each station's fuel supply, environmental controls, reserve sharing obligations and regulatory status concerning environmental regulation. In addition, this chapter highlights its current use of the wholesale power market for firm capacity resources.

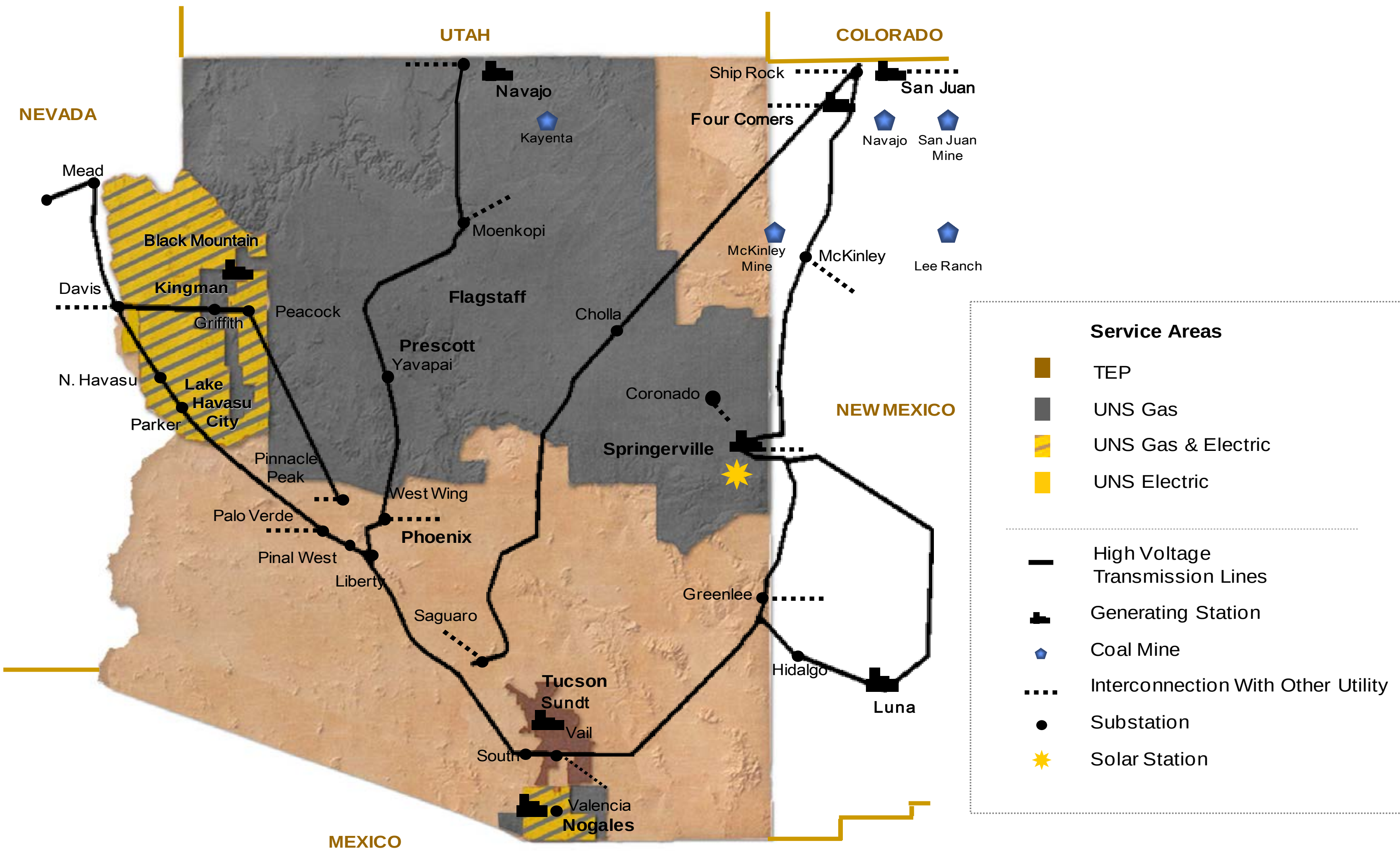
TEP's existing resource capacity currently owned or leased by the Company is 2,224 MW. In addition, the Company also relies on the wholesale market for firm capacity purchase power agreements to meet its summer peak obligations. Table 8 below provides a summary of TEP's existing thermal resources.

Table 8 - TEP Existing Thermal Resources

Generating Station	Unit	Fuel Type	Net Nominal Capability MW	Commercial Year	Operating Agent	TEP's Share %	TEP Planning Capacity
Springerville	1	Coal	387	1985	TEP	100	387
Springerville	2	Coal	390	1990	TEP	100	390
San Juan	1	Coal	340	1976	PNM	50	170
San Juan	2	Coal	340	1973	PNM	50	170
Navajo	1	Coal	750	1974	SRP	7.5	56
Navajo	2	Coal	750	1975	SRP	7.5	56
Navajo	3	Coal	750	1976	SRP	7.5	56
Four Corners	4	Coal	785	1969	APS	7	55
Four Corners	5	Coal	785	1970	APS	7	55
Sundt Steam	1-4	Coal/Gas	422	1958-1967	TEP	100	422
Luna Energy Facility	1-2	Gas	570	2006	PNM	33.3	190
Combustion Turbines		Gas/Oil	217	1972-2001	TEP	100	217
Total Planning Capacity							**2,224**

Existing Resource Overview

Map 3 - TEP Generation and Transmission Resources



Springerville Generating Station

Station Overview

Springerville Generating Station (SGS), operated by TEP, is located in Springerville, Arizona. SGS consists of four coal-fired units. TEP currently leases 86% of Unit 1 of the Springerville Generating Station and holds an undivided one-half interest in certain Springerville Common Facilities under seven separate lease agreements that are accounted for as capital leases. The leases expire in January 2015 and include fair market value renewal and purchase options. TEP owns a 14.1% undivided ownership interest in Springerville Unit 1, representing approximately 55 megawatts (MW) of capacity. Unit 2 of the Springerville Generating Station is owned by San Carlos Resources, Inc., a wholly-owned subsidiary of TEP. TEP's other interests in the Springerville Generating Station include leasehold interests in the Springerville Coal Handling Facilities (lease term expiring April 2015) and in a one-half interest in certain other facilities at Springerville used in common by all four Springerville units (Springerville Common Facilities). The common facilities lease term expires in 2017 with respect to one lease participant and 2020 with respect to the two other owner participants. Unit 3 is owned by Tri-State Generation and Transmission Association and Unit 4, completed in December, 2009 is owned by SRP.

Picture 2 - Springerville Generating Station

Springerville Unit 1 Purchase Option

In December 2011, TEP and the owner participants of the Springerville Unit 1 Leases completed a formal appraisal procedure to determine the fair market value purchase price. The formal appraisal process was completed in accordance with the Springerville Unit 1 lease agreements. The purchase price was determined to be $478 per kW of capacity. In 2013, TEP elected to exercise it purchase option with three of the five lessors to acquire an additional 35.5% for $65 million; In combination with TEP's current ownership share of 14%, TEP will increase its ownership interest in Springerville Unit 1 to 49% (190 MW) upon the January 2015 purchase option close.

Primary Fuel Supply

The coal supply for SGS is secured from Peabody Coal Sales and its Lee Ranch and El Segundo Mines which are located near Grants, New Mexico. Tucson Electric Power is under a long-term contract that runs through 2020. Lee Ranch Mine shipped 3.3 million tons to TEP in 2012, and owns or controls approximately 150 million tons of recoverable low sulfur coal reserves. Coal supplies for the TEP units are transported by rail under a long-term contract with The Burlington Northern and Santa Fe Railway Company (BNSF).

Environmental Controls

Each of Springerville Units 1 and 2 is equipped with a spray dryer absorber (SDA) for control of SO_2, advanced Low NO_x burners (LNBs) with Overfire Air (OFA) for NO_x control and a bag house for particulate control. Emission limits for SO_2 and NO_x are based on plant-wide caps that were incorporated into the Title V permit that was amended for the Units 3 and 4 expansions. In order to meet the plant wide caps, Units 1 and 2 underwent upgrades to their SDA and had next generation LNB and OFA installed on the boilers in 2004 and 2005. The emission limit for particulate matter is based on a rate incorporated into the Title V permit as part of the Units 3 and 4 expansions.

Table 9 - Springerville Current Environmental Controls

Springerville	Controls Summary
SO2 Controls	SDA
NO_x Controls	LNB with OFA
Particulate Controls	Baghouses
Mercury Controls	Co-benefit of SDA with Baghouses
Coal Ash	Dry Ash Landfill

Springerville - Mercury & Air Toxics Standard (MATs)

EPA's Mercury and Air Toxics Standards ("MATS) rule, designed to control emissions of Hazardous Air Pollutants from utility boilers was issued in February 2012. Based on the EPA's final standards, mercury emission control equipment will be required at Springerville by 2015. The estimated capital cost of this equipment for Springerville Units 1 and 2 is approximately $5 million.

Springerville – Regional Haze

Regional Haze regulations requiring emission control upgrades do not apply to Springerville currently and are not likely to impact Springerville operations until after 2018.

Springerville – Coal Ash

Coal ash and other residual products of coal combustion generated at SGS are disposed of in an on-site landfill that operates under a State of Arizona Aquifer Protection Permit. The EPA has proposed rules to regulate coal ash either as a non-hazardous solid waste (similar to municipal solid waste), or as a hazardous waste, which could require physical or operational changes relating to coal ash disposal. The nature of any necessary changes will not be known until the rule is finalized, which is expected in late 2014.

Reserve Sharing Agreements

To mitigate problems resulting from a decrease in unit capacity associated with the loss of either Springerville unit, the Company has a reserve sharing agreement in place with Tri-State. In the event of a Springerville outage, the Company has the option to call upon reserve capacity from Tri-State. In return the Company provides reserve capacity to Tri-State in the event of outages at Springerville Unit 3 or Tri-State's Pruitt Escalante Generating Station located in New Mexico.

San Juan Generating Station

Station Overview

San Juan Generating Station (SJGS), operated by Public Service Company of New Mexico (PNM), is a four unit coal-fired generating station located in Farmington, New Mexico. The Company owns 50% interests in each of Units 1 and 2 providing generating capacity of 170 MW each or 340 MW total.

Picture 3 - San Juan Generating Station

Primary Fuel Supply

The SJGS coal supply is provided by the San Juan Coal Company (SJCC) from an underground mine located in Northern New Mexico.

Environmental Controls

SJGS entered into a consent decree in 2005 which committed the station to reduce emissions of SO_2, NO_x, particulates, and mercury. In 2005 and 2006, enhancements were made to the existing wet scrubber which increased the level of control of SO_2 to 90%. In 2008 and 2009, next generation LNB with OFA were installed to reduce the NOx emission rate to 0.30lbs/MMBtu, and bag houses were installed to reduce particulate emissions to 0.015lbs/MMBtu.

Table 10 - San Juan Current Environmental Controls

San Juan	Controls Summary
SO_2 Controls	Wet Scrubber
NO_x Controls	LNB with OFA
Particulate Controls	Baghouses
Mercury Controls	ACI with Baghouses
Coal Ash	Beneficial Use / Dry Ash Mine Placement

San Juan - Mercury & Air Toxics Standard (MATs)

Activated carbon injection (ACI) systems were installed in 2009 to reduce emissions of mercury. The ACI systems are expected to be adequate to achieve compliance with the EPA's MATS rule.

San Juan - Regional Haze

In August 2011, EPA published its Federal Implementation Plan (FIP) that included a regional haze BART determination for SJGS that requires installation of selective catalytic reduction (SCR) with sorbent injection on all four units within five years of the rule's effective date of September 21, 2011. The FIP required a stringent NOx emission limit of 0.05 lb/mmBtu based on a rolling 30-boiler operating day average. At that the time, TEP estimated that its share of the cost to install SCR technology to be between $180 million and $200 million. In addition, TEP expected its share of the annual operating costs for SCR technology to be approximately $6 million.

In September 2011, PNM filed a Petition for Review in the U.S. Court of Appeals for the Tenth Circuit challenging EPA's regional haze FIP decision and requesting a stay pending the litigation. In March 2012, The Tenth Circuit denied to stay the decision. In separate litigation with several environmental groups, the U.S. District Court for the District of Columbia entered into a consent decree, which, required EPA to review and take action on the proposed rulemaking on New Mexico's regional haze SIP on or before May 31, 2012 and a final rulemaking on or before November 15, 2012. As a result of this consent decree, On May 31, 2012, EPA issued its proposed action on the regional haze SIP. EPA proposed approval of all components of the SIP, except for the BART determination for SJGS. With respect to the BART determination, EPA determined that with the FIP in place, it had met its obligation under the consent decree, and stated that it would issue a separate proposal and would entertain the withdrawal of the FIP in favor of an alternative that may be developed through discussions with the State of New Mexico and PNM.

In September 2012, the New Mexico Environmental Department (NMED) proposed an alternative to the EPA suggesting the closure of two units at SJGS and the installation of SNCRs on the remaining two units by the end of 2017. NMED also suggested replacement of a portion of PNM's share of the capacity from the two closed units with gas-fired generation.

In February 2013, the State of New Mexico, the EPA, and PNM signed a non-binding agreement (Settlement Agreement) that outlines an alternative to the FIP. The terms of the Settlement Agreement include: the retirement of San Juan Units 2 and 3 by December 31, 2017; the replacement by PNM of those units with non-coal generation sources; and the installation of Selective Non-Catalytic Reduction technology (SNCR) on San Juan Units 1 and 4 by January 2016 or later depending on the timing of EPA approvals. The New Mexico Environmental Department (NMED) prepared a revision to the regional haze State Implementation Plan (SIP) incorporating the provisions of the Settlement Agreement, and in September 2013, the New Mexico Environmental Improvement Board approved the SIP revision. The SIP revision now awaits final EPA approval. The EPA is expected to issue a final BART determination in the second or third quarter of 2014.

In connection with the implementation of the SIP revision and the retirement of San Juan Units 2 and 3, some of the San Juan owner participants (Participants) have expressed a desire to exit their ownership in the plant. As a result, the Participants are attempting to negotiate a restructuring of the ownership in San Juan, as well as addressing the obligations of the exiting Participants for plant decommissioning, mine reclamation, environmental matters, and certain ongoing operating costs, among other items. The Participants have engaged a mediator to assist in facilitating the resolution of these matters among the owners. The owners of the affected units also may seek approvals of their utility commissions or governing boards.

San Juan – Coal Ash

A small portion of coal ash generated at SJGS is sold for beneficial use (primarily as a concrete supplement). The majority of coal ash and other residuals are returned to the San Juan mine, which operates under a permit issued to the mine operator by the New Mexico Mining and Materials Department. At the federal level, the Department of Interior's Office of Surface Mining, Reclamation, and Enforcement oversees placement of coal ash in mines.

Reserve Sharing Agreement

To mitigate problems resulting from a decrease in capacity associated with the loss of either San Juan units, the Company has entered into a reserve sharing agreement with M-S-R Energy Authority, which is a participant owner in San Juan Unit # 4. In the event of an outage of either or both San Juan Units 1 or 2, the Company is entitled to reserve capacity from M-S-R Energy Authority. In return the Company provides reserve capacity to M-S-R Energy Authority in the event of outages at San Juan Unit # 4.

Navajo Generating Station

Station Overview

Navajo Generating Station (NGS), operated by SRP, is a three unit coal-fired generating station located in Page, Arizona. The Company owns 7.5% interests in each of the 750 MW Units, providing generating capacity of 56 MW from each unit.

Picture 4 - Navajo Generating Station

Primary Fuel Supply

Coal is supplied under a long-term contract with Peabody Energy. Coal supplies are surface-mined at the Kayenta Mine in northern Arizona, fifty miles east of the power plant. The coal for the power plant is hauled by the electrified Black Mesa and Lake Powell Railroad that is owned by Salt River Project and the co-owners of the NGS. This isolated railroad serves only NGS.

Environmental Controls

NGS is equipped with a wet scrubber for control of SO_2, and a hot-side electrostatic precipitator (h-ESP) for particulate control. The SO_2 control requirement at NGS is based on a 1991 EPA rule to address visibility concerns. This represents approximately 94% removal on a facility-wide basis. Between 2009 and 2011, advanced LNB with OFA were installed on each of the three units on a voluntary basis, which reduced NOx emissions by 50%.

Table 11 - Navajo Current Environmental Controls

Navajo	Controls Summary
SO_2 Controls	Wet Scrubber
NO_x Controls	LNB with OFA
Particulate Controls	Electrostatic Precipitator
Mercury Controls	Wet Scrubber
Coal Ash	Beneficial Use / Dry Ash Landfill

Navajo - Mercury & Air Toxics Standard (MATs)

Based on the EPA's final MATS rule, NGS will need mercury emission control equipment by 2015, which may involve the installation of bag houses. TEP's share of the estimated capital cost of this equipment is less than $1 million for mercury control and about $43 million if the installation of bag houses is necessary. TEP expects its share of the annual operating costs for mercury control and bag houses to be less than $1 million each. The operator of Navajo is currently analyzing the need for bag houses under various regulatory scenarios, which includes the regional haze final Best Available Retrofit Technology (BART) rules

Navajo Generating Station - Regional Haze

In February 2013, the Environmental Protection Agency (EPA) issued a proposed Best Available Retrofit Technology (BART) rule for NGS under the Regional Haze Rule of the Clean Air Act. EPA's proposal would require Selective Catalytic Reduction (SCR) emission control technology to be installed and operational on all three NGS units by 2018. The EPA also proposed an alternative that would give the NGS owners credit for early installation of low-NOx burners at NGS, and allow SCR to be installed on one unit per year between 2021 and 2023.

Given the potential economic impacts NGS would have on the Navajo and Hopi tribes, as well as Central Arizona Project (CAP) users, the EPA invited the submittal of "Better-than-BART" alternatives would result in greater emission reductions than EPA's original proposal. As a result, a Technical Work Group (TWG) was formed and consisted of representatives from the Central Arizona Water Conservation District, the Environmental Defense Fund, the Gila River Indian Community, the Navajo Nation, Salt River Project, the U.S. Department of the Interior, and Western Resource Advocates.

In July 2013, the TWG submitted an alternative plan to the EPA for final consideration. The TWG proposal included two emission reduction alternatives that would achieve "Better-than-BART" results and included commitments by the U.S. Department of Interior to reduce CO2 emissions and study opportunities to transition the U.S. Bureau of Reclamation's share of NGS to other resources. The potential alternatives are explained below.

NGS BART Alternative 1

NGS Alternative 1 requires the NGS participants to cease coal generation on one of the NGS units at the station by January 1, 2020 and SCR would be installed on the remaining units by 2030. Under Alternative 1, it is expected that the Los Angeles Department of Water & Power (LADWP) and NV Energy would exit NGS by 2019. Together, LADWP and NV Energy own the equivalent of almost exactly one unit at NGS.

This alternative also requires the NGS participants to achieve the same amount of NOx emissions reductions as provided for under EPA's BART proposal, while meeting a 30-day rolling average NOx emission rate limit of 0.07 lb/MMBtu on two units at NGS after installing SCR or an equivalent technology no later than December 31, 2030.

NGS BART Alternative 2

If the conditions for Alternative 1 are not met, Alternative 2 requires a reduction of NOx emissions equivalent to the shutdown of one Unit from 2020 to 2030. This alternative also requires the submittal of annual Implementation Plans describing the measures to be implemented to achieve greater emission reductions than EPA's proposed rule through a combination of retirement in capacity or curtailment in utilization at the plant and new emission controls.

Under either Alternative 1 or 2, to ensure that the proposed alternative meets the "Better than BART" criteria, the NGS Participants agree to maintain emissions below the total 2009-2044 NOx emissions cap delineated under EPA's BART proposal. The 2009-2044 NOx cap is calculated based on an annual emission rate of 0.055 lb/MMBtu for SCR, which is the emission rate assumed by EPA in its proposed rule. Finally, under both scenarios, the current NGS owners are committed to cease operation of all conventional coal-fired generation at NGS no later than December 22, 2044. The Navajo Nation can continue operation after 2044 at its election. The EPA is currently accepting public comment on the BART Determination and the alternatives. A final decision is expected sometime in 2014.

Navajo – Coal Ash

The majority of coal ash generated at NGS is sold for beneficial use. The remainder is disposed in an on-site landfill. The EPA has proposed rules to regulate coal ash either as a non-hazardous solid waste, or as a hazardous waste, which could require physical or operational changes relating to coal ash disposal. The nature of any necessary changes will not be known until the rule is finalized, which is expected in late 2014

Four Corners Power Plant

Station Overview

Four Corners Power Plant (FCPP), operated by Arizona Public Service Company (APS), is a five unit coal-fired generating station located near Farmington, New Mexico. The Company owns 7.0% interests in each of the 784 MW Units 4 and 5, providing combined generating capacity of 110 MW.

Picture 5 - Four Corners Power Plant

Primary Fuel Supply

The Four Corners Plant purchases all of its coal from the Navajo mine, which is a mine-mouth facility located adjacent to the plant. Prior December 2013, the mine was owned and operated by BHP Billiton, the parent company of BHP Navajo Coal Company (BNCC) which held long-term leases for the coal reserves with the Navajo Nation. However, as part of the on-going fuel negotiations with the plant participants, BHP announced that the mine would be sold to the Navajo Nation. As part of the ownership transition, BHP Billiton would be retained by BNCC under contract as the mine manager and operator through July 2016.

On December 30, 2013, the ownership of BHP Navajo Coal Company was transferred to Navajo Transitional Energy Company, LLC ("NTEC"), a company formed by the Navajo Nation to own the mine and develop other energy projects. On the same date, the Four Corners co-owners executed a long term fuel agreement for the supply of coal to Four Corners from July 2016, when the current coal supply agreement expires, through 2031.

Environmental Controls

FCPP is equipped with a wet scrubber for control of SO_2, cell burners for NO_x control and a bag house (preceding the scrubber) for particulate control. The current requirement for SO_2 control is 88% removal based on a FIP for the facility which became effective June 6, 2007. The FIP also made federally enforceable the NO_x and PM emission limits that FCPP has historically achieved in voluntary compliance with the New Mexico State Implementation Plan (SIP).

Table 12 - Four Corners Current Environmental Controls

Four Corners	Controls Summary
SO_2 Controls	Wet Scrubber
NO_x Controls	Cell Burners
Particulate Controls	Bag house
Mercury Controls	Wet Scrubber with Bag house
Coal Ash	Beneficial Use / Dry Ash Landfill

Four Corners - Mercury & Air Toxics Standard (MATs)

Based on the EPA's final MATS rule, mercury emission control equipment may be required at FCGS by 2015. TEP's share of the estimated capital cost of this equipment is less than $1 million. The annual operating cost associated with the mercury emission control equipment is expected to be less than $1 million for TEP.

Four Corners – Regional Haze

In October 2010, the EPA issued its proposed BART determination for Four Corners. The proposed rule would require the installation of SCR on each of Units 1-5 at Four Corners by 2016 to reduce nitrogen oxides (NOx) emissions. In November 2010, Arizona Public Service Company (APS) and Southern California Edison Company (SCE) entered into an asset purchase agreement providing for the purchase by APS of SCE's 48% interest in each of Units 4 and 5 of Four Corners. Following this announcement, APS submitted a letter to the EPA proposing an alternative to the EPA's original BART proposal. Specifically, APS proposed to close Four Corners Units 1, 2, and 3 by 2014 and to install SCR for NOx on Units 4 and 5 by the end of 2018. In February 2011, the EPA issued a Supplemental Notice, related to the BART rulemaking for Four Corners. In the Supplemental Notice, the EPA proposed to find that a different alternative emission control strategy, based upon APS's November 2010 letter, would achieve more progress than the EPA's October 2010 BART proposal. The Supplemental Notice proposed that Units 1, 2, and 3 would close by 2014, SCR for NOx control would be installed on Units 4 and 5 by July 31, 2018, and the NOx emission limitation for Units 4 and 5 would be 0.098 lbs/MMBtu, rather than the 0.11 lbs/MMBtu proposed by the EPA in October 2010.

In March 2012, the California Public Utility Commission (CPUC) issued an order to SCE approving the sale of their ownership share in Units 4 & 5 to APS. In April 2012, the Arizona Corporation Commission (ACC) voted in favor of allowing APS to move forward with the SCE purchase transaction. This authorization also included a regulatory order allowing for an accounting deferral of costs associated with the purchase of Units 4 & 5 and closure of Units 1-3.

Finally, on December 30, 2013, Arizona Public Service Company and Southern California Edison Company closed their announced transaction whereby APS purchased SCE's 48% interest in each of Units 4 and 5 of the Four Corners Power Plant. The final purchase price for the interest was approximately $182 million. Concurrently with the closing of the SCE transaction, APS, on behalf of the co-owners, notified EPA that they had chosen the alternative BART compliance strategy requiring the permanent closure of Units 1, 2, and 3 by January 1, 2014 and installation and operation of selective catalytic reduction controls on Units 4 and 5 by

July 31, 2018. TEP's estimated share of the capital costs to install SCR technology on Units 4 and 5 is approximately $36 million ($327/kW). TEP's share of incremental annual operating costs for SCR is estimated at $2 million.

Four Corners – Coal Ash

The EPA has proposed rules to regulate coal ash either as a non-hazardous solid waste, or as a hazardous waste, which could require physical or operational changes relating to coal ash disposal. The nature of any necessary changes will not be known until the rule is finalized, which is expected in late 2014.

Sundt Generating Station

Sundt Generating Station

Sundt Generating Station (Sundt) is a four unit generating station located in Tucson, Arizona. Units 1, 2, and 3 are gas or oil burning generating units with capacities of 81 MW, 81 MW and 105 MW, respectively. Unit 4 is capable of burning gas or coal and land fill gas. Originally designed as a gas or oil-burning unit, Unit 4 was converted to coal-fired capability in January 1988 in response to a federal mandate issued by the Department of Energy. Unit 4 has a capacity rating of 156 MW burning gas and a capacity rating of 125 MW burning coal.

Sundt Unit 4 plays a unique role in TEP's resource portfolio. Historically, Sundt Unit 4 has operated on coal and was run as a local area baseload resource. This baseload dispatch, combined with the close proximity to the Tucson load center, enables the Sundt generating facility to provide year round support for system contingencies. In addition, Sundt Unit 4 has the ability to fuel switch between coal or natural gas fuel sources. This fuel switching capability on Unit 4 provides additional option value within TEP's resource portfolio to deal with uncertainties regarding fuel price volatility and future environmental regulation.

In 2010, TEP purchased 100% of the equity interest in the Sundt Unit 4 lease for approximately $51 million, redeemed the outstanding Sundt Unit 4 lease debt of $5 million, and terminated the lease agreement.

The 2014 Reference Case plan shows Sundt Unit 4 being dispatched on coal through 2017 and then operated on natural gas for the duration of the IRP study period.

Picture 6 - Sundt Generating Station

Primary Fuel Supply

Historically, coal for the Sundt Station was supplied through a long-term contract that took deliveries from the McKinley mine located in Window Rock, Arizona. Today, coal is typically purchased on the spot market from various suppliers in Colorado or Utah. Coal supplies are transported by rail under contracts with The Burlington Northern and Santa Fe Railway Company or the Union Pacific and Southern Pacific Railroad. In addition, the Company purchases natural gas for Sundt on the spot market. In 1999, Sundt Unit 4 began producing approximately 5 MW of electricity by burning land fill gas from the Los Reales landfill.

Environmental Controls

Sundt Units 1-3 are steam generating units fueled primarily with natural gas. These units must comply with the Acid Rain program limits for SO_2 and NO_x; however, no emission control equipment is required to meet the applicable standards.

Table 13 - Sundt Current Environmental Controls

Sundt Coal	Controls Summary
SO_2 Controls	Low Sulfur Coal Limit
NO_x Controls	LNB with OFA
Particulate Controls	Bag house
Mercury Controls	Bag house
Coal Ash	Beneficial Use / Off-Site Dry Ash Landfill

Sundt Unit 4 is equipped with LNBs and early generation OFA for NO_x control and a bag house for particulate control. The Title V permit has emission limits of 1 lb/MMBtu for SO_2, which is met through use of low-sulfur coal, and 0.7 lbs/MMBtu for NO_x. This unit also must comply with the Acid Rain program limits for SO_2 and NO_x.

Based on the EPA's final MATS rule, mercury emission control equipment may be required at Sundt Unit 4, depending on characteristics of the coal supplied to the plant. The selection of technology for mercury control, if required, is further complicated by the uncertainty in the pending regional haze rulemaking. Therefore, TEP has requested and received an extension for compliance with MATS requirements to April 2016. Beginning in 2016, the Arizona Mercury rule will require Sundt Unit 4 to achieve an emission limit of 90% removal or an output limit of 0.0087lbs/GWh, however, the ADEQ is expected to harmonize the requirements these requirements with those in the MATS rule.

Under the 1999 Regional Haze rule, Sundt Unit 4 must install BART for visibility impairing pollutants. Current controls for particulates will likely satisfy BART for those pollutants. BART for SO_2 and NO_x will likely require the installation of additional controls. In July 2013, EPA issued a final rule disapproving portions of the Arizona SIP for regional haze. Among the portions of the Arizona plan that were disapproved was their determination that Sundt Unit 4 was not "BART eligible". In February 2014, EPA issued a proposed FIP covering the disapproved portions of the Arizona SIP, including BART requirements for Sundt Unit 4. EPA's proposed BART for Sundt Unit 4 is SNCR for control of NOx emissions and Dry Sorbent Injection (DSI) for control of SO2 emissions to be implemented within three years of the effective date of the final rule. The proposed FIP also includes an alternative to BART, based on a proposal offered by TEP, which calls for the elimination of coal as a fuel source for Sundt Unit 4 by December 31, 2017. The capital cost to install SNCR and DSI on Sundt Unit 4 is estimated to be $11.7 million. The annual operating costs are anticipated to be $6 million. EPA is expected to issue a final rule by June 2014.

The majority of coal ash generated at Sundt is sold for beneficial use. The remainder is hauled off-site for disposal in a local municipal solid waste landfill or in the coal ash landfill at SGS. The EPA has proposed rules to regulate coal ash either as a non-hazardous solid waste, or as a hazardous waste, which could require physical or operational changes relating to coal ash disposal. The nature of any necessary changes will not be known until the rule is finalized, which is expected in late 2014.

Luna Generating Facility

Station Overview

The Luna Energy Facility (Luna), located in Southern New Mexico, is a 570 MW combined cycle plant and was completed in 2006. TEP's one-third share of the plant's capacity is 190 MW. Luna allows TEP to displace some of its less efficient gas-fired generation and purchased power requirements and to make additional short-term energy sales in the wholesale market.

Primary Fuel Supply

The Company purchases natural gas for Luna on the spot market.

Picture 7 - Luna Energy Facility

Luna Energy Emission Controls

Luna Energy Facility is a natural gas-fired combined cycle combustion turbine with dry LNB and SCR for NO_x control. As a greenfield site, a Prevention of Significant Deterioration (PSD) permit was obtained prior to construction. A PSD permit requires that Best Available Control Technology (BACT) be applied for control of SO2 and NOx, and the facility must comply with the Acid Rain program limits for SO_2 and NO_x.

Combustion Turbines

Turbine Overview

The Company has 217 MW of gas or oil fired combustion turbines for peaking capacity. This capacity is comprised of 6 units at three locations, 48 MW in two units at Sundt, 94 MW in four units at North Loop, and one 75 MW unit at DeMoss-Petrie. All locations are in or around Tucson and remotely operated from the Sundt Station.

Primary Fuel Supply

The Company purchases natural gas for its combustion turbines on the spot market.

Picture 8 - North Loop - Local Area Combustion Turbines

Sundt Combustion Turbine Emission Controls

The Sundt combustion turbines primarily burn natural gas, and are not equipped with emission control equipment. These combustion turbines were installed prior to the applicability of New Source Performance Standards (NSPS) for combustion turbines, and they are each less than 25 MW capacity; therefore, they are not subject to the Acid Rain provisions.

DeMoss Petrie Combustion Turbine Emission Controls

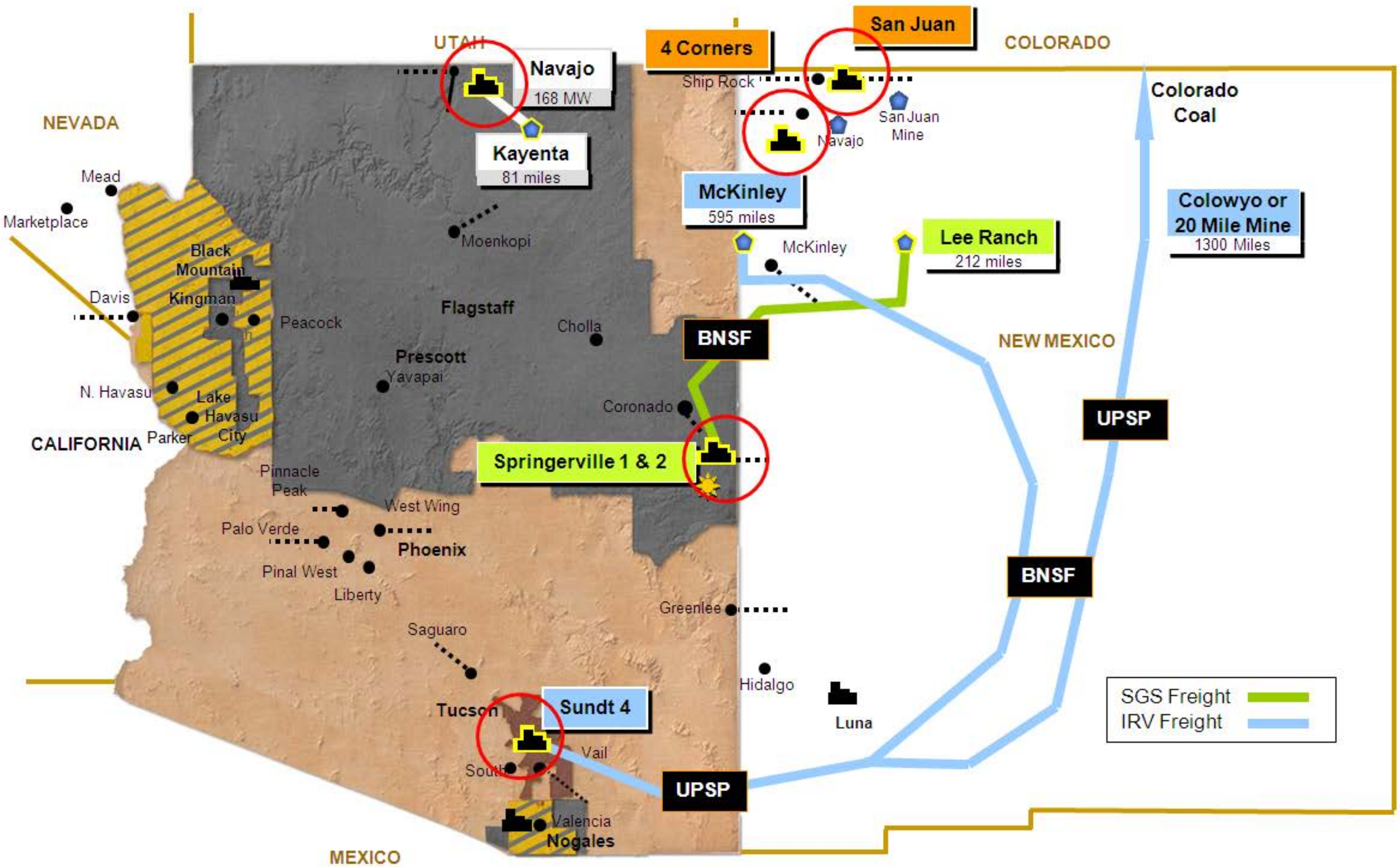
DeMoss Petrie (DMP) is a natural gas-fired combustion turbine equipped with dry LNB for NOx control. Voluntary emission limits of 250 tons per year for SO_2 and NO_x were incorporated into the Title V permit in order to maintain below “major source” thresholds. This unit was designed to meet NSPSs and must comply with the Acid Rain program limits for SO_2 and NO_x.

North Loop Combustion Turbine Emission Controls

North Loop combustion turbine Units 1-4 burn primarily natural gas. Unit 4 is equipped with water spray injection for control of NO_x. Units 1 through 3 are not equipped with emission control equipment. Unit 4 is subject to NSPS for NO_x and SO_2, while Units 1 - 3 were installed prior to NSPS applicability to combustion turbines. Each of the units is less than 25 MW in capacity; therefore, they are not subject to Acid Rain provisions.

Coal Generation and Primary Fuel Sources

Map 4 - Map of Coal Generation and Primary Fuel Sources



Wholesale Market Resources

TEP's Wholesale Marketing Department is charged with procuring firm capacity to cover TEP's peak load and reserve requirements. TEP utilizes a 3-year hedging policy to incrementally lock in firm capacity resources from a wide range of wholesale merchant counterparties through multiple transactions. In addition, to acquiring firm capacity, TEP's hedging policy firms up its natural gas fuel supply with the use of financial transactions to hedge fuel volatility risk.

Reserve Sharing

The Company is a member of Southwest Reserve Sharing Group (SRSG). SRSG participants share contingency reserves. The SRGS's geographic area includes the southwest including Arizona, New Mexico, southern Nevada and southern California (including the Imperial Valley) and El Paso, Texas. Participants of SRSG share generation reserves to realize more efficient, reliable and economic operation while mitigating potential contingency outages of generation units. The intent of this group agreement is designed for real-time and near-term operational events. The reserves available are only considered for operational purposes and not toward the planning reserve criterion.

CHAPTER 5

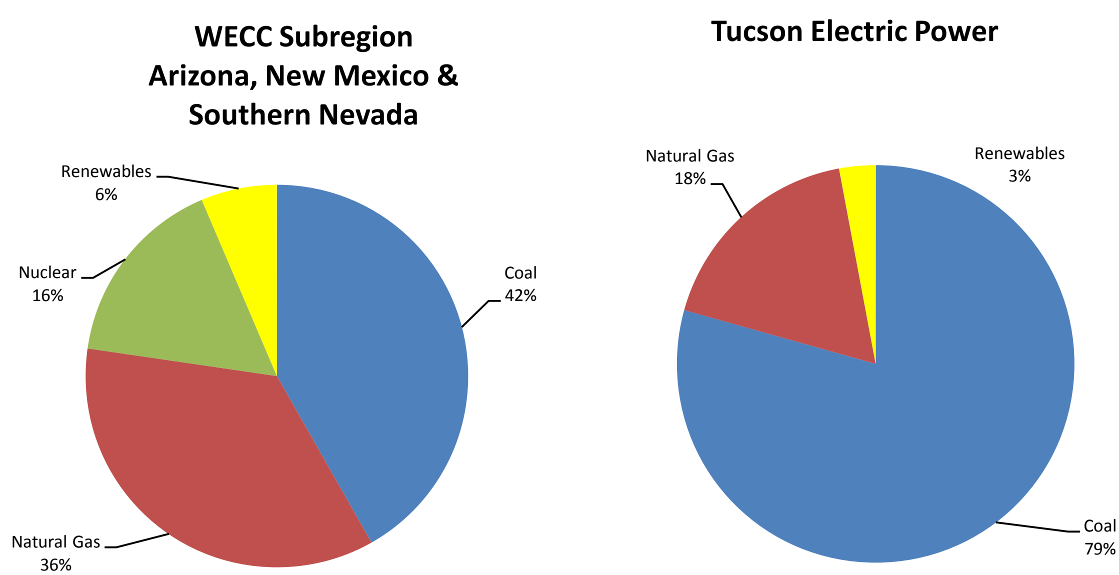
LOAD AND RESOURCE ADEQUACY

A significant consideration in the development of a long-range plan is the extent to which current and proposed resources meet the load requirements. TEP strives to maximize the value of service to its customers while maintaining a safe, reliable, and efficient balance of resources. In order to derive an adequate and integrated balance of resources, an accounting of loads and resources must be quantified. This assessment of the existing resources and market purchases, in part, predetermines the need or resource adequacy for the future. This chapter presents an assessment of generation resources, culminating with a preview of the generation required in order to maintain a flexible, and adequate balance of resources.

Load and Resource Assessment

The mix of existing resources for TEP is dominated by coal-fired electric generation. The TEP coal generating stations, which are detailed in Chapter 3, account for approximately 79 percent of the energy production in recent years, while the balance of energy was supplied and derived from gas-fired resources and recent renewable resource installations. See Chart 15 - 2013 Energy Composition below. The renewables for the WECC Subregion exceed TEP's renewable resources because hydro-electric generation is included in this category. In total, the energy output from TEP's renewable resources has increased since the most recent IRP filing. Output from renewable resources was minimal relative to the coal and gas generating resources at the time of TEP previous filing, whereas it now represents approximately 3% of generation.

Chart 15 - 2013 Energy Composition



By comparison, the Desert Southwest sub-region of Western Electricity Coordinating Council (WECC) has a broader mix of resources. The Palo Verde Nuclear Generating Station represents 16% of the sub-region generation while gas resources have a larger role than they have for TEP. Contributing to the mix are resources such as hydro-electric and other renewable resources.

A critical component to the IRP is the assessment of resources and the corresponding load obligations. TEP's peak demand occurs during the summer months of July and August. The highest 100 peak values for a single year represent a range of about 250 MWs. Alternatively stated, if we rank the hourly demand from highest to lowest, the peak value and the 100th highest value differ by approximately 250 MWs. Table 14 - TEP Existing Load and Resources (Excluding Future Resources) presents a tabular assessment of TEP's resources and loads for the single-hour peak demand for the years represented.

Table 14 - TEP Existing Load and Resources (Excluding Future Resources)

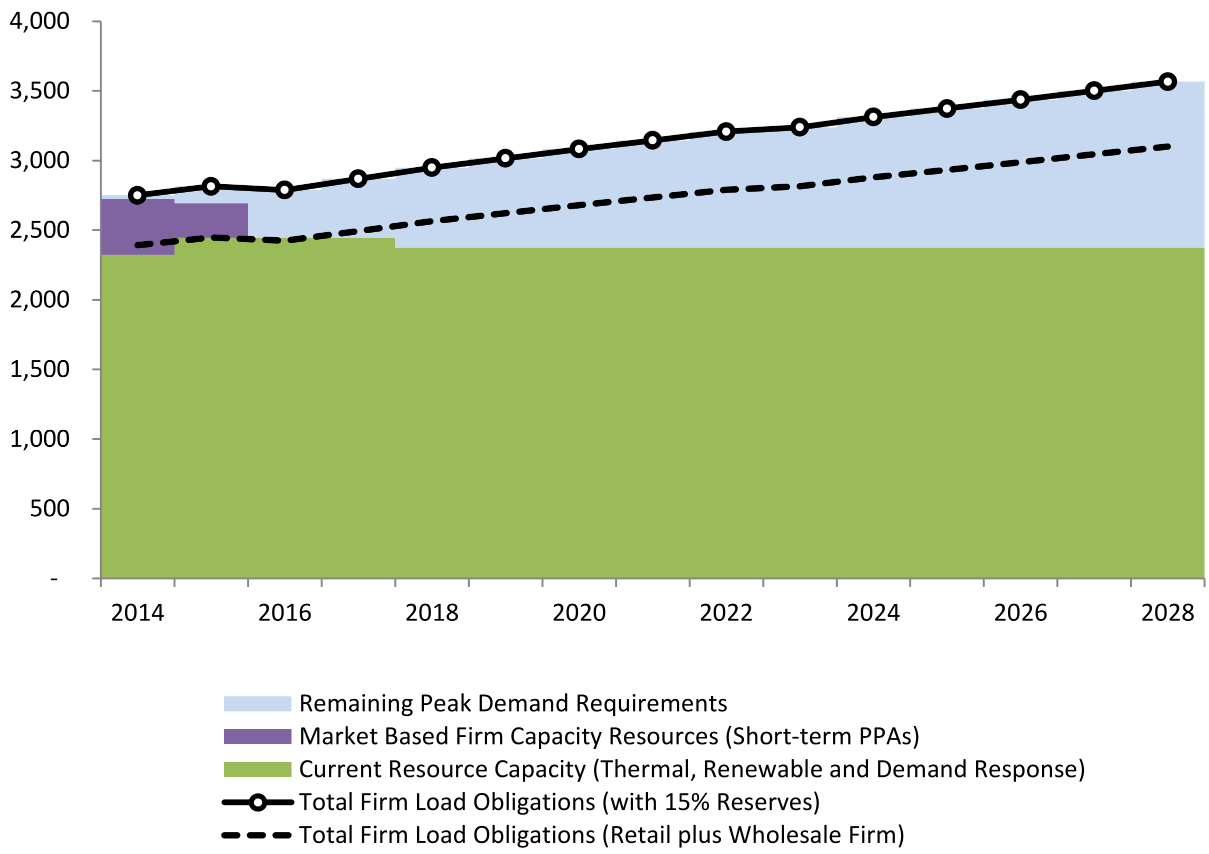
Firm Loads, MW	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Retail Demand	2272	2330	2391	2461	2532	2591	2645	2696	2752	2816	2881	2933	2992	3052	3113
Energy Efficiency	-48	-80	-110	-137	-164	-191	-217	-229	-233	-238	-244	-249	-253	-259	-262
Distributed Generation	-19	-21	-25	-29	-33	-37	-41	-46	-50	-55	-61	-66	-67	-68	-70
Net Retail Demand	2205	2229	2256	2295	2335	2363	2387	2421	2469	2523	2576	2618	2672	2725	2781
SRP	100	100	100	0	0	0	0	0	0	0	0	0	0	0	0
NTUA	17	17	33	33	33	33	36	43	43	0	0	0	0	0	0
TOUA	3	3	0	0	0	0	0	0	0	0	0	0	0	0	0
Firm Wholesale Demand	120	120	133	33	33	33	36	43	43	0	0	0	0	0	0
Retail and Firm Wholesale	2325	2349	2389	2328	2368	2396	2423	2464	2512	2523	2576	2618	2672	2725	2781
Planning Reserves %	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%
Reserve Margin	349	352	358	349	355	359	363	370	377	378	386	393	401	409	417
Total Firm Load Obligations	2674	2701	2747	2677	2723	2755	2786	2834	2889	2901	2962	3011	3073	3134	3198
Firm Resources, MW	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
Thermal Resources	2235	2402	2402	2402	2267	2267	2267	2267	2267	2267	2267	2267	2267	2267	2267
Demand Response	15	19	24	29	35	40	45	45	45	45	45	45	45	45	50
Utility Scale Renewables	60	69	69	69	69	69	69	69	84	84	117	129	129	129	129
Short-Term Market Resources	400	250													
Total Firm Resources	2710	2564	2309	2304	2333	2158	2153	2153	2138	2138	2105	2093	2093	2093	2088
Needed Resource Capacity		137	438	373	560	597	633	681	751	763	857	918	980	1,041	1,110

The table above presents only retail and wholesale firm peak demands with a 15% reserve margin. The effect of Energy Efficiency (EE) programs are explored and detailed in subsequent chapters. Similarly for the supply-side resources; proposed thermal and/or renewable resources will be addressed in other chapters. The intent of this table is to gauge the 'Net Capacity Obligations' for the future. This table reveals a distinct need for resources for this planning horizon and subsequent chapters will discuss the process and results derived for meeting TEP's capacity obligations.

A visual depiction of Table 14 - TEP Existing Load and Resources (Excluding Future Resources) is presented below, in Chart 16 - TEP Existing Loads and Resources. The top-most area in red represents the Net Capacity Obligation for the planning period. Included in this figure is an 'Operating Reserve' target which represents about 7.5% of retail and firm demand. In the near term, planning reserves transition into operating reserves. Planning reserves account for the potential of generating unit outages, regulating reserves, extreme weather fluctuations, and for unforeseen load growth in the long term, while operating reserves are derived with a more certain and near-term set of planning assumptions.

Chart 16 - TEP Existing Loads and Resources

Total Firm Load Obligations versus Firm Capacity Resources



WECC Southwest Resource Sharing Group – Resource Adequacy

Based on a NERC 2013 Summer Reliability Assessment, the Southwest Reserve Sharing Group (SRSG) within WECC has approximately 34% of anticipated reserve margins for the 2013 summer peak season. The SRSG's geographic area covers the southwest United States including Arizona, New Mexico, southern Nevada, parts of southern California including the Imperial Valley, and El Paso, Texas. Reliability assessments administered by the NERC, demonstrate that the SRSG Region will have adequate operating reserve capacity for the next several years. For the entire region, WECC exceeds the NERC reference margin of 14.5% through the year 2023. The summer peak demand is estimated to increase by 1.7 % for the region per year for 2014 to 2013. The anticipated region margin is approximately 20% in the year 2023.

Figure 12 – NERC – 2013 Planning Reserve Margins for WECC

WECC

Demand Projections

	WECC-CAMX Megawatts (MW)	WECC-NWPP Megawatts (MW)	WECC-RMRG Megawatts (MW)	WECC-SRSG Megawatts (MW)
Total Internal Demand	56,548	59,004	11,610	28,957
Load-Modifying DCLM	677	673	0	60
Load-Modifying Contractually Interruptible	670	251	473	419
Load-Modifying Load as a Capacity Resource	1,081	0	0	0
Net Internal Demand	54,120	58,080	11,137	28,478

Resource Projections

	WECC-CAMX Megawatts (MW)	WECC-NWPP Megawatts (MW)	WECC-RMRG Megawatts (MW)	WECC-SRSG Megawatts (MW)
Net Firm Capacity Transfers	7,301	620	446	-5,368
Existing-Certain & Future-Planned Capacity	56,497	69,771	16,630	43,490
Anticipated Resources	63,798	70,391	17,076	38,122
Prospective Resources	63,798	70,391	17,076	38,122

Planning Reserve Margins

	WECC-CAMX Percent (%)	WECC-NWPP Percent (%)	WECC-RMRG Percent (%)	WECC-SRSG Percent (%)
Anticipated Reserve Margin	17.88	21.20	53.32	33.87
Prospective Reserve Margin	17.88	21.20	53.32	33.87
NERC Reference Margin Level	15.01	15.02	14.45	13.56

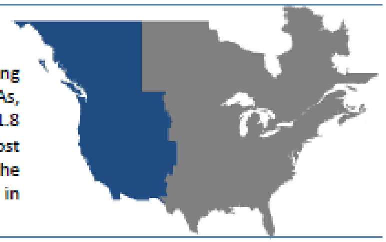
WECC is one of eight electric reliability councils in North America and is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members, including 38 BAs, represent a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and approximately 81 million people, it is the largest and most diverse of the NERC Regional Reliability Organizations. WECC's service territory extends from Canada to Mexico. It includes the Canadian provinces of Alberta and British Columbia, the northern portion of Baja California in Mexico, and all or portions of the 14 western states in between. For seasonal planning, the WECC Region is divided into four subregions: Northwest Power Pool (NWPP), Rocky Mountain Reserve Group (RMRG), Southwest Reserve Sharing Group (SRSG), and California/Mexico (CA/MX). These subregions are used for two reasons. First, the subregions are structured around Reserve Sharing Groups. These groups have similar demand patterns and operating practices. Second, the WECC RC collects actual demand data from the BAs within the Reserve Sharing Groups. Creating the seasonal assessments using the same boundary allows for after-the-fact comparison between demand forecasts and actual demand.

WECC Internal Boundary Changes: In 2013, there was a small change in the footprints of two of the subregions. Valley Electric Association, Inc. moved from Nevada Power within the SRSG to the CAISO in the CA/MX subregion. In addition, several subregions have different boundaries in the Seasonal Assessment than in the Long-Term Reliability Assessment. The BA of Northern California and the Turlock Irrigation District, although physically located in California, are members of the NWPP, and their demand and resources are reported in that subregion. Likewise, California's Imperial Irrigation District is a member of the SRSG, and their demand and resources are reported in that subregion.

Figure 13 – NERC 2013 Long-Term Reliability Assessment (WECC)

WECC

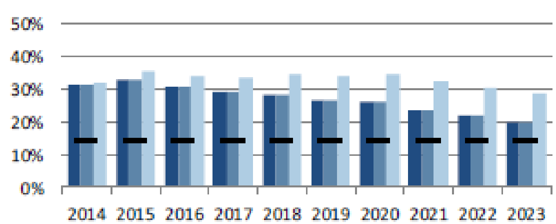
The Western Electricity Coordinating Council (WECC) is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members, which include 39 BAs, represent a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and approximately 81 million people, it is geographically the largest and most diverse of the NERC Regional Reliability Organizations. WECC's service territory includes the Canadian provinces of Alberta and British Columbia, the northern portion of Baja California in Mexico, and all or portions of the 14 western states in between.



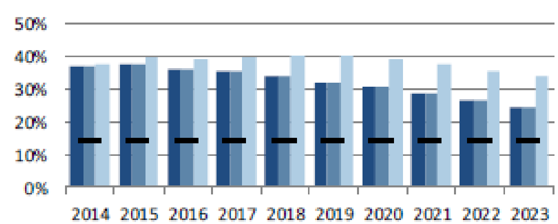
Planning Reserve Margins

WECC-TOTAL-Summer		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
ANTICIPATED		31.18%	33.03%	30.72%	29.29%	28.02%	26.44%	26.02%	23.37%	21.76%	19.93%
PROSPECTIVE		31.18%	33.03%	30.72%	29.29%	28.02%	26.44%	26.02%	23.37%	21.76%	19.93%
ADJUSTED POTENTIAL		31.95%	35.39%	34.20%	33.68%	34.41%	34.03%	34.57%	32.16%	30.49%	28.64%
NERC REFERENCE	-	**14.70%**	**14.70%**	**14.70%**	**14.70%**	**14.70%**	**14.70%**	**14.70%**	**14.70%**	**14.70%**	**14.70%**
WECC-TOTAL-Winter		**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
ANTICIPATED		37.07%	37.61%	36.33%	35.83%	33.95%	32.06%	30.62%	28.69%	26.41%	24.72%
PROSPECTIVE		37.07%	37.61%	36.33%	35.83%	33.95%	32.06%	30.62%	28.69%	26.41%	24.72%
ADJUSTED POTENTIAL		37.83%	39.62%	39.46%	39.86%	40.35%	40.15%	39.47%	37.82%	35.44%	33.76%
NERC REFERENCE	-	**14.50%**	**14.50%**	**14.50%**	**14.50%**	**14.50%**	**14.50%**	**14.50%**	**14.50%**	**14.50%**	**14.50%**

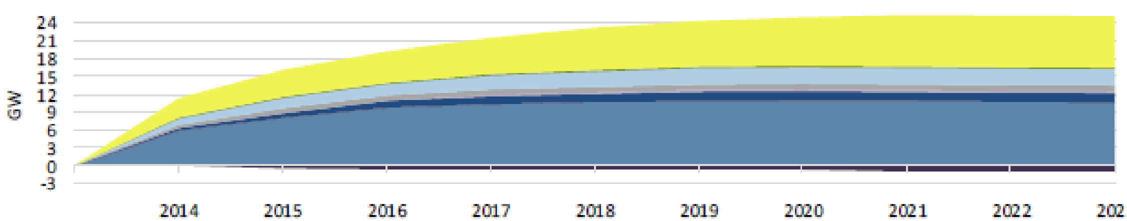
Summer



Winter



Cumulative 10-Year Planned Capacity Change

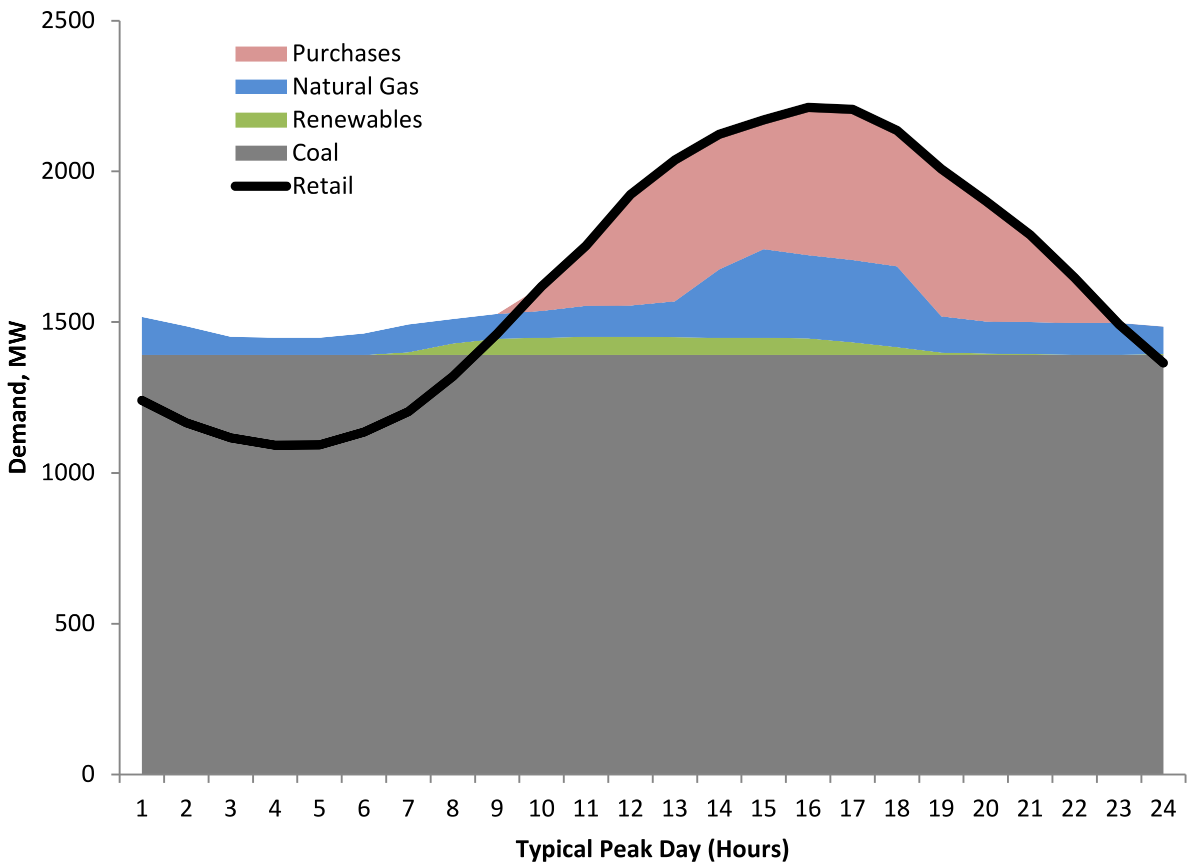


		2013 Existing		2023 Planned			2023 Planned & Conceptual		
WECC-TOTAL		Capacity (MW)	Share (%)	Capacity (MW)	Share (%)	Change (MW)	Capacity (MW)	Share (%)	Change (MW)
Coal		38,798	19.7%	37,787	17.1%	-1,011	37,787	16.0%	-1,011
Petroleum		1,047	0.5%	1,047	0.5%	0	1,047	0.4%	0
Gas		89,870	45.6%	100,534	45.4%	10,664	111,762	47.3%	21,892
Nuclear		9,553	4.8%	9,553	4.3%	0	9,553	4.0%	0
Hydro		42,577	21.6%	44,131	19.9%	1,554	44,728	18.9%	2,152
Pumped Storage		4,441	2.3%	4,688	2.1%	248	4,688	2.0%	248
Geothermal		2,597	1.3%	3,602	1.6%	1,005	3,713	1.6%	1,116
Wind		5,381	2.7%	8,174	3.7%	2,793	9,544	4.0%	4,163
Biomass		1,279	0.6%	1,555	0.7%	276	1,582	0.7%	303
Solar		1,718	0.9%	10,343	4.7%	8,625	12,080	5.1%	10,361
TOTAL		**197,261**	**100.0%**	**221,415**	**100.0%**	**24,155**	**236,484**	**100.0%**	**39,223**

Typical Dispatch Profiles

Chart 17 – 2013 Example Summer Day Dispatch and Chart 18 - illustrates the manner in which existing resources were dispatched to meet anticipated load requirements during a peak-type day in 2013. The figures do not represent the actual peak days; instead the demand profiles demonstrated in these figures are a typical day representative of each respective season for 2013. Chart 17 and Chart 18 are derived from a sample of actual production data. The area shown above the 'Retail' line represents opportunity sales made to the spot market.

Chart 17 – 2013 Example Summer Day Dispatch

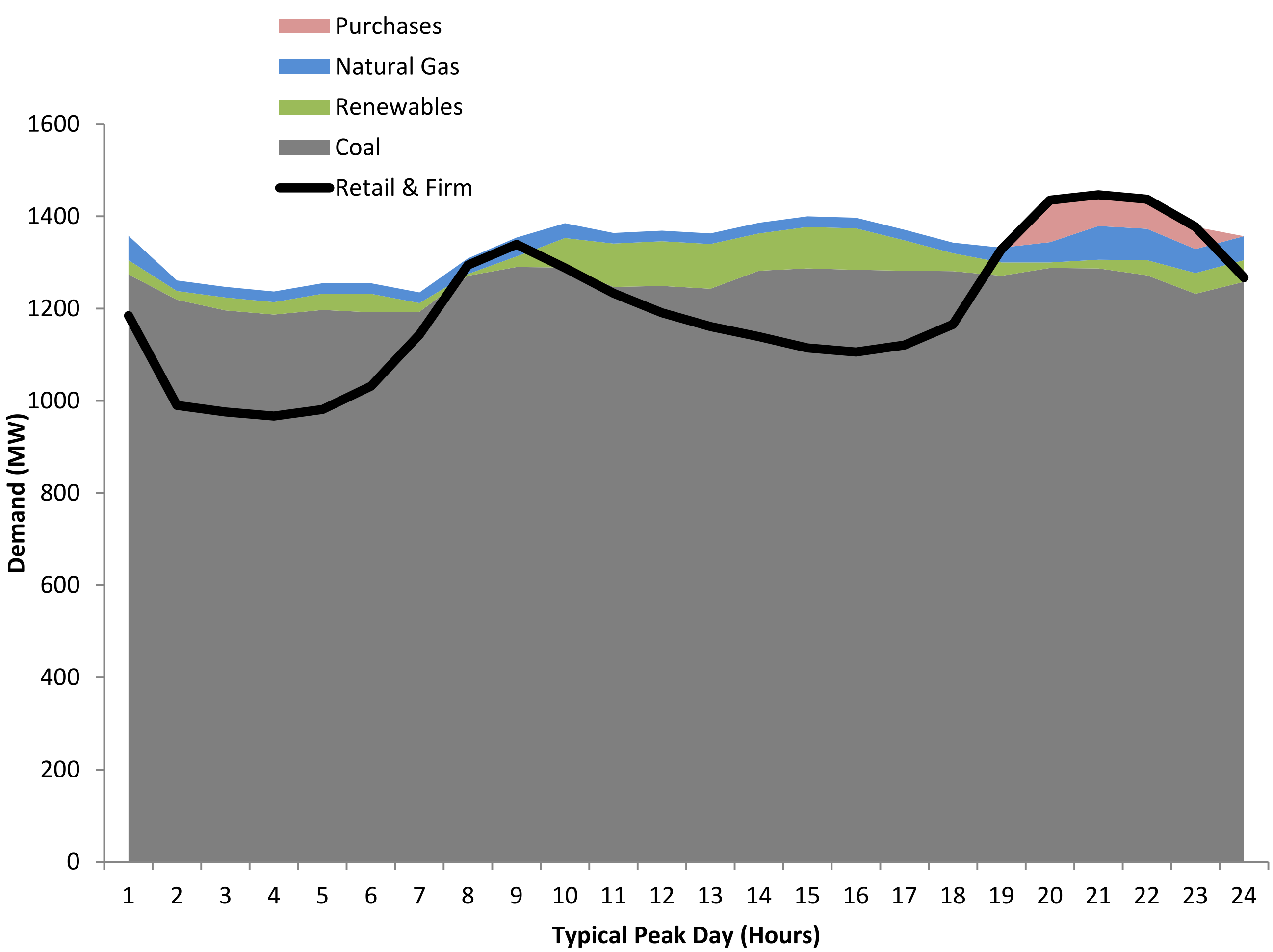


In Chart 17 above, we observe that the high peak demand experienced in the summer can be met with substantial market purchases and the utilization of existing peaking resources (gas turbines). In the chart above, there is a contribution from renewables as seen in green. With capacity available for purchase, the gas and energy market price forecasts dictate that a part of TEP's gas resources would be displaced. The portion of the gas resources that are not dispatched serve as stand-by (reserve) capacity, thus serving a vital purpose in maintaining system reliability. During the summer off-peak hours, spot market sale opportunities exist.

Market sale opportunities are limited to the surplus above retail and firm obligations. Given the existing set of resources, this opportunity for sales diminishes as the coal and gas resources are ramped up steadily to meet the peak demand. As demonstrated in Chart 17, TEP experiences its peak demand at 4 to 5 PM in either July or August.

The TEP winter load profile, as seen in Chart 18 below, differs significantly from the summer profile. The peak demand experienced on weekdays in the winter is dramatically lower than those seen in the summer. In the winter months, the load peaks in the early morning hours and then again in the late evening. The dispatch strategy in the winter differs significantly from the strategy in the summer. With some exceptions, such as planned maintenance on base load generation, gas-peaking resources are not extensively dispatched. There is typically a surplus of coal and other base load resources available in the region. Given this surplus of base load resources, market purchases are often available below the cost of most gas-fired generation.

Chart 18 - 2013 Example Winter Day Dispatch

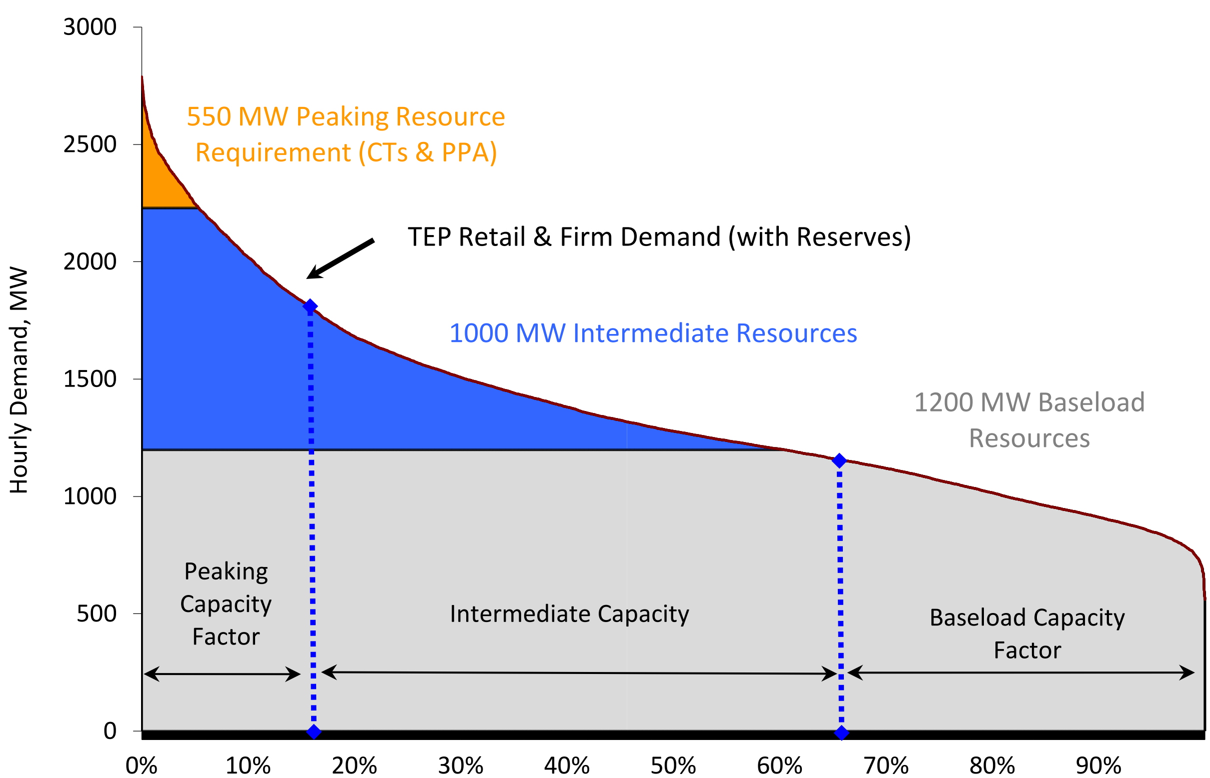


Projected Capacity Requirements

The seasonal load diversity in TEP's service territory presents different challenges and opportunities. While TEP is more actively involved as a seller in the wholesale market during the winter season, in the summer the focus is shifted toward meeting the retail and firm peak demand. In order to attain an adequate balance of resources, it is crucial to understand the dynamics and characteristics of the customer load. The operating and economic characteristics of the typical generation fleet distinguish the resources into 3 categories; base load, intermediate and peaking resources.

The 'base load' requirement can be defined as a minimum level of demand on an electrical system over a specified time interval. Base load generation is dependable, consistent and low cost and is dispatched to serve above the minimum load requirement. This specific type of generation is most efficient and reliable when continuously run at high capacity levels. Base load generation can be expected to operate at high capacity factors that exceed 65% of the base load requirement (See Chart 19 - 2015 TEP Load Duration and Resource Type below). In 2015, TEP's base load units will consist of approximately 1,200 MWs of coal generating plants and often reach annual equivalent capacity factors of 90%. The 1,200 MWs includes the assumption that TEP will retain approximately 50% ownership of Springerville Unit 1. In 2015, the base load minimum requirement is approximately 600 MWs.

Chart 19 - 2015 TEP Load Duration and Resource Type

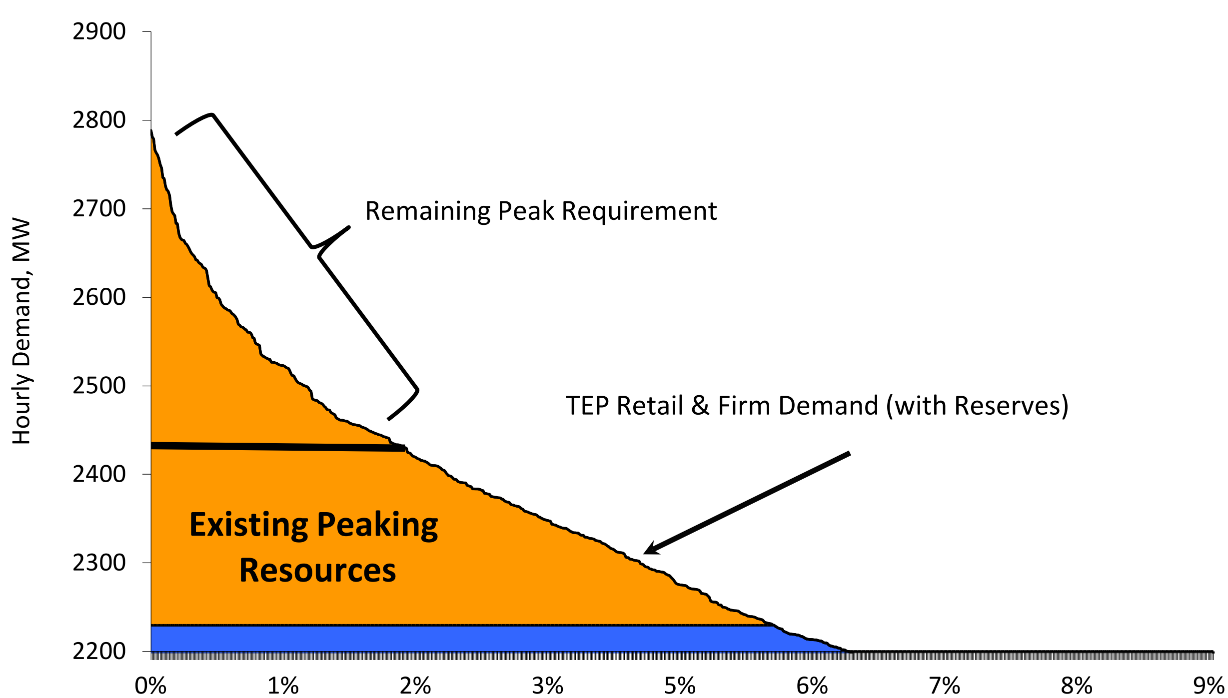


Demand fluctuations above the base load capacity described above are met by intermediate and peaking type resources. These resources are typically more responsive and quicker to ramp and start than base load resources. Sundt Generating Station includes 4 gas/steam units; Unit 4 has fuel switching capabilities and can fire on coal. Sundt along with Luna Energy Facility (LEF), a combined-cycle plant, operate at high capacity factors during the summer peak period and at much lower capacity factors during the winter. TEP anticipates taking ownership of Gila River Block 3 in 2015. This unit is included as an intermediate resource. The dispatch order within the intermediate resource fleet is driven primarily by the fuel source costs and the unit efficiency. These plants tend to operate between 20 and 60 percent of the time.

Peaking resources are also called upon to serve during the summer peaking hours. 'Peakers' are typically combustion turbines that have a fast start time and are very responsive to peak load fluctuations. This type of resource is typically called upon to operate less than 15% of the time. TEP has approximately 200 MW of combustion turbines to utilize during the summer peak season.

Chart 19 - 2015 TEP Load Duration and Resource Type above demonstrates the mix of resources (base load, intermediate and peaking) evaluated with a load duration curve for 2015. The load duration curve (8760 hours) is derived from a chronological forecast that has been sorted from highest MW value to the lowest to form the curve. This load duration curve is offset by hourly renewable resource generation and 15% planning reserves were applied. Chart 20 - 2015 TEP Peaking below shows a magnified view of the capacity shortfall for peaking resources.

Chart 20 - 2015 TEP Peaking Requirements



From Chart 20 we observe that there are approximately 600 MWs of peaking capacity required for 2015. Of those 600 MWs, 200 MWs is secured with existing combustion turbine capacity. The capacity shortfall is 350 MWs to include a margin for planning. The 350 MW shortage, though substantial, occurs approximately 2.0 % of the time. This is equivalent to about one week during the summer peak season. An assessment of TEP's loads and resources shows that TEP has adequate base load and intermediate resources. Based on this assessment, we foresee a need for peaking resources in the near-term. The addition of combustion turbines, combined cycle and solar resources (or a combination thereof) seems to best complement the existing load and resource portfolio.

CHAPTER 6

FUTURE RESOURCE OPTIONS

In considering future resources, the resource planning team evaluated a mix of renewable and conventional generation technologies. This mix of technologies included both commercially available resources and promising new technologies that are likely to become technically viable in the near future. The IRP process takes a high-level approach and focuses on evaluating resource technologies rather than specific projects. This approach allows the resource planning team to develop a wide-range of scenarios and contingencies that result in a resource acquisition strategy that contemplates future uncertainties.

Assumptions on cost and operating characteristics were gathered from several data sources, including:

- PACE Global
- Ventyx
- U.S. Department of Energy (DOE)
- Black & Veatch
- National Renewable Energy Laboratory (NREL)
- Lazard
- ICF International
- National Energy Technology Laboratory (NETL)

In addition, information gathered through our competitive bidding process or request for proposal process (RFP) was used to put both self-build resources and market-based purchase power agreements on a comparative basis. All resources include the costs associated with a transmission interconnection. Additional transmission costs are assumed for any resources sited in remote areas and the costs are based on the required transmission voltage level and the distance to load center.

This section provides a brief overview of the types of generating resources that were included and evaluated in the resource planning process for the 2014 IRP. For each technology type a brief summary of potential risks and benefits are listed. In addition, attributes such as costs, siting requirements, dispatchability, transmission requirements and environmental potential are summarized. The table shown below summarizes the technology types.

Generation Resources – Matrix of Applications

Each type of generating resource has a unique combination of advantages and disadvantages, including costs, benefits, opportunities and risks. The matrix below shows some of the issues that must be taken into consideration when comparing resources. Issues such as location, dispatch characteristics and carbon output must be factored into the cost of each resource.

Table 15 - Resource Matrix

		Zero or Low Carbon Potential	State of Technology	Local Area Option	Intermittent	Peaking	Load Following	Base Load
Energy Efficiency	Energy Efficiency	Yes	Mature	Yes				
Demand Response	Direct Load Control	Yes	Mature	Yes		✓		
Renewables	Wind	Yes	Mature		✓			
	Solar PV	Yes	Commercial	Yes	✓	✓		
	Solar Thermal	Yes	Commercial		✓	✓	Storage (2)	
	Biomass Direct	Neutral	Mature				✓	✓
Conventional	Compressed Air Energy Storage	Low	Emerging			✓	✓	
	Combustion Turbines		Mature	Yes		✓	✓	
	Combined Cycle		Mature	Yes		✓	✓	✓
	IGCC	CCS (1)	Emerging				✓	✓
	Coal (PC)	CCS (1)	Mature				✓	✓
	Nuclear (NUC)	Yes	Mature					✓

(1) Technology innovations in carbon capture and sequestration (CCS) could result in low carbon output.
(2) Natural Gas hybridization or thermal storage could allow resource to be dispatched to meet utility peak load requirements.

Energy Efficiency

Energy Conservation Technologies

Technology	Wide range of technologies and customer incentives. Many of the program ranges from customer installed high efficiency electrical devices to design and construction of high efficiency building standards.
Characteristics	TEP offers a variety of energy efficiency programs designed for both the residential and commercial customers. The primary objective of these programs is to provide customers with consumption based information and financial incentives which reduce overall energy consumption. Energy efficiency programs give customers the opportunities to reduce their monthly electric bills. Energy efficiency programs provide incentives for customers to invest in high efficiency technologies such as home appliances, compact fluorescent lighting, pumps, motors and HVAC equipment. Other programs provide incentives for builders to design and construct both residential and commercial buildings based on higher energy efficiency construction standards.
Benefits	Lowest cost resource. Environmental benefits include reductions in air emissions and water usage. The effect of energy efficiency reduces system losses and often defers the need to construct new power plants and transmission lines.
Risks	Challenges include customer participation, market potential and sustained load reduction.
Resource Lead Time	1-2 Years

Energy Conservation Modeling Assumptions

Technology Type	Energy Conservation
Coincident System Peak Capacity	80%
Capacity Cost $/kW	$100
Fixed O&M $/ kW-Year	0
Annual Capacity Factor, %	45%
Emissions	Zero Emissions
Levelized Cost $/MWh	$60

Demand Response

Direct Load Control Technology

Technology	Customer installed thermostats and switches used to control customer demand.
Characteristics	The goal of demand response is to reduce customer peak demand rather than overall energy use. Programs target summer peak periods to offset the utilities' need to procure additional resource capacity. Programs may utilize cycling methodologies, load shifting, or direct interruption during summer peaks or system emergencies. For planning purposes, TEP assumed that the sum of the DLC programs would contribute 80-100% of expected nameplate capacity to coincide with system peak.
Benefits	Depending on program design, DLC is often utilized as a dispatchable resource as part of utility operations. Emissions and water usage reduction. Defers the need to construct new power plants and transmission lines.
Risks	Challenges include limited customer participation, minimum yearly call options and low dispatch duration.
Program Lead Time	1 Year

Demand Response Modeling Assumptions

Technology Type	Demand Response
Coincident System Peak Capacity	80-100%
Capacity Cost $/kW	$150
Fixed O&M $/ kW-Year	0
Annual Capacity Factor, %	N/A
Emissions	Zero Emissions
Levelized Cost $/MWh	N/A

Wind Power Technology

Renewable Resources

Technology	Wind Turbines
Characteristics	Unit capacity can range in size from 1 to 5 MW. Based on recent regional wind studies, annual capacity factors for Arizona wind resources average about 30% and New Mexico wind resources average about 38%. Annual production is predominately in non-summer months during off-peak hours. For planning purposes, TEP assumed that wind resources would contribute 9-13% of nameplate capacity during coincident system peak.
Benefits	Zero emissions and low water usage. Qualifies for 30% federal investment tax credit and accelerated asset depreciation.
Risks	Non-firm, non-dispatchable resource. Requires backup capacity and regulation. Remote location and low capacity factors make transmission investment costly requirement. Primary environmental concerns are avian mortality and visual impacts
Construction Lead Time	2 Years

Utility Scale Wind Farm Modeling Assumptions

Location	Arizona	New Mexico
Coincident System Peak Capacity	9%	13%
Capacity Cost $/kW	$2,278	$2,278
Fixed O&M $/ kW-Year	$52	$52
Annual Capacity Factor, %	30%	38%
Emissions	Zero Emissions	Zero Emissions
System Integration Costs, $/MWh	$1.40	$1.40
Levelized Cost $/MWh	$181	$150

Photovoltaic Solar Power Technology

Renewable Resources

Technology	PV (Fixed) and PV (Single-Axis Tracking)
Characteristics	Unit capacity can vary in size from 1 kW to 20 MW. Annual capacity factors for these units range from 17-24%. Annual production is predominately during on-peak hours. For planning purposes TEP assumed that utility scale solar resources would contribute 33% for PV (Fixed) and 51% of name plate capacity for PV (Single-Axis Tracking) during the coincident system peak.
Benefits	Zero emissions. Units can be sited near or within load centers, thus reducing transmission investment. Scalable resource with low water usage. Qualifies for 30% federal investment tax credit and accelerated asset depreciation.
Risks	Intermittent resource, significant variance with cloud cover. Requires backup capacity and regulation. Significant land requirements of approximately 8 acres per MW.
Construction Lead Time	2 Years

Utility Scale Photovoltaic Modeling Assumptions

Technology	PV Fixed	PV Single Axis
Coincident System Peak Capacity	33%	51%
Capacity Cost $/kW	$1,993	$3,313
Fixed O&M Cost $/ kW-Year	$14.50	$27
Annual Capacity Factor, %	19%	24%
Emissions	Zero Emissions	Zero Emissions
System Integration Costs, $/MWh	$5.20	$5.20
Levelized Cost $/MWh	$164	$180

Concentrating Solar Power Technology

Renewable Resources

Technology	Trough Concentrating Solar Power (with and without storage)
Characteristics	Unit capacity can range in size from 50 to 300 MW. Annual capacity factors for these units range from 30-38%. Annual production is predominately during on-peak hours. For planning purposes TEP assumed that CSP resources would contribute 70% (without storage) and 87% (with storage) of nameplate capacity during coincident system peak.
Benefits	Zero emissions. Thermal inertia dampens cloud effects. CSP with storage or natural gas hybridization can be dispatched to meet utility peak load requirements. Qualifies for 30% federal investment tax credit and accelerated asset depreciation.
Risks	CSP storage is in an emerging stage of development. Due to large facility size, CSP plants tend to be located in remote areas. Remote location and low capacity factors make transmission investment costly requirement. Compared to other renewables, CSP requires high water usage unless dry cooled. Large land requirements.
Construction Lead Time	2 Years

Utility Scale Concentrating Solar Modeling Assumptions

Technology	**CSP**	**CSP with Storage**
Coincident System Peak Capacity	70%	87%
Capacity Cost $/kW	$5,591	$7,144
Fixed O&M Cost $/kW-Year	$35	$70
Annual Capacity Factor, %	30%	38%
Emissions	Zero Emissions	Zero Emissions
Water, Gal/MWh	800	800
System Integration Costs, $/MWh	$3.80	$3.80
Levelized Cost $/MWh	$204	$210

Biomass Direct Technology

Renewable Resources

Technology	Biomass Direct (Combustion or Gasification)
Characteristics	Unit capacity typically ranges in size from 15 to 50 MW. Plants are usually operated as base load facilities. Annual capacity factors for these units range from 80-90%. For planning purposes TEP assumed that utility scale biomass resources would contribute 100% of nameplate capacity during coincident system peak.
Benefits	CO2 emission neutral. One of the lower cost resources for renewable energy. Units can be sited near or within load centers, thus reducing transmission investment.
Risks	Fuel supply and transportation
Construction Lead Time	2 Years

Utility Scale Biomass Modeling Assumptions

Coincident System Peak Capacity	100%
Heat Rate Btu/kWh	11,000
Capacity Cost $/kW	$3,624
Fixed O&M Cost $/kW-Year	$85
Annual Capacity Factor, %	85%
CO2 Rate, lbs/MWh	Carbon-Neutral
SO2 Rate, lbs/MWh	0.008
NOX Rate, lbs/MWh	0.446
PM10 Rate, lbs/MWh	0.100
Water, Gal/MWh	100
Levelized Cost $/MWh	$120

Combustion Turbine Technology (CT)

Peaking Resources

Technology and Fuel	Combustion Turbine, Natural Gas
Characteristics	Unit capacity can range in size from 20 to 150 MW. Performance characteristics range anywhere from 9,000 to 12,000 Btu per kWh. Typically, combustion turbines are considered quick start units that can be dispatched within 10 minutes. Combustion turbines provide ancillary system benefits by meeting non-spinning reserve requirements. Annual capacity factors for these units range from 5 to 18%
Benefits	Combustion turbines meet the need for peaking capacity during peak load conditions. Combustion turbines can be sited closer to the load centers thus reducing transmission infrastructure and provide local area voltage support. Lower capital costs, shorter construction lead time and multiple unit siting configurations allow flexibility to match load serving requirements as well as planned future build outs for combined-cycle conversions. Combustion turbines also have lower water consumption.
Risks	Natural gas price volatility and CO2 risk
Construction Lead Time	4 Years

Combustion Turbine Modeling Assumptions

Unit Description	GE 7FA	GE LMS100	GE LM6000
Dispatch Capacity MW	160	90	45
Heat Rate Btu/kWh	10,500	9,000	9,800
Capacity Cost $/kW	$808	$1,243	$1,062
Fixed O&M $/ kW-Year	$13.60	$11.95	$15.00
Annual Capacity Factor, %	8%	18%	10%
CO2 Rate, lbs/MWh	1,248	1,070	1,165
SO2 Rate, lbs/MWh	0.006	0.005	0.006
NOX Rate, lbs/MWh	0.347	0.323	0.297
HG Rate, lbs/MWh	2.70E-06	2.30E-06	2.50E-06
PM10 Rate, lbs/MWh	0.078	0.067	0.073
Water, Gal/MWh	150	150	150
Levelized Cost $/MWh	$281	$194	$249

Combined Cycle Plant Technology (CC)

Intermediate Resources

Technology and Fuel	Combined Cycle Plants, Natural Gas
Characteristics	Unit capacity can range in size from 250 to 600 MW. Performance characteristics range anywhere from 7,000 to 8,500 Btu per kWh. Annual capacity factors for these units are about 40% for units serving intermediate needs and 85% for baseload.
Benefits	Combined cycle resources are used to serve intermediate and base load obligations. Combined-cycle plants are often used for system regulation and meeting spinning reserve requirements.
Risks	Natural gas price volatility and CO_2 emission risk
Construction Lead Time	5 Years

Combined-Cycle Plant Modeling Assumptions

Dispatch Capacity MW	570	570
Heat Rate Btu/kWh	7,200	7,200
Capacity Cost $/kW	$1,367	$1,367
Fixed O&M Cost $/ kW-Year	$18.60	$16.50
Annual Capacity Factor, %	40%	75%
CO_2 Rate, lbs/MWh	850	850
SO_2 Rate, lbs/MWh	0.004	0.004
NOX Rate, lbs/MWh	0.094	0.094
HG Rate, lbs/MWh	1.80E-06	1.80E-06
PM10 Rate, lbs/MWh	0.054	0.054
Water, Gal/MWh	350	350
Type	Intermediate	Baseload
Levelized Cost $/MWh	$119	$88

Pulverized Coal Technology

Base Load Resources

Technology and Fuel	Sub-Critical Design, Pulverized Coal
Characteristics	Unit capacity can range in size from 250 to 600 MW. Performance characteristics range anywhere from 9,500 to 10,500 Btu per kWh. Annual capacity factors for these units range from 80 to 90% Units
Benefits	Mature technology. Fuel price stability and abundant supply. Resources are used to serve base load obligations. Coal plant plants are often used for system regulation and meeting spinning reserve requirements.
Risks	Coal plants are typically sited in remote locations requiring high capital investment in both plant and transmission. High CO2 emissions risk and high cooling water requirements.
Construction Lead Time	7 Years

Coal Plant Modeling Assumptions

Dispatch Capacity MW	400
Heat Rate Btu/kWh	10,250
Capacity Cost $/kW	$4,144
Fixed O&M Cost $/ kW-Year	$30.45
Annual Capacity Factor, %	85%
CO2 Rate, lbs/MWh	2,101
SO2 Rate, lbs/ MWh	1.046
NOX Rate, lbs/ MWh	0.656
HG Rate, lbs/ MWh	1.17E-05
PM10 Rate, lbs/ MWh	0.210
Water, Gal/MWh	750
Levelized Cost $/MWh	$125

Integrated Gasification Combined-Cycle (IGCC)

Base Load Resources

Technology and Fuel	Combined Cycle Plants, Coal Gasification
Characteristics	Newer technology. Unit capacity can range in size from 400 to 600 MW. Performance characteristics range anywhere from 9,000 to 11,000 Btu per kWh. Annual capacity factors for these units average 75%
Benefits	Designs that incorporate carbon capture and storage (CCS) are projected to be less expensive than coal facilities equipped with CCS.
Risks	Higher capital costs than other coal and natural gas resources. Carbon capture and storage technology unproven.
Construction Lead Time	8 Years for IGCC without CCS, 9 Years for IGCC with CCS

Integrated Gasification Combined-Cycle (IGCC) Assumptions

CCS Capability	No	Yes
Dispatch Capacity MW	600	380
Heat Rate Btu/kWh	9,200	11,000
Capacity Cost $/kW	$6,523	$8,190
Fixed O&M Cost $/ kW-Year	$50.80	$57.90
Annual Capacity Factor, %	75%	70%
CO2 Rate, lbs/MWh	1,886	226
SO2 Rate, lbs/ MWh	0.117	0.094
NOX Rate, lbs/ MWh	0.406	0.450
HG Rate, lbs/MWh	4.25E-06	4.59E-06
PM10 Rate, lbs/ MWh	0.007	0.007
Water, Gal/MWh	800	900
Levelized Cost $/MWh	$194	$261

Nuclear Power Technology

Base Load Resources

Technology and Fuel	Advanced Boiling Water Reactor, Plutonium
Characteristics	Unit capacity can range in size from 1000 to 1500 MW. Annual capacity factors for these units average 85%
Benefits	Zero Emissions.
Risks	Capital and construction risk, spent nuclear fuel disposal risk. High water requirements.
Construction Lead Time	12 Years

Nuclear Plant Modeling Assumptions

Dispatch Capacity MW	1,000
Heat Rate Btu/kWh	10,400
Capacity Cost $/kW	$8,210
Fixed O&M Cost $/ kW-Year	$75.55
Annual Capacity Factor, %	85%
CO_2 Rate, lbs/ MWh	0
SO_2 Rate, lbs/ MWh	0
NOX Rate, lbs/ MWh	0
HG Rate, lbs/ MWh	0
PM10 Rate, lbs/MWh	0
Water, Gal/MWh	1,000
Levelized Cost $/MWh	$154

Comparison of Resources

Generation planning and resource analysis can be performed by using a wide spectrum of tools and methodologies. Prior to running detailed simulation models, the resource planning team performed a number of simple comparisons that analyzed each potential resource on a stand-alone basis. Table 16 shown below summarizes these comparisons and shows how each resource performed in terms of capital costs, levelized cost of energy, water usage and CO_2 profiles.

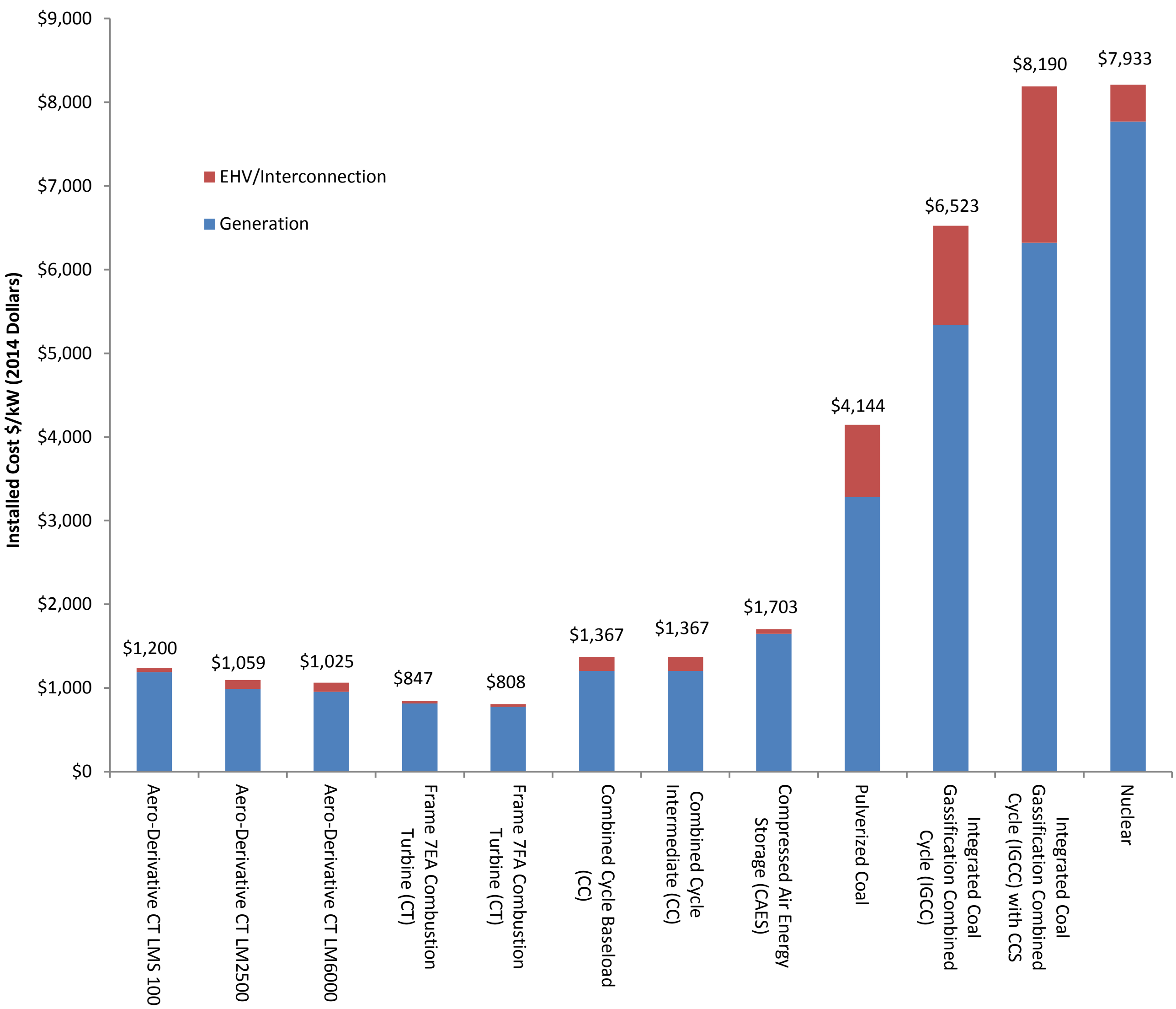
Table 16 - Resource Comparisons

		Capital Cost ($/kW)	Levelized Cost of Energy ($/MWh)	Water Usage (Gallons/ MWh)	CO2 Profile (lbs/ MWh)
Energy Efficiency	Energy Efficiency			0	0
Demand Response	Direct Load Control			0	0
Renewables	New Mexico (NM Wind)	2,278	146	0	0
	Arizona (AZ Wind)	2,278	177	0	0
	Solar PV (Single Axis)	3,313	184	0	0
	Solar PV (Fixed)	1,993	166	0	0
	Biomass Direct	3,624	120	100	0
	Solar CSP	5,591	206	800	0
	Solar CSP (Storage)	7,144	212	800	0
Conventional	Nuclear	8,210	136	1,000	0
	IGCC with CCS	8,190	200	900	226
	Compressed Air Energy Storage (CAES)	1,703	252	75	267
	Combined Cycle (CC)	1,367	88/119	350	850
	Aero-Derivative CT LMS 100	1,200	194	150	1,070
	Aero-Derivative CT LM6000	1,025	249	150	1,165
	Frame 7FA Combustion Turbine (CT)	808	281	150	1,248
	IGCC	6,523	193	800	1,886
	Pulverized Coal	4,144	125	750	2,101

Capital Costs – Conventional Resources

Chart 21 below shows the breakdown on the costs of conventional generation resources used in the 2014 IRP. The costs are shown for both the generating plant and the transmission and associated interconnection costs. All costs reflect 2014 $/kW for invested capital.

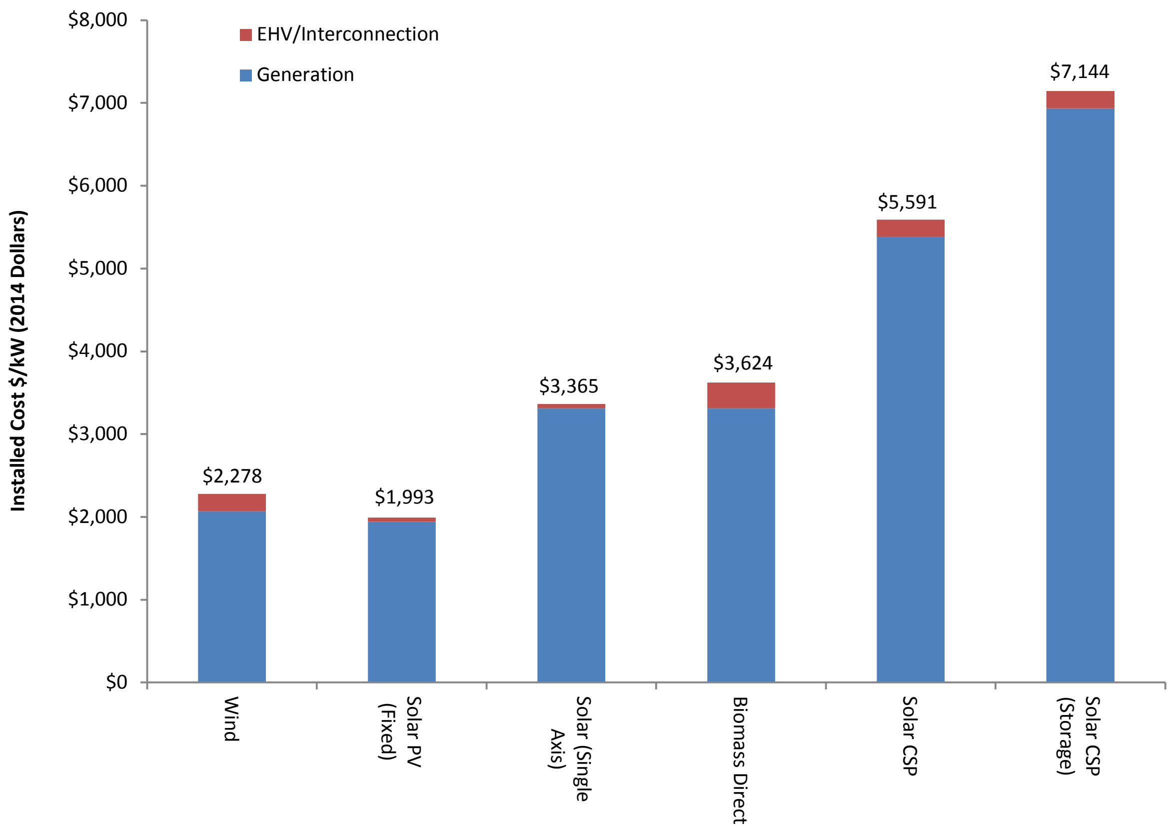
Chart 21 - Conventional Resource Capital Costs, $/kW



Capital Costs – Renewable Resources

Chart 22 below shows the breakdown on the costs of renewable resources used in the 2014 IRP. The costs are shown for both the generating plant and the transmission and associated interconnection costs. All costs reflect 2014 $/kW for invested capital. This summary reflects the capital cost requirements prior to the adjustment for the 30% federal investment tax credit (ITC) applied against the generation capital costs.

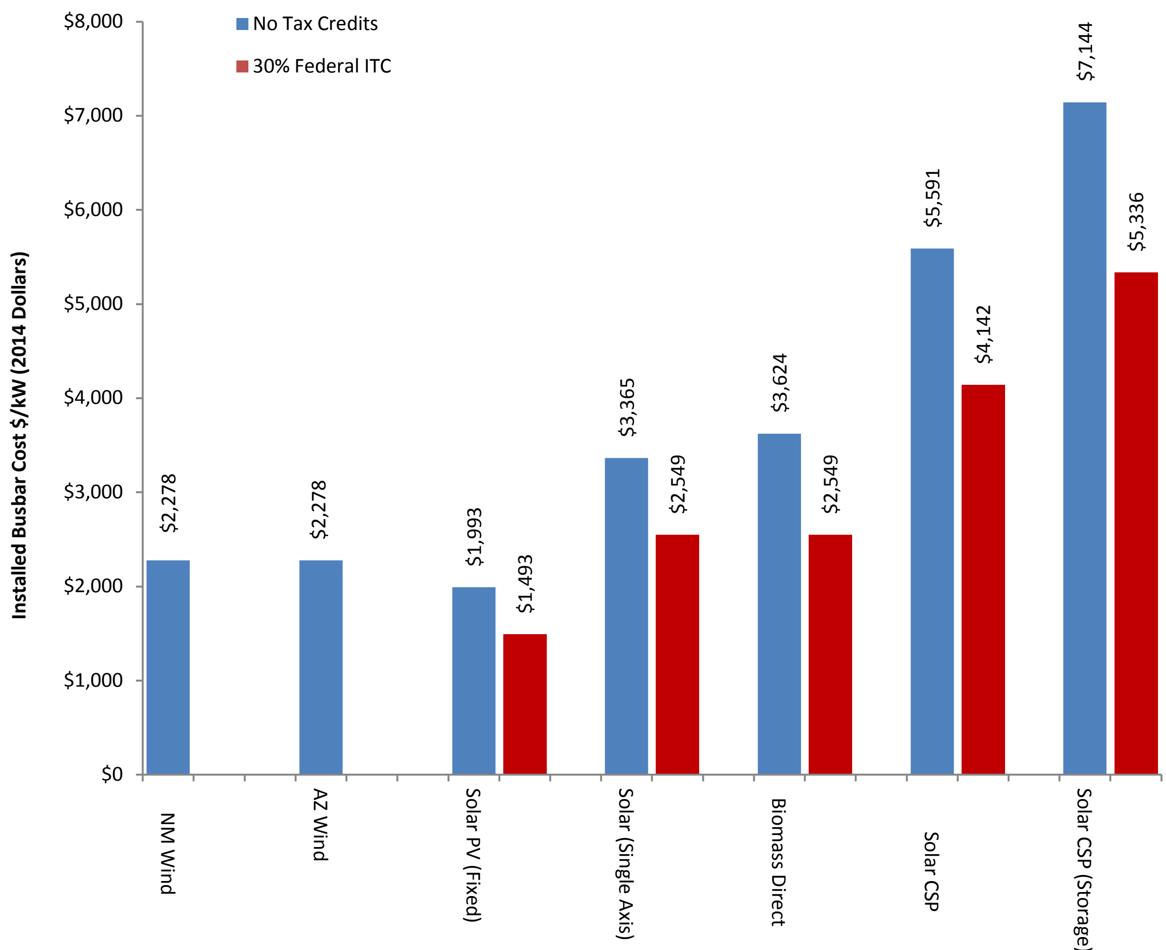
Chart 22 - Renewable Resource Capital Costs, $/kW



The Effects of Investment Tax Credits on Renewables

Chart 23 below shows the benefit associated with the Federal investment tax credit (ITC) for renewable resources. For the 2014 IRP, it is assumed that costs reflect 2014 $/kW for invested capital after the ITC. As shown below, it is assumed that the 30% ITC was reduced to zero for wind resources starting in 2014. Solar resources still qualify for the 30% ITC, however, the ITC for solar resources is set to step down to 10% at the end of 2016.

Chart 23 - Investment Tax Credit Impacts on Renewable Resources, $/kW



LEVELIZED COST COMPARISONS

The calculation of the levelized cost of electricity (LCOE) provides a common way to compare the cost of energy across different demand and supply-side technologies The LCOE takes into account the installed system price and associated costs such as financing, land, insurance, transmission, operation and maintenance, and depreciation and converts them into a common metric: $/MWh. The calculation for the LCOE is the net present value of total life cycle costs of the project divided by the quantity of energy produced over the system life.

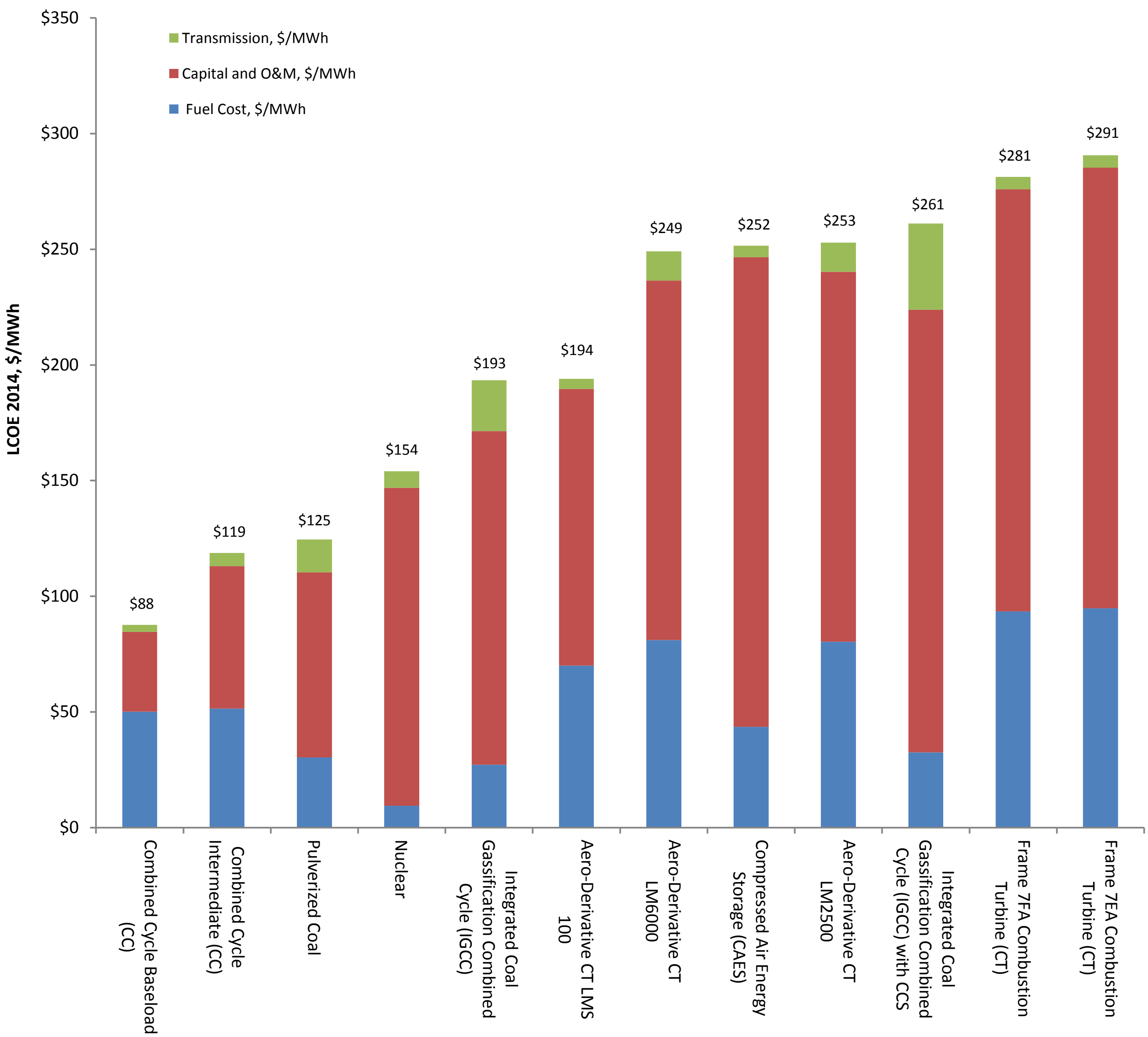
Levelized costs represent the present value of the total cost of building and operating a generating plant over its financial life, converted to equal annual payments and amortized over expected annual generation from an assumed duty cycle.

Because intermittent technologies such as renewables do not provide the same contribution to system reliability as technologies that are operator controlled and dispatched, they require additional system investment for system regulation and backup capacity.

LEVELIZED COST OF ENERGY – CONVENTIONAL RESOURCES

Chart 24 below provides a comparison on the levelized costs of conventional generation resources used in the 2012 IRP. The costs are shown for both the generating plant and the transmission and associated interconnection costs. All costs reflect 2012 $/MWh.

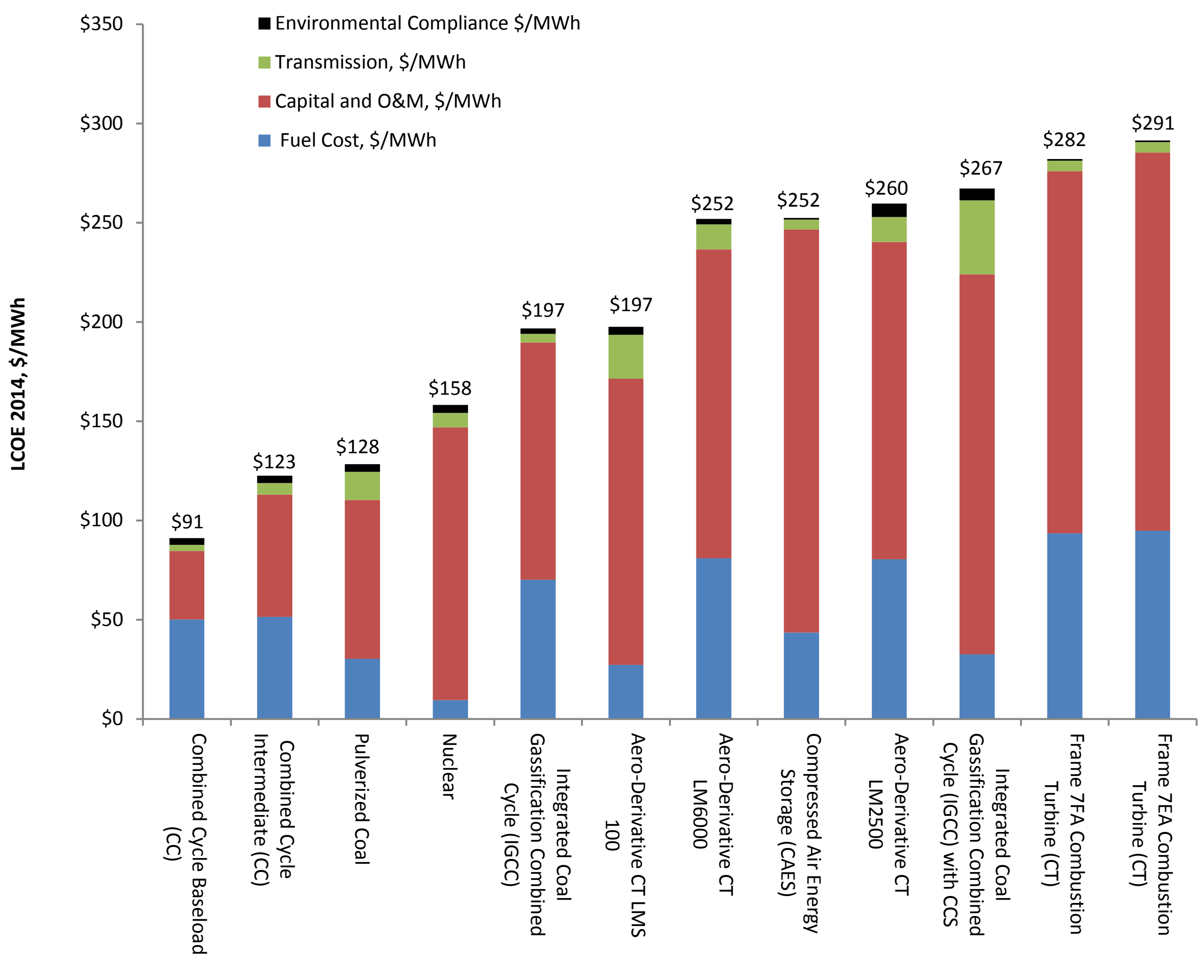
Chart 24 - Levelized Cost of Conventional Resources



LEVELIZED COST OF ENERGY – CONVENTIONAL RESOURCES WITH CO_2

Chart 25 below provides a comparison on the levelized costs of conventional generation resources assuming a carbon cost based on the CO_2 forecast assumptions in Chapter 15. All costs reflect 2014 $/MWh.

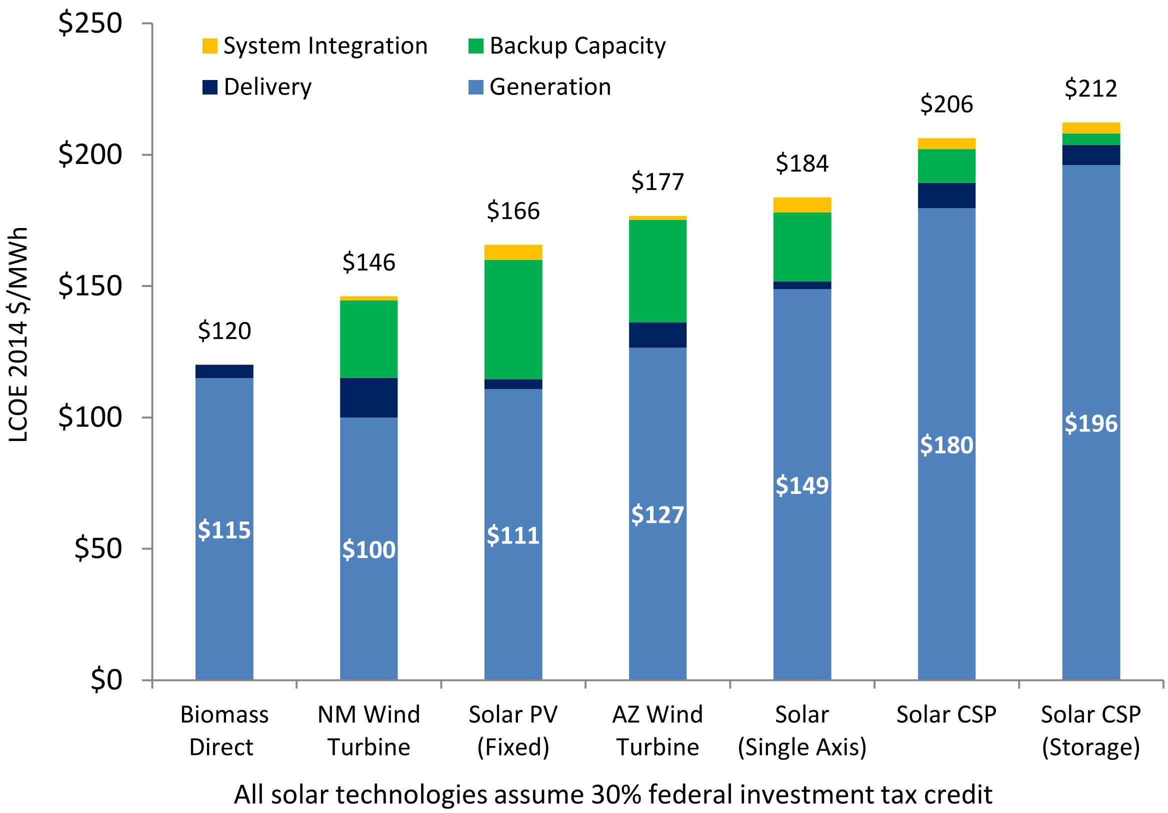
Chart 25 - Levelized Cost of Conventional Resources with CO2 Tax



LEVELIZED COST OF ENERGY – RENEWABLE RESOURCES

Chart 26 below provides a comparison on the levelized costs of renewable resources. The costs are shown for the generating plant, transmission, system integration and backup capacity costs. All solar and biomass projects are adjusted for the 30% federal investment tax credit and reflect 2014 $/MWh.

Chart 26 - Levelized Cost of Renewable Resources, $/MWh



RENEWABLE TECHNOLOGIES – COST DETAILS

Table 17 includes the renewable technology cost assumptions used in the 2014 Integrated Resource Plan.

Table 17 - Renewable Resource Cost Assumptions

Cost and Operating Characteristics	Units	NM Wind	AZ Wind	Solar PV (Fixed)	Solar PV (Single Axis)	Solar CSP	Solar CSP (Storage)	Biomass Direct
Project Lead Time	Years	2	2	2	2	2	2	2
Installation Years	First Year Available	2014	2014	2014	2014	2014	2014	2014
Peak Capacity	MW	50	50	20	20	50	50	20
Construction Cost	2014 $/kW	$1,864	$2,071	$1,941	$3,161	$5,384	$6,937	$3,313
EHV/Interconnection Cost	2014 $/kW	$414	$207	$52	$52	$207	$207	$311
Total Construction Cost	2014 $/kW	$2,278	$2,278	$1,993	$3,313	$5,591	$7,144	$3,624
Construction Cost with ITC	2014 $/kW			$1,493	$2,549	$4,142	$5,336	$2,549
Fixed O&M	2014 $/kW-yr	$52	$52	$15	$27	$35	$70	$85
Variable O&M	2014 $/MWh	$0.00	$0.00	$0	$0	$0	$5.00	$15
Fuel Cost	2014 $/MWh							$42
System Integration Costs	2014 $/MWh	$1.40	$1.40	$5.20	$5.20	$3.80	$3.80	
Levelized Cost of Energy	$/MWh	$146	$177	$166	$184	$206	$212	$120
Typical Capacity Factor	Annual %	38%	30%	17%	24%	30%	38%	85%
Net Coincident Peak Contribution	NCP %	9%	9%	33%	51%	70%	87%	100%
Water Usage	Gal/MWh	0	0	0	0	800	800	100
30% Federal ITC	Qualify	NO	NO	YES	YES	YES	YES	YES

CONVENTIONAL TECHNOLOGIES – COST DETAILS

Table 18 includes the conventional resource cost assumptions used in the 2014 Integrated Resource Plan.

Table 18 - Conventional Resource Cost Assumptions

Plant Construction Costs	Units	GE Aero-Derivative CT LMS 100	GE Aero-Derivative CT LM6000	Frame 7FA Combustion Turbine (CT)	Combined Cycle (CC) (Baseload)	Compressed Air Energy Storage (CAES)	Pulverized Coal	IGCC	IGCC with CCS	Nuclear
Project Lead Time	Years	4	4	4	5	4	7	8	9	12
Installation Years	First Year Available	2016	2016	2016	2017	2016	2019	2020	2021	2024
Peak Capacity	MW	90	45	160	570	100	400	600	380	1000
Plant Construction Cost	2014 $/kW	$1,189	$954	$778	$1,202	$1,651	$3,280	$5,340	$6,320	$7,769
EHV/Interconnection Cost	2014 $/kW	$52	$108	$30	$165	$52	$864	$1,183	$1,870	$441
Total Construction Cost	2014 $/kW	$1,243	$1,062	$808	$1,367	$1,703	$4,144	$6,523	$8,190	$8,210
Operating Characteristics										
Fixed O&M	2014 $/kW-yr	$11.95	$15.53	$13.60	$16.50	$29.00	$30.45	$50.80	$57.90	$75.55
Variable O&M	2014 $/MWh	$3.30	$2.85	$3.75	$3.28	$1.80	$2.35	$4.65	$5.35	$2.12
Gas Transportation, $/kW	2014 $/kW-yr	$16.80	$16.80	$16.80	$16.80	$16.80	$0.00	$0.00	$0.00	$0.00
Annual Heat Rate	Net Btu/kWh	9,000	9,800	10,500	7,200	4,500	10,250	9,200	11,000	10,400
Typical Capacity Factor	Annual %	18%	10%	10%	85%	15%	85%	75%	70%	85%
Expected Annual Output	GWh	138	39	140	2,247	131	5,957	3,942	2,330	7,446
Levelized Cost of Energy	$/MWh	$194	$249	$281	$88	$227	$125	$194	$261	$154

CONVENTIONAL TECHNOLOGIES – ENVIRONMENTAL DETAILS

Table 19 includes the conventional resource environmental assumptions used in the 2014 Integrated Resource Plan.

Table 19 - Conventional Resource Environmental Assumptions

Environmental Assumptions	Units	Aero-Derivative CT LMS 100	Aero-Derivative CT LM6000	Frame 7FA Combustion Turbine (CT)	Combined Cycle (CC)	Compressed Air Energy Storage (CAES)	Pulverized Coal	IGCC	IGCC with CCS	Nuclear
CO2 Rate	lbs/MWh	1,070	1,165	1,248	850	267	2,101	1,886	226	0
SO2 Rate	lbs/MWh	0.005	0.006	0.006	0.004	0.001	1.046	0.117	0.094	0
NOX Rate	lbs/MWh	0.297	0.323	0.347	0.094	0.173	0.656	0.058	0.058	0
HG Rate	lbs/MWh	2.30E-06	2.50E-06	2.70E-06	1.80E-06	1.35E-06	1.17E-05	4.25E-06	4.59E-06	0
PM10 Rate	lbs/MWh	0.067	0.073	0.078	0.054	0.039	0.210	0.007	0.007	0
Water Usage	Gal/MWh	150	150	150	350	75	750	800	900	1,000

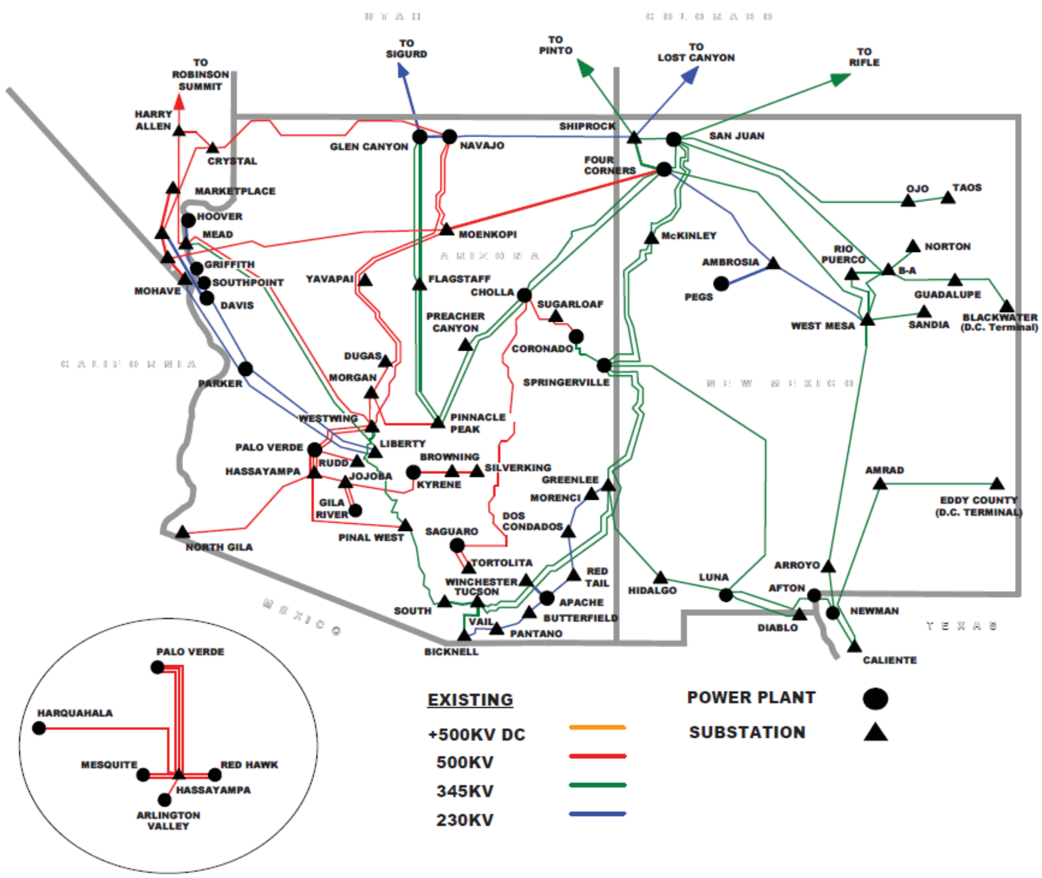
CHAPTER 7

Transmission Resources

Overview

Transmission resources are a key element in TEP's resource portfolio. Adequate transmission capacity must exist to meet TEP's existing and future load obligations. TEP's resource planning and transmission planning groups coordinate their planning efforts to ensure consistency in development of its long-term planning strategy. On a statewide basis, TEP participates in the ACC's Biennial Transmission Assessment (BTA) to develop a transmission plan that ensures that Arizona's transmission organizations are coordinated in their efforts to maintain system adequacy and reliability.

Map 5 – Arizona and New Mexico Generation and Transmission

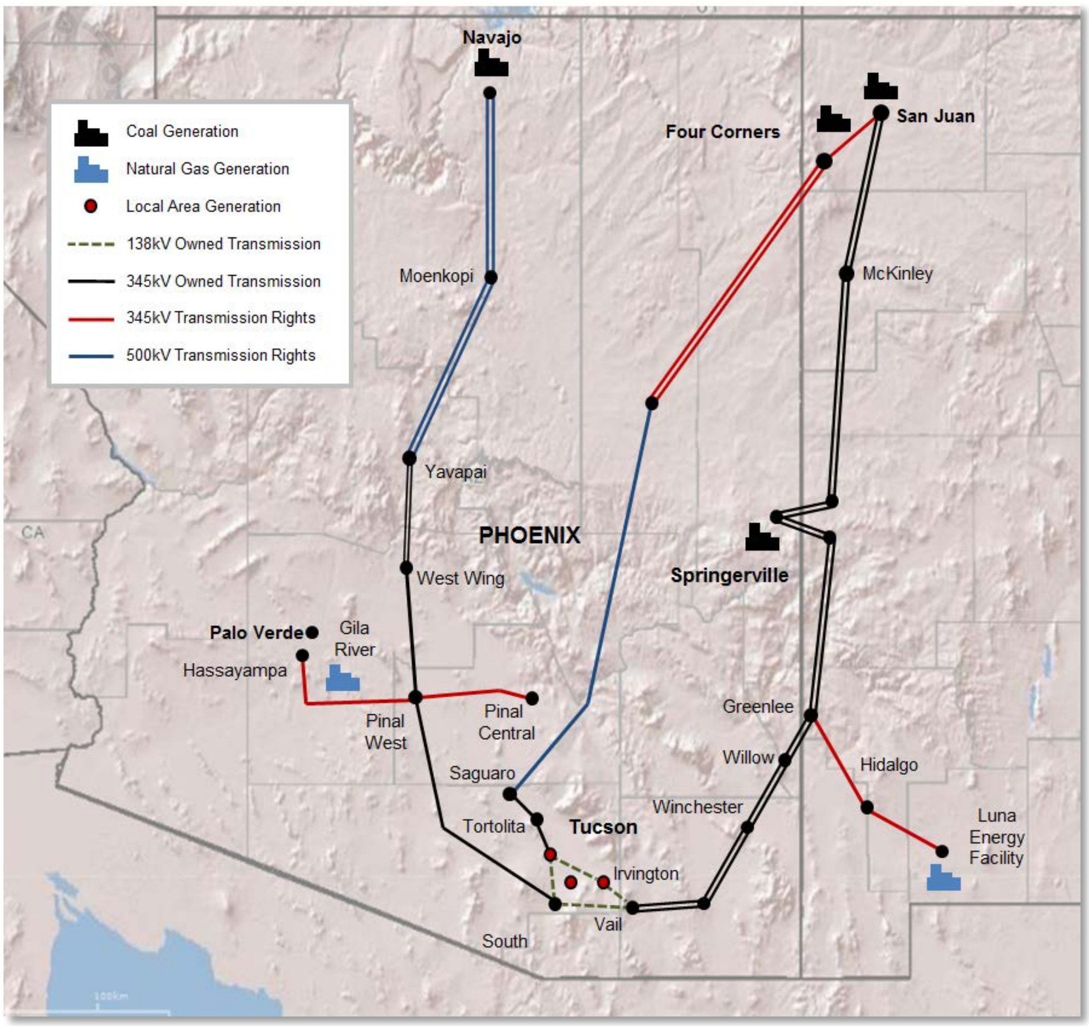


TEP's Existing Transmission Resources

TEP's existing transmission system was constructed over the last several decades to support the delivery of the base load coal generation resources in northern Arizona and New Mexico. Today, TEP owns approximately 422 miles of 138 kV lines, and is owner and part owner of 1109 miles of 345 kV lines and 564 miles of 500 kV lines. As shown in

Map 6 the Tucson service territory area is interconnected to the Western Interconnection Bulk Electric System (BES) via 345 kV interconnections at the South Loop and Vail substations, and a 500 kV interconnection at the Tortolita substation. These three substations interconnect and deliver energy from the EHV transmission network to the local TEP 138 kV system. To keep up with future retail load obligations, additional transmission capacity will be needed to maintain system reliability and provide adequate import capacity.

Map 6 - TEP's Existing Transmission Resources

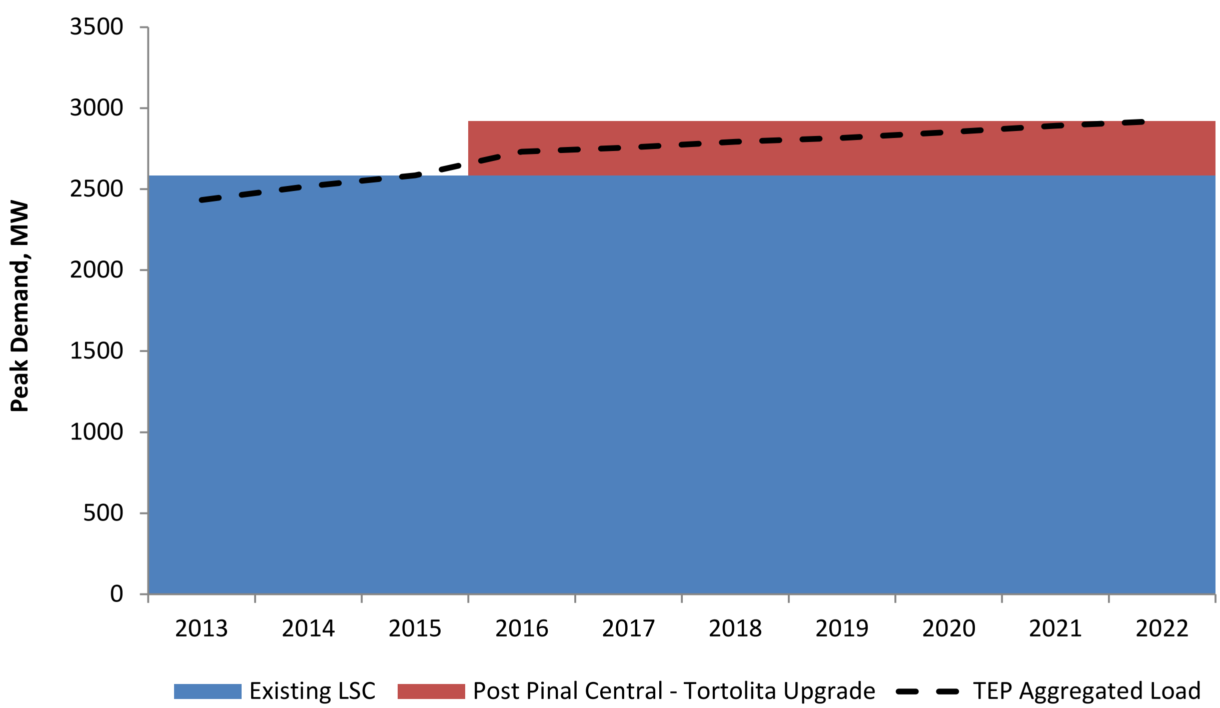


TEP's Load Serving Capability

As part of the resource planning process, TEP's transmission planning group developed a number of transmission alternatives that optimized future supply-side requirements along with maximizing future load serving capabilities. TEP load serving requirement is defined around TEP's ability to adequately serve its retail load obligations within the Tucson metropolitan area. TEP's wholesale load obligations outside of the Tucson area are not factored into this equation. TEP's load serving capability is defined as the sum of local area generation capacity plus TEP's transmission import capacity as measured at the EHV interconnections at the Tortolita, South Loop and Vail substations at system peak. Adequate capacity to meet TEP's load serving capability is one of four mandatory planning requirements that is required in all potential resource portfolios. This next section discusses TEP load serving capabilities in more detail.

Chart 27 below shows TEP's current load serving capability at approximately 2585 MW. This is based on TEP's existing transmission import capabilities and local area generation capacity. The Reference Case plan assumes that the Pinal Central – Tortolita 500 kV transmission project is developed and put into service before the summer of 2016. This transmission upgrade increases TEP's load serving capability to approximately 2,921 MW. The inclusion of the Pinal Central – Tortolita transmission project in the resource plan assures that TEP maintains adequate load serving capacity until the Tucson area load approaches 2,921 MW.

Chart 27 - TEP's Load Serving Capability Forecast



Other Transmission Projects included in the Resource Plans

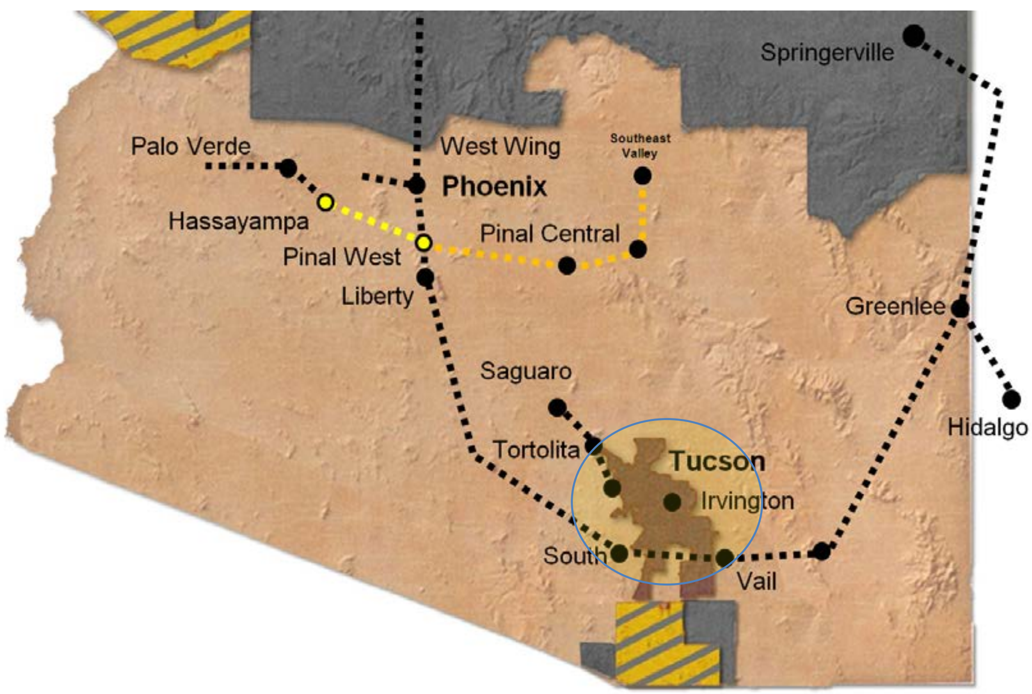
The remaining list of transmission projects modeled in the 2014 IRP were chosen based on TEP's previous work done through the biannual transmission assessments. These transmission projects are covered in detail within this chapter.

Hassayampa – Pinal West 500 kV Project

Based on the work of previous BTA studies, TEP made a commitment to participate in the SRP sponsored Southeast Valley (SEV) project. The Hassayampa to Pinal West project is part of a 500 kV joint proposal to extend transmission from the Palo Verde hub into the southeast valley area of Phoenix. The joint participants include three Arizona Electric Districts, SRP and Southwest Transmission Cooperative (SWTC) along with TEP.

The first segment of this project, shown in yellow on Map 7 below was placed into service in 2008. In terms of TEP's system interconnection, the Pinal West switchyard consists of a 500 kV yard and a 345 kV yard with one 500/345 kV transformer. TEP's Westwing-South 345 kV line is looped into the Pinal West 345 kV yard. The Pinal West switchyard is located approximately 60 miles from the Westwing Substation and 120 miles from South Substation. When fully completed, this project will increase TEP's transfer capability into Tucson from the Palo Verde Market region. The second segment of the SEV project which is shown in orange on Map 7 below terminates at the Browning substation which is owned by SRP.

Map 7 - Hassayampa - Pinal West Upgrade



Future Transmission Resources

TEP has developed a number of conceptual EHV projects in the TEP transmission plan and resource plan. Along with the conceptual projects, Transmission Planning has also identified upgrades and generation changes that will increase the load serving capability into the Tucson metro area. The EHV project from Pinal Central to Tortolita (PC-TO) that is currently planned to be in service prior to the summer of 2016 will increase TEP's ability to reliably serve its load. The PC-TO 500 kV line is the second phase of TEP's commitment to the SRP SEV project. In addition to increasing TEP load serving capabilities, this project will provide TEP with additional access to generation resources located north of Tucson, specifically the Palo Verde market.

Conceptual EHV Transmission Projects:

- Irvington-Vail-South 345 kV Line
- Irvington-South 345 kV Line
- Vail-South #2 345 kV Line
- Springerville – Greenlee #2 345 kV Line
- Tortolita – South 345kV Line
- Westwing – South #2 345 kV Line or Pinal West-South #2 345kV or 500 kV Line

Planned EHV Transmission Projects:

- Pinal Central-Tortolita 500 kV
- Hassayampa – Pinal West 500 kV Line Loop-In

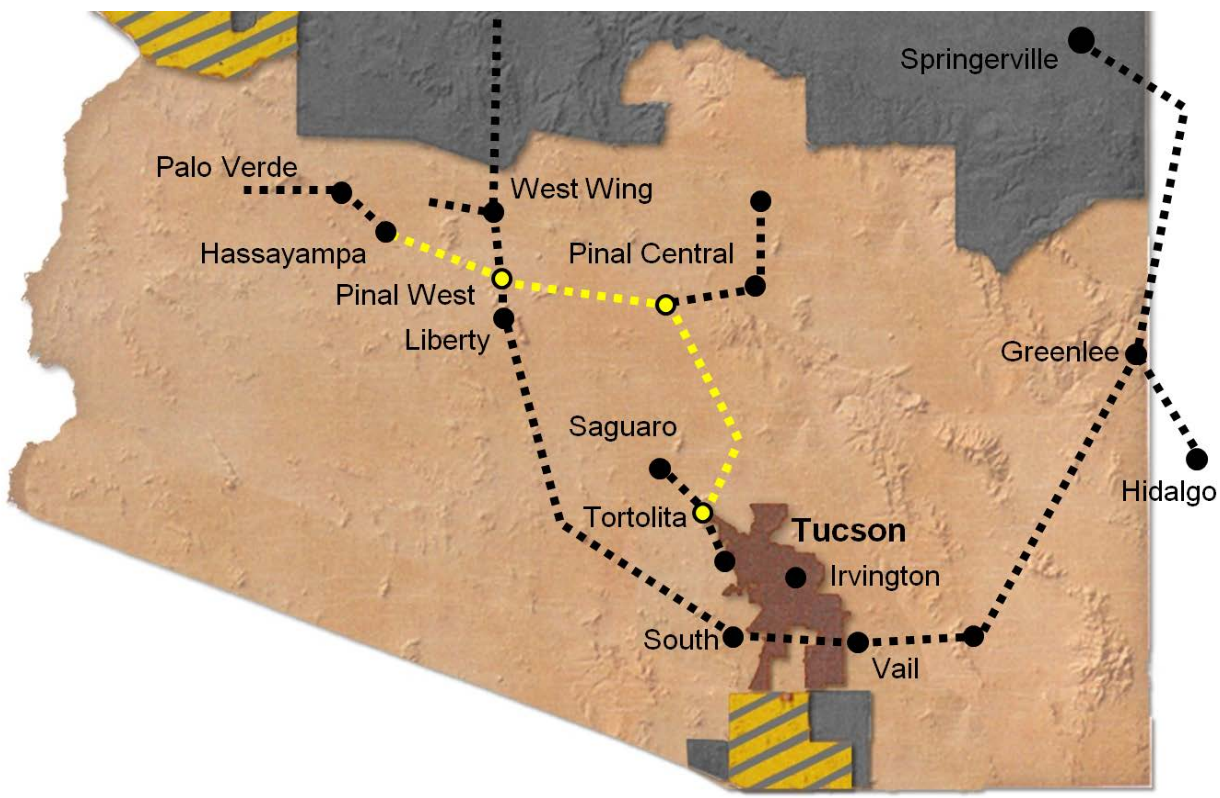
Pinal Central – Tortolita 500 kV Project

The Pinal Central - Tortolita 500 kV line is the second phase of the SEV Project referenced above. TEP plans to construct a line from the Pinal Central switchyard to a new Tortolita 500 kV yard adjacent to TEP's existing Tortolita 138 kV yard. The new Tortolita 500 kV yard will include bay positions for the two existing lines from Saguaro and the three existing 500/138 kV transformers. The third transformer was placed into service in the second quarter of 2011. It also includes a bay position for the Pinal Central - Tortolita 500 kV line. The switchyard will also be expandable for future line or transformer additions.

The Pinal West – Pinal Central line is approximately 45 miles long. TEP's intention was to participate in this project at a level so that TEP would not have to purchase transmission rights to schedule from Pinal Central to Tortolita and at the same level in the Pinal Central switchyard to the extent possible. At this time TEP was unable to acquire the sufficient rights due to inadequate capacity to meet the needs of all SEV project owners. Current participation is expected to provide 279/306 MW of rights in the Pinal West – Pinal Central project. The Pinal Central – Tortolita 500 kV line is approximately 40 miles long. TEP would be the major participant in this line and take the lead in developing this part of the project. The estimated cost for the Pinal West – Pinal Central – Tortolita 500 kV project is $111 million.

This project will increase TEP's scheduling capability by approximately 279/306 MW while reducing TEP's dependence on local area generation within TEP's local area. Based on the current Salt River Project construction schedule, it is currently estimated that the SEV project will be in service in mid-2014, while the Pinal Central – Tortolita project will go into service in 2016.

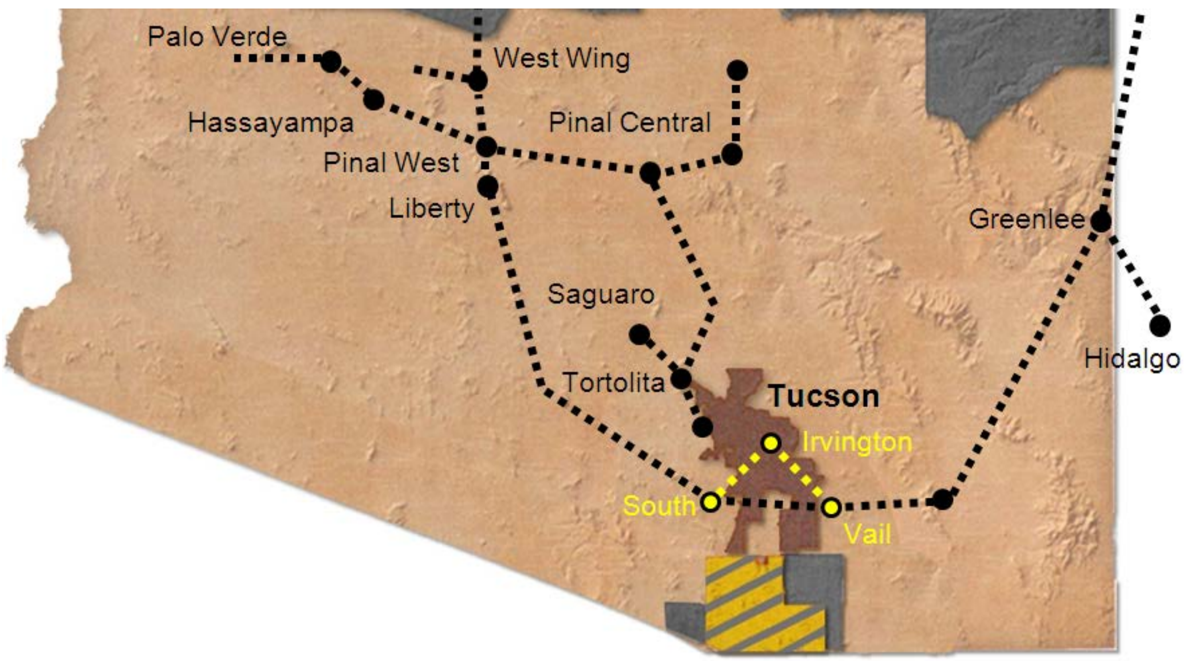
Map 8 - Pinal Central - Tortolita 500kV Project



Conceptual Future Local Area 345 kV EHV Transmission Projects

The Irvington-Vail, Irvington-South Loop 345 kV projects are two conceptual projects that were analyzed as possible long term transmission scenarios to improve local area transmission capacity. These are two phase projects that are part of a larger EHV reach-in strategy to serve the growing load in Tucson without requiring EHV lines across the central metro area. In addition, these projects are coordinated with the potential build out of local generation resources at Sundt Generating Station. In Phase 1, a new 10 mile 345kV line would be constructed between the Irvington and Vail Substations. Phase 2 of this project would complete a new 26 mile 345 kV line interconnecting the Irvington and South Loop Substations. Phase 1 would be expected to precede Phase 2 by several years. New Phase 1 facilities would include a 345 kV termination at Vail and a 345/138 kV substation at Irvington.

Map 9 – Local Area Conceptual 345 kV EHV Projects

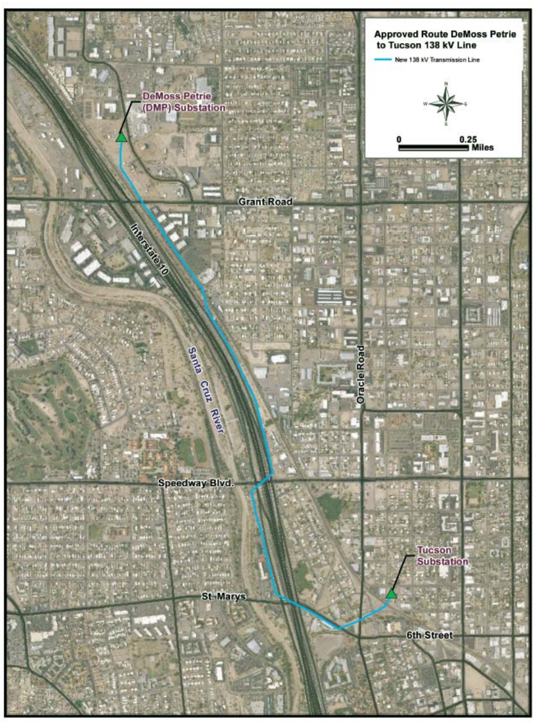


DeMoss Petrie Transmission Project

Tucson Electric Power (TEP) is planning to build a new 138 kilovolt (kV) transmission line and relocate an existing 46kV transmission line to link the DeMoss Petrie (DMP) Substation near Interstate 10 and West Grant Road to the Tucson Substation near West 5th Street and North 11th Avenue. The new line will add transmission capability between these substations, increasing electrical system reliability throughout Tucson. The purpose of the project is to construct the facilities necessary to provide additional transmission capability between the DMP and Tucson substations. In particular, the new line will provide additional capacity for TEP substations on Tucson's west side in order to meet future expected electrical load growth in the city and to help reduce the frequency and duration of electrical service outages.

TEP received approval to build the transmission line from the Arizona Corporation Commission (ACC) in March 2011. As part of the approval process, TEP conducted extensive natural, cultural and visual resource studies. Additionally, TEP mailed out numerous newsletters to thousands of landowners and residents in the project area, held public open houses and attended meetings with a Community Working Group that included neighborhood residents, jurisdictional representatives, and other stakeholders. Based on considerable public involvement, the ACC approved construction of the project along a route supported not only by TEP, but also by area residents who participated in the planning process. The new transmission line is approximately 2.4 miles in length and follows a route that starts at the DMP Substation, located near the northeast corner of Interstate 10 and West Grant Road, and terminates at the Tucson Substation, located at the intersection of West 5th Street and North 11th Avenue. Generally, the line traverses private property on its northern segment, Arizona Department of Transportation (ADOT) right-of-way on its middle segment and City of Tucson right-of-way on its southern segment. The project is to be constructed and operational before summer 2014.

Map 10 – DeMoss Petrie Transmission Route



Transmission Resources Needed for New Generating Resources

Additional transmission resources will be needed for specific generation interconnections. For purposes of this resource plan, the resource planning group developed a set of transmission cost assumptions based on the list of potential generation resources. These generation resource options include the additional costs associated with any transmission improvements that would be required to connect the resources to the transmission system.

For example, some of the larger base load resource options are expected to be constructed far from the TEP service territory and would require significant transmission infrastructure improvements with the construction of the generation facility. Smaller generation facilities such as gas turbines would likely be constructed within the Tucson metro area and would require a much smaller interconnection investment. Finally, in addition to construction capital, the resource plan also includes the cost with the on-going O&M that is required to maintain these transmission facilities. These costs are also included and are factored into the total cost of each resource alternative.

Table 20 summarizes the costs components for the substation interconnection, transmission construction and future operations and maintenance associated with each generating resource.

Generation Interconnection Cost Assumptions

Table 20 - Generation Interconnection Costs and Assumptions

Transmission Assumptions Annual O&M Costs	Units	Aero-Derivative CT LMS 100	Aero-Derivative CT LM6000	Frame 7FA Combustion Turbine (CT)	Combined Cycle (CC)	Compressed Air Energy Storage (CAES)	Pulverized Coal	Integrated Coal Gasification Combined Cycle (IGCC)	Integrated Coal Gasification Combined Cycle (IGCC) with CCS	Nuclear
Voltage Level	kV	138	138	138	138-345	138	345	345	345	500
EHV Transmission O&M Costs/kW	2014 $/kW	$1.04	$1.04	$1.04	$2.59	$1.04	$3.62	$3.62	$3.62	$5.18
Annual EHV Transmission O&M Costs	**$000**	**$93**	**$47**	**$166**	**$1,475**	**$1,035**	**$1,450**	**$2,174**	**$1,377**	**$5,177**

Transmission Assumptions Project Capital	Units	Aero-Derivative CT LMS 100	Aero-Derivative CT LM6000	Frame 7FA Combustion Turbine (CT)	Combined Cycle (CC)	Compressed Air Energy Storage (CAES)	Pulverized Coal	Integrated Coal Gasification Combined Cycle (IGCC)	Integrated Coal Gasification Combined Cycle (IGCC) with CCS	Nuclear
Transmission Line Cost	$000/Mile	$1,242	$1,242	$1,242	$1,760	$1,242	$1,760	$1,760	$1,760	$2,692
Transmission Distance	Miles	1	1	1	50	25	100	400	400	150
Transmission Line Cost	$000	$1,242	$1,242	$1,242	$88,009	$31,062	$176,018	$704,072	$704,072	$403,806
Substation Interconnection	$000	$3,624	$3,624	$3,624	$5,902	$3,624	$5,902	$5,902	$5,902	$10,872
Total Interconnection-Transmission Cost	**$000**	**$4,866**	**$4,866**	**$4,866**	**$93,911**	**$34,686**	**$181,920**	**$709,974**	**$709,974**	**$414,678**

Other Regional Transmission Projects

Other large projects proposed for interconnection in eastern and southeastern Arizona may influence TEP's long-term resource planning decisions.

Sunzia Southwest Transmission Project

The SunZia Southwest Transmission Project (SunZia). SunZia is a double-circuit 500 kV line that will originate in central New Mexico at a proposed SunZia E station near Ancho, New Mexico and terminate at the proposed Pinal Central substation near Casa Grande, Arizona. It is being planned to provide New Mexico and Arizona additional access to renewable energy resources. TEP is currently an active participant in this project. If this project moves ahead within the next three years, TEP will likely seek to revise the proposed RTPs or possibly expand on them. SunZia could increase import capacity from New Mexico by as much as 3,000 MW.

The SunZia Southwest Transmission Project is planned to be approximately 515 miles of two single-circuit 500 kV transmission lines and associated substations that interconnect SunZia with numerous 345 kV lines in both states. SunZia will connect and deliver electricity generated in Arizona and New Mexico to population centers in the Desert Southwest.

SunZia will increase power reliability and enhance domestic energy security in the Desert Southwest through strategic interconnections with the underlying extra high voltage grid in Arizona and New Mexico. The electricity distributed by SunZia will help meet the nation's demand for renewable energy and reduce dependence on fossil fuels for power production.

Land Use

The 'Preferred Alternative' identified by the Bureau of Land Management (BLM) in the Final Environmental Impact Statement (EIS) is approximately 515 miles and is comprised of 185 miles of federal lands, 220 miles of state lands and 110 miles of private or other lands in Arizona and New Mexico. The BLM's final determination on SunZia's alignment has not been made. View detailed maps.

Substations

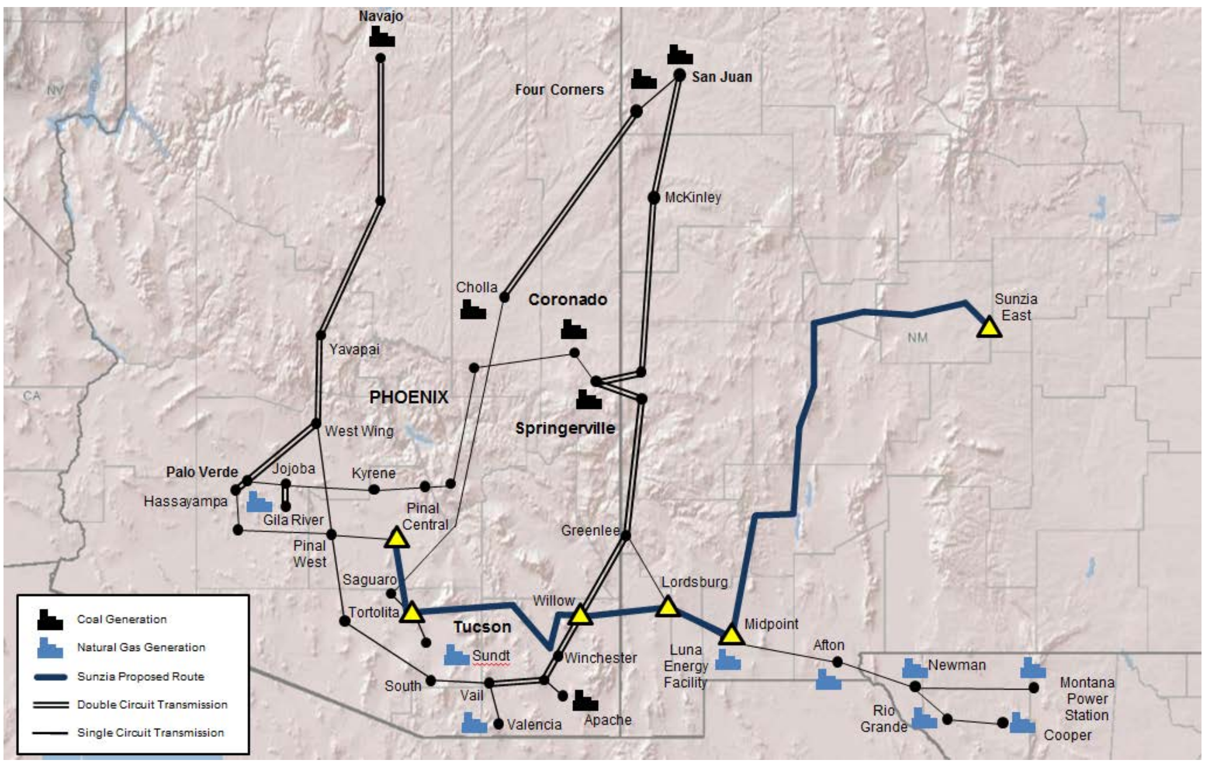
- SunZia currently proposes to interconnect with up to five substations:
- Pinal Central (near Coolidge in Pinal County, AZ)
- Willow 500 kV (East of US 191 in Graham County, AZ)
- Lordsburg (located in Hidalgo County, NM)
- SunZia South, also referred to as Midpoint (near Deming in Luna County, NM)
- SunZia East (near Corona in Lincoln County, NM)
- Other substations may be constructed along SunZia's route.

Configuration Options

1. Two single-circuit 500 kV AC lines that have an approved rating of 3,000 MW from the Western Electricity Coordinating Council.

2. One single-circuit 500 kV AC line and one single circuit 500 kV DC line with an estimated power transfer capacity of up to 4,500 megawatts.

Map 9 - Sunzia Proposed Project Route



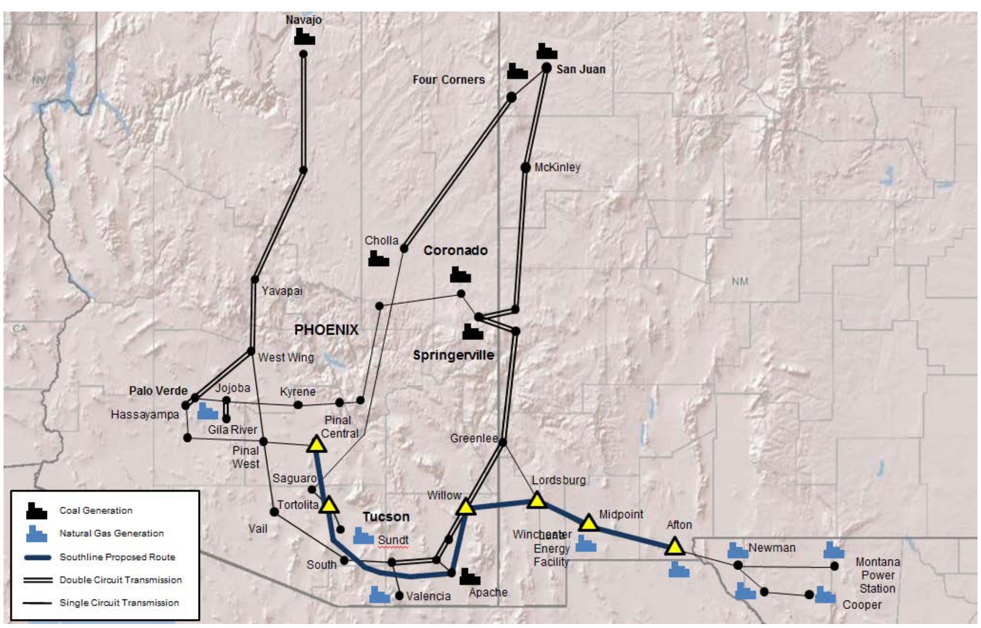
The Southline Transmission Project

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. 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. 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 New Build Section would involve the construction of approximately 240 miles of new 345kV double-circuit electric transmission lines in New Mexico and Arizona. The New Build is defined by end points of the existing Afton Substation, south of Las Cruces, New Mexico, and the existing Apache Substation, south of Willcox, Arizona. This section includes an approximately 30-mile segment between Hwy 9 and I-10, which would enable potential access to the renewable resource areas of southern New Mexico, and a 5-mile loop between the existing Afton Substation and the existing Luna-Diablo 345-kV transmission.

The Upgrade Section would consist of double-circuit 230-kV lines connecting the Apache Substation to the existing Saguaro Substation northwest of Tucson, Arizona. The Upgrade Section would rebuild approximately 120 miles of existing single-circuit 115-kV transmission lines, currently owned by the Western Area Power Administration (WAPA), providing up to 1,000 MW of transmission capacity between these substations. A new line segment approximately 2 miles in length will be required to interconnect with the existing Tucson Electric Power Vail Substation, located just north of the existing Western line. The Project will interconnect with up to 14 existing substation locations and may include development of a new substation in Luna County, New Mexico. The Southline proposal, if it succeeds will support development of the Apache to Saguaro - Tortolita project by the 2017 timeframe.

Map 9 - Southline Proposed Project Route



CHAPTER 8

Environmental Regulations

Overview

The electric generating sector currently faces numerous regulations related to air quality, waste generation, protection of waterways, and climate change. Fossil fuel-fired power plants, particularly coal-fired power plants, are significant sources of SO_2, NO_x, particulate matter (PM), and CO_2, as well as mercury, and other hazardous air pollutants. These power plant emissions are limited through several statutory and regulatory programs. As these regulatory programs continue to evolve, they will have important implications for public health, for the mix of U.S. generating resources, and for economic growth by driving investment in new and cleaner technologies and contributing to the retirement of the more inefficient and higher polluting plants. The discussion below provides a snapshot of the major environmental regulatory programs facing the electric generating sector that may have an impact on TEP.

Four Corners Generating Station, Federal Implementation Plan for Regional Haze

In October 2010, the EPA issued its proposed BART determination for Four Corners. The proposed rule would require the installation of SCR on each of Units 1-5 at Four Corners by 2016 to reduce nitrogen oxides (NOx) emissions. In November 2010, Arizona Public Service Company (APS) and Southern California Edison Company (SCE) entered into an asset purchase agreement providing for the purchase by APS of SCE's 48% interest in each of Units 4 and 5 of Four Corners. Following this announcement, APS submitted a letter to the EPA proposing an alternative to the EPA's original BART proposal. Specifically, APS proposed to close Four Corners Units 1, 2, and 3 by the end of 2014 and to install SCR for NOx on Units 4 and 5 by the end of 2018. In February 2011, the EPA issued a Supplemental Notice, related to the BART rulemaking for Four Corners. In the Supplemental Notice, the EPA proposed to find that a different alternative emission control strategy, based upon APS's November 2010 letter, would achieve more progress than the EPA's October 2010 BART proposal. The Supplemental Notice proposed that Units 1, 2, and 3 would close by 2014, SCR for NOx control would be installed on Units 4 and 5 by July 31, 2018, and the NOx emission limitation for Units 4 and 5 would be 0.098 lbs/MMBtu, rather than the 0.11 lbs/MMBtu proposed by the EPA in October 2010.

In March 2012, the California Public Utility Commission (CPUC) issued an order to SCE approving the sale of their ownership share in Units 4 & 5 to APS. In April 2012, the Arizona Corporation Commission (ACC) voted in favor of allowing APS to move forward with the SCE purchase transaction. This authorization also included a regulatory order allowing for an accounting deferral of costs associated with the purchase of Units 4 & 5 and closure of Units 1-3.

Finally, on December 30, 2013, Arizona Public Service Company and Southern California Edison Company closed their announced transaction whereby APS purchased SCE's 48% interest in each of Units 4 and 5 of the Four Corners Power Plant. The final purchase price for the interest was approximately $182 million. Concurrently with the closing of the SCE transaction, APS, on behalf of the co-owners, notified EPA that they had chosen the alternative BART compliance strategy requiring the permanent closure of Units 1, 2, and 3 by January 1, 2014 and installation and operation of selective catalytic reduction controls on Units 4 and 5 by July 31, 2018. TEP's estimated share of the capital costs to install SCR technology on Units 4 and 5 is approximately $36 million ($327/kW). TEP's share of incremental annual operating costs for SCR is estimated at $2 million.

San Juan Generating Station, Federal Implementation Plan for Regional Haze

In August 2011, EPA published its Federal Implementation Plan (FIP) that included a regional haze BART determination for SJGS that requires installation of selective catalytic reduction (SCR) with sorbent injection on all four units within five years of the rule's effective date of September 21, 2011. The FIP required a stringent NOx emission limit of 0.05 lb/mmBtu based on a rolling 30-boiler operating day average. At that the time, TEP estimated that its share of the cost to install SCR technology to be between $180 million and $200 million. In addition, TEP expected its share of the annual operating costs for SCR technology to be approximately $6 million.

In September 2011, PNM filed a Petition for Review in the U.S. Court of Appeals for the Tenth Circuit challenging EPA's regional haze FIP decision and requesting a stay pending the litigation. In March 2012, The Tenth Circuit denied to stay the decision. In separate litigation with several environmental groups, the U.S. District Court for the District of Columbia entered into a consent decree, which, required EPA to review and take action on the proposed rulemaking on New Mexico's regional haze SIP on or before May 31, 2012 and a final rulemaking on or before November 15, 2012. As a result of this consent decree, On May 31, 2012, EPA issued its proposed action on the regional haze SIP. EPA proposed approval of all components of the SIP, except for the BART determination for SJGS. With respect to the BART determination, EPA determined that with the FIP in place, it had met its obligation under the consent decree, and stated that it would issue a separate proposal and would entertain the withdrawal of the SIP in favor of an alternative that may be developed through discussions with the State of New Mexico and PNM.

In September 2012, the New Mexico Environmental Department (NMED) proposed an alternative to the EPA suggesting the closure of two units at SJGS and the installation of SNCRs on the remaining two units by the end of 2017. NMED also suggested replacement of a portion of PNM's share of the capacity from the two closed units with gas-fired generation.

In February 2013, the State of New Mexico, the EPA, and PNM signed a non-binding agreement (Settlement Agreement) that outlines an alternative to the FIP. The terms of the Settlement Agreement include: the retirement of San Juan Units 2 and 3 by December 31, 2017; the replacement by PNM of those units with non-coal generation sources; and the installation of Selective Non-Catalytic Reduction technology (SNCR) on San Juan Units 1 and 4 by January 2016 or later depending on the timing of EPA approvals. The New Mexico Environmental Department (NMED) prepared a revision to the regional haze State Implementation Plan (SIP) incorporating the provisions of the Settlement Agreement, and in September 2013, the New Mexico Environmental Improvement Board approved the SIP revision. The SIP revision now awaits final EPA approval. The EPA is expected to issue a final BART determination in the second or third quarter of 2014.

In connection with the implementation of the SIP revision and the retirement of San Juan Units 2 and 3, some of the San Juan owner participants (Participants) have expressed a desire to exit their ownership in the plant. As a result, the Participants are attempting to negotiate a restructuring of the ownership in San Juan, as well as addressing the obligations of the exiting Participants for plant decommissioning, mine reclamation, environmental matters, and certain ongoing operating costs, among other items. The Participants have engaged a mediator to assist in facilitating the resolution of these matters among the owners. The owners of the affected units also may seek approvals of their utility commissions or governing boards.

Navajo Generating Station - Regional Haze

In February 2013, the Environmental Protection Agency (EPA) issued a proposed Best Available Retrofit Technology (BART) rule for NGS under the Regional Haze Rule of the Clean Air Act. EPA's proposal would require Selective Catalytic Reduction (SCR) emission control technology to be installed and operational on all three NGS units by 2018. The EPA also proposed an alternative that would give the NGS owners credit for early installation of low-NOx burners at NGS, and allow SCR to be installed on one unit per year between 2021 and 2023.

Given the potential economic impacts NGS would have on the Navajo and Hopi tribes, as well as Arizona Central Arizona Water (CAP) users, the EPA invited the submittal of "Better-than-BART" alternatives that resulted in greater emission reductions than EPA's original proposal. As a result, a Technical Work Group (TWG) was formed and consisted of representatives from the Central Arizona Water Conservation District, the Environmental Defense Fund, the Gila River Indian Community, the Navajo Nation, Salt River Project (on behalf of itself and the other NGS owners), the U.S. Department of the Interior, and Western Resource Advocates.

In July 2013, the TWG submitted an alternative plan to the EPA for final consideration. The TWG proposal included two emission reduction alternatives that would achieve "Better-than-BART" results and included commitments by the U.S. Department of Interior to reduce CO_2 emissions and study opportunities to transition the U.S. Bureau of Reclamation's share of NGS to other resources.

NGS BART Alternative 1

NGS Alternative 1 requires the NGS participants to cease coal generation on one 750 MW unit at the power plant would be shut down by January 1, 2020 and SCR would be installed on the remaining units by 2030 – if the Los Angeles Department of Water & Power (LADWP) and NV Energy exit NGS as expected by 2019, and if the Navajo Nation chooses not to exercise an option to purchase a portion of the plant's ownership shares. Together, LADWP and NV Energy own the equivalent of almost exactly one unit at NGS.

This alternative also requires the NGS participants to achieve the same amount of NOx emissions reductions as provided for under EPA's BART proposal, while meeting a 30-day rolling average NOx emission rate limit of 0.07 lb/MMBtu on two units at NGS after installing SCR or an equivalent technology no later than December 31, 2030.

NGS BART Alternative 2

If the conditions for Alternative 1 are not met, Alternative 2 requires a reduction of NOx emissions equivalent to the shutdown of one Unit from 2020 to 2030. This alternative also requires the submittal of annual Implementation Plans describing the measures to be implemented to achieve greater emission reductions than EPA's proposed rule through a combination of retirement in capacity or curtailment in utilization at the plant and new emission controls.

Under either Alternative 1 or 2, to ensure that the proposed alternative meets the "Better than BART" criteria, the NGS Participants agree to maintain emissions below the total 2009-2044 NOx emissions cap delineated under EPA's BART proposal. The 2009-2044 NOx cap is calculated based on an annual emission rate of 0.055 lb/MMBtu for SCR, which is the emission rate assumed by EPA in its proposed rule. Finally, under both scenarios, the current NGS owners are committed to cease operation of all conventional coal-fired generation at NGS no later than December 22, 2044. The Navajo Nation can continue operation after 2044 at its election.

The EPA is currently accepting public comment on the BART Determination and the alternatives. A final decision is expected sometime in 2014.

Mercury and Air Toxics Standards (MATS)

EPA finalized the Mercury and Air Toxics Standard (MATS) rule on December 21st, 2011, specifying requirements to control emissions of mercury, acid gases and toxic metals from power plants. These hazardous air pollutants (HAPs) are regulated under Section 112 of the Clean Air Act, which does not permit use of a cap and trade system to meet reduction requirements. Instead, the MATS Rule sets emission rate standards for affected sources that must be complied at the unit- or facility-level. These standards are determined by EPA based on a maximum achievable control technology (MACT) limitation for each pollutant. Emission rates at the top 12 percent performing existing units will be used to set the limitation. MATS sets compliance requirements for three pollutants as surrogates for larger classes of pollutants: mercury (Hg), filterable particulate matter (PM), and hydrogen chloride (HCl), for acid gases. The EPA claims that the final rule will eliminate 90% of mercury emissions from power plants, 88% of acid gas emissions, and reduce SO2 emissions 41% more than what they expected to achieve through CSAPR.

With the release of the final rule at the end of 2011, the final compliance date for the affected sources under MATS under the Clean Air Act will be April 16th, 2015 (three years from publication of the final rule, April 16th, 2012). However, as the permitting authorities under the rule, states have the option to grant up to one additional year for affected entities to complete control installations. Assuming such extensions are widely available, many plants may have until April 2016 to achieve a fourth year for compliance.

National Ambient Air Quality Standards

A core element of Clean Air Act is the establishment of National Ambient Air Quality Standards (NAAQS). NAAQS are levels of air pollution in the ambient air that is determined to be protective of the general public (including sensitive populations) with an adequate margin of safety. NAAQS has been established for six specific criteria pollutants (ozone, particulate matter, sulfur dioxides, nitrogen oxides, lead, and carbon monoxide). NAAQS have two components: primary standards to protect public health and secondary standards to protect public welfare and the environment. NAAQS are implemented through enforceable source specific emission limitations and other air quality regulations established by states via State Implementation Plans (SIPs). The SIPs detail each state's strategy to "attain" or "maintain" the NAAQS.

The CAA requires EPA to review and, if appropriate, revise each NAAQS every five years. These revisions often result in more stringent standards, which may lead to further restrictions of emissions from power plants and other sources.
In 2010, EPA revised the primary NAAQSs for NO_2 and SO_2. SIPs for these standards are due to EPA in 2013. EPA anticipates finalizing a revised NAAQS for ozone by July 2014. All areas in which TEP has operations are either in attainment with the current standards or do not have enough information to classify their attainment status.

Mandatory Reporting of Greenhouse Gases

Pursuant to existing EPA authority under Clean Air Act, as well as direction included in the Fiscal Year 2008 Consolidated Appropriations Act, all major stationary sources of greenhouse gas emissions, including power plants, must report their greenhouse gas emissions. The first annual reports for the largest emitting facilities, covering calendar year 2010, were to be submitted to EPA by March 31, 2011; however, EPA extended the deadline to September 30, 2011. The program is expected to cover approximately 85 percent of the nation's greenhouse gas emissions and apply to approximately 10,000 facilities. All of TEP's coal-fired facilities, and larger natural gas-fired facilities submitted reports.

Regulation of Greenhouse Gases under the Clean Air Act

In December 2009, EPA signed the GHG endangerment finding in response to the U.S. Supreme Court's 2007 decision in *Massachusetts v. EPA* that GHGs are a "pollutant" in the context of the Clean Air Act. In the endangerment finding, EPA made an official determination that climate change does threaten public health and welfare and those GHG emissions from new motor vehicles contribute to climate change. This decision set the stage for EPA to establish the first-ever federal vehicle emissions standards for GHGs.

In April 2010, EPA finalized emissions standards for new motor vehicles (in coordination with Department of Transportation fuel economy standards), which triggered air permitting requirements for stationary sources of GHG emissions under the Prevention of Significant Deterioration (PSD) and Title V permitting programs. PSD is a preconstruction permitting program under the Clean Air Act that requires companies to install Best Available Control Technology (BACT) when constructing a new facility or when undertaking a major upgrade at an existing facility that significantly increases emissions. There is little precedent for what would qualify as BACT for GHG emissions from power plants.

The new motor vehicle rules also triggered a CAA requirement for EPA to establish New Source Performance Standards (NSPS) for certain new and existing sources. In December 2010, the EPA entered into a consent agreement that required it propose GHG NSPSs.

Greenhouse Gases (GHG) New Source Performance Standards (NSPS)

On March 27, 2012, EPA proposed the GHG New Source Performance Standards for Electric Generating Units (EGU GHG NSPS). EPA's proposed NSPS for GHG requires all new fossil-fuel-fired power plants to meet an emissions rate standard of 1,000 lb. CO2/MWh, roughly similar to the emission rate of widely used natural gas combined cycle technologies, regardless of fuel type. Plants can either meet the proposed standards through fuel switching, or by incorporating carbon capture sequestration (CCS) technology. EPA's proposal does not apply to plants currently operating or newly permitted plants that begin construction within a year of the release of the proposed rule. The proposed rule's definition of fossil-fuel-fired EGUs includes fossil-fuel-fired boilers. It excludes integrated gasification combined cycle (IGCC) units, and stationary natural gas combined cycle turbine units that generate electricity for sale and are larger than 25 MW in capacity.

There are several aspects of the proposed NSPS rule that have caused controversy, especially among owners and operators of coal-fired plants. First, this is a single-standard rule regardless of fuel type. By establishing a common NSPS for EGUs under this rule, EPA is setting a stricter standard for coal compared to new natural gas combined cycle units. Second, as the rule will apply to units that begin construction after April 27, 2013, "transitional sources" have voiced concerns that the proposed one-year timeline is insufficient for the proposed rule to become effective, especially while the new source performance standards under MATS are being reconsidered by EPA. Transitional sources are those sources that are far enough along in development that EPA allowed them one year to begin construction in order to avoid being subject to the standard. Finally, the proposed 1,000 lb. CO2/MWh standard is fairly stringent and challenging for compliance. Such a standard requires a coal-based unit to use CCS technology, which is not yet mature and is quite expensive.

On June 25, 2013, President Obama announced in the President's Climate Action Plan that he is issuing a Presidential Memorandum directing the EPA to effectively reissue carbon pollution standards for new generating sources, and for the first time, to issue carbon standards for existing sources. The President's proposed schedule for this rulemaking process appears in Figure 14.

Figure 14 – Proposed Deadlines for New and Existing Source Rulemaking

EPA Rulemaking	Stage	Proposed Deadline
New Sources	Updated Proposal	September 20, 2013
	Final	Expected sometime in 2014
Existing Sources	Proposed Standards from EPA	June 1, 2014
	Final Standards from EPA	June 1, 2015
	State Implementation Plans submitted to EPA	June 30, 2016

On January 8, 2014, EPA published the Proposed New Source Performance Standards (NSPS) for Greenhouse Gas Emissions from New Sources in the Federal Register. This publication date kicks off the official 60-day comment period, during which time interested parties can submit comments to EPA regarding the proposed rule. EPA's issuance of New Source NSPS and the finalization of that rule will then enable them to proceed with the issuance of Existing Source NSPS, with the proposed rule due in June 2014.

The emissions rate requirements for affected sources under the New Source NSPS published in the Federal Register appears to be, for the most part, unchanged from the revised proposed GHG NSPS for New Sources that EPA published on September 20, 2013. Those revised standards, in turn, replaced the initial set of proposed standards that were issued in April 2012. Those standards called for a single standard for all new fossil-fired generation units, regardless of fuel source.

The reproposed standards published in the Federal Register are based on Section 111(b) of the Clean Air Act and include subcategorization between coal and gas-fired plants that reflect separate determinations of the Best System of Emissions Reductions (BSER) for each of those technology types. The Proposed rule published in the Federal Register elaborates on EPA's justification for developing separate standards for BSER based on carbon capture and storage (CCS) on coal-fired utility boilers and integrated gasification combined cycle (IGCC's), but not on natural-gas fired facilities. The factors EPA indicated that it used to determine BSER are: feasibility, cost, size of emissions reductions, and technology. After considering these four factors, EPA proposed that efficient generation technology implementing partial CCS is the BSER for new affected fossil fuel-fired boilers and IGCC units, and modern efficient NGCC technology is the BSER for new affected combustion turbines.

New coal-fired plants (utility boilers and IGCC's) must meet an emissions standard of 1,100 lb/MWh, based on partial installation of CCS. EPA deemed partial CCS to be technically feasible and cost-effective due to its planned installation on several plants under construction in the US and Canada. New gas-fired stationary combustion turbine (CT) plants with a design heat input greater than 850 MMBtu/hr (85 MW at a 10,000 heat rate) are not required to install CCS, but must meet an emissions rate of 1,000 lb/MWh based on the BSER standard of a new efficient combined cycle unit. Smaller CTs with a design input of less than 850 MMBtu/hr must meet a standard of 1,100 lb/MWh.

Electric generators, including Combined Heat and Power (CHP) units that sell more than 219,000 MWh of electric output to the grid are considered affected sources under this program. This is the functional equivalent of a 25 MW unit running at 100% capacity. However, units greater than 25MW that sell less than one third of their potential output to the grid on a three-year rolling average basis are exempt from the regulation. Moving the standard from an annual to a three-year rolling average is meant to avoid a compliance burden for CTs that must generate beyond their design criteria for a period of time due to system operational requirements.

EPA has stated that while it is proposing specific standards of performance for each subcategory, it is also taking comment on a range of potential emission limitations, including:

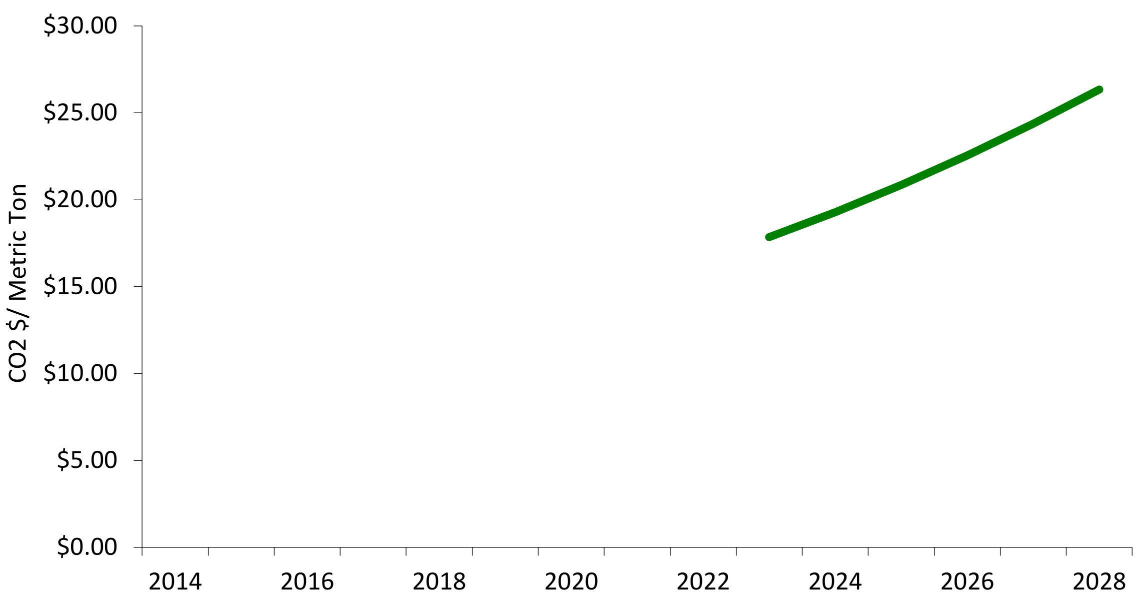
- a range of 950 – 1,100 lb CO2/MWh for new stationary combustion turbines with a heat input rating greater than 850 MMBtu/hr
- an emission limitation range of 1,000 – 1,200 lb CO2/MWh for new stationary combustion turbines with a heat input rating less than or equal to 850 MMBtu/hr
- an emission limitation for new fossil fuel-fired boilers and IGCC units in the range of 1,000 – 1,200 lb CO2/MWh

In summary, both new and existing coal-fired power plants face an array of regulations that, together with low natural gas prices, will fundamentally alter the role of coal-fired generation going forward. With 40 GW of coal-fired capacity retirements already announced, and more expected by the 2015 compliance deadline, existing coal-fired capacity are likely to be reduced nationally from approximately 315GW to 250GW. Beyond that, another 50 GW of coal-fired capacity is "on the margin" and will have some tough decisions regarding whether to retrofit to meet the new rules in light of low gas and power prices, or to retire. New coal plants face the double challenge of, while being generally compliant with MATS and other potential SO2 and NOX requirements, low natural gas prices and new source GHG NSPS requirements. If currently NSPS regulations remain in place, the only way new coal plants could be built is with CCS, which in and of itself, presents both technological and cost hurdles.

Carbon Price Assumptions Used in the 2014 IRP

For the 2014 IRP, we assume a federal carbon price, beginning in 2023 at $17.26/metric ton and escalating at 6% annually in real terms. While the current political environment is unlikely to yield substantive legislation in the near term, rising emission levels over the coming years are expected to provide the political backing for carbon policy to re-emerge around 2020. We assume a three-year window to implement such policy and have chosen a price path that reflects the middle ground of two previous proposals (Bingaman-Specter in 2007 and Kerry-Lieberman in 2010) that garnered some political backing. This assumes that a price containment mechanism would be imposed if and when such legislation is passed. Beyond the legislative approach, potential new regulatory rules could limit carbon emissions. A key difference between a legislative and a regulatory approach is how compliance is monetized-whether through a tax or allowance price, or via capital expenditures needed to meet potential efficiency or emission rate limits. An upcoming proposal to regulate emissions from existing sources is expected in June 2014 with a final rule coming one year later. While EPA has publicly indicated that it will take a flexible approach it remains difficult to project potential impacts until the proposal is issued.

Chart 28 - CO_2 Emission Prices, $/ Metric Ton



Coal Combustion Residuals

Coal combustion residuals (CCRs), primarily consisting of coal ash, are byproducts of the combustion of coal at power plants and are typically disposed of in solid form "dry" at landfills, or in liquid form "wet" at large surface impoundments , often adjacent to power plant properties. There are almost 900 landfills and surface impoundments nationwide. Essentially all CCRs generated at TEP's coal-fired generating stations that are not beneficially reused are landfilled in "dry" form.

Following the massive coal ash spill at the Tennessee Valley Authority's Kingston facility in December 2008, EPA took aggressive steps to assess impoundments and other units that manage CCRs. TVA's Kingston spill, the result of a failure of a wet ash surface impoundment flooded more than 300 acres of land, damaging homes and property. The released materials flowed into the Emory and Clinch rivers, filling large areas of the rivers.

On June 21, 2010, the EPA published co-proposals to regulate the management of coal ash from coal-fired power plants. EPA presented two possible options for the management of coal ash under regulations pursuant to the Resource Conservation and Recovery Act (RCRA). Under the first proposal, EPA would list these residuals as "special wastes" subject to hazardous waste provisions under Subtitle C of RCRA, when destined for disposal in landfills or surface impoundments. Under the second proposal, EPA would regulate coal ash as non-hazardous solid waste (similar to municipal solid waste) under Subtitle D of RCRA.

Both approaches would require groundwater monitoring and the installation of liners for surface impoundments and lateral expansions of landfills. The hazardous waste option would also require physical and operational changes relating to the handling, storage, and transportation of CCRs.

The proposed rules will apply to CCRs produced by all of TEP's coal-fired generating assets. San Juan may also be subject to separate regulations being drafted by the Office of Surface Mining Reclamation and Enforcement because it disposes of CCRs in surface mine pits.

TEP expects the EPA to issue a final rule in late 2014.

CHAPTER 9

Air Emissions and Control Technologies

Nitrogen Oxide Overview

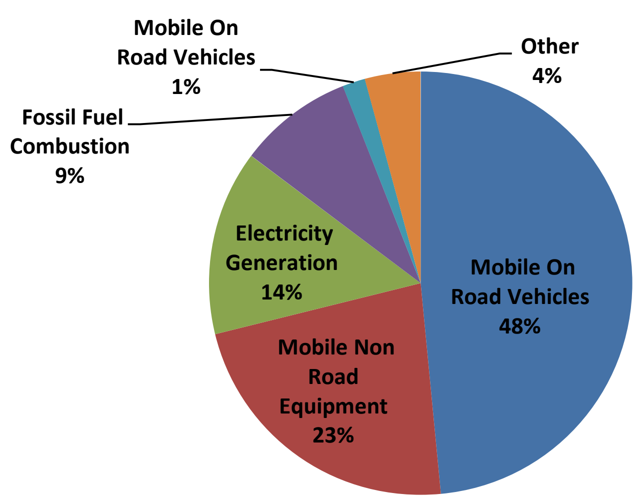
Nitrogen dioxide (NO_2) is a member of the nitrogen oxide (NO_x) family of gases. There are two primary sources of NO_x when burning fossil fuels: fuel and thermal NOx. Fuel NO_x results from the combustion of nitrogen in the coal, while thermal NO_x is formed when nitrogen in the air reacts with oxygen during combustion. NO_x causes brown haze and atmospheric particles, and is a precursor to the formation of ground-level ozone. The major sources of NOx emissions are automobiles, power plants, and any other industrial, commercial, or residential source that burns fuel.

Based on 2011 state use data obtained from the EPA National Emissions Inventory, electricity generation accounts for 14% of Arizona's NO_x air emissions. NO_x output is summarized by the following use categories:

Table 21 – 2011 Arizona NO_x Emission by Use Category

Category	Tons	Annual %
Mobile On Road Vehicles	121,579	48%
Mobile Non Road Equipment	56,834	23%
Electricity Generation	35,433	14%
Fossil Fuel Combustion	21,966	9%
Industrial Processes	4,355	2%
Other	10,645	4%

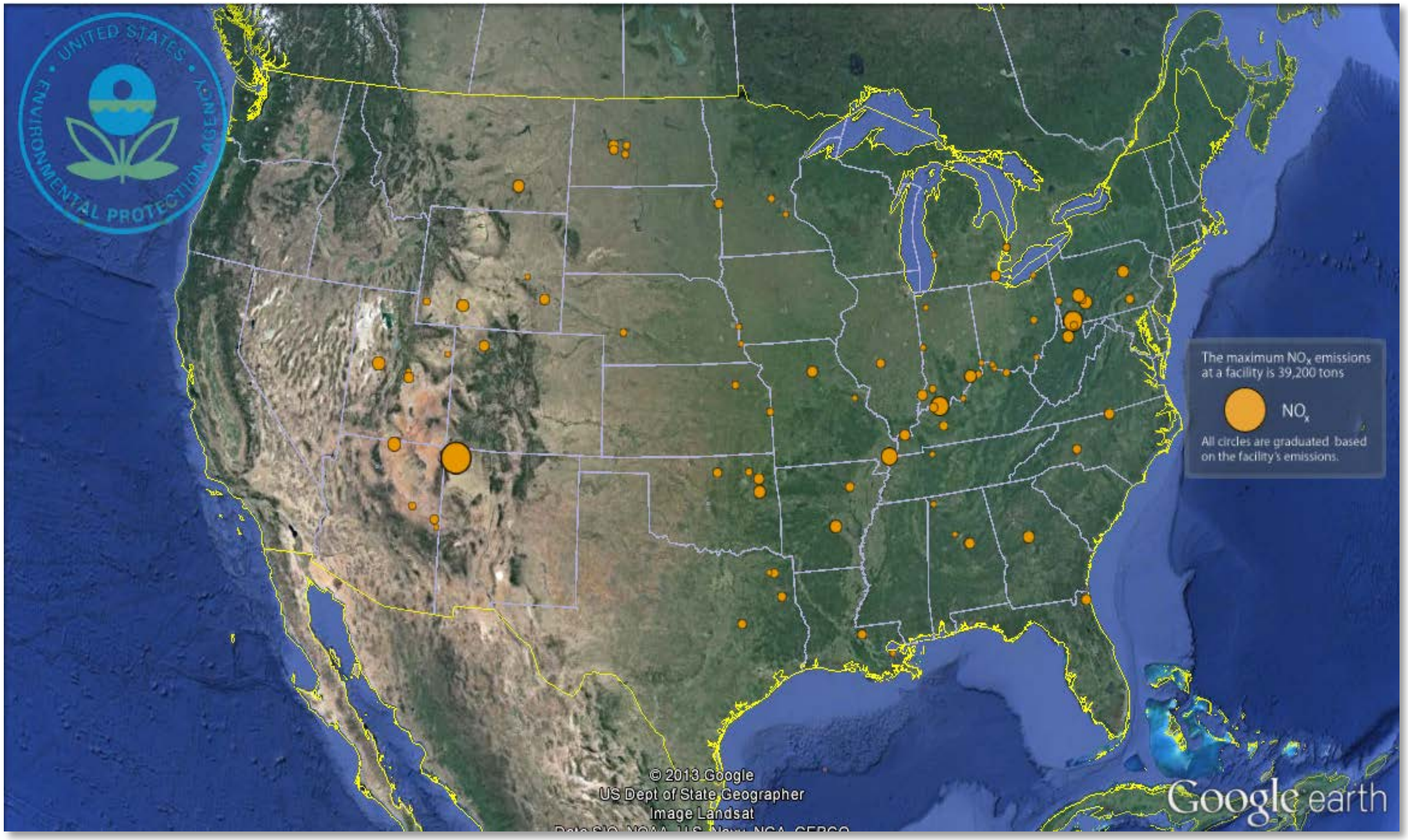
Chart 29 – Arizona NO_x Emission by Use Category



EPA 2012 NO_x Source Emission Data (United States)

Based on 2012 source emission data compiled by the Environmental Protection Agency, the map below shows the relative nation-wide NO_x emissions from each power plant.

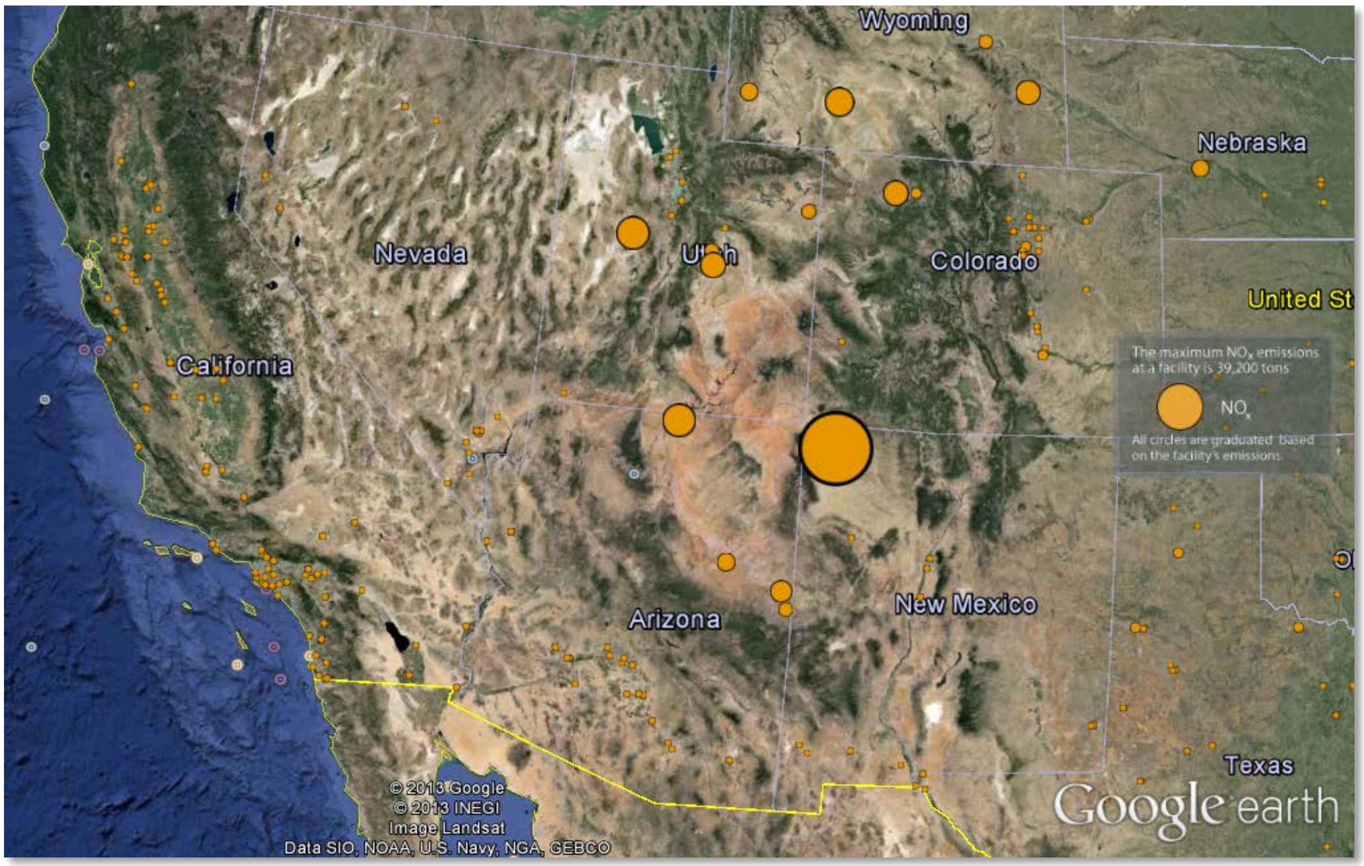
Map 11 – 2012 NO_x Emissions by Electric Generating Facility (National)



EPA 2012 NO_x Source Emission Data (Desert Southwest)

Based on 2012 source emission data compiled by the Environmental Protection Agency the below shows the relative Desert Southwest NO_x emissions from each power plant.

Map 12 – 2012 NO_x Emissions by Electric Generating Facility (Desert Southwest)



NOx Emissions Control Technologies

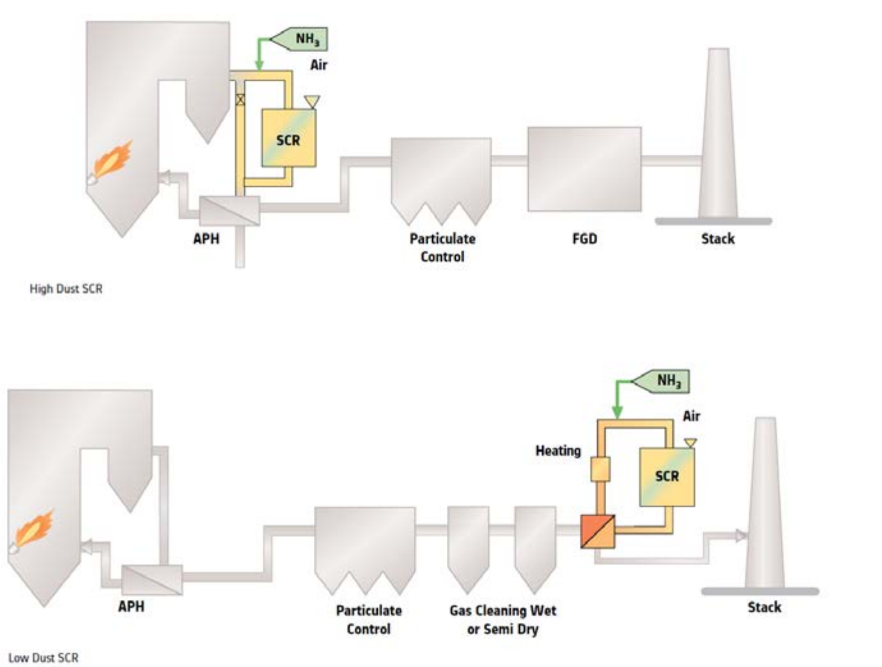
Selective Non-Catalytic Reduction (SNCR) and Selective Catalytic Reduction (SCR) are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The primary difference between the two technologies is that SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. The technologies can be used separately or in combination with other NOx combustion control technologies such as low NOx burners (LNB) and natural gas reburn (NGR).

Category	Selective Catalytic Reduction (SCR)	Selective Non-Catalytic Reduction (SNCR)
Capital Costs	$400-600/kW	$150-200/kW
Removal Efficiency	80-90%	30-50% (Stand-Alone) 65-75% (with LNB)

Selective Catalytic Reduction (SCR)

Selective catalytic reduction (SCR) technology is a proven and effective method to reduce nitrogen oxides (NO_x) emissions from coal fired power plants. During the combustion process, the nitrogen that is present naturally in the coal, and the nitrogen and oxygen present in the combustion air combine to form NO_x. Prior to being released to the atmosphere, the exhaust gas is passed through a large catalyst where the NO_x reacts with the catalyst and ammonia and is converted to nitrogen and water. Selective catalytic reduction removes between 80 and 90 percent of the NO_x that is in the exhaust gas of a coal-fired power plant. SCR systems can be configured differently depending on the application. (1) Hot side, high dust: upstream of the air preheater (APH) and particulate control (2) Cold side, low dust: downstream of the APH and particulate control.

Figure 15 - Selective Catalytic Reduction (SCR) Control Systems



Source: Alstom Environmental Control Systems

Selective Non-Catalytic Reduction (SNCR)

Selective Non-Catalytic Reduction (SNCR) is based on the chemical reduction of the NOX molecule into molecular nitrogen (N2) and water vapor (H2O). A nitrogen based reagent, such as ammonia or urea, is injected into the post combustion flue gas. NOX reduction levels range from 30% to 50%. For SNCR applied in conjunction with combustion controls, such as low NOX burners, reductions of 65% to 75% can be achieved.

Urea-based systems have advantages over ammonia based systems. Urea is non-toxic, less volatile liquid that can be stored and handled more safely. Urea solution droplets can penetrate farther into the flue gas when injected into the boiler, enhancing the mixing with the flue gas which is difficult in large boilers. However, urea is more expensive than ammonia.

The Normalized Stoichiometric Ratio (NSR) defines the ratio of reagent to NOX required to achieve the targeted NOX reduction. In practice, more than the theoretical amount of reagent needs to be injected into the boiler flue gas to obtain a specific level of NOX reduction.

The SNCR process occurs within the combustion unit which acts as the reaction chamber. Reagent is injected into the flue gas through nozzles mounted on the wall of the combustion unit. The injection nozzles are generally located in the post-combustion area, the upper area of the furnace and convective passes. The injection causes mixing of the reagent and flue gas. The heat of the boiler provides the energy for the reduction reaction. The NOx molecules are reduced and the reacted flue gas then passes out of the boiler.

Low NO_x Burners

Low NO_x burners are designed to control fuel and air mixing at each burner in order to create larger and more branched flames. Peak flame temperature is thereby reduced, and results in less NO_x formation. The improved flame structure also reduces the amount of oxygen available in the hottest part of the flame thus improving burner efficiency. Low NO_x burners can be combined with other primary measures such as overfire air, reburning or flue gas recirculation. Depending on plant configuration the combination of low NO_x burners with other primary measures typically achieves 25% to 45% NO_x removal efficiency.

Historical NO_x Emissions

Chart 30 below summarizes the historical NO_x emissions levels for TEP's coal plants. NO_x emissions from TEP's generation portfolio have declined from a high of 17.1 thousand tons in 2006 to 13.0 thousand tons in 2012. A large portion of this decline was driven by recent environmental upgrades (low NO_x burners) that have been installed at Navajo and San Juan generating stations, in addition, declines from reduced customer demand, and coal to natural gas fuel switching on Sundt unit 4 have also contributed to this trend. Chart 30below provides a percentage breakdown of NO_x emissions by plant for 2012 based on TEP's ownership share.

Chart 30 – Annual NO_x Emissions by Plant, Tons

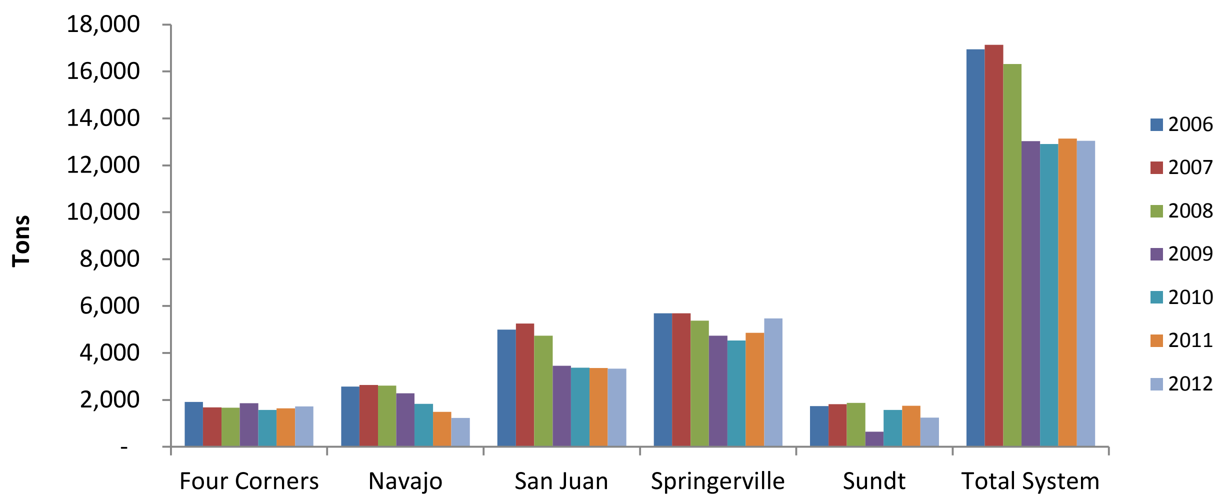
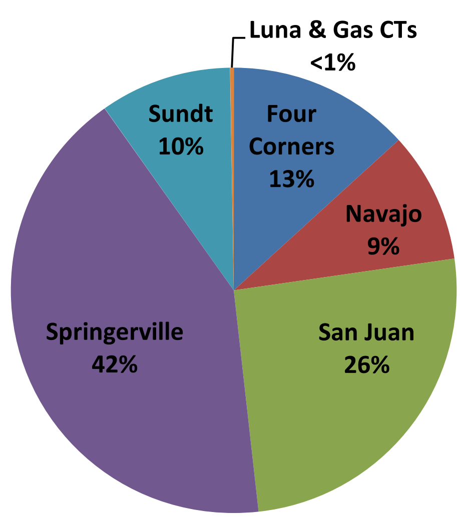


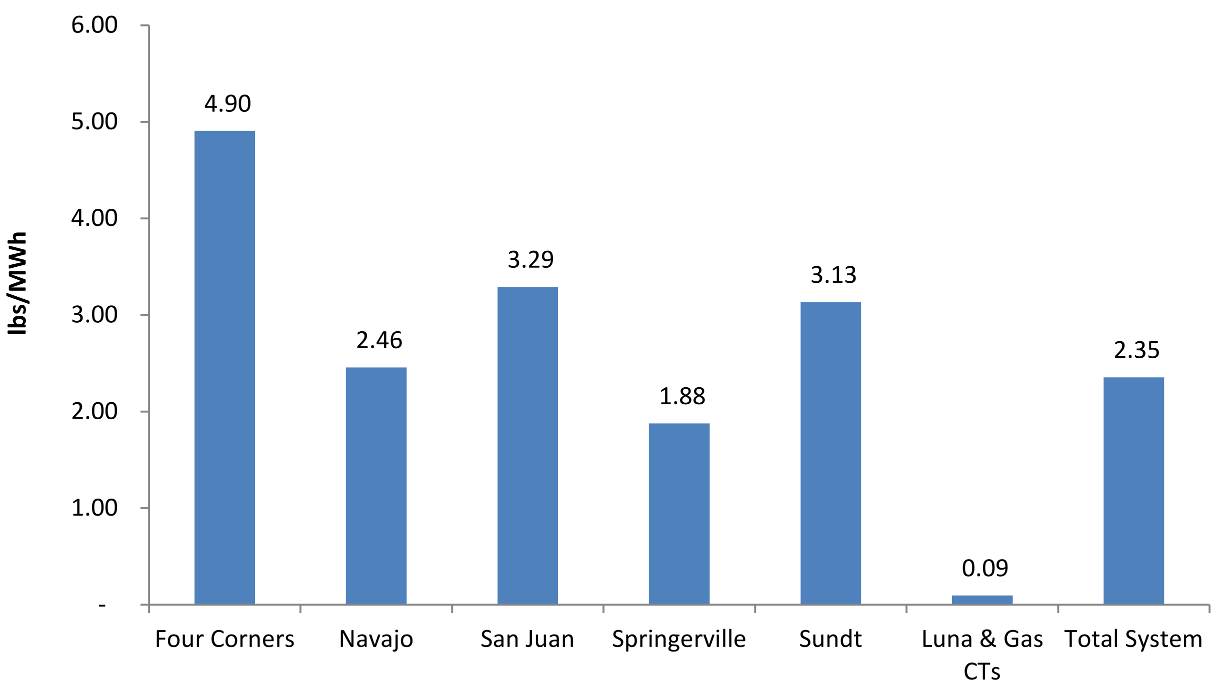
Chart 31 – TEP Resource Portfolio NO_x - Composition by Plant



NO_x Emission Rates

Chart 32 below summarizes the 2012 NO_x emission rates for TEP's generating facilities. On average, TEP's coal resources emitted approximately 2.5 pounds of NO_x per megawatt hour. In comparison, natural gas resources produce approximately one thirtieth the amount of NO_x versus coal fired resources on a pound per megawatt hour basis. For example, Luna Energy Facility, a natural gas combined cycle plant emits approximately 0.09 pounds of NO_x per megawatt hour. On a system level, TEP's NO_x emission profile averages approximately 2.35 pounds per megawatt hour.

Chart 32 – Average NO_x Output, lbs/MWh



Sulfur Dioxide Overview

Sulfur dioxide (SO_2), a colorless, reactive gas, is produced during the burning of sulfur-containing fuels such as coal and oil, during metal smelting, and by other industrial processes. Major sources include power plants, industrial boilers, petroleum refineries, smelters, iron and steel mills. Generally, the highest concentrations of sulfur dioxide are found near large fuel combustion sources.

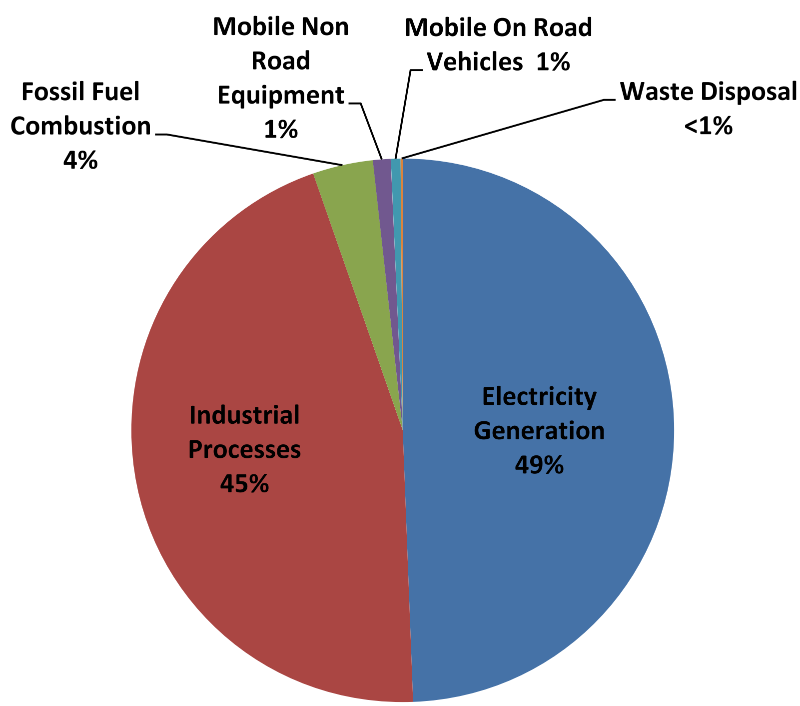
Arizona SO_2 Summary

Based on 2011 state use data obtained from the EPA National Emissions Inventory, electricity generation is the largest source of Arizona's SO_2 air emissions. SO_2 output is summarized by the following use categories:

Table 22 – 2011 Arizona SO_2 Emission by Use Category

Category	Tons	Annual %
Electricity Generation	37,997	49%
Industrial Processes	34,820	45%
Fossil Fuel Combustion	2,765	4%
Mobile Non Road Equipment	818	1%
Mobile On Road Vehicles	440	1%
Waste Disposal	98	<1%

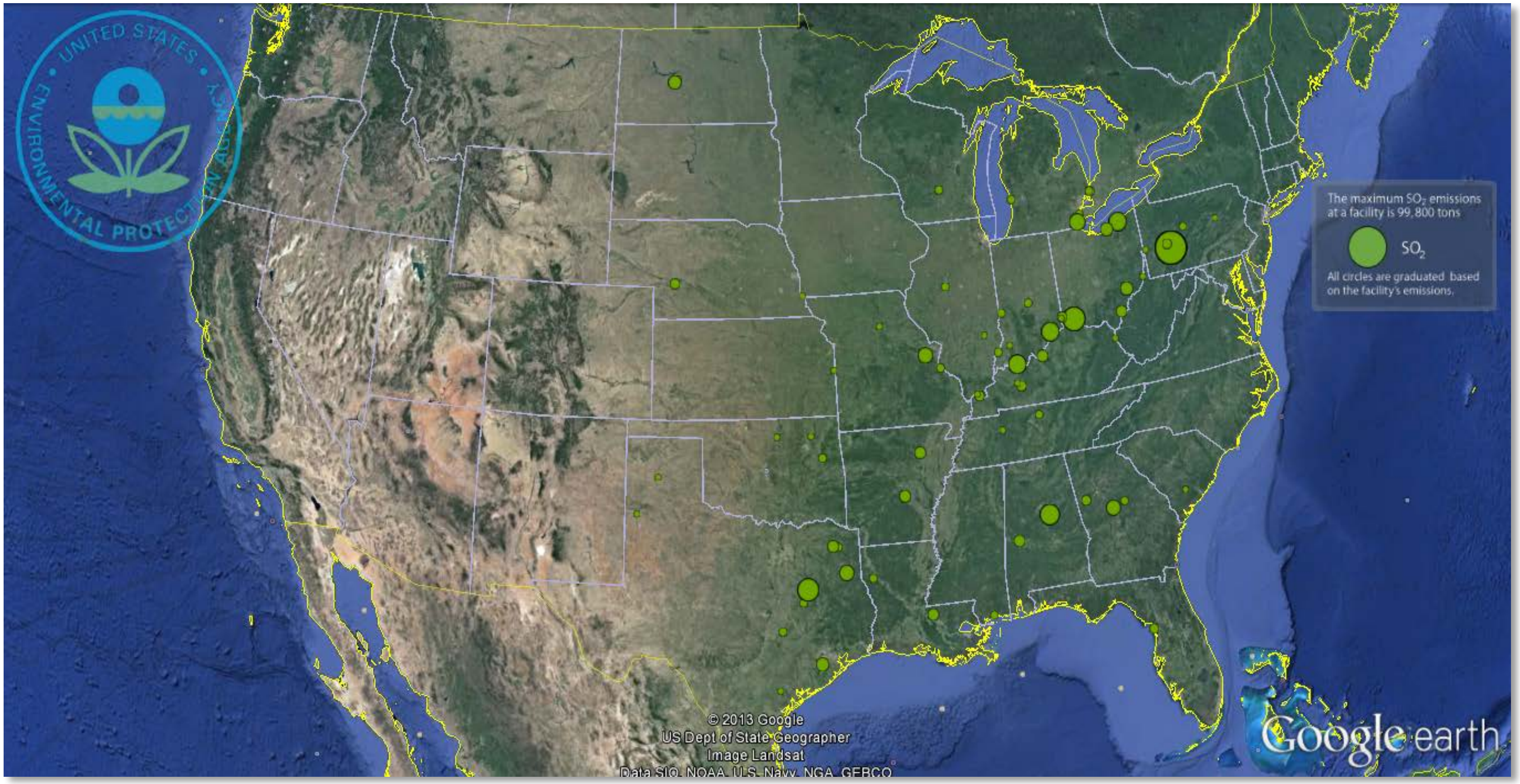
Chart 33 – Arizona 2011 SO_2 Emission by Use Category



EPA 2012 SO_2 Source Emission Data

Based on 2012 source emission data compiled by the Environmental Protection Agency, the map below shows the relative nation-wide SO_2 emissions from each power plant.

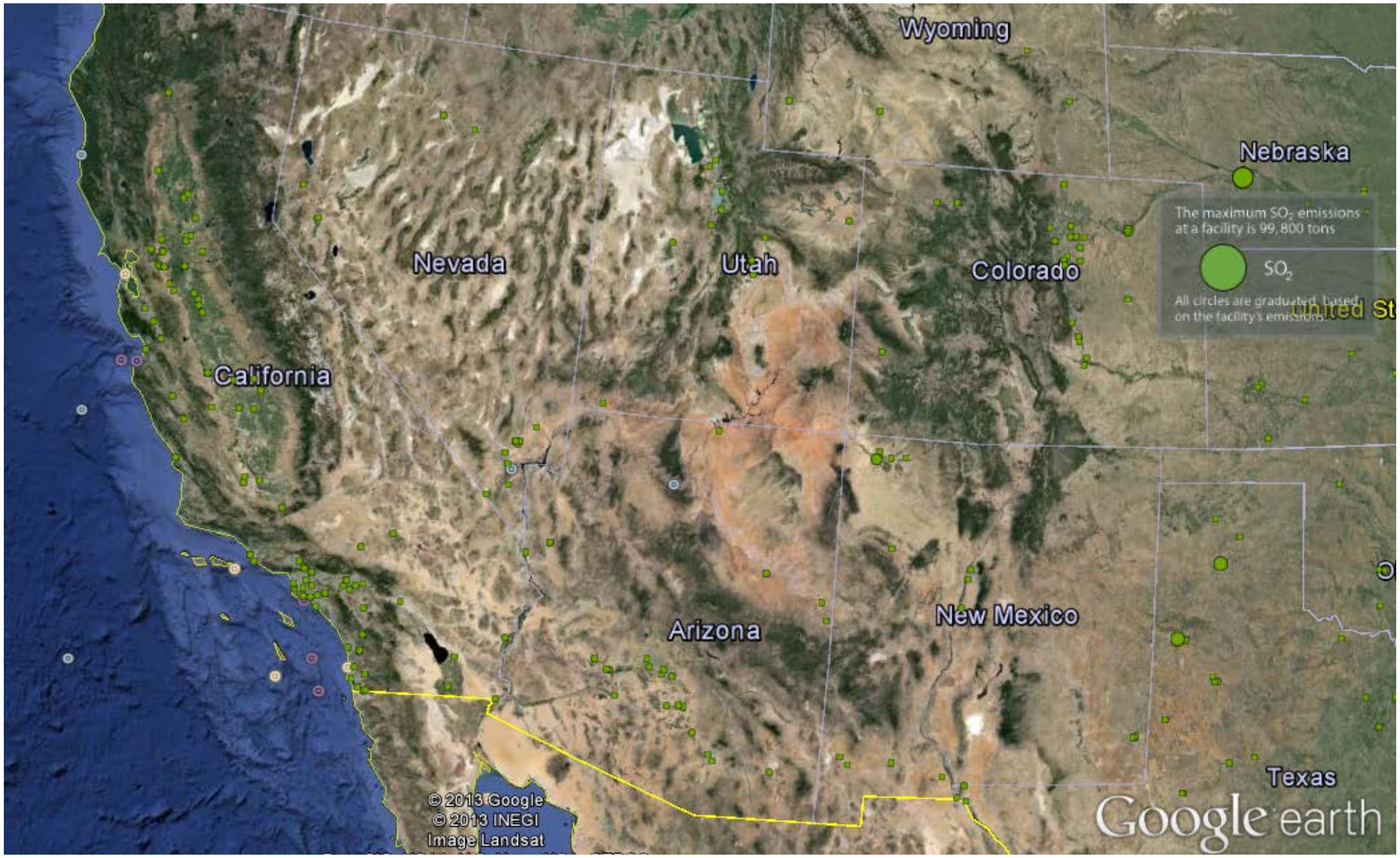
Map 13 – 2012 SO_2 Emissions by Electric Generating Facility (National)



EPA 2012 SO2 Source Emission Data

Based on 2012 source emission data compiled by the Environmental Protection Agency, Map 13 below shows the relative Desert Southwest SO_2 emissions from each power plant.

Map 14 – 2012 SO_2 Emissions by Electric Generating Facility (Desert Southwest)



SO_2 Emissions Control Technologies

Flue gas desulfurization (FGD) technology, commonly referred to as a "scrubber", is a proven and effective method for removing sulfur dioxide (SO_2) emissions from the exhaust of coal-fired power plants.

During the combustion process the sulfur that is present naturally in the coal combines with the oxygen in the combustion air to form SO_2. The SO_2 is captured by contacting the exhaust gas with a mixture of lime or limestone and water. This mixture reacts with the SO_2 to remove it before the exhaust gas is released to the atmosphere. On average, the scrubbers on TEP's fleet remove 90 percent or more of the SO_2 that is contained in the exhaust gas.

The SO_2 that is captured in a scrubber combines with the lime or limestone to form a number of byproducts. A primary byproduct is calcium sulfate, commonly known as synthetic gypsum. It is a recyclable product and has many beneficial uses. Synthetic gypsum is the primary ingredient in the manufacture of wallboard. It is also used as a soil amendment in agricultural and construction applications, and in the manufacturing of cement. Much of the synthetic gypsum that is produced from the plant scrubbers is reused in these and other applications.

Flue Gas Desulfurization Overview

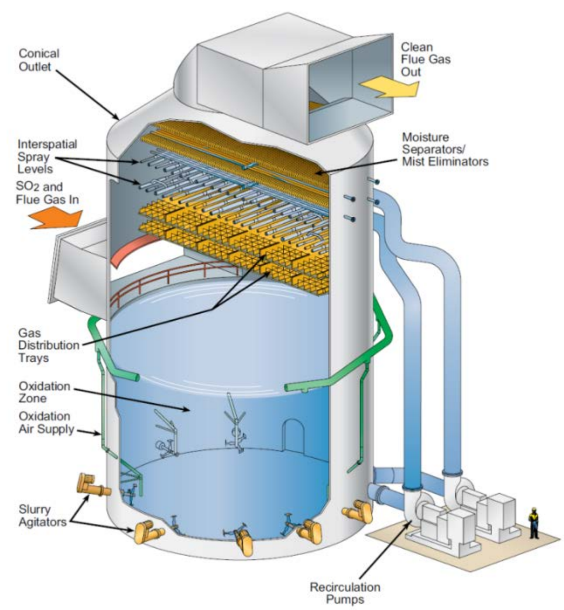
Commercially available FGD technologies can be classified as throwaway or regenerable, depending on how sorbent is treated after it has sorbed SO_2. In throwaway technologies, the SO_2 is permanently bound by the sorbent, which must be disposed of as a waste or utilized as a by-product. In regenerable technologies, the SO_2 is released from the sorbent during the regeneration step and may be further processed to yield sulfuric acid; elemental sulfur, or liquid SO_2. The regenerated sorbent is recycled in the SO_2 scrubbing step.

Both throwaway and regenerable technologies can be further classified as wet or dry. In wet processes, wet slurry waste or by-product is produced and flue gas leaving the absorber is saturated with moisture. In dry processes, waste material is produced and flue gas leaving the absorber is not saturated with moisture.

Wet Flue Gas Desulfurization Systems

In a wet scrubber, lime slurry is sprayed downward from a series of headers and nozzles and scrubs the flue gas as it moves upward through the absorption tray and spray zone. The control system automatically adjusts the feed of fresh reagent to achieve an outlet SO_2 emission limit or the required SO_2 removal efficiency.

The gas rises through the absorber, contacting a froth of slurry on the tray. This action results in efficient contact of gas and reagent throughout the absorber. Absorbers use trays to provide uniform gas distribution and effective gas/slurry contact.

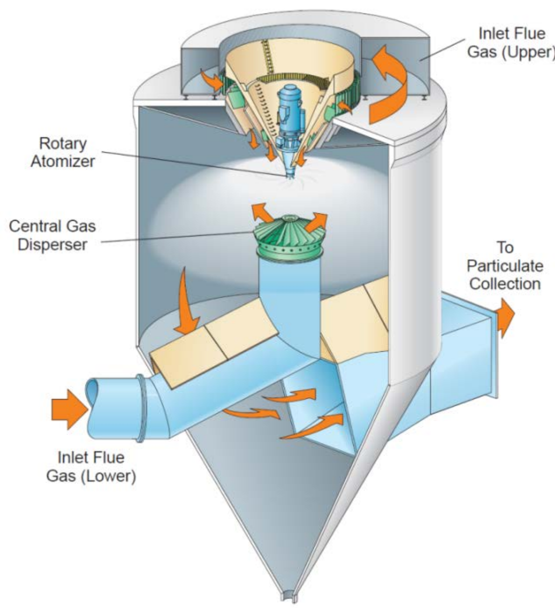


Wet Flue Gas Desulfurization Systems
Source: The Babcock & Wilcox Company

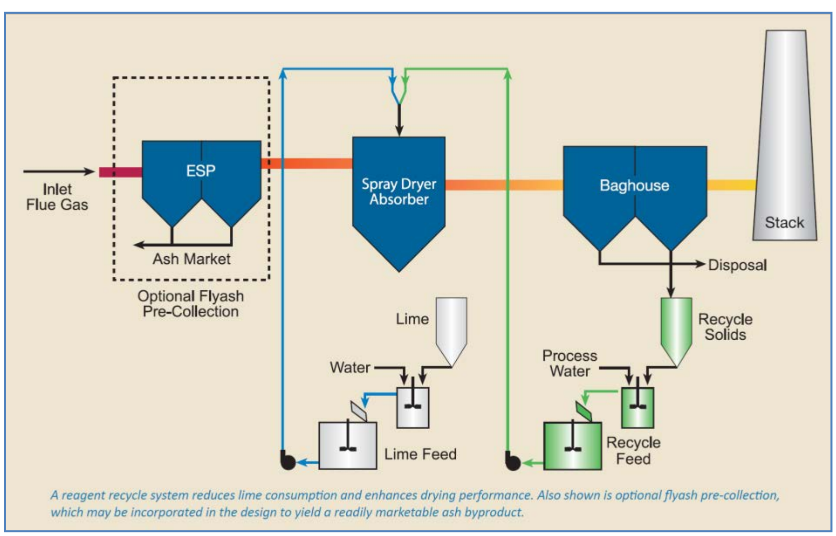
In addition, wet scrubber can provide control of several pollutants in addition to SO_2. Filterable (solid) particulate is removed in the wet scrubber. The wet scrubber removes 40-90% of the fly-ash entering the scrubber, depending upon the ash inlet loading and the type of upstream particulate collector. Mercury and acid gases (HCl and HF) are also removed in the wet scrubber process. Depending on the technology, 50% to 90% removal of oxidized mercury can be achieved along with up to 20% removal of elemental mercury. Significant removal of acid gas can also be achieved.

Spray Dry Flue Gas Desulfurization Systems

In a typical FGD with a spray dry absorber (SDA) system a rotary atomizer is used to atomize a mixture of lime and recycle slurry into a fine spray. The spray droplets are well distributed and mix with the hot, untreated flue gas. A series of chemical reactions result in the removal of SO_2, SO_3, HCl and HF from the gas, and the simultaneous evaporation of the water. A single, central atomizer promotes an even distribution of the fine spray throughout the chamber while minimizing the potential for wall wetting and deposition. The alkaline slurry is converted into a dry, free-flowing powder of calcium/sulfur compounds. Fly-ash from the boiler and the dry reaction products are then collected downstream of the spray chamber.



Spray Dryer Flue Gas Desulfurization (FGD) Systems
Source: The Babcock & Wilcox Company



Source: The Babcock & Wilcox Company

Historical SO_2 Emissions

Chart 34 below summarizes the historical SO_2 emissions levels for TEP's coal plants. On average the TEP portfolio of generation assets produced approximately 10 thousand tons of SO_2 for years 2006 through 2012. Chart 35 below provides a percentage breakdown of SO_2 emission by plant for 2012 based on TEP's ownership share.

Chart 34 – Annual SO_2 Emissions Output by Plant, Tons

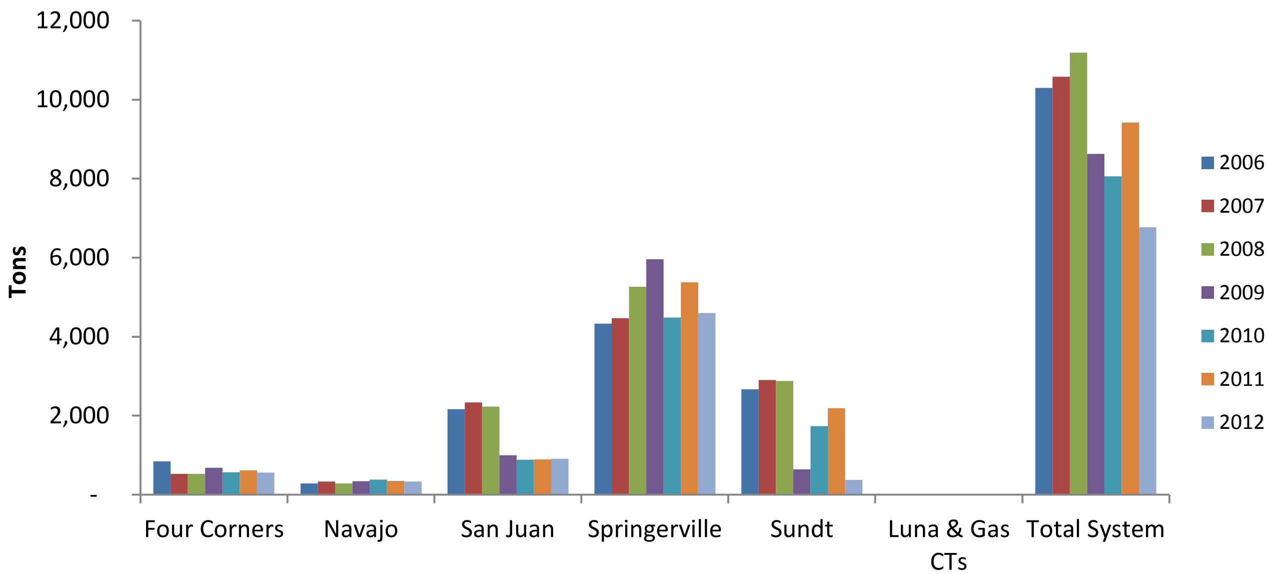
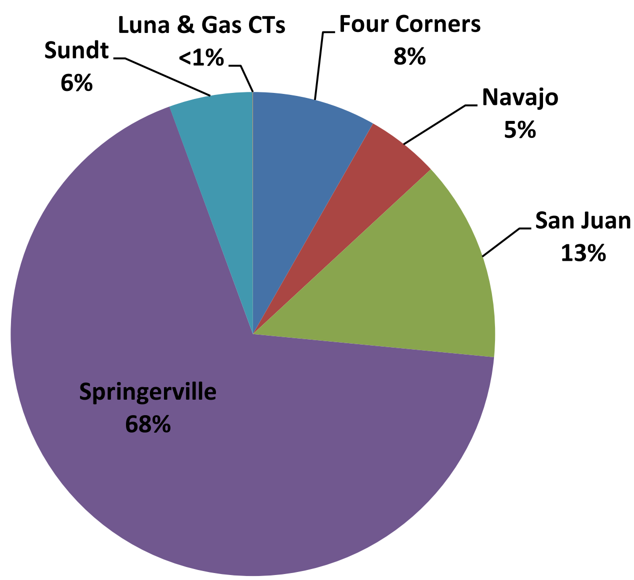


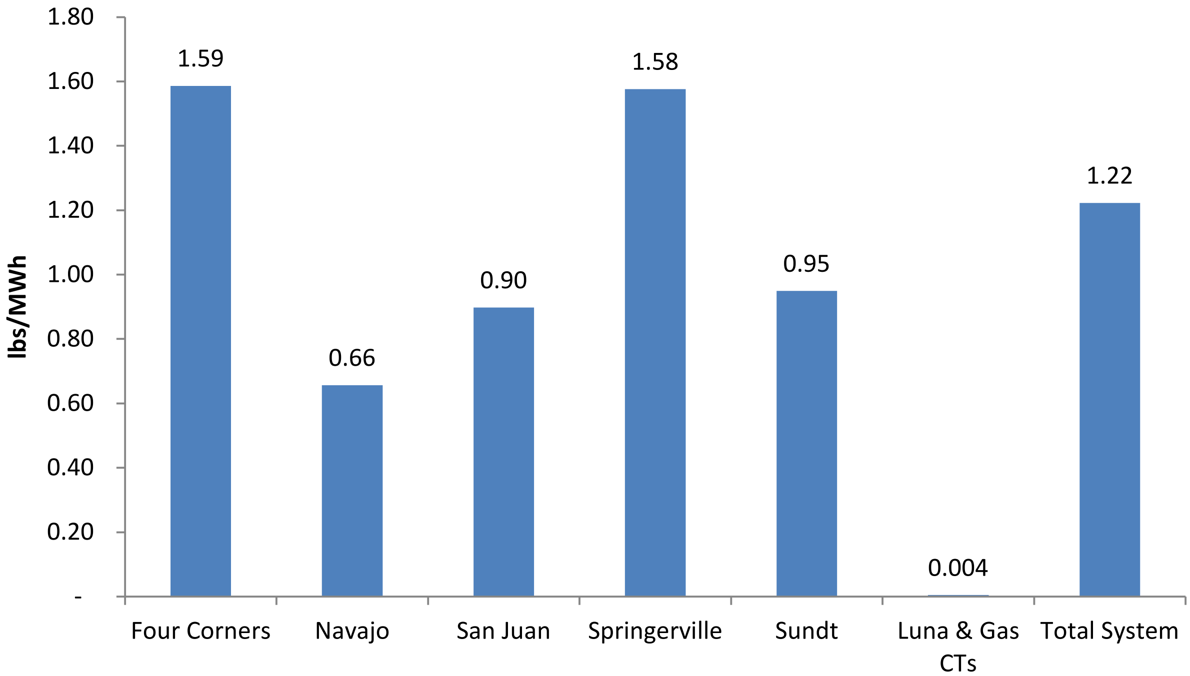
Chart 35 – TEP Resource Portfolio SO_2 - Composition by Plant



SO_2 Emission Rates

Chart 36 below summarizes the 2012 SO_2 emission rates for TEP's generating facilities. On a weighted average basis, TEP's coal resources emitted approximately 1.30 pounds SO_2 per megawatt hour. In comparison, natural gas resources produce significantly less SO_2 versus a typical coal based resource. For example, Luna Energy Facility, a natural gas combined cycle plant emits approximately 0.004 pounds of SO_2 per megawatt hour. On a system level, TEP's SO_2 emission profile averages approximately 1.22 pounds per megawatt hour.

Chart 36 – Average SO_2 Output, lbs/MWh



Carbon Dioxide Overview

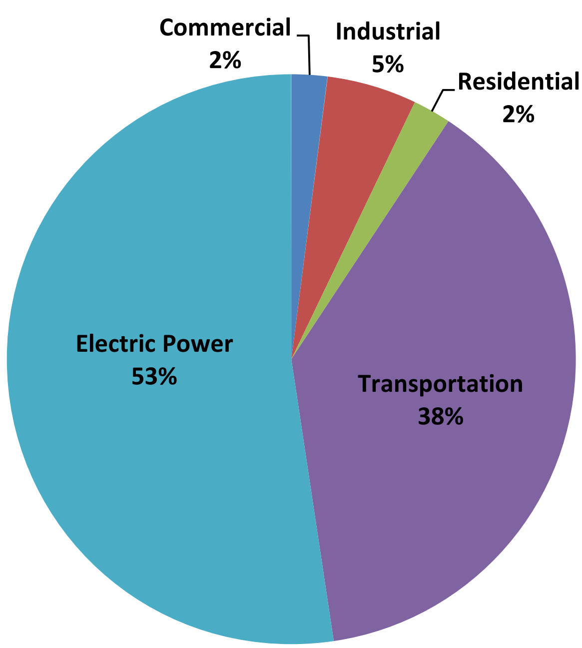
Arizona CO_2 Summary

Based on 2011 state use data obtained from the US Energy Information Administration, electricity generation is the largest source of Arizona's CO_2 air emissions. CO_2 output is summarized by the following use categories:

Table 23 – 2011 Arizona CO_2 Emission by Use Category

Category	Million Tons	Annual %
Electric Power	58.3	52%
Transportation	36.9	38%
Industrial	4.7	5%
Commercial	2.4	2%
Residential	2.4	2%

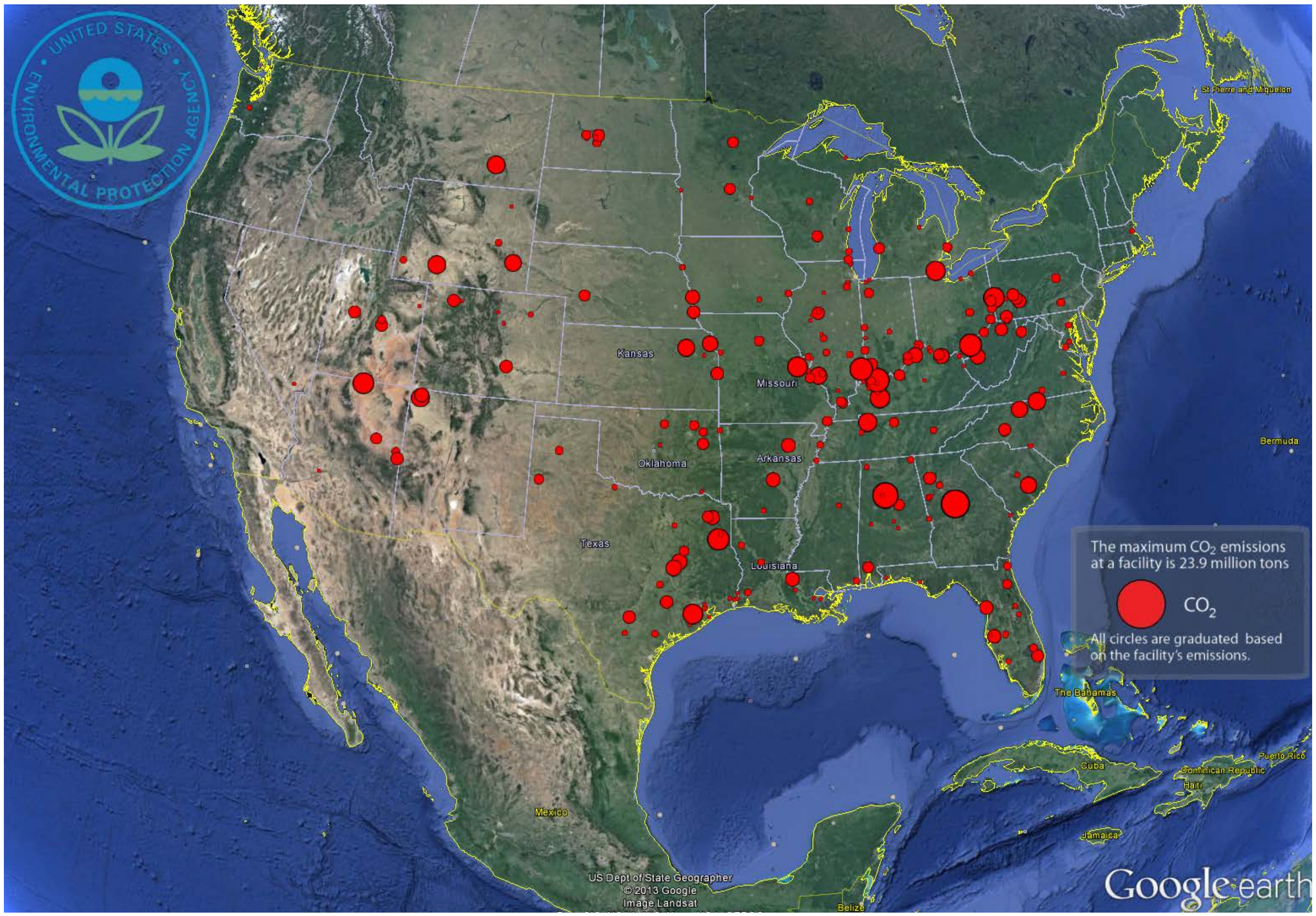
Chart 37 - Arizona CO_2 Emissions Composition



EPA 2012 CO_2 Source Emission Data

Based on 2012 source emission data compiled by the Environmental Protection Agency, the map below shows the relative nation-wide CO_2 emissions from each electric generating facility nationwide.

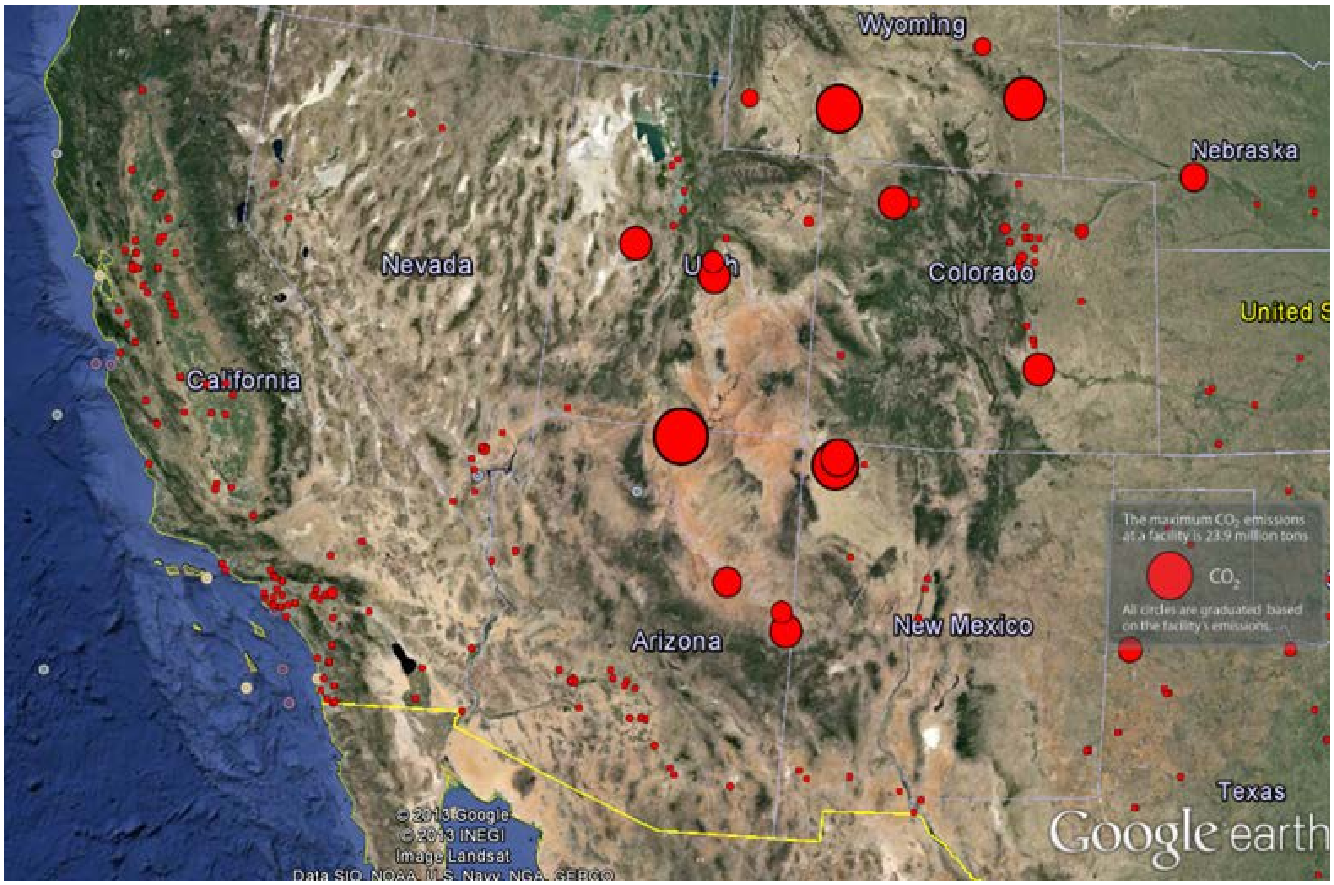
Map 15 – 2012 CO_2 Emissions by Electric Generating Facility (National)



EPA 2012 CO_2 Source Emission Data

Based on 2012 source emission data compiled by the Environmental Protection Agency, the map below shows the relative Desert Southwest CO_2 emissions from each electric generating facility.

Map 16 – 2012 CO_2 Emissions by Electric Generating Facility (Desert Southwest)



Historical CO_2 Emissions

Chart 38 below summarizes the historical CO_2 emissions for TEP's generation assets. TEP's fossil fuel resources produced between 12.7 and 11.2 million tons of CO_2 on an annual basis from 2006 through 2012. The decline over the last five years is driven by the decline in customer loads, reduced coal availability and coal to natural gas fuel switching on Sundt unit 4. Chart 39 below provides a percentage breakdown of CO_2 emission by plant for 2012, based on TEP's ownership share.

Chart 38 – Annual CO_2 Emissions Output by Plant, Tons

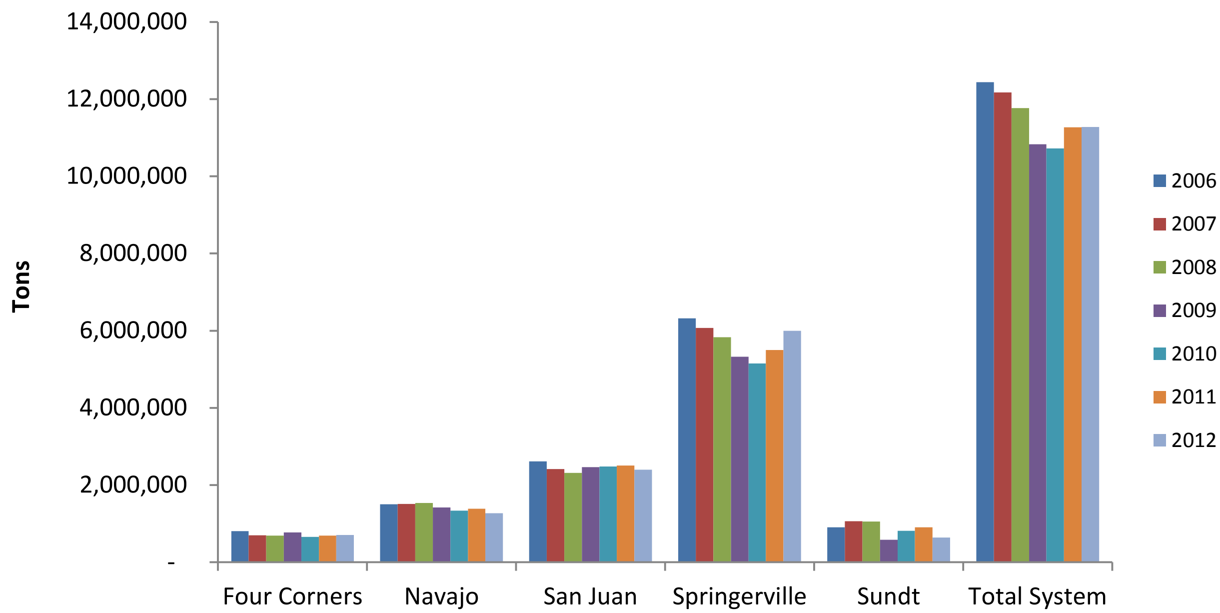
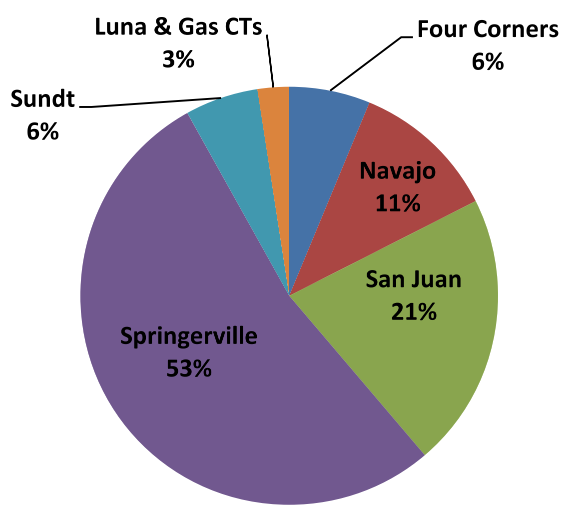


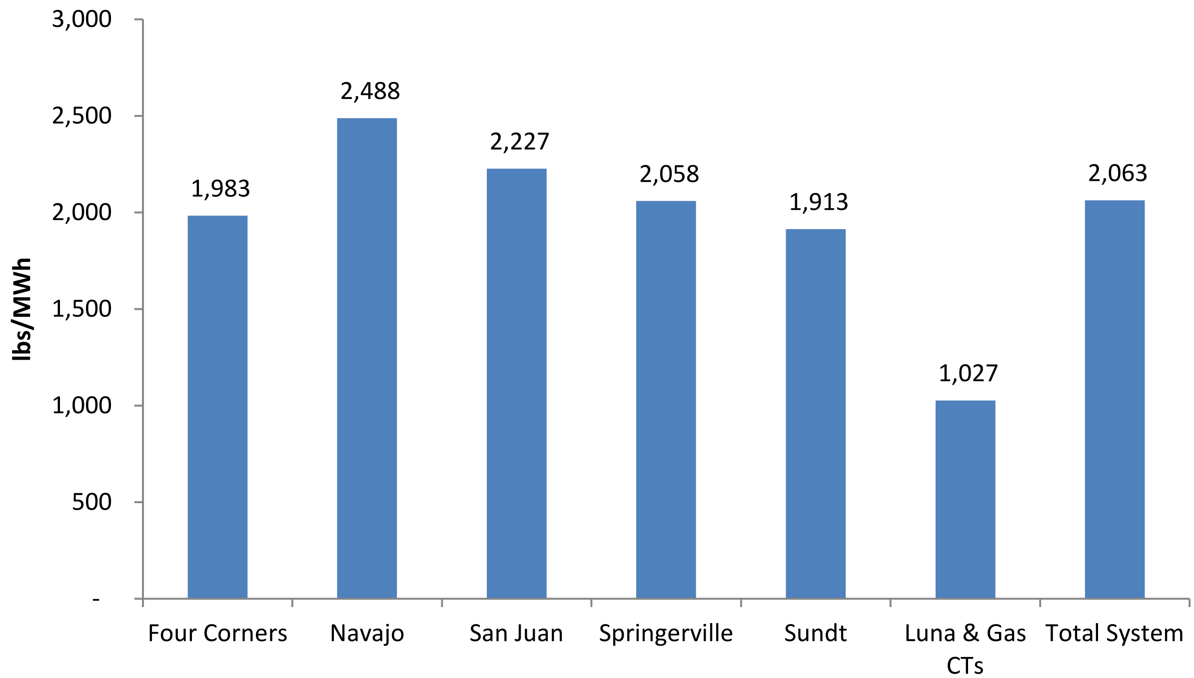
Chart 39 – TEP Resource Portfolio CO_2 - Composition by Plant



Historical CO_2 Emission Rates

Chart 40 below summarizes the average historical CO_2 emission rates for TEP's generating fleet from 2006 through 2012. On average, TEP's coal resources emitted approximately 2,134 pounds of CO_2 per megawatt hour. In comparison, natural gas resources produce approximately fifty percent less CO_2 on a megawatt basis versus a TEP coal based resources. For example, Luna Energy Facility, a natural gas combined cycle plant emitted approximately 1,027 pounds of CO_2 per megawatt hour. On a system level, TEP's CO_2 emission profile averages approximately 2,063 pounds per megawatt hour.

Chart 40 – Average CO_2 Output, lbs/MWh



Particulate Emissions

Particle pollution also called particulate matter or PM is the term for a mixture of solid particles and liquid droplets found in the air. Some particles, such as dust, dirt, soot, or smoke can be seen with the naked eye. Others can only be detected using an electron microscope.

These particles come in many sizes and shapes and can be made up of hundreds of different chemicals. Some particles, known as primary particles are emitted directly from a source, such as construction sites, unpaved roads, fields, smokestacks or fires. Others form in the atmosphere as a result of complicated reactions of chemicals such as sulfur dioxides and nitrogen oxides that are emitted from power plants, industries and automobiles. These particles, known as secondary particles, make up most of the fine particle pollution in the country.

EPA regulates inhalable particles designated as PM_{10} and $PM_{2.5}$. PM_{10} are considered course particles with aerodynamic diameters smaller than 10 micrometers and larger than 2.5 micrometers. $PM_{2.5}$ are considered fine particles with aerodynamic diameters that are 2.5 micrometers and smaller. The Clean Air Act requires EPA to set air quality standards for particulate matter to protect both public health and the public welfare. Chart 41 below summarizes the historical PM emissions for TEP's generating fleet for 2012. Chart 42 below provides a percentage breakdown of PM emission by plant for 2012, based on TEP's ownership share. Chart 43 presents the emission rates by plant.

Chart 41 – 2012 Annual PM Emissions Output by Plant, lbs

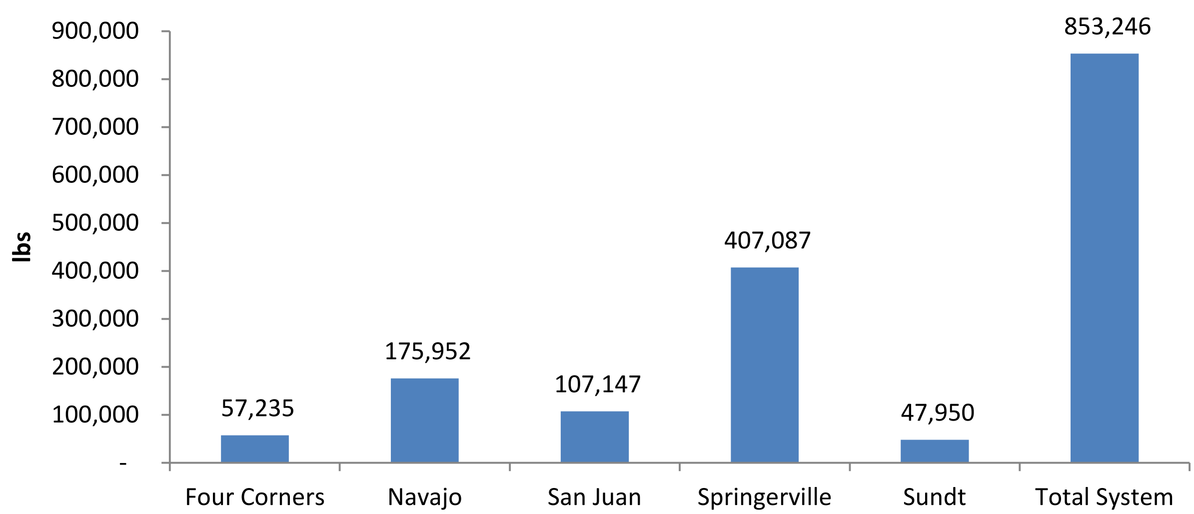


Chart 42 – TEP Resource Portfolio PM Emissions - Composition by Plant

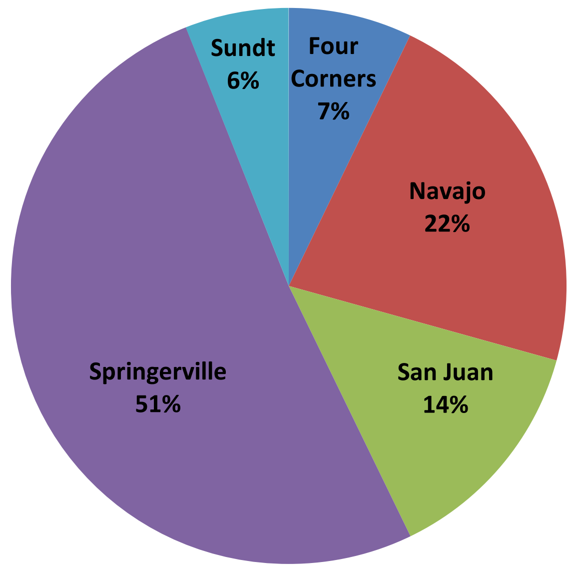
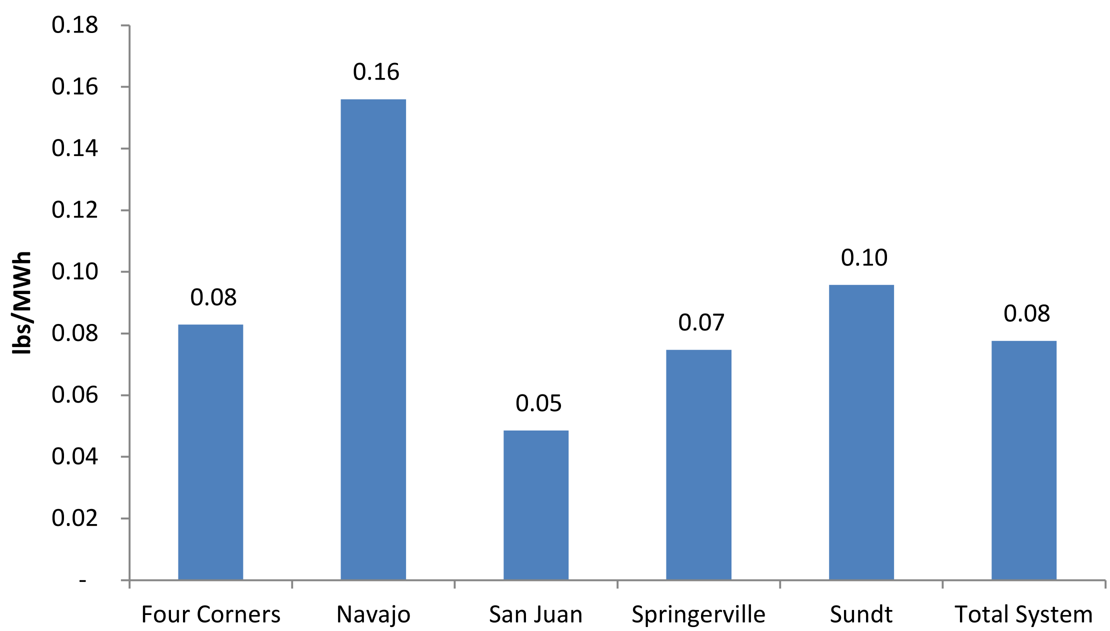


Chart 43 – Average PM Output, lbs/MWh



Coal Ash

Coal contains varying amounts of naturally occurring noncombustible mineral material that remains after the coal is burned. Most of this material exits the boiler with the exhaust gas in a form that is commonly referred to as fly ash. The remaining unburned material is collected in the bottom of the boiler. Hence the term bottom ash. Bottom ash is removed from the boiler by gravity while fly ash is captured by the particulate control devise (e.g. electrostatic precipitators and baghouses).

There are two primary strategies for long-term management of fly ash, surface impoundments and landfills. Surface impoundments are essentially ponds that receive coal ash in a wet slurry and retain the wet material within engineered embankments or dams. Landfills are engineered excavations where dry ash is placed for final disposal then capped with a synthetic material or native soil. Since the material is placed in dry form (the material is kept just moist enough to minimize fugitive dust emissions). All of TEP's coal-fired plants dispose of coal ash that cannot be resold in landfills. Chart 44 below summarizes the annual average ash output for TEP's generating fleet for 2012. Chart 45 presents the percentage of ash in the coal for each plant.

Chart 44 – 2012 Annual Ash Output by Plant, Tons

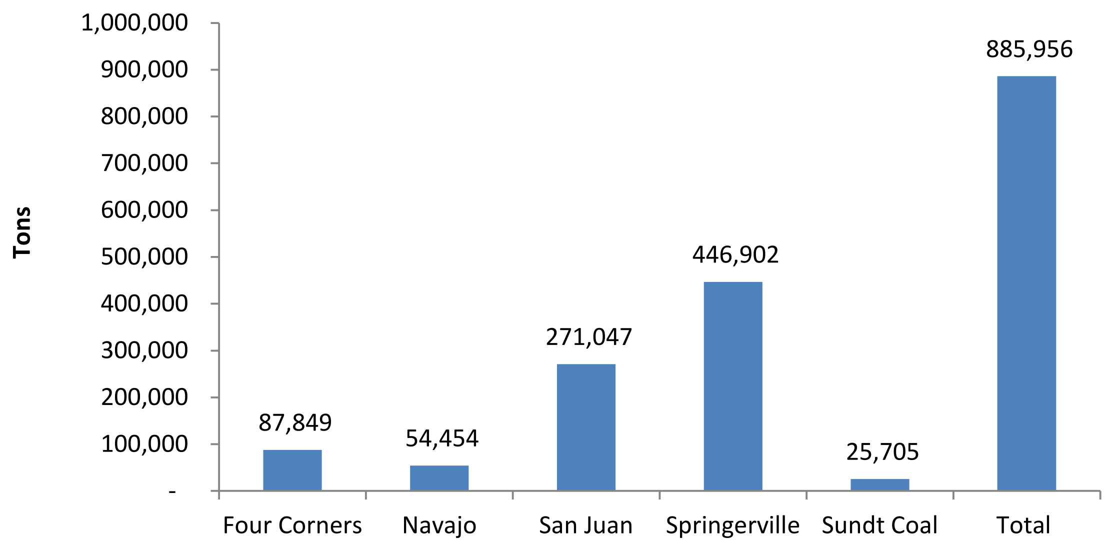
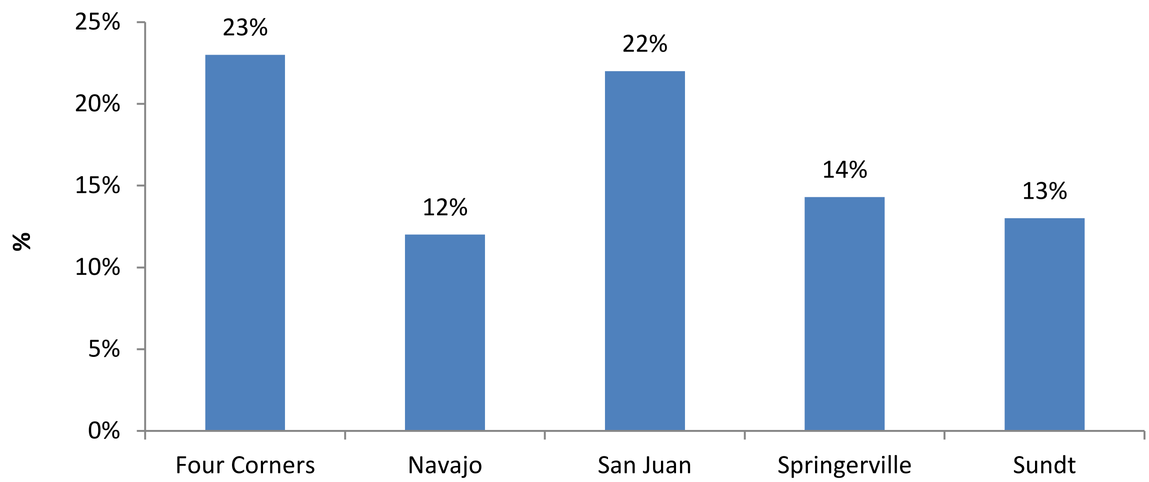


Chart 45 –2012 Annual Ash Content by Station



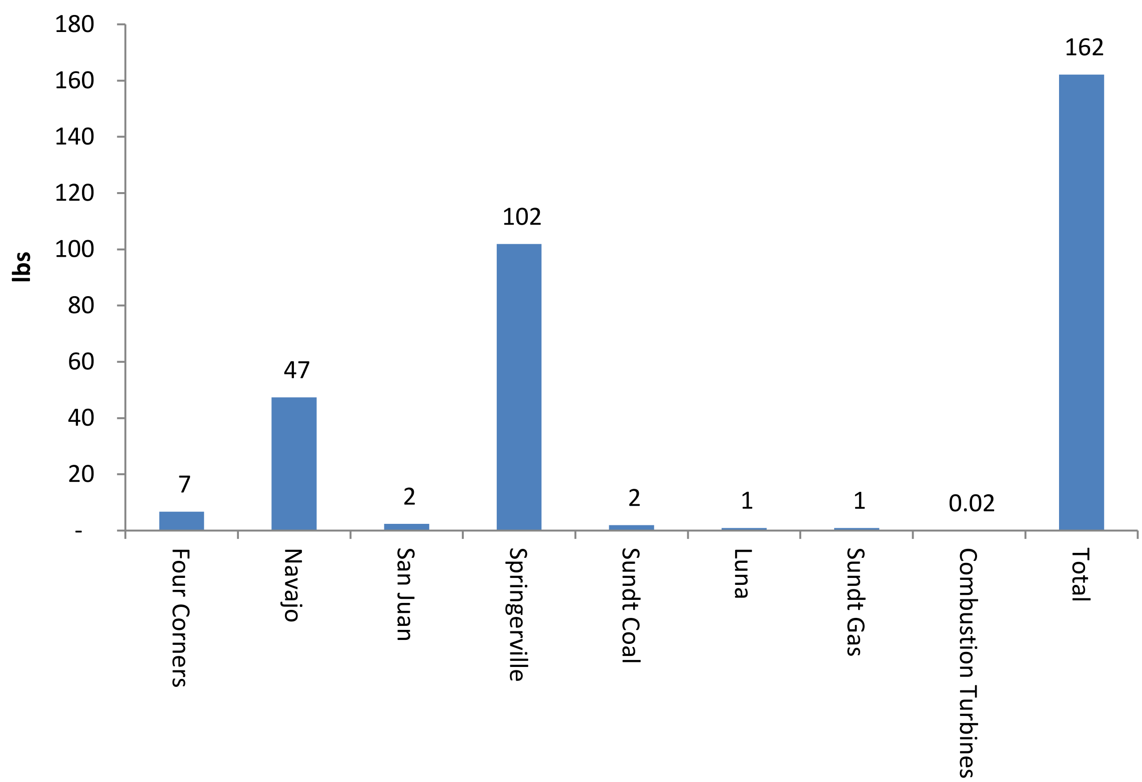
Dry Ash Handling

Dry ash handling describes the process of how the ash is transported and placed in an engineered landfill. All of TEP's coal-fired power plants manage coal ash in this manner, except at San Juan Generating Station where the coal ash is used to reclaim the underground portion of the San Juan coal mine. When a portion of a landfill reaches its capacity, it is covered with soil and revegitated to manage rainwater infiltration – or otherwise capped in accordance with the permit conditions.

Mercury Control Technologies

The scrubbers and baghouses that TEP has installed on its coal-fired power generating units to control sulfur dioxide (SO_2) and particulate matter (PM) emissions have a co-benefit of removing a significant amount of mercury. While we're still in the process of understanding how much mercury will be removed by these control devices on a consistent basis, we currently estimate reductions in mercury from these devices to be between 60 percent and 80 percent. Capturing additional mercury emissions can be achieved with Activated Carbon Injection (ACI) or addition of bromine to coal. ACI involves the injection of activated carbon into the flue gas stream where mercury is adsorbed to the porous activated carbon particles. The particles are then collected either in the ESP or baghouse. The addition of bromine to coal converts mercury to its oxidized and more reactive form such that existing pollution control equipment can remove it. Bromine addition can serve as a standalone technology or it can be combined with ACI. Mercury reductions using multi-pollution controls along with ACI and or bromine addition can achieve removal rates greater than 90%. Chart 46 below summarizes the mercury emissions for TEP's generating fleet for 2012.

Chart 46 – 2012 Annual Hg Emissions Output by Plant, lbs



CHAPTER 10

Power Generation and Water Resources

Overview

Water availability is a major issue for utilities operating and planning new generation resources in the desert southwest. The need to deploy technologies and develop strategies to increase power plant water use efficiency has become an important planning goal within the integrated resource planning process. Although water consumption used for energy is low (between 2 – 3%) compared to other consumptive uses, water consumption associated with thermoelectric power is increasing. This section provides an overview of TEP's water use at its existing generating facilities and discusses how future resource technologies may develop to reduce overall water consumption.

Based on the latest data obtained from Arizona Department of Water Resources (ADWR), Arizona's water consumption is split into the following use categories:

Consumption Category	Acre Feet per Year	Annual %
Energy	180,000	3%
Industrial	220,000	4%
Municipal	1,600,000	26%
Agriculture	4,100,000	67%
Annual Consumption	6,100,000	100%

Chart 47 – Arizona Water Consumption by Use Category

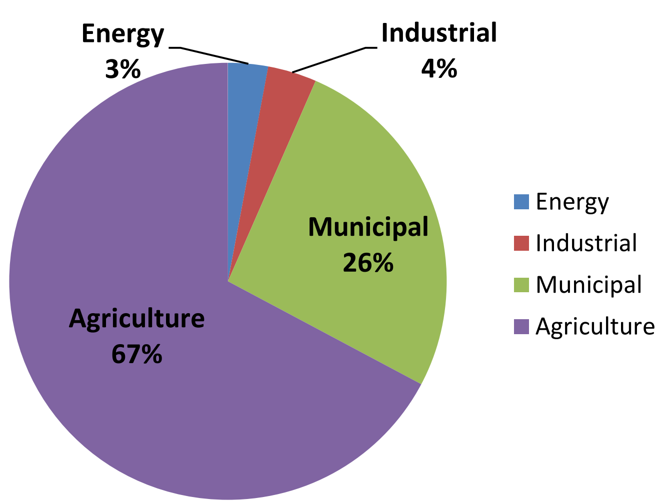


Chart 48 – Average Annual Water Consumption by Station (TEP Share)

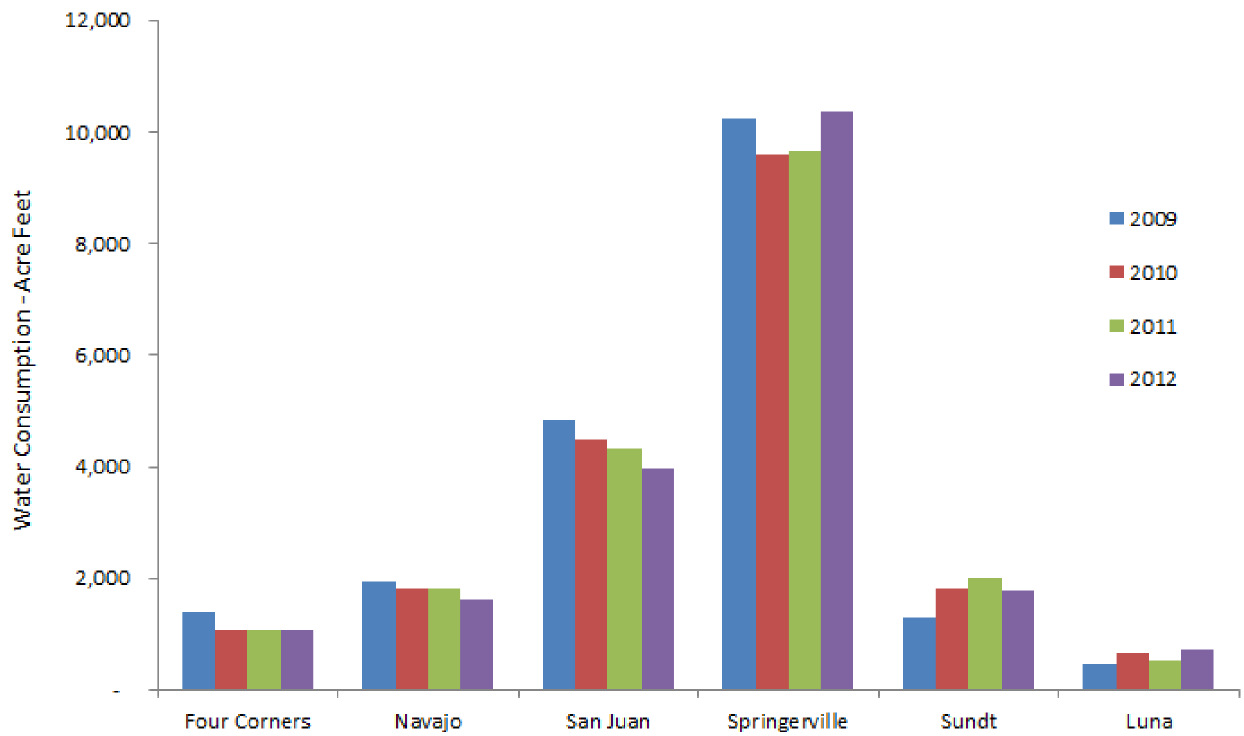
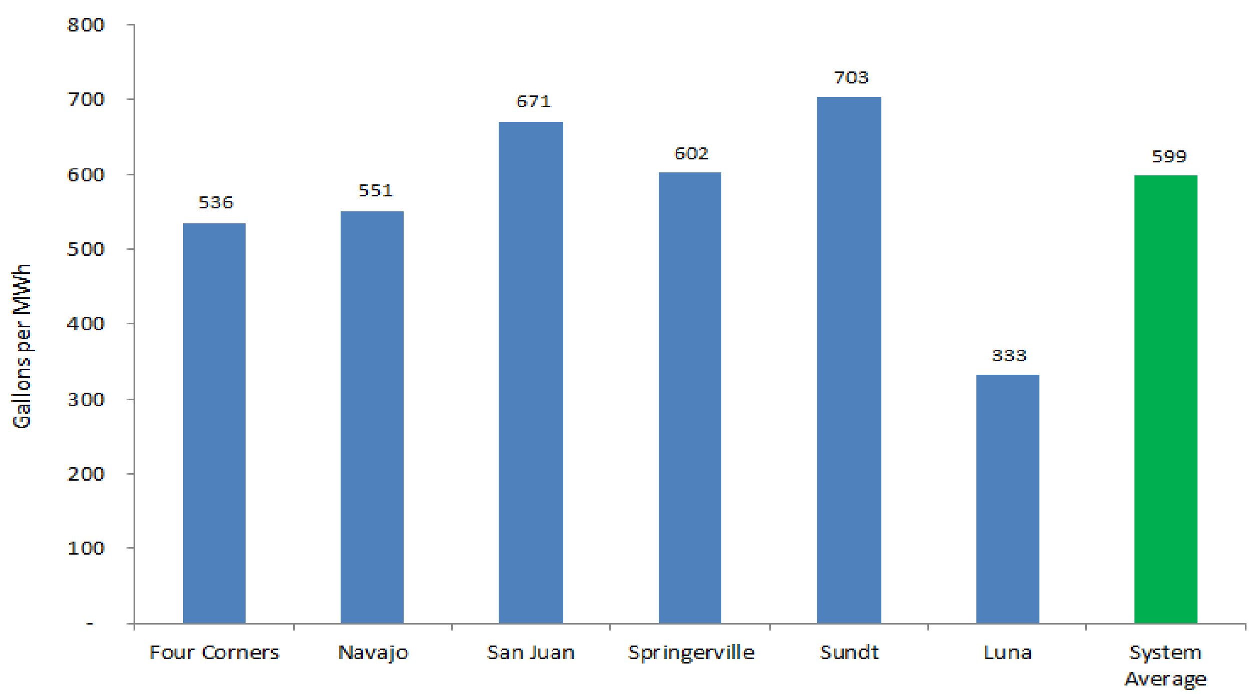


Chart 49 – 2009-2012 Avg. Water Usage by Station, Gallons/MWh



TEP Water Utilization and Standards

TEP Plant Water Utilization

TEP's primary water use is at its coal and natural gas fired power plants. These plants use water in the power cycle (boiler water), the cooling cycle (cooling water) and environmental systems (flue gas desulphurization systems).

TEP Water Conservation

Sundt and SGS employ standard industry practices to limit water use. For example, at Sundt, water is recycled through the cooling towers seven times prior to blowdown, while at SGS cooling water is recycled 15 times. In addition, SGS is the only power plant in Arizona or New Mexico that uses SDAs for SO_2 control. Spray dry absorbers (SDA) use considerable less water than wet scrubbers while achieving a comparable level of SO_2 control.

TEP Groundwater Protection Standards

While limiting water use is important, it is also important to preserve the quality of those water resources. For groundwater resources, as is the case for Sundt and SGS, that means preventing contaminants from reaching the groundwater table. Sundt and SGS operate under strict aquifer protection permits, which establish engineering controls and monitoring provisions to ensure that groundwater is not impacted by our operations.

Overview on Power Plant Cooling Technologies

Electric power generation utilizes water in many ways and in varying amounts depending on the type of generating plant and the type of cooling system employed. The primary use of water is for the condensation of steam, referred to as power plant cooling. Water is also used in some processes to control emissions output as well as for general plant use. There are several types of power plant cooling systems. These are commonly categorized as:

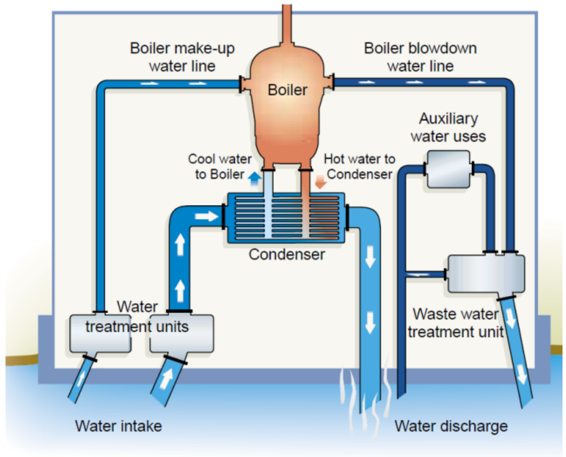
- Once-Through Cooling,
- Recirculation Wet Cooling
- Dry Cooling
- Hybrid or Wet/Dry Cooling

These systems vary widely in the amount of water withdrawn from the environment and in the amount of water consumed by the plant through evaporation.

Once-Through Cooling

This type of system is used where water is plentiful. As the name implies, once-through cooling uses water only once as it passes through a condenser to absorb heat. This heated, treated water is then discharged downstream from the intake into a receiving water body with the volume of intake and discharge water being roughly the same. The water consumption at the power plant is minimal, because the water does not directly contact the air. However, the temperature increase of the river water increases the evaporation rate, thus indirectly increasing the amount of water consumption. Although the consumptive water use is minimal, the amount of water withdrawn from the river is significant although the water is only used for a short time before it is returned to the stream.

Figure 16 – Once Through Cooling Diagram



Source: EPRI Journal 2007

While this is the most common cooling technology currently in use nationwide, it is used for only about 15 percent of generation in the Southwest region. In April 2011, the EPA proposed new rules under Section 316 of the Clean Water Act to reduce impingement of fish and shellfish on intake structures and entrainment of aquatic life into plant cooling systems. The proposal called for fish mortality and water intake velocity standards for impingement and site-specific technology standards for entrainment.

Table 24 – Once Through Cooling Comparison

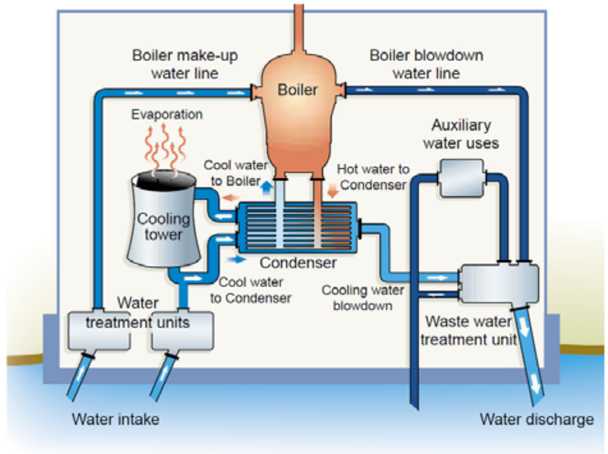
Advantages	Disadvantages
Highest efficiency	Highest withdrawal rates
Lowest installation and operating cots	Entrainment and impingement losses
Low water consumption	Thermal discharge plume
	Drought conditions can curtail plant

Recirculation (Closed-Cycle) Systems

Used where water is less available or for fish protection. Closed-cycle, re-circulating systems are the most common cooling system in western states – meeting the cooling needs of nearly 85 percent of the region's generation. Re-circulating systems, by recycling water, can reduce water withdrawals by at least 95 percent compared to once-through cooling.

The cooling tower water, or circulating water passes through the condenser and absorbs the heat in the steam through metal heat exchanger tubes. The heat in the circulating water is carried by the water to the cooling tower. The circulating water is raised to the top of the cooling tower where it falls through fill material that breaks the water into small water droplets for better air contact. Fans are used to pull air through the falling water. The air/water contact results in water evaporation. The evaporation process cools the remaining water which is collected in the bottom of the cooling tower and pumped back to the condenser. The use of "wet cooling towers" results in large amounts of water evaporated into the surrounding atmosphere.

Figure 17– Recirculation (Closed-Cycle) Systems Diagram



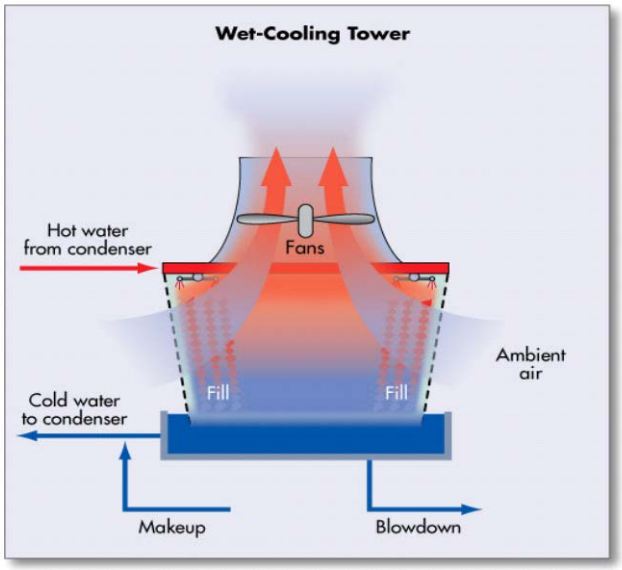
Source: EPRI Journal 2007

While re-circulating systems withdraw much less water than once-through systems, in general they consume more water per kWh of electricity produced. The water also requires more chemical treatment because the fresh water used by the cooling systems contains natural background salts and solids, which can accumulate in the cooling equipment as water evaporates. To reduce deposits and prevent corrosion in order to support a smooth cooling operation, at regular intervals some water is discharged (termed cooling tower blowdown), and fresh water is added that has been treated with chlorine and other chemicals (biocides) to control corrosion, scaling and microbes. The cooling tower blowdown water, which contains the residues of the chemicals used for water treatment, is discharged into designated wastewater collection ponds.

Table 25 – Recirculation (Closed-Cycle) Cooling Comparison

Advantages	Disadvantages
Reduced withdrawal rates	Higher water consumption
Reduced entrainment and impingement losses	Visible plume and drift emissions
	Water treatment requirements
	Water pathogens
	Site space requirements

Figure 18 – Wet Cooling Systems Diagram



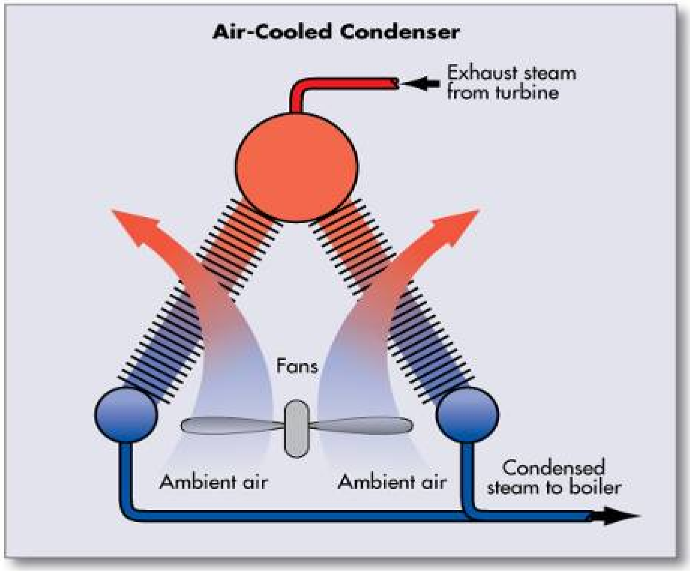
Source; EPRI Journal 2007

In a wet-cooling system, hot water from the plant's condenser is piped to the top of the cooling tower, where it flows downward through fill material cooled by ambient air. Additional makeup water is necessary to replace water lost by evaporation and blowdown.

Dry Cooling Systems

Dry cooling systems are used in arid regions or where water is difficult to obtain. Modern dry cooling systems use air-cooled condensers for the conversion of steam to water in the boiler steam cycle. Steam leaving the final turbine is directed outside the turbine/generator facility to large free-standing air-cooled heat exchanger very similar to an automobile radiator. Steam passes through finned heat exchanger tubes and is condensed back to water by air blown across the outer tube surfaces by large fans. The water demands from dry cooling are extremely low. There are no evaporative losses, and water consumption is limited to boiler requirements, including routine cleaning and maintenance. However, the costs are significantly higher than conventional wet Cooling systems.

Figure 19 – Dry Cooling Systems Diagram



Source: EPRI Journal 2007

Table 26 – Dry Cooling System Comparison

Advantages	Disadvantages
Lowest water consumption	Highest installation and operating costs
No entrainment or impingement losses	Highest efficiency penalty
	Unit deratings on hottest days
	Lower unit reliability
	Site space requirements

Dry Cooling Facilities

There are three facilities in the West that rely on dry cooling: El Dorado Energy Facility, a 540 MW combined-cycle plant in Boulder, Nevada, Walter M. Higgins Generating Station, a 570 MW combined cycle plant in Clark County, Nevada and the Wyodak Generating Station, a 330 MW coal-fired generating station located in Gillette, Wyoming. The Wyodak Station, the first large power plant in the US to use dry cooling technology, was built by the Black Hills Power and Light Company in 1977 in northeastern Wyoming. A dry cooling system was installed because local rivers and groundwater could not otherwise support the cooling demands of the plant.

Picture 9 – 570 MW Air Cooled Combined Cycle Plant in Clark County, Nevada

Walter M. Higgins Generating Station

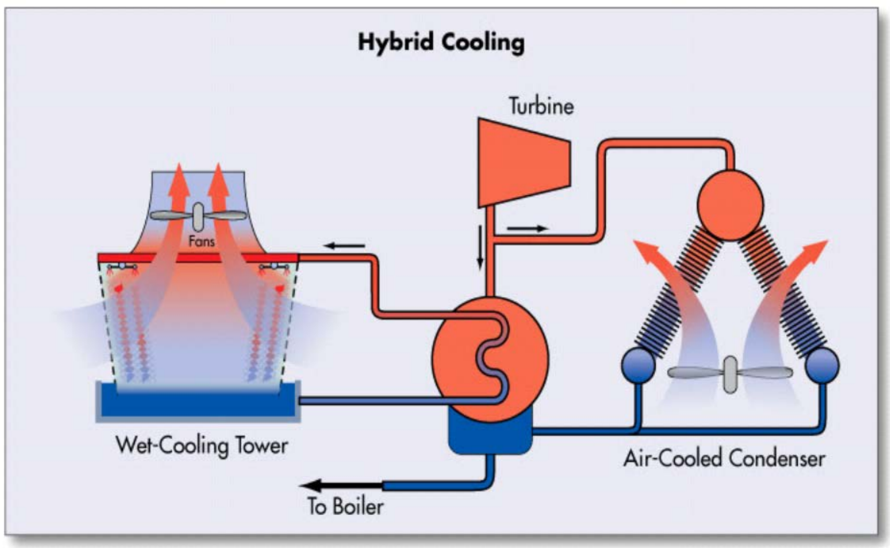
TEP has participated in studies to better understand the benefits and limitations of employing dry-cooling technology. The Electric Power Research Institute (EPRI), of which TEP is a member, is studying advanced Cooling technologies (including dry cooling) as part of its Technology Innovation program. The Technology Innovation program focuses on stimulating innovation and developing enabling technologies that can be deployed in a 5-10 year period.

Hybrid Cooling Systems

Wet- and dry-cooling systems can be combined into hybrid systems to gain the advantages of both and offset the disadvantages of each. A hybrid system can be used to substantially reduce the makeup water consumed in wet cooling without incurring the large heat rate penalties associated with all-dry systems. The capital costs tend to fall halfway between the all-dry and all-wet cooling systems.

Hybrid systems designed for maximum water conservation are essentially dry systems with just enough wet-cooling capacity to prevent significant deterioration in power plant efficiency during the hottest days of the year. When temperatures rise, the wet-cooling system is turned on, improving heat rates and generation capacity. These systems can economically reduce the amount of water that would be required by all-wet cooling system by as much as 80%

Figure 20 – Hybrid Cooling Systems Diagram



Source: EPRI Journal 2007

CHAPTER 11

Energy Efficiency

Tucson Electric Power – Overview

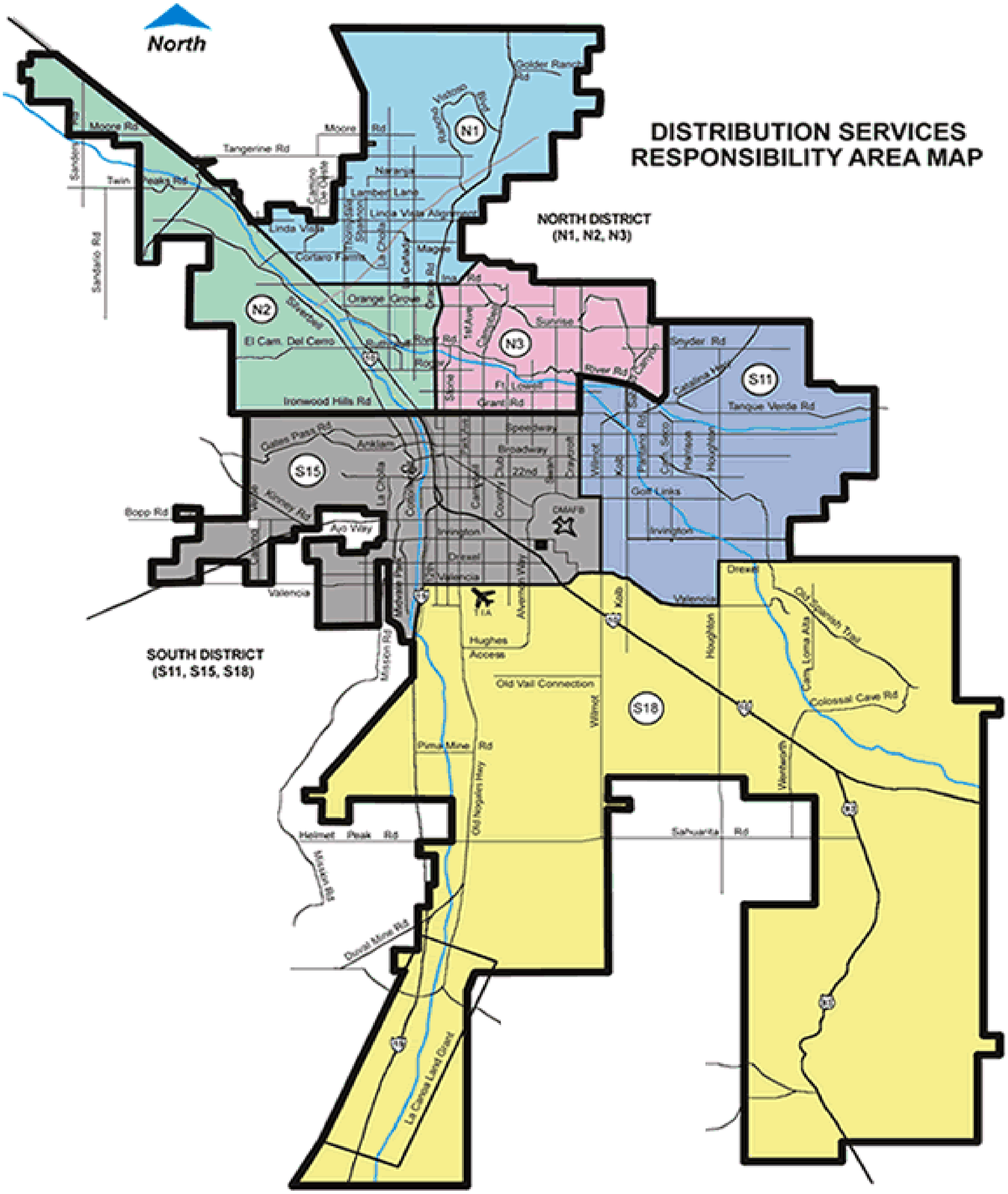
Tucson Electric Power (TEP) recognizes that energy efficiency can be a cost-effective way to reduce our reliance on fossil fuels. TEP offers a variety of energy saving options for customers, from simple consultation to incentives that encourage both homeowners and businesses to invest in efficient heating and cooling and other energy efficiency upgrades.

TEP has made great strides toward meeting the aggressive goals in Arizona's Energy Efficiency Standard (the Standard). The standard calls on investor-owned electric utilities in Arizona to increase the kilowatt-hour savings realized through customer ratepayer-funded energy efficiency programs each year until the cumulative reduction in energy achieved through these programs reaches 22 percent by 2020.

This section presents a detailed overview of the proposed electric Demand-Side Management (DSM) programs targeted at the residential, commercial and industrial ("C&I") sectors, as well as their associated proposed implementation costs, savings, and benefit-cost results.

TEP, with input from other parties such as Navigant Consulting, Inc. (Navigant) and the Southwest Energy Efficiency Project (SWEEP), has designed a comprehensive portfolio of programs to deliver electric energy and demand savings to meet annual DSM energy savings goals outlined in the Arizona Energy Efficiency Standard. These programs include incentives, direct-install and buy-down approaches for energy efficient products and services; educational and marketing approaches to raise awareness and modify behaviors; and partnerships with trade allies to apply as much leverage as possible to augment the rate-payer dollars invested. For context and reference, TEP's service territory is shown on the following page.

Figure 21 - Tucson Electric Power Service Territory



2014 Implementation Plan, Goals, and Objectives

TEP's high-level energy efficiency-related goals and objectives are as follows:

- Implement only cost-effective energy efficiency programs.
- Design and implement a diverse group of programs that provide opportunities for participation for all customers.
- Achieve annual savings goals.
- When feasible, maximize opportunities for program coordination with other efficiency programs (e.g., Southwest Gas Corporation, Arizona Public Service Corporation) to yield maximum benefits.
- Maximize program savings at a minimum cost by striving to achieve comprehensive cost-effective savings opportunities.
- Provide TEP customers and contractors with web access to detailed information on all efficiency programs (residential and business) for electricity savings opportunities at www.tep.com.
- Expand the energy efficiency infrastructure in the state by increasing the number of available qualified contractors through training and certification in specific fields.
- Use trained and qualified trade allies such as electricians, HVAC contractors, builders, architects and engineers to transform the market for efficient technologies.
- Inform and educate customers to modify behaviors that enable them to use energy more efficiently.

Planning Process

TEP's portfolio of programs incorporates elements of the most successful energy efficiency programs across North America. Where possible, many of the program designs were enhanced to further incentivize the Tucson market area and TEP customers in particular. A substantial amount of information including evaluations, program plans and potential studies were used to develop specific programs for TEP. With input from Navigant and SWEEP, TEP also used a benchmarking process to review the most successful energy efficiency programs from across the country, with a focus on successful Desert Southwest programs to help shape the portfolio.

Portfolio Risk Management

Arizona is in the process of recovering from economic setbacks. In this economic environment, TEP's ability to attract residential and business customers to voluntarily take on additional expenses for the installation of cost-effective measures, even with very short pay-back periods, continues to be a challenge. TEP recognizes this challenge and has developed a portfolio of programs that provide opportunities for participation at multiple levels. By proposing a multi-faceted and broad portfolio of programs, TEP will attempt to capitalize on those sectors of the market willing to invest in energy efficiency regardless of the challenging economic landscape. In balance, this will allow us to meet aggressive regulatory energy efficiency goals.

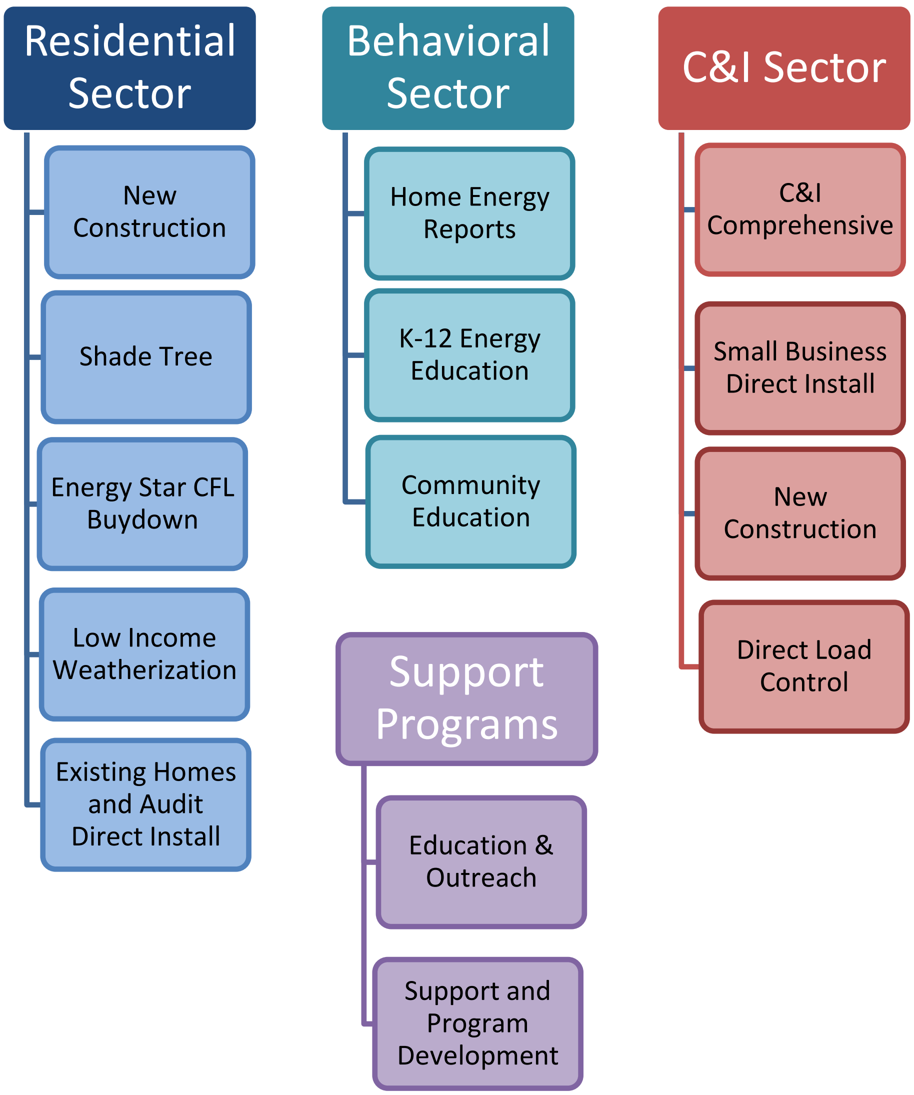
TEP used the following strategies to minimize the risks and produce the lowest cost portfolio of energy efficiency programs:

- Implementing primarily "tried and true" programs that have been successfully applied by other utilities in the Southwest and across the country.
- Implementing programs through a combination of third-party contractors and TEP staff. TEP designs programs on the most cost-effective basis utilizing implementation contractors where they provide the lowest cost per kWh and likewise utilizing TEP staff when appropriate.

Program Portfolio Overview

As demonstrated in Figure 22, TEP's portfolio of programs can be divided into residential, commercial, behavioral, and support sectors with administrative functions providing support across all program areas.

Figure 22 - Tucson Electric Power Portfolio of Programs



Savings, Budgets, and Benefit-Cost Results Overview

The TEP 2011-2012 Energy Efficiency Plan was filed on January 31, 2011, in accordance with Section R14-2-2405 of the Standard. In June 2013 Commission Decision No. 73912 approved an increased budget for TEP's existing DSM programs, but did not approve any of the new programs or EE measures contained in the 2011-2012 EE Plan, and Docket No. E01933A-11-0055 (the docket for the 2011-2012 energy efficiency Plan) was closed. This has hindered TEP's ability to meet the Standard for 2013. Without new energy efficiency measures or programs, meeting the Energy Efficiency Standard will be difficult in future years.

In June 2013, TEP submitted an Implementation Plan for 2014. While the 2014 plan will not allow TEP to meet the Energy Efficiency Standard, TEP will continue to monitor projected program funding and program participation.

Additionally, incentive levels and other program elements will be reviewed and modified on an annual basis to reflect changes in market conditions or implementation processes in order to maximize cost-effective savings. Such modifications will be reported in the annual reports submitted to the Arizona Corporation Commission.

As detailed in Table 27, TEP has developed this plan with the intent of meeting statutory electric savings goals as a percentage of prior year retail sales as outlined in Energy Efficiency Standard Section R14-2-2418 in the Commission Rules. For 2013, TEP's budget forecast was $19.2 million increasing to $20.7 million in 2014.

Table 27 – Energy Efficiency Implementation Plan Summary Costs and Savings

Program Year	Total Program Budget ($000)	Annual Savings (MWh)	Lifetime Savings (MWh)	Total Net Benefits ($000)	Portfolio Societal Costs Ratio
2011	$15,003	127,924	1,170,111	$53,130	3.2
2012	$7,448	89,274	701,912	$35,386	3.0
2013	$19,234	159,098	2,336,163	$51,059	1.9

As noted in Table 28, the initial 2011 Energy Efficiency Standard cumulative target was 1.50% savings as a percent of sales of the previous calendar year; for 2014 this increases to 7.25%. TEP's proposed portfolio of new and expanded programs is not projected to meet the 2014 goals resulting from the programs that were shutdown in 2012.

Table 28 - Planned Savings and Energy Efficiency Standard Target Savings

Targets	2011	2012	2013
EE Standard Target Cumulative Savings (% of Retail Sales)	1.50%	3.00%	5.00%
Actual Cumulative Savings (% of Retail Sales of prior year)	1.25%	2.63%	4.56%
Actual Annual MWh Savings (required by Energy Efficiency Standard)	116,147	245,434	422,476
EE Standard Target Annual MWh Savings	139,377	279,963	463,241
% of Planned Savings Goal Achieved (Incremental Year)	83%	88%	91%

The Actual Annual MWh Savings stated in both Table 27 and Table 28 is a summation of annual savings obtained by each program in TEP's portfolio with the exception of TEP's C&I Direct Load Control Program. Savings from the C&I Direct Load Control Program and the Energy Efficiency Building Codes Program are not calculated into the Lifetime MWh Savings and therefore have no impact on it.

Review of Different Benefit-Cost Tests and Results

Program development involves selecting the technologies to include in each program as well as estimating participation levels and program costs. Though the DSM portfolio must be cost-effective, there are a number of perspectives on cost effectiveness. Some of these alternative perspectives are described below.

As detailed in Table 29 - Comparative Benefit-Cost Tests, there are five major benefit-cost tests commonly utilized in the energy efficiency industry, each of which addresses different perspectives. The Arizona Energy Efficiency Standard established that the societal cost test should be used as the key perspective for judging the cost-effectiveness of the energy efficiency measures and programs. Regardless of which perspective is used, benefit-cost ratios greater than or equal to 1.0 are considered beneficial. While various perspectives are often referred to as tests, the following list of criteria demonstrates that decisions on program development go beyond a pass/fail test.

Table 29 - Comparative Benefit-Cost Tests

	SOCIETAL TEST	TOTAL RESOURCE COST TEST	UTILITY RESOURCE COST TEST	PARTICIPANT COST TEST	RATE IMPACT MEASURE TEST
BENEFITS					
Reduction in Customer's Utility Bill				✓	
Incentive Paid by Utility				✓	
Any Tax Credit Received		✓		✓	
Avoided Supply Costs	✓	✓	✓		✓
Avoided Participant Costs	✓	✓		✓	
Participant Payment to Utility			✓		✓
External Benefits	✓				
COSTS					
Utility Administration Costs	✓	✓	✓		✓
Participant Costs	✓	✓		✓	
Incentive Costs			✓		
External Costs	✓				
Lost Revenues					✓

Although TEP is only required to analyze its programs using the SCT, the Company evaluated the cost-effectiveness of its measures, programs, and overall portfolio based on all of the following standard tests.

Utility Resource Cost Test

The Utility Resource Cost Test (UCT), also referred to as the Program Administrator Test (PAT), measures the net benefits of a DSM program as a resource option based on the costs and benefits incurred by the utility (including incentive costs) and excluding any net costs incurred by the customer participating in the efficiency program. The benefits are the avoided supply costs of energy and demand, the reduction in transmission, distribution, generation and capacity valued at marginal costs for the periods when there is a load reduction. The costs are the program costs incurred by the utility, the incentives paid to the customers, and the increased supply costs for the periods in which load is increased.

Total Resource Cost

The Total Resource Cost (TRC) is a test that measures the total net resource expenditures of a DSM program from the point of view of the utility and its ratepayers. Resource costs include changes in supply and participant costs. A DSM program that passes the TRC test (i.e., has a ratio greater than 1) is viewed as beneficial to the utility and its customers because the savings in electric costs outweigh the DSM costs incurred by the utility and its customers.

Participant Cost Test

The Participant Cost Test (PCT) illustrates the relative magnitude of net benefits that go to participants compared to net benefits achieved from other perspectives. The benefits derived from this test reflect reductions in a customer's bill and energy costs plus any incentives received from the utility or third parties, and any tax credit. Savings are based on gross revenues. Costs are based on out-of-pocket expenses from participating in a program, plus any increases in the customer's utility bills.

Rate Impact Measure Test

The Rate Impact Measure (RIM) Test measures the change in utility energy rates resulting from changes in revenues and operating costs. Higher RIM test scores indicate there will be less impact on increasing energy rates. While the RIM results provide a guide as to which technology has more impact on rates, generally it is not considered a pass/fail test. Instead, the amount of rate impact is usually considered at a policy level. The policy level decision is whether the entire portfolio's impact on rates is so detrimental that some net benefits have to be forgone.

Societal Cost Test

The SCT is similar to the TRC test, but it is also intended to account for the effects of externalities (such as reductions in carbon dioxide (CO_2), nitrogen oxides (NOx), and sulfur dioxide (SO_2). One additional difference between the TRC and the SCT is that the SCT uses a societal discount rate in the analysis. The SCT is the regulated benefit cost analysis required in the Standard and TEP has provided a SCT that accounts for the societal discount rate. TEP is however, unable to provide a true societal test given the uncertain values of environmental externalities. As required by the Commission, TEP will work in 2011 with stakeholders to develop appropriate metrics for and to monetize the costs of water, SO_2, PM_{10} and NO_x emissions savings as part of the societal cost test in program filings. Until a true market value is available for CO_2, the Company will not separately monetize carbon. In compliance with Commission Decision No. 72028 (December 12, 2010), TEP filed the societal costs as the results of the stakeholder meetings.

Residential Energy Efficiency Programs

Residential New Construction

The Residential New Construction is a continuation of an existing program designed with an incentive schedule awarding above code energy efficiency homes. To qualify for an incentive, homes must be tested by an RESNET approved energy rater, and be certified as an Energy Star V-3 home. On the HERS index scale, a score of 100 is considered the average efficiency of baseline new construction. A HERS index score of 0 represents a home that produces all of its energy through on-site generation from renewable energy. Therefore, the lower the HERS score, the more efficient the home. All jurisdictions served by TEP have adopted the 2012 International Energy Conservation Code, (IECC2012). IECC compliant homes have a HERS score of approximately 72. Program Homes require a minimum HERS score that is less than or equal to 65, The objectives of the residential new construction program are to advance energy efficient building practices through builder training, and customer awareness of the benefits of energy efficient construction.

Existing Homes Program

The Existing Homes Program is designed to encourage homeowners to increase the energy efficiency of their homes. The Program provides incentives for high-efficiency heating, ventilation and air conditioning (HVAC) equipment; as well as home performance services such as sealing leaky duct work, installing insulation, air sealing, and other thermal envelope improvements in existing homes. The Program provides direct incentives to participating contractors with the requirement that the incentives be passed on to utility customers as a line item credit toward approved Program measures. Furthermore, TEP requires customers to utilize specific Program participating contractors who are required to be Building Performance Institute certified and complete Program administrative training. The energy and demand savings from the installation of these energy efficient measures, and it contributes toward transforming the residential HVAC industry to emphasize best practice building science principles.

Shade Tree

The Shade Tree Program is an ongoing environmental element of the TEP's Energy Efficiency portfolio. The Program promotes energy conservation and environmental benefits by motivating customers to plant desert-adapted trees in targeted locations where the trees will provide shade to habited dwellings, thus reducing HVAC load. TEP partners with Trees for Tucson, a local non-profit organization that manages and administers the program. The objectives of the program are to promote the strategic planting of trees to provide shade, thereby reducing the cooling load of homes and associated energy usage, and to educate school-age children and the public on the conservation and environmental benefits of planting trees.

Low Income Weatherization

The Low Income Weatherization Program helps conserve energy and lower utility bills for TEP households with limited incomes by funding the weatherization of eligible homes. Weatherization measures fall into four major categories of duct repair, pressure management/infiltration control, attic insulation, and repair or replacement of non-functional or hazardous appliances. Weatherization is conducted in accordance with the Weatherization Assistance Program (WAP), a program funded by the U.S. Department of Energy. Household income and participation guidelines will be consistent in an on-going manner with current policy criteria used by the Arizona Energy Office, a division of the Arizona Department of Commerce. The income eligibility is 200% of poverty level which is the current level set by Low-Income Home Energy Assistance Program (LIHEAP). TEP coordinates with the Arizona Energy Office to follow approved state WAP rules when using funding from TEP, to lower the average household energy consumption for low-income customers and to increase the number of homes weatherized annually. The program funding provides up to $3,000 per residence for energy efficient weatherization measures, equipment replacement and/or repair, etc. for low-income customers within the TEP service area. Agencies are allowed to use up to 25% of their annual budget for Health and Safety related repairs. Agencies may request a waiver of the $3,000 limitation on a case-by-case basis.

Energy Star CFL Buy-down

This program promotes the purchase of energy efficient lighting ENERGY STAR® approved lighting products by residential and small commercial customers through in-store buy-down promotions. TEP provides funds to manufacturers of ENERGY STAR® approved Compact Fluorescent Lamp (CFL) products to reduce the cost of CFLs. TEP then partners with local retailers to pass on these savings to the customer.

Commercial and Industrial (C&I) Programs

The following section presents a summary of TEP's Commercial and Industrial ("C&I") programs including new programs and enhancements to existing programs.

Small Business Direct Install

The Small Business Direct Install Program is an existing program that offers incentives for a select group of retrofit (RET) and replace-on-burnout (ROB) energy efficiency measures in existing facilities. Eligible customers include customers who qualify for TEP's Rate 10 – Small General Service pricing plan (typically an aggregate monthly demand of 200 kW or less). The program offers incentives for the installation of energy efficiency measures to serve end uses of HVAC, refrigeration, lighting, motors, and plug loads. The Small Business Direct Install program is designed to address the barriers to this market segment, including limited investment capital, limited awareness of energy cost savings, and required short-term payback. The program's purpose is to persuade small business customers to install high-efficiency equipment at their facilities and encourage contractors to promote the program.

There are over 25 unique measures available to this market segment through this program. Some are a continuation of the program from previous years, and others have been added as part of the 2011 commercial portfolio. The main measures that are provided through the Small Business Direct Install program include:

- HVAC applications such as air conditions, heat pumps, programmable thermostats, shade screens, and window films;
- Lighting technology including LEDs, CFLs, and T8s;
- Refrigeration technology such as beverage and snack controls, refrigerator gaskets, refrigerator displays, and refrigerator door closers; and
- Advanced Power Strips

C&I Comprehensive

The C&I Comprehensive Program is an existing program, approved previously under the name of Non-Residential Existing Facilities Program. This newly-named program provides prescriptive incentives to large commercial customers who are under TEP's Rate 13 and Rate 14 pricing plans (typically an aggregate monthly demand exceeding 200 kW) for the installation of energy-efficiency measures including lighting equipment and controls, HVAC equipment, motors and motor drives, and refrigeration measures. Prescriptive incentives are offered for a schedule of measures in each of these categories. Customers can also propose innovative energy efficiency solutions by offering a custom energy efficiency measure.

The C&I Comprehensive Program is designed to address the barriers to this market segment, including limited awareness and lack of knowledge about the benefits and cost of energy efficiency improvements, performance uncertainty associated with energy efficiency projects and the required short-term payback. The program's purpose is to persuade large business customers to install high-efficiency equipment at their facilities and encourage contractors to promote the program and provide turn-key installation services to small business customers.

There are about 50 unique existing and new measures, through which incentives are offered to large business customers in TEP's service territory, including:

- Coin Operated Clothes Washers
- Advanced Power Strips
- Refrigerator Displays, Gaskets, Door Closers
- Ice Makers and Reach-In Refrigerators
- Strip Curtains and Night Covers
- LED Pedestrian Signals and Traffic Lights
- LED Street and Parking Lights
- Induction, LED, CFL and Advanced Lighting Technology
- Heat Pump Water Heaters
- CO_2 Sensors, CO Sensors
- Shade Screens, Window Films
- Air Conditioners and Heat Pumps
- Efficient Motors and Variable Speed Drives
- Custom Measures

Commercial New Construction

The Commercial New Construction program is intended to assist customers in designing and constructing energy efficient buildings. It is a performance based program that includes design assistance for the design team, performance based incentives for the building owner/developer, and energy design information resources. Design assistance involves efforts to integrate energy-efficiency into a customer's building plan to influence equipment/systems selection and specifications as early in the design process as possible. The performance based incentives for the building owner/developer is based on improved efficiency compared to a baseline design. The building's energy use is modeled against code based standards to determine projected energy savings. Rebate amounts are based on the estimated energy savings over a one year period. The program also provides consumer educational and promotional pieces designed to assist building owners/developers with the information necessary to understand various energy efficiency options, encourage them to explore these options with their design professionals as early in the design process as possible, and improve the efficacy while reducing the energy use of their buildings.

The primary goal of the program is to encourage more energy efficient new building design for new non-residential projects in TEP's service area. This objective is reached through providing incentives to building owners/developers to design and build more energy efficient buildings and offering assistance to design teams to offset the additional cost and time of exploring more energy efficient design. The program helps overcome market barriers, such as increased upfront cost of an integrated design approach, lack of awareness and knowledge about the benefits, and the cost and the performance of energy efficient measures. It encourages building owners/developers and the design community to consider energy efficiency options as early in the design process as possible.

Direct Load Control (DLC)

The C&I DLC program is an existing voluntary load curtailment program for larger commercial and industrial customers in TEP's service territory. During peak hours (late afternoon and evening) of the summer months, commercial and industrial load represents a total of approximately 22% of system demand. Modification of controls for chillers, rooftop AC units, lighting, fans, and other end uses is capable of significantly reducing power demand at peak times. Participating customers will voluntarily reduce their electricity consumption during times of peak electricity demand or high wholesale electricity prices (when alerted by TEP).

The program anticipates enrolling enough customers to progress towards reaching a target of 50 MW of summer peak demand reduction, available for up to 80 hours per year, with a typical load control event lasting 3-4 hours. Customers will be compensated with incentives for their participation at negotiated levels that will vary depending on multiple factors including the size of the facility, amount of kW under load control, and the frequency with which the resource can be utilized.

In addition, the program may be used to support standard benefits of demand-response programs which include avoided firm capacity required to meet reserve requirements, reduced or avoided open-market power purchases during periods of high energy prices, and greater grid stability and reduction in outages due to reduced grid demand.

Behavioral Energy Efficiency Programs

Behavioral Energy Efficiency programs are designed to affect habitual behaviors like turning off lights or adjusting the thermostat, purchasing behaviors such as buying efficient lights and appliances, and the behavior of participating in utility DSM programs. More specifically, the types of behaviors to be influenced include:

- Habitual Behaviors
  - » Adjust thermostat setting
  - » Turn off unnecessary lights
- Small Purchasing and Maintenance Behaviors
  - » Purchase and install faucet aerators and low flow shower heads
  - » Purchase and install compact fluorescent light bulbs
  - » HVAC maintenance
- Larger Purchasing Decisions
  - » Purchase an ENERGY STAR appliance
  - » Purchase higher EE heating and cooling system through participation in a TEP DSM program

TEP proposes to continue our K-12 Education and Community Education for the 2014 program year portfolio, as shown in Table 30.

Table 30 - Summary of Behavioral Energy Efficiency Programs

Behavioral Energy Efficiency Programs	
K-12 Education	Classroom education including take home direct install kits
Community Education	"Train the trainer" approach and give away direct install kits

Behavioral Comprehensive Programs

The Behavioral Comprehensive program is meant to address the fact that technology-based energy efficiency achieves only a finite amount of efficiency potential. The barriers to wider-spread implementation of energy efficiency are sociological, not technological. The suite of programs approaches such sociological barriers using different avenues, such as schools, and community organizations.

K-12 Education

The K-12 Education approach is an extension of the existing TEP education program. In this approach, in addition to energy-based classroom curriculum, students will be instructed in energy saving approaches that can be implemented in their homes. Students will be provided a take home kit which includes several energy saving devices such as CFLs, refrigerator thermometers, and educational materials regarding actions that can be taken to reduce energy use.

Community Education

The Community Education Program will engage community groups and work with public entities on "train the trainer" hands-on energy efficiency seminars. Community trainers will be given a broad-based review of energy, energy efficiency, and comfort principles. This creates a level of understanding which dovetails into identifying specific actions and behaviors to reduce energy consumption at home, work or play. Community groups and other neighborhood organizations are engaged both to identify mentors to be trained and to schedule sessions led by these mentors for community members on a grassroots level. The seminars include hands-on training with a wide sample of materials such as weather stripping, low flow showerheads, caulk or foam sealant, CFL's, etc. provided to participants.

Support Programs

Support programs cut across residential and commercial program areas and provide technical and financial support for the effective implementation of all other programs.

Education and Outreach (E&O)

The program consists of education and marketing intended to inform customers about the benefits of energy conservation and to inform those customers on how to achieve energy savings. All components of this program are a continuation of current program offerings. Components of the E&O programs include:

- General Energy Efficiency advertising component to cover seasonal ad's that encourage energy savings through energy saving tips, marketing the on-line energy audit, and marketing other energy efficiency programs to customers;
- On-Line Energy Audits and Carbon calculator on TEP website that will be part of the Behavior Energy Efficiency Program offering;
- Academic Education that is anticipated to be part of the Behavioral Energy Efficiency Program offering;
- Time-of-Use education to teach residential and small commercial customers about the benefits of TOU rates and enable customers to maximize savings through load shifting; and
- Program evaluation.

Because the aim of this program is to change behavior it is difficult to objectively assess cost effectiveness or measure actual energy or environmental savings. However, since it is anticipated to consist only of education and marketing, this program does not require a cost-effectiveness test.

2014 Resource Planning Integration

DSM Forecasting

Consistent with the ACC's Decision No. 71435 on Resource Planning, TEP forecasted cumulative energy savings for TEP's DSM portfolio. TEP prepared a monthly energy savings distribution for a full calendar year's annual savings impacts that results from the implementation of 2011 programs, which is the first year of the Energy Efficiency Standard. This was done to showcase how the annual savings reported toward the Energy Efficiency Standard would impact the actual system loads throughout the year. In addition, TEP prepared a monthly peak savings distribution for a full calendar year's savings from the programs in order to incorporate how coincident peak reduction impacts the TEP system load and gets factored into resource planning. Energy efficiency forecasts for TEP were projected over the IRP planning period.

Methodology

In order to integrate the savings impact of TEP's portfolio of DSM programs into a 15-year planning horizon, TEP determined the hourly savings of each individual energy efficiency measures and then aggregated them at the portfolio-level by customer rate class. The hourly savings resolution can be summed into monthly energy and peak demand savings.

TEP carefully considered all available resources and options for determining energy efficiency measure hourly level savings data. One option was to conduct long-term end-use metering and analysis for the measures installed at customer premises, which would be multi-year projects and very costly. Another option was to utilize data made available from national and other state-level funded multi-year studies and research that incorporated best practices for determining hourly level measure savings. TEP found this latter option to be more prudent given the time sensitivity and expense.

TEP relied upon 8,760 hourly savings load shapes taken from the most widely referenced and recognized industry sources for individual energy efficiency measures that comprised each particular DSM program. These sources include California's Database for Energy Efficient Resources (DEER), which is developed by the California Public Utilities Commission; California's Commercial End-Use Survey (CEUS), which was prepared by Itron, Inc. for the California Energy Commission in cooperation with California's investor-owned utilities (i.e., Pacific Gas and Electric, San Diego Gas and Electric, Southern California Edison, Southern California Gas Company) and the Sacramento Municipal Utilities District; and the Building America – National Residential Efficiency Measures Database, which is developed by the National Renewable Energy Laboratory (NREL) with support from the U.S. Department of Energy (DOE). These load shapes were developed through extensive building end-use metering and energy simulation modeling and were normalized for historical weather conditions and patterns applicable to particular climate regions. The load shapes selected from these sources targeted the residential and customer sectors separately with different building end-uses that relate to the energy efficiency measures in the programs. TEP selected the load shapes carefully to account for seasonal or diurnal variations in operational or end-use patterns for different measures. TEP utilized the CA-based DEER and CEUS load shapes only as a means to develop 8,760 hourly shaping on the energy efficiency measures. The annual savings values that will be attributed to these hourly savings load shape are calculated specifically for TEP's programs through program design and third-party Measurement, Evaluation, and Research (MER).

Since the weather-sensitive energy efficiency measure load shapes from DEER and CEUS were developed for California, TEP had to apply adjustment factors appropriate for its particular service territory in Arizona. First for weather calibration purposes, TEP utilized typical meteorological year (TMY3) weather data for Tucson, AZ and compared that to the load shapes developed for CA's Climate Zone 15, which is the closest geographically as well as the most compatible weather region in CA to TEP's service territory, and then adjusted hourly indexed values as needed. This approach of weather calibration ensures that weather-sensitive energy efficiency measures that have seasonal or diurnal variations in energy savings would have the appropriate effect for TEP's climate region. Furthermore, the TMY3 weather data sets, which were developed by NREL with support from DOE, are based on climate data from a period from 1991-2005. Utilizing recent historical weather data helps to weather normalize the savings effects of weather-sensitive energy efficiency measures at the hourly level. The Building America database included measure savings load shapes developed utilizing TMY3 weather data for Tucson, AZ; therefore, no such weather adjustments were needed for these load shapes.

After determining the measure shapes, TEP was able to apply a measure's annual energy savings value with the appropriate measure end-use load shape to determine a unique measure-specific savings load shape. TEP was then able to aggregate the hourly savings value for all given measures in a particular program to determine a program-level savings load shape. From these composite program-level savings load shape, TEP is able to apply its definition of peak periods to determine coincident and non-coincident peak demand savings.

Additionally, to determine long-term cumulative energy savings forecasted on the 15-year time-frame, TEP multiplied the effective measure life for each particular measure to the measure's annual energy savings value and aggregated these cumulative savings at the program-level and portfolio-level. The end result of the aggregation is a 15-year outlook on how the total incremental program year savings will carry out through the effective measure lives of all the measures that comprise the programs.

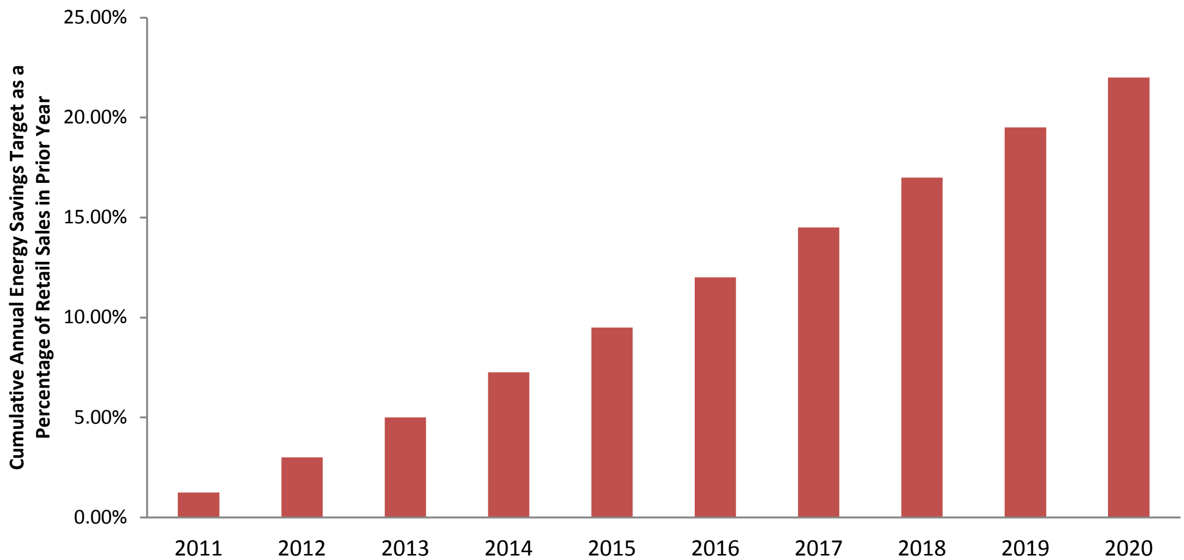
While the focus of this IRP is on future resources planning, TEP also acknowledges the importance of attributing verified savings values for individual measures and programs from Measurement, Evaluation, and Research (MER) results. TEP has retained the services of Navigant to serve as the MER contractor for TEP's portfolio of DSM programs. Navigant verifies energy savings for the programs utilizing the most rigorous industry evaluation standards and protocols as outlined by sources such as the International Performance Measurement and Verification Protocol (IPMVP) and Federal Energy Management Plan (FEMP).

Load Shape Results

The hourly savings determined through the Methodology Section above allowed TEP to forecast annual energy and peak demand savings for TEP's portfolio of DSM programs both to determine a 15-year outlook on resources and to meet the Energy Efficiency Standard savings targets by 2020.

The cumulative annual energy savings from the implementation of the 2012 DSM programs and prior 2011 programs towards meeting the energy savings goals within the time-frame of the Energy Efficiency Standard (2011 to 2020) are shown in the following figure.

Figure 23 - Cumulative Annual Savings Impacts



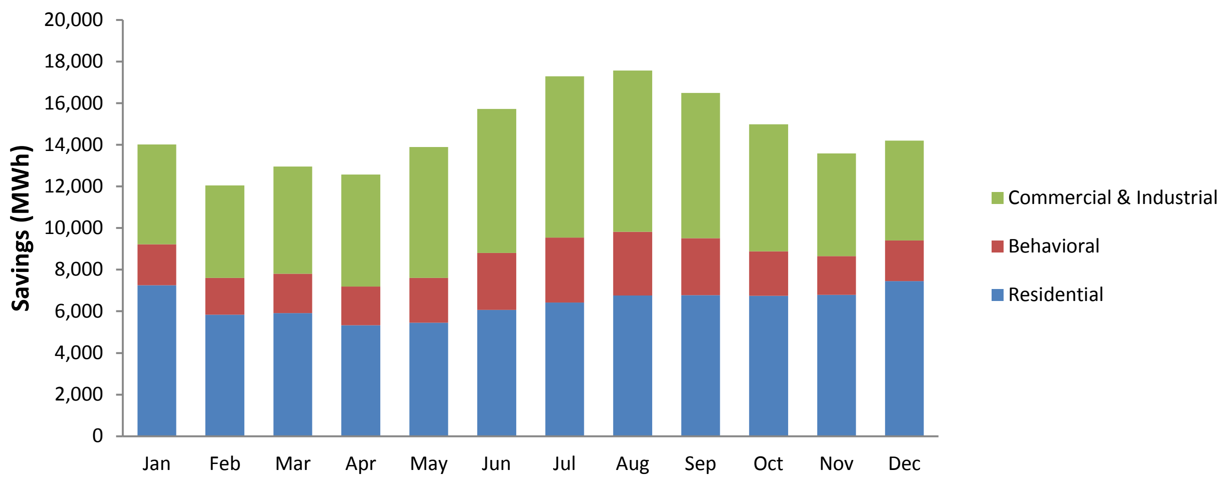
TEP chose to include the savings impact from 2011 due to the fact that the Energy Efficiency Standard is a cumulative annual energy savings target goal that began in 2011 and carries through the end of 2020. The Energy Efficiency Standard has significant savings target ramp ups in 2013 through 2020 that will require increase in DSM program investments for those years to meet those savings targets. TEP is strongly committed to investing in DSM to meeting the cumulative annual savings target in the Energy Efficiency Standard and also integrating DSM into its Resource Planning. As taken from the Energy Efficiency Standard, Table 31 illustrates the ramp up effect of the Energy Efficiency Standard (i.e., an increase in the cumulative annual energy savings by the end of each calendar year as a percentage of the retail energy sales in the prior calendar year).

Table 31 – Energy Efficiency Standard Cumulative Annual Savings Target

Calendar Year	Energy Efficiency Standard (Cumulative Annual Energy Savings by the End of Each Calendar Year as a Percentage of the Retail Energy Sales in the Prior Calendar Year)
2011	1.25%
2012	3.00%
2013	5.00%
2014	7.25%
2015	9.50%
2016	12.00%
2017	14.50%
2018	17.00%
2019	19.50%
2020	22.00%

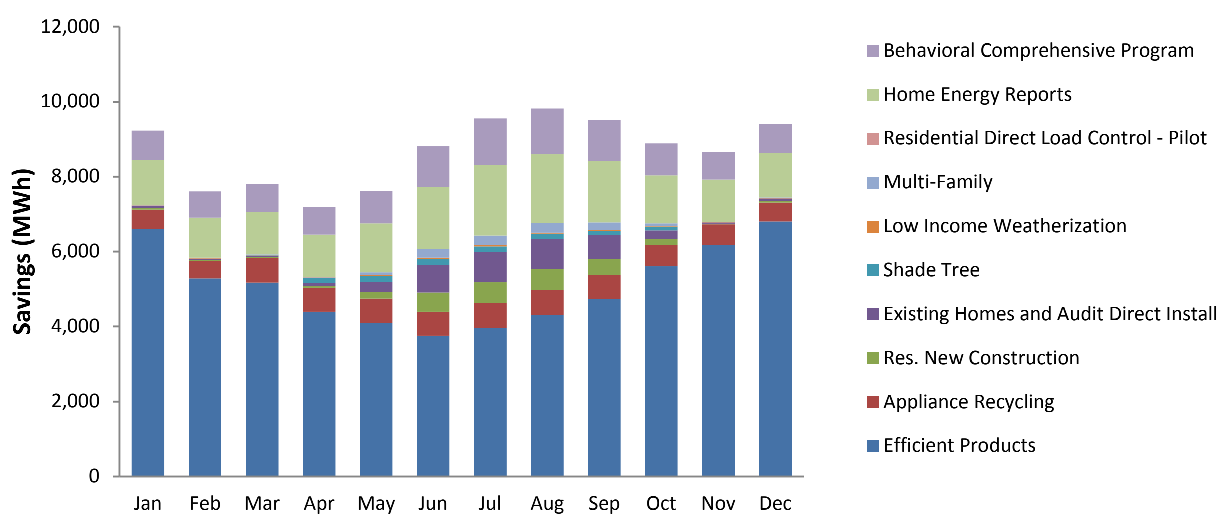
While the focus of this IRP is the long-term savings impact of the implemented programs in TEP's DSM portfolio, considering the full incremental year's savings impacts is beneficial to understanding how DSM program savings will affect TEP's load on a monthly level. Utilizing the hourly savings load shape data, TEP is able to portray the monthly energy savings that result from a full year's effect for the 2012 portfolio of programs. Figure 24 shows monthly energy savings for a full year's impact that result from the implementation of the TEP's portfolio of programs in 2012. The monthly energy savings were determined from aggregating hourly measure-level savings in the Methodology section above.

Figure 24 – Monthly Energy Savings for a Full Year's Impact of TEP's Implemented 2012 DSM Portfolio



Energy savings across the portfolio are greatest in the summer months due to measures that seek to reduce cooling consumption associated with Tucson's hot summer temperatures. In addition, the energy savings are relatively high in the winter months largely due to measures that reduce heating consumption and due to residential lighting measures that have greater usage from limited daylight hours and sunlight exposure. As expected, the shoulder months have the least savings due to limited heating or cooling usage and a more even distribution of daylight to non-daylight hours. Figure 25 shows monthly energy savings for a full year's impact that result from the implementation of the 2012 Residential and Behavioral DSM programs.

Figure 25 - 2012 Residential & Behavioral DSM Programs



The Efficient Products Program, which is largely comprised of indoor lighting measures have the greatest savings during winter months. This reflects the fact that winter months have on average fewer daylight hours and less sunlight exposure than those of the summer months; this seasonal difference typically results in greater lighting usage in the winter months. In addition, as expected, savings where higher in summer months due to programs and measures that targeted reducing cooling consumption.

Figure 26 shows monthly energy savings for a full year's impact that result from the implementation of the 2012 commercial and industrial DSM programs.

Figure 26 - 2012 Commercial & Industrial DSM Programs

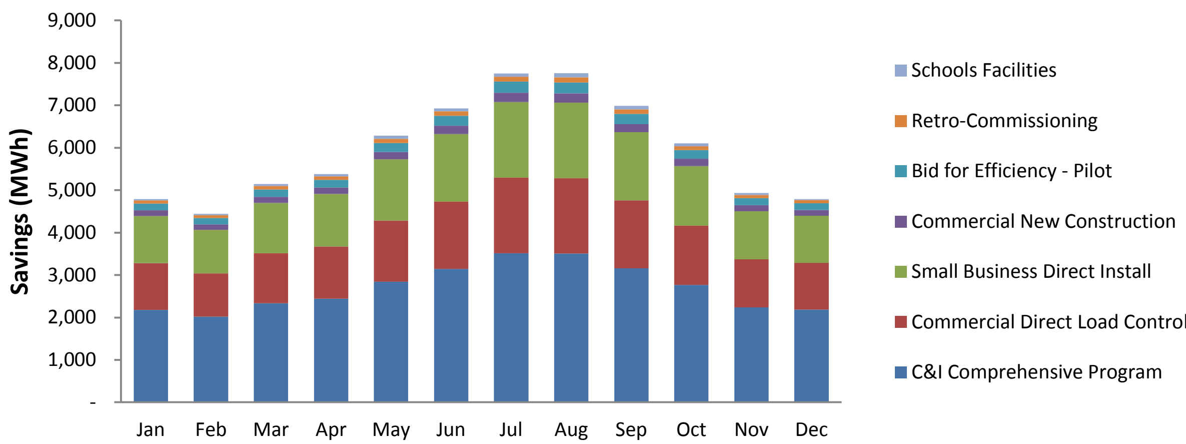
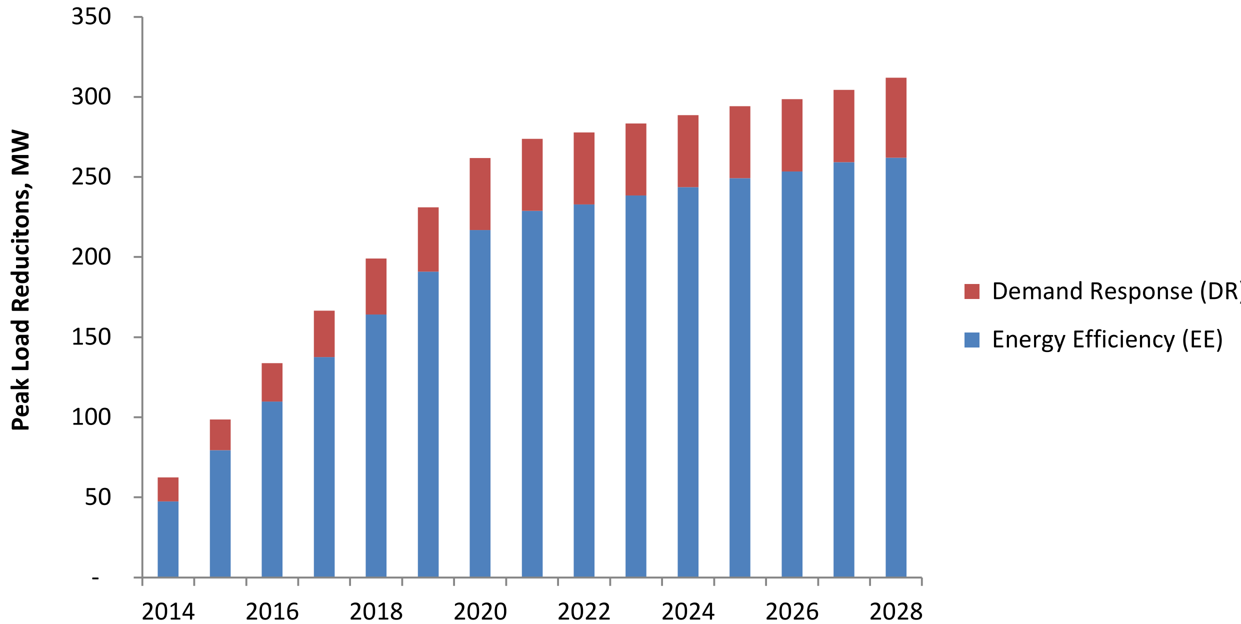


Figure 26 shows the monthly distribution of savings that result from commercial and industrial DSM programs. Many of these programs show the greatest impact in the summer months resulting from energy efficiency measures that are targeted towards reducing cooling consumption during those months. Unlike the residential programs, commercial programs are generally unaffected by limited daylight hours during winter months as most interior lighting measures are more reflective of business operations, which is typically consistent year-round.

While TEP's goal is to meet the Energy Efficiency Standard goal by 2020 and determine DSM program savings through 2028, TEP also considered the impact that TEP's portfolio of DSM programs will have on reducing TEP's system peak demand. TEP's system peak period occurs throughout the summer months; therefore, TEP determined the cumulative long-term impact that its programs will have on reducing TEP's system peaks throughout the peak period. The following figure depicts the cumulative annual peak demand savings for TEP's portfolio of programs 2014 through 2028.

Figure 27 - Long-term Cumulative Annual Peak Demand Reduction Impacts



As expected, the cumulative annual peak demand savings from TEP's DSM programs will increase with the increase in cumulative annual savings target goals in the Standard that TEP will meet. The peak demand reduction that occurs through TEP's programs will allow energy efficiency to reduce TEP's system peak that occurs throughout the summer months.

Projected Energy Efficiency Requirements in the 2014 IRP

Energy Efficiency

TEP proposes to pursue a range of cost-effective and industry-proven programs to meet future energy efficiency targets. TEP's proposed energy efficiency portfolio maintains compliance with the Arizona Energy Efficiency Standard which targets cost effective programs that reach a 22% cumulative energy reduction by 2020. By 2020, this offset to future retail load growth is expected to reduce TEP's annual energy requirements by approximately 1,816 GWh and reduce TEP's system peak demand by 312 MW.

Demand Response

The Reference Case plan targets dispatchable demand response programs that reduce TEP's summer peak loads. TEP's future demand response programs are expected to reduce TEP's system peak demand by 50 MW by 2028. Figure 28 shows the equivalent capacity reductions installed under future energy efficiency and demand response programs for the Reference Case plan from 2014 through 2028.

Figure 28 - Energy Efficiency and Demand Response (Equivalent Capacity Reductions)

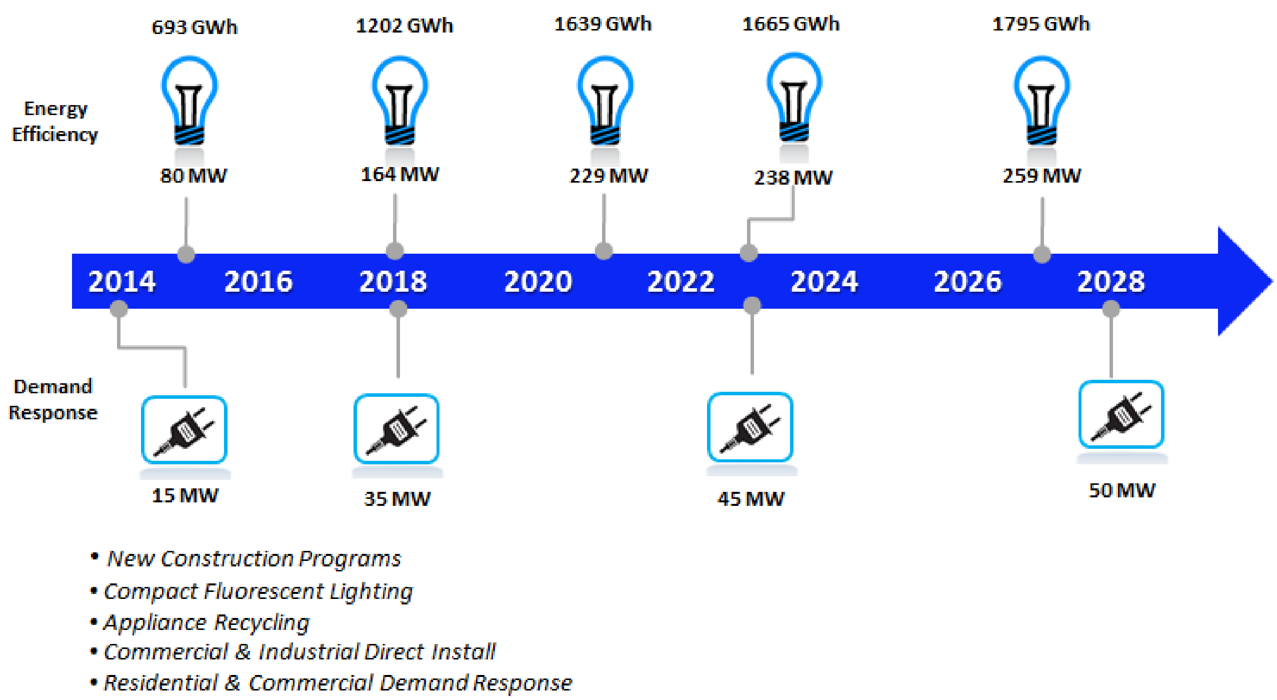


Table 32 – 2014-2021 Projected Energy Efficiency Program Schedule

Energy Efficiency Programs	2014	2015	2016	2017	2018	2019	2020	2021
Energy Efficiency, GWh	537.4	692.8	862.8	1,033.0	1,202.4	1,376.1	1,544.3	1,618.7
Demand Response, GWh	3.1	3.1	3.8	3.2	3.0	2.8	2.7	3.0
Total Energy Efficiency, GWh	540.5	695.8	866.5	1,036.2	1,205.4	1,378.9	1,547.0	1,621.7
Energy Efficiency, MW	48	80	110	137	164	191	217	229
Demand Response, MW	15	19	24	29	35	40	45	45
Total Energy Efficiency, MW	63	99	134	166	199	231	262	274
Energy Efficiency, $000	$17,944	$20,387	$25,087	$28,482	$32,449	$38,393	$43,302	$20,441
Demand Response, $000	$1,353	$1,765	$2,296	$2,858	$3,552	$4,182	$4,845	$4,991
Total EE and DR Programs	$19,296	$22,152	$27,383	$31,339	$36,001	$42,574	$48,148	$25,432

Table 33 – 2022-2028 Projected Energy Efficiency Program Schedule

Energy Efficiency Programs	2022	2023	2024	2025	2026	2027	2028
Energy Efficiency, GWh	1,635.9	1,665.3	1,693.6	1,725.1	1,754.7	1,794.7	1,813.3
Demand Response, GWh	3.5	3.1	3.3	3.3	3.2	3.9	3.3
Total Energy Efficiency, GWh	1,639.5	1,668.4	1,696.9	1,728.4	1,757.9	1,798.6	1,816.6
Energy Efficiency, MW	233	238	244	249	253	259	262
Demand Response, MW	45	45	45	45	45	45	50
Total Energy Efficiency, MW	278	283	289	294	298	304	312
Energy Efficiency, $000	$5,153	$9,649	$10,399	$13,138	$14,177	$22,241	$12,152
Demand Response, $000	$5,140	$5,295	$5,454	$5,617	$5,786	$5,959	$6,820
Total EE and DR Programs	$10,294	$14,944	$15,853	$18,755	$19,962	$28,200	$18,972

Conclusion

The implementation of TEP's 2014 DSM programs will help TEP meet the cumulative annual savings targets in the Energy Efficiency Standard and incorporate energy efficiency into its 15-year resource planning time-frame. Furthermore, stratifying annual measure-level energy savings from a full calendar year's savings on a 8,760 hourly level and then aggregating hourly savings on a monthly program-level portrays the impacts of TEP's DSM programs with respect to seasonal and diurnal weather variations and TEP's system peak periods. With the Energy Efficiency Standard savings target ramping up annually this decade, DSM programs are expected to play a much larger role in TEP's Resource Plan. TEP will continue to monitor DSM program activity and research energy efficiency industry best practices to determine the most cost-effective portfolio of programs that provides energy efficiency solutions to its customers and allows DSM investments to become more incorporated into TEP's resource planning.

Tucson Electric Power BrightEE Awards

In 2014, Tucson Electric Power Co. held an event to recognize customers and other community partners with TEP BrightEE Awards for energy savings achieved through the company's successful energy efficiency (EE) programs. The inaugural TEP BrightEE Awards were presented to local nonprofit organizations, school districts, small businesses and homebuilders. The BrightEE recipients were customers who reduced their energy use and lowered their monthly electric bills by participating in TEP's customer-funded EE programs.

The BrightEE categories and winners selected by TEP's EE team are as follows:

Large Business — Carondelet St. Mary's Hospital: St. Mary's most notable projects include retrofitting more than 20,000 florescent T12 tube lamp fixtures with more efficient lamps and thousands of electronic ballasts. The hospital also installed variable speed drives, which can raise or lower motor speeds used in HVAC and other systems. Installation of an automated energy management system is scheduled to be completed this summer.

Small Business — Vroom Engineering: This local engineering firm participated in the Small Business program to replace more than one hundred 1,000-Watt, metal halide light fixtures with energy efficient high bay fluorescent fixtures.

Contractor — Inline Electrical Resources: Inline was the first applicant to register as a contractor for TEP's Small Business program. Since then, Inline has completed more than 200 energy efficiency projects.

Schools — Sunnyside Unified School District: Sunnyside has upgraded classroom lighting and mechanical equipment at the majority of its schools and several support facilities. In 2013, the company gave 17 EE classroom presentations and distributed more than 450 energy efficiency kits for Sunnyside students to use at home through TEP's Outreach Program. Desert View High School also participates in TEP's Direct Load Control program.

Schools — Marana Unified School District: Marana has upgraded lighting and HVAC equipment in several schools by combining TEP incentives with federal funding available through the 2009 American Recovery and Reinvestment Act. More than two dozen EE classroom presentations were given in 2013 alone and TEP has distributed more than 550 EE kits to students.

Non-Profit — The Primavera Foundation: In 2013, Primavera completed construction of a new energy-efficient, 12-unit family complex that was built in South Tucson using sustainable principles. The project is designed to meet LEED and Net-Zero Energy Building standards through a mix of 2- and 3-bedroom patio units that are ADA compliant. (Note: This nonprofit organization, which administers affordable housing, workforce development and neighborhood revitalization programs, is a past recipient of TEP's Grants That Make a Difference program, which is funded with shareholder dollars.)

Homebuilder — Meritage Homes: Meritage was the first national builder to construct every home using standards that meet or exceed ENERGY STAR® requirements. Meritage, which participates in TEP's New Construction program, builds homes that are twice as energy efficient as a typical U.S. home of the same size.

Lifetime Contribution to Residential Energy Efficiency — John Wesley Miller: Miller, a national leader in energy conservation and green building practices, has received numerous industry honors and awards for energy conservation and building quality. He has consulted with Pima County to promote a program for energy-efficient homes and the use of solar energy, and with the University of Arizona's Environmental Research Laboratory in developing new energy-saving products and technologies. Miller is one of four builders selected by the U.S. Department of Energy to develop highly-efficient "zero-energy use" homes. The second such home built by Miller costs an average of about $300 annually to heat and cool.

CHAPTER 12

Renewable Resources

Overview

The resource planning team relied on a number of industry experts such as Black and Veatch, United States Department of Energy, National Renewable Energy Laboratory to help develop the operational and cost assumptions for renewable technologies. This chapter provides an overview on the assumptions used in the resource planning evaluations. For the 2014 resource plan the following renewable technologies were considered:

- Solar - Photovoltaic
- Solar - Concentrating PV Technology (CPV)
- Solar - Concentrating Solar Power Technology (CSP)
- Wind Turbines
- Bio-Resources

Renewable resource assumptions were based on the following data sources:

1. United States Department of Energy (DOE), Energy Efficiency & Renewable Energy Website
   http://www1.eere.energy.gov/solar/

2. United States Department of Energy (DOE), Electricity Advisory Committee
   2012 Storage Report: Progress and Prospects
   http://energy.gov/oe/downloads/eac-2012-storage-report-progress-and-prospects-recommendations-department-energy

3. National Renewable Energy Laboratory (NREL) Website
   http://www.nrel.gov/

4. PACE Global Insights

5. TEP's competitive procurement process and on-going R&D efforts.

EXISTING RENEWABLE RESOURCES

Overview

Over the last several years, Tucson Electric Power has constructed solar, wind and biofuel resources or entered into purchased power agreements (PPAs) to provide renewable energy for its service territory. This is part of the company's commitment to meeting the Arizona Renewable Energy standard. The table below lists TEP's existing and planned renewable resources. This table is followed by descriptions of the various renewable technologies and detailed descriptions of each individual project.

Table 34 – TEP's Existing Renewable Resources

Resource- Counterparty	Owned/PPA	Technology	Location	Operator-Manufacturer	Completion Date	Capacity MW
Fixed PV						
Springerville	Owned	Fixed PV	Springerville, AZ	Various	Dec 10	6.4
Solon UASTP III	Owned	Fixed PV	Tucson, AZ	Solon	January 2012	5
Astrosol UASTP IV	PPA	Fixed PV	Tucson, AZ	Astrosol	June 2012	6
Solon Prairie Fire	Owned	Fixed PV	Tucson, AZ	Solon	Oct 2012	5
NRG Solar Avra Valley	PPA	Fixed PV	Tucson, AZ	First Solar	Oct 2012	35
TEP Warehouse	Owned	Fixed PV	Tucson, AZ	Various	2012	0.5
Ft Huachuca (Planned)	Owned	Fixed PV	Sierra Vista, AZ	Solon	Q4 2014	17.6
Single Axis Tracking						
Solon UASTP I	Owned	SAT PV	Tucson, AZ	Solon	Dec 2010	1.6
E.On UASTP	Owned	SAT PV	Tucson, AZ	Suntech	Dec 2010	6.6
FRV Picture Rocks	PPA	SAT PV	Tucson, AZ	MEMC	Oct 2012	25
E.On/TEP Valencia	PPA	SAT PV	Tucson, AZ	Areva	July 2013	13.2
Pima Mine Rd (Planned)	PPA	SAT PV	Tucson, AZ	Avalon	Q4 2014	28.0
Concentrated PV						
Amonix UASTP II	PPA	CPV	Tucson, AZ	Amonix	Apr 11	2
Wind						
Macho Springs	PPA	Wind	Deming, NM	Element Power	Nov 2011	50.4
Red Horse 2 (Planned)	PPA	Wind	Willcox, AZ	Torch Renewables	Q4 2015	40.0
Biomass						
Sexton Energy	PPA	Landfill Gas	Tucson, AZ	Sexton Energy	Dec 11	2.2

Notes: PPA – Purchase Power Agreement - Energy is purchased from a third party provider.
Fixed PV – Fixed Photovoltaic – Stationary Solar Panel Technology
SAT PV – Single Axis Tracking Photovoltaic
CPV – Concentrated Photovoltaic
Sundt's Biogas capacity estimates are representative of capacity that would have been utilized by Sundt Unit 4 if burning conventional natural gas.

SOLAR PV TECHNOLOGY

Solar cells, also called photovoltaic (PV), convert sunlight directly into electricity. PV gets its name from the process of converting light (photons) to electricity (voltage), which is called the *PV effect*. The PV effect was discovered in 1954, when scientists at Bell Telephone discovered that silicon (an element found in sand) created an electric charge when exposed to sunlight. Soon solar cells were being used to power space satellites and smaller items like calculators and watches. Today, thousands of people power their homes and businesses with individual solar PV systems. Utility companies are also using PV technology for large power stations.

Solar panels used to power homes and businesses are typically made from solar cells combined into modules that hold about 40 cells. A typical home will use about 10 to 20 solar panels to power the home. The panels are mounted at a fixed angle facing south, or they can be mounted on a tracking device that follows the sun, allowing them to capture the most sunlight. Many solar panels combined together to create one system is called a solar array. For large electric utility or industrial applications, hundreds of solar arrays are interconnected to form a large utility-scale PV system.

Traditional solar cells made from silicon, are usually flat-plate, and generally are the most efficient. Second-generation solar cells are called thin-film solar cells because they are made from amorphous silicon or non-silicon materials such as cadmium telluride. Thin film solar cells use layers of semiconductor materials only a few micrometers thick. Because of their flexibility, thin film solar cells can double as rooftop shingles and tiles, building facades, or the glazing for skylights.

Third-generation solar cells are being made from variety of new materials besides silicon, including solar inks using conventional printing press technologies, solar dyes, and conductive plastics. Some new solar cells use plastic lenses or mirrors to concentrate sunlight onto a very small piece of high efficiency PV material. The PV material is more expensive, but because so little is needed, these systems are becoming cost effective for use by utilities and industry. However, because the lenses must be pointed at the sun, the use of concentrating collectors is limited to the sunniest parts of the country.

Solar Resource Characteristics

Several forms of solar power technology are available. One form is photovoltaic solar power, in which semiconductor solar cells use the photovoltaic effect to absorb sunlight and convert it into direct current power. An inverter then converts the direct current power into alternating current power. Another form of solar concentrating solar power (CPV), uses large reflectors and tracking systems to gather energy from sunlight and focus it into a concentrated beam. Heat from the concentrated beam then creates steam that turns a turbine generator to generate alternating current power.

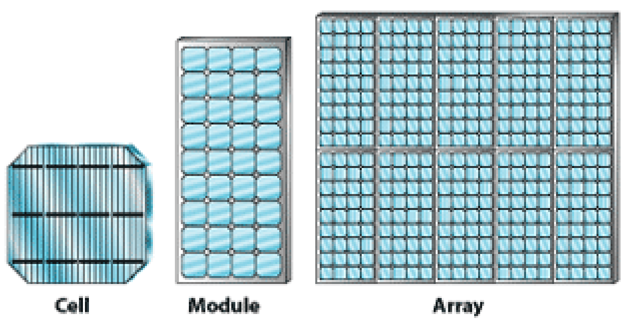
In certain respects, the technological development and commercialization of utility-scale solar power is currently at a stage similar to that of wind power prior to its recent period of rapid growth and widespread adoption by the electric utility industry. For example, large amounts of capital are being invested in research, design and demonstration efforts to improve solar power generating technologies and achieve improved economies of scale. Examples include intensive R&D on advanced forms of solar photovoltaic technologies, and construction of demonstration projects based on large-scale concentrating solar generating technology.

Photovoltaic Solar Power Technology

As noted above, the two primary forms of solar power generating technologies are photovoltaic and concentrating solar. Photovoltaic systems make up the bulk of existing installed solar generating facilities, and can be produced at practically any size. A photovoltaic (PV) or solar cell is the basic building block of a PV (or solar electric) system. An individual PV cell is usually quite small, typically producing about 1 or 2 watts of power. To boost the power output of PV cells, we connect them together to form larger units called modules. Modules, in turn, can be connected to form even larger units called arrays, which can be interconnected to produce more power, and so on. In this way, we can build PV systems able to meet almost any electric power need, whether small or large.

Flat-Plate Photovoltaic Array

Source: Renewable Energy Atlas of the West: A Guide to the Region's Resource Potential

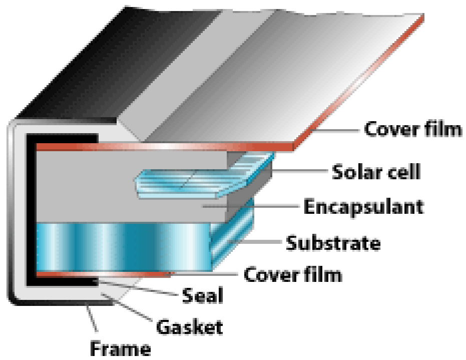


Source: NREL: National Renewable Energy Laboratory

The basic photovoltaic or solar cell typically produces only a small amount of power. To produce more power, cells can be interconnected to form modules, which can in turn be connected into arrays to produce yet more power. Because of this modularity, PV systems can be designed to meet any electrical requirement, no matter how large or how small.

Flat-Plate PV Systems

The most common array design uses flat-plate PV modules or panels. These panels can either be fixed in place or allowed to track the movement of the sun. They respond to sunlight that is either direct or diffuse. Even in clear skies, the diffuse component of sunlight accounts for between 10% and 20% of the total solar radiation on a horizontal surface. On partly sunny days, up to 50% of that radiation is diffuse. And on cloudy days, 100% of the radiation is diffuse.



Source: NREL: National Renewable Energy Laboratory

One typical flat-plate module design uses a substrate of metal, glass, or plastic to provide structural support in the back; an encapsulant material to protect the cells; and a transparent cover of plastic or glass.

Mounting Structures

Photovoltaic arrays must be mounted on a stable, durable structure that can support the array and withstand wind, rain, hail, and other adverse conditions. However, stationary structures are usually used with flat-plate systems. These structures tilt the PV array at a fixed angle determined by the latitude of the site, the requirements of the load, and the availability of sunlight. Among the choices for stationary mounting structures, rack mounting may be the most versatile. It can be constructed fairly easily and installed on the ground or on flat or slanted roofs.

The advantages of fixed arrays are that they lack moving parts, there is virtually no need for extra equipment, and they are relatively lightweight. These features make them suitable for many locations, including most residential roofs. Because the panels are fixed in place, their orientation to the sun is usually at an angle that practically speaking is less than optimal. Therefore, less energy per unit area of array is collected compared with that from a tracking array. However, this drawback must be balanced against the higher cost of the tracking system.

EXISTING SOLAR PV PROJECTS

Table 35 – TEP's Existing Solar PV Resources

Resource- Counterparty	Owned/PPA	Technology	Location	Operator-Manufacturer	Completion Date	Capacity MW
Springerville	Owned	Fixed PV	Springerville, AZ	Various	Dec 2010	6.4
TEP: UASTP III- Solon	Owned	Fixed PV	Tucson, AZ	Solon	Jan 2012	5
Gato Montes	PPA	Fixed PV	Tucson, AZ	Duke Energy	Jun 2012	6
Solon Prairie Fire	Owned	Fixed PV	Tucson, AZ	Solon	Oct 2012	5
NRG Solar Avra Valley	PPA	Fixed PV	Tucson, AZ	First Solar	Oct 2012	35
TEP Warehouse	Owned	Fixed PV	Tucson, AZ	Various	2012	0.5
Picture Rocks Solar	PPA	Fixed PV	Tucson, AZ	Sun Edision	Dec 2012	25
Ft. Huachuca (Planned)	Owned	Fixed PV	Tucson, AZ	Solon	Q4 2014	17.6

Springerville Solar

The 6.8 MW Springerville Solar project is a fixed photovoltaic located on the property of the Springerville Generating Station, 12 miles north of Springerville, AZ, in Northeast Arizona. Tucson Electric Power (TEP) currently has 6.4 MW of solar at the Springerville site. TEP expanded its 4.6 MW solar facility in Springerville at the end of 2010 by adding an additional 1.8 MW solar field adjacent to the current site. The combined systems generate enough electricity to power about 1,024 homes.

Picture 10 - Springerville Solar

The system produces the most power capacity during the cooler months of the year when the sun is near latitude angle. The station averages an annual capacity factor of about 19% with an expected annual output of 10,600 MWh.

The system operates as an unmanned site and is monitored continuously via an Internet based communications channel. Near real time performance is available on the Internet at https://www.tep.com/tracker/

Future plans include the installation of 2 MW to 5 MW of additional solar PV at the Springerville site over the next few years. Technologies of various types for this future expansion will be considered, including Single Axis Tracking (SAT) PV, and High Concentrated PV. TEP will continue to evaluate these technologies and their relative performance over time.

SunPower Rooftop Solar

The SunPower Rooftop Solar projects are being located on otherwise unused roof space that is leased from schools and other public entities throughout the TEP service territory. This provides the public institutions with revenue from, an environmentally friendly source, from an otherwise underutilized asset. Tucson Electric Power granted SunPower Corp. a contract to provide 11 MW of solar power systems technology for the utility's TEP Bright Roofs program.

During the next few years, TEP will use the SunPower technology to install, own and operate multiple solar power systems on leased rooftop space atop schools and other large public buildings in the Tucson area. The solar installations will be connected directly to neighborhood distribution circuits where the rooftops are located, and will generate enough renewable power to serve more than 1,800 Tucson homes.

TEP has purchased the SunPower T5 Solar Roof Tile product, the solar industry's first non-penetrating rooftop product that combines a high-efficiency SunPower solar panel, frame and mounting system into a single pre-engineered unit. Tilted at a five-degree angle, the T5 Roof Tile system nearly doubles the energy generated per square meter compared to conventional systems that are mounted flat onto commercial rooftops. The T5 Solar Roof Tiles interlock for secure, rapid installation and maximum power output. Smooth-edged, durable and lightweight polymer material designed for a 30-year life protects the roof and eliminates the need for electrical grounding. The patented design resists high winds and corrosion and is flexible to adapt to virtually any flat or low-slope roof.

Solon / TEP U of A STP III

SOLON III is a 5-megawatt fixed photovoltaic system designed and built by SOLON Corporation, and installed at University of Arizona Science and Technology Park (UASTP). The fixed tilt array sits on 34 acres and is powered by twenty-one thousand high efficiency modules.

NRG Solar / Avra Valley

The 35 MW NRG Solar project is a fixed photovoltaic located on 320 acres on the Lupari Farm in Avra Valley, AZ. NRG Energy, through its wholly owned subsidiary NRG Solar, is developed the Avra Valley Solar Project, a 25 megawatt (MW) solar photovoltaic facility. The facility will produce clean, renewable electricity that will be sold to Tucson Electric Power under a 20-year power purchase agreement. At full capacity, the Avra Valley Solar Project will generate enough power to supply approximately 20,000 homes. The Avra Valley Solar Project is located on approximately 300 acres of fallow agricultural land, located about 20 miles west of Tucson, Arizona.

Gato Montes

Gato Montes is a 6.1 megawatt photovoltaic (PV) system designed and built by Astroenergy, and installed at the University of Arizona Science and Technology Park (UASTP). The array is comprised of thin-film, amorphous silicon modules mounted on a fixed-tilt racking structure. Astroenergy will sell its output to TEP through a 20-year purchase power agreement

Solon Prairie Fire

Prairie Fire is a 5-megawatt (MW) DC solar facility located in Pima County off Valencia Road east of Kolb Road in Tucson. SOLON designed and constructed the array. The PV technology used is a crystalline fixed system photovoltaic (PV) module. The plant consists of 17,604 PV panels. Prairie Fire began providing power to TEP customers in late December 2012. TEP owns and operates this system, and will continue to handle operations, monitoring and maintenance.

TEP Warehouse

The TEP Warehouse is a 0.5 MW Fixed Photovoltaic solar installation on the warehouse at the Irvington Sundt Generating station campus.

Solon / Ft. Huachuca (Future Project)

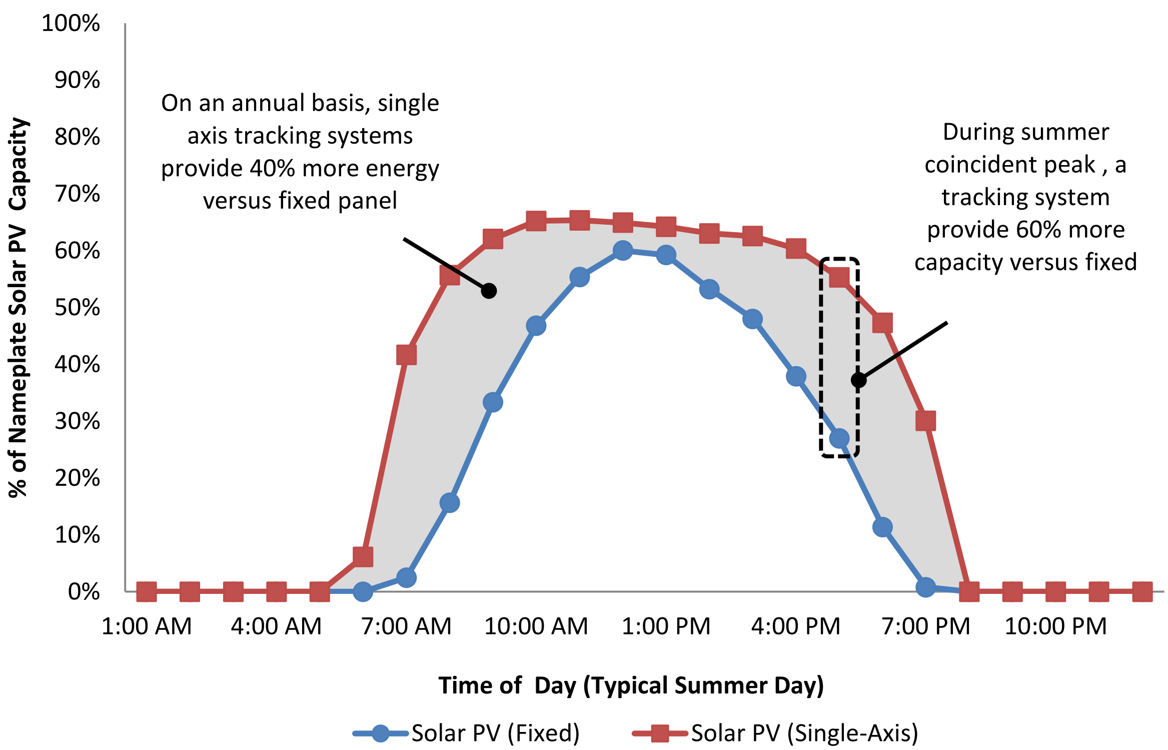
The Fort Huachuca project which will be owned by TEP is a 17.6-megawatt fixed photovoltaic system that will be installed at Ft. Huachuca Army base. The fixed tilt array will be sighted on 300 acres and is powered by 1,872-watt high efficiency modules manufactured by BYD Company Limited. This project is scheduled to go on line in the fourth quarter of 2014.

Single Axis Tracking Systems

Sometimes, the solar mounting structure is designed to track the sun. There are two basic kinds of tracking structures: one-axis and two-axis. The one-axis trackers (SAT PV) are typically designed to track the sun from east to west. They are used with flat-plate systems and sometimes with concentrator systems. The two-axis type is used primarily with PV concentrator systems. These units track the sun's daily course and its seasonal course between the northern and southern hemispheres. Naturally, the more sophisticated systems are the more expensive ones, and they usually require more maintenance.

Chart 50 - Comparison of Solar Photovoltaic Systems

(Fixed Panel vs. Single Axis Tracking)



EXISTING SINGLE AXIS TRACKING PROJECTS

Table 36 – TEP's Existing Single Axis Tracking Resources

Resource- Counterparty	Owned/PPA	Technology	Location	Operator-Manufacturer	Completion Date	Capacity MW
UASTP I	Owned	SAT PV	Tucson, AZ	Solon	Dec 11	1.6
E-ON UASTP	PPA	SAT PV	Tucson, AZ	Astronergy	2012	6.6
E-ON Valencia	PPA	SAT PV	Tucson, AZ	EON	2013	13.2
Pima Mine Road Solar (Future)	PPA	SAT PV	Tucson, AZ	Avalon	Q4 2014	28.0

TEP U of A STP I

UASTP 1 is a 1.6-megawatt single-axis tracking system designed and built by the Tucson-based SOLON Corporation, and installed at the University of Arizona Science and Technology Park (UASTP).
TEP customers can purchase solar power through Bright Tucson Community Solar, a TEP program that allows customers to reduce their conventional energy usage.

E-ON Valencia

The 6.6 MW EON UASTP project is a Single Axis Tracker located the University of Arizona Science and Technology Park in Tucson, AZ

E-ON UASTP

The 13.2 MW Foresight Solar (FSP Solar Two) project is a Single Axis Tracker located the University of Arizona Science and Technology Park in Tucson, AZ

Avalon / Pima Mine Road Solar Generating Facility (Future Project)

The Pima Mine Rd. project is a 28-megawatt single axis tracking photovoltaic system designed, built and owned by Equator Solar, LLC's subsidiary Avalon Solar Partners, LLC, and will be located near the Asarco LLC Mission Mine 12 miles south of Tucson, AZ. Construction on this project is scheduled to begin at the end of April, 2014 with the system going on line in the fourth quarter of 2014. TEP will take power from this project under a 20-year purchase power agreement.

Concentrating Solar Power Technology (CPV)

Overview

Concentrating photovoltaic systems use lenses or mirrors to concentrate sunlight onto high-efficiency solar cells. These solar cells are typically more expensive than conventional cells used for flat-plate photovoltaic systems. However, the concentration decreases the required cell area while also increasing the cell efficiency.

Amonix Concentrating Photovoltaic System

Concentrating photovoltaic technology offers the following advantages:

- Potential for solar cell efficiencies greater than 40%
- No moving parts
- No intervening heat transfer surface
- Near-ambient temperature operation
- No thermal mass; fast response
- Reduction in costs of cells relative to optics
- Scalable to a range of sizes.

The high cost of advanced, high-efficiency solar cells requires the use of concentrated sunlight for systems to achieve a cost-effective comparison with both the cost of concentrator optics and other solar power options. NREL has focused on the development of multi-cell packages (dense arrays) to improve overall performance, improve cooling, and install reliable prototype systems.

Concentrating PV Projects

Table 37 – TEP's Existing Concentrating PV Resources

Resource-Counterparty	Owned/PPA	Technology	Location	Operator-Manufacturer	Completion Date	Capacity MW
Amonix UASTP II	PPA	CPV	Tucson, AZ	Amonix	Mar 11	2

UASTP – TEP II

UASTP TEP II is a 2-megawatt photovoltaic (CPV) system designed and built by Amonix, Inc., and installed at the UA Tech Park. UASTP2 consists of 12 acres lined with 34 dual-axis trackers that reach up to 50 feet off the ground on pedestals that track the sun horizontally and vertically. Amonix will sell its output to TEP through a 20-year purchase power agreement.

Concentrating Solar Power Technology (CSP)

Concentrating solar is the second main type of solar power generation. Concentrating solar power uses mirrors to reflect and concentrate sunlight onto receivers that collect the solar energy and convert it to heat. This thermal energy can then be used to produce electricity via a steam turbine or heat engine driving a generator. In virtually all applications, CSP is large in scale, on the order of 100 MW or larger.

There are three generic system architectures: line-focus (trough systems), point-focus central receiver (power towers), and point-focus distributed receiver (dish-engine systems).

Power Tower Systems

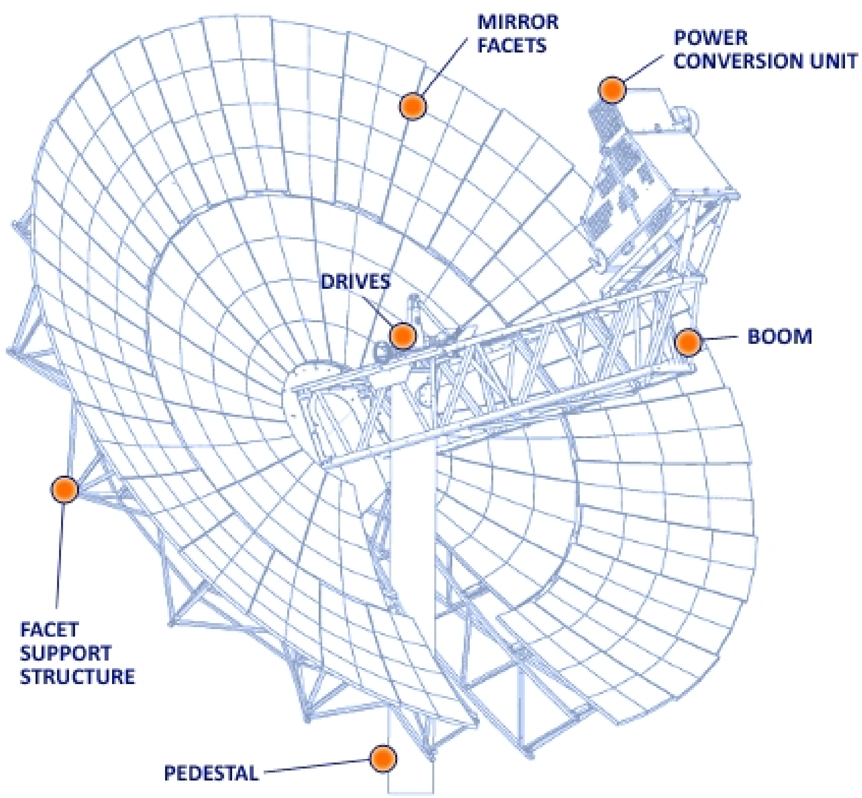
Power tower systems consist of a field of large, nearly-flat mirror assemblies (heliostats) that track the sun and focus the sunlight onto a receiver at the top of a tower. In a typical configuration, a heat-transfer fluid such as water/steam or molten nitrate salt mixture is pumped through the receiver, and used to generate steam to power a conventional steam-turbine power cycle generating electricity. In some systems, excess thermal energy can be stored during daylight hours to provide electricity at times when the sun is not available and at night. An advantage of power tower systems over linear concentrator systems is that higher temperatures can be achieved in the working fluid, leading to higher efficiencies and lower-cost electricity.

Ivanpah Solar Electric Generating Station (392 MW)

The Ivanpah Solar Electric Generating Station is located in Ivanpah Dry Lake, Calif., about 40 miles southwest of Las Vegas. BrightSource began development in 2006, and construction commenced in October 2010, led by engineering, procurement, and construction partner Bechtel. The station was first synced to the grid in September 2013 and went into commercial operation at the end of 2013. The station is comprised of three separate units and has long-term purchase power agreements in place with Pacific Gas & Electric (Units 1 and 3) and Southern California Edison (Unit 2).

Stirling Solar Dish Technology

The solar dish Stirling technology is well beyond the research and development phase, with more than 20 years of recorded operating history. The equipment is well characterized with over 50,000 hours of on-sun time. The Stirling technology is based on a 25-kilowatt-electrical solar dish system which consists of a unique radial solar concentrator dish structure that supports an array of curved glass mirror facets, designed to automatically track the sun, collect and focus, that is, concentrate, its solar energy onto a patented Power Conversion Unit (PCU). The PCU is coupled with, and powered by, a completely re-engineered SES Stirling engine that generates power grid-quality electricity.



The PCU converts the focused solar thermal energy into grid-quality electricity. The conversion process in the PCU involves a closed-cycle, high-efficiency four-cylinder, reciprocating Solar Stirling Engine utilizing an internal working fluid that is recycled through the engine. The Solar Stirling Engine operates with heat input from the sun that is focused by the dish assembly mirrors onto the PCU's solar receiver tubes which contain hydrogen gas. The PCU solar receiver is an external heat exchanger that absorbs the incoming solar thermal energy. This heats and pressurizes the gas in the heat exchanger tubing, and this gas in turn powers the Solar Stirling Engine.

25 MW Solar Parabolic Dish-Engine System (NREL)

A generator is connected to the Solar Stirling Engine; and produces the grid-quality electrical output. Waste heat from the engine is transferred to the ambient air via a radiator system similar to those used in automobiles. The gas is cooled by a radiator system and is continually recycled within the engine during the power cycle. The conversion process does not consume water, as is required by most thermal-powered generating systems.

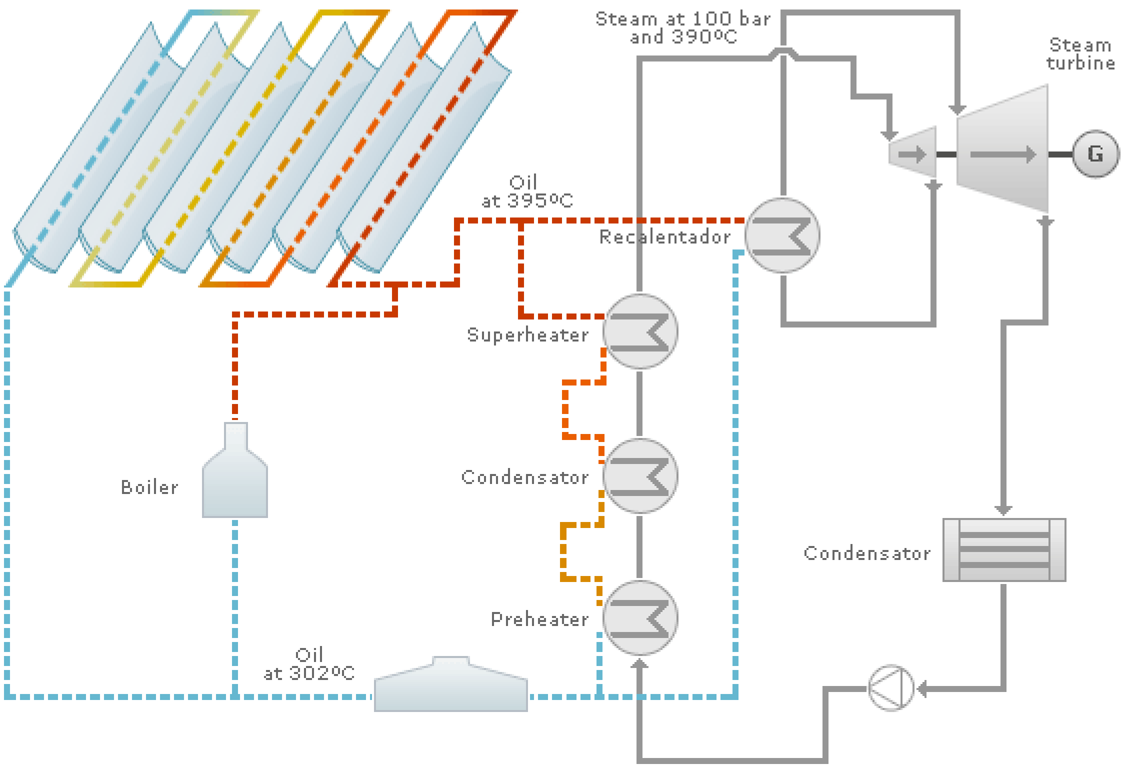
Trough Systems

A trough system is usually oriented in a north-south direction and tracks the sun from east to west focusing solar energy on a long tubular receiver. The typical working fluid in a trough system is synthetic oil that is heated to about 390°C (734°F). The hot oil is used to generate steam for use in a conventional Rankine cycle steam turbine system. The predominant CSP systems in operation in the United States are linear concentrators using parabolic trough collectors. In addition, trough systems can be hybridized (natural gas co-firing) or use thermal storage to dispatch power to meet utility peak load requirements. The variants of these CSP technologies are shown in detail below.

Harper Lake Solar CSP Project (NREL)

Concentrating Solar Power Technology

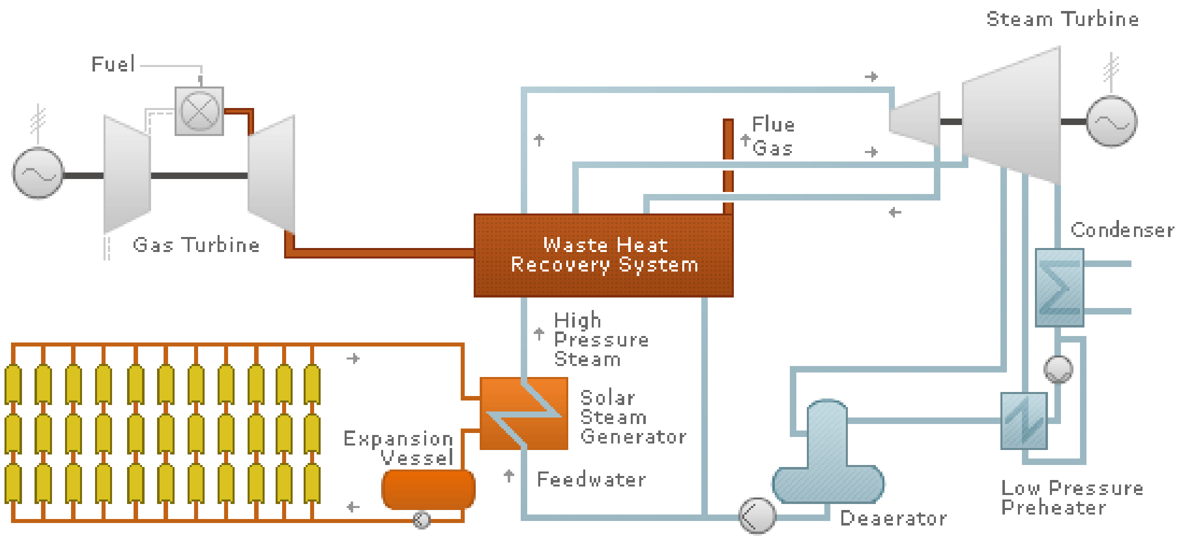
As shown below, the solar trough field heats synthetic transfer oil. Energy in the oil is used to generate superheated, high pressure steam that is delivered to a steam turbine. This turbine powers an electrical generator, creating electricity



Solar CSP (Abengoa Solar)

Concentrating Solar Power Technology – Hybridized Configuration with Natural Gas Co-Firing

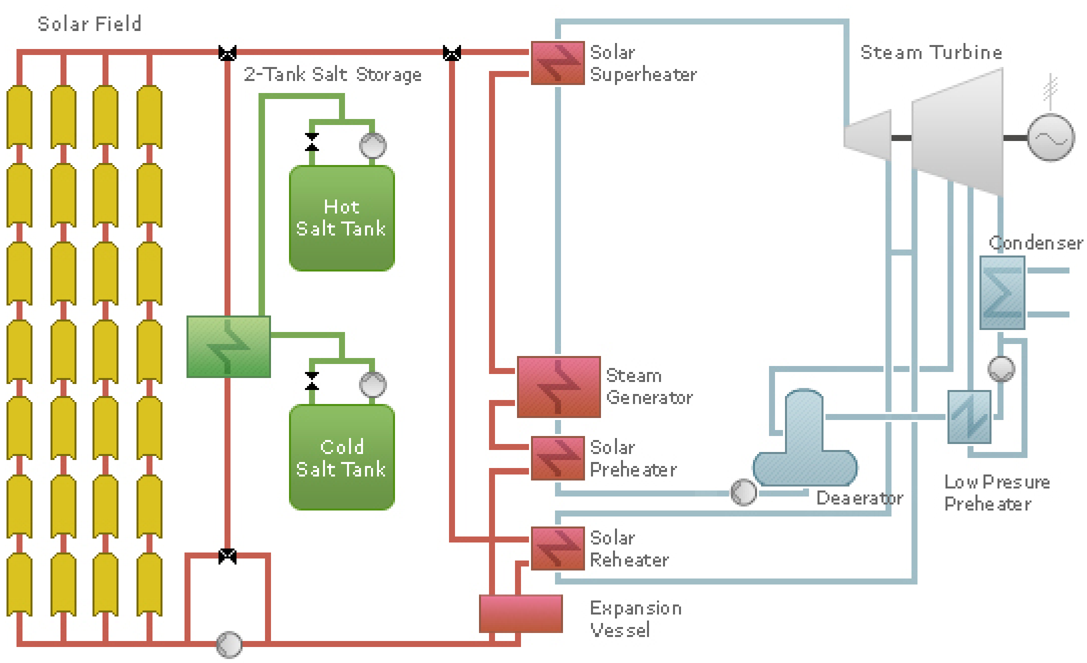
New innovative designs that incorporate hybridized configurations such as Integrated Solar Combined Cycle (ISCC) are also in the early stages of development. ISCC technology combines the benefits of solar energy with the benefits of a combined cycle. The solar resource partially substitutes the fossil fuel. The operation of a solar combined hybrid plant is similar to the one of a conventional combined cycle plant. The fuel (preferably natural gas) is burned generally on a combustion chamber of a gas turbine. The heat coming from the solar field is added to escape gases that are directed to the heat retriever, resulting in increased steam generation and, consequently, an increase of electricity production from the steam turbine.



Solar CSP Hybrid with Natural Gas Co-Firing (Abengoa Solar)

Concentrating Solar Power Technology – Storage Configuration based on Two-Tank Molten Salt System

Future solar technologies are being enhanced with the addition of energy storage systems. With the use of a thermal energy storage system, future solar plants will be able to produce output during non-daylight hours. One of the promising materials being used to store the sun's thermal capacitance is molten-nitrate salt. In this design configuration, large insulated tanks filled with molten salt are used with solar trough technology to store the heat from the synthetic transfer oil. This stored heat is used to improve the dispatchability of the solar resource. Current projects being developed using this type of advanced thermocline thermal storage system are projecting a six hour storage capacity.



Solar CSP with Thermal Storage (Abengoa Solar)

CONCENTRATING SOLAR PROJECTS

Areva Solar

Areva Solar is TEP's first use of solar thermal technology to augment existing steam generation at the Sundt Generating Station. Named the Sundt Solar Boost Project, TEP described the project as 5-megawatt equivalent renewable resource. Integrated with the existing duel fuel (Coal or Natural Gas) Sundt Unit 4, the Areva addition is expected to boost peak capacity of the unit by 5 MW.

Areva's Compact Linear Fresnel Reflector (CLFR) technology uses mirrors to concentrate sunlight to directly create steam power. Rather than using trough- or dish-shaped mirrors common to other concentrating solar systems, Areva's technology uses a system of nearly flat mirrors, arranged in louver like arrays and motorized to track the sun, to heat up water passing overhead through a linear absorber. The Areva system also is designed to heat water directly, compared with other systems that generate steam indirectly with heat-transfer fluids such as oil or molten salt. The Areva system is expected to be completed in 2014.

Areva acquired the reflector technology, pioneered in Australia, in 2010 when it bought California-based Ausra Inc. The technology is used in a 5MW stand-alone solar plant in Bakersfield and is being added to provide 44 megawatts of new steam power to CS Energy's coal-fired Kogan Creek power plant in Queensland, Australia.

Areva Solar – Sundt Generating Station

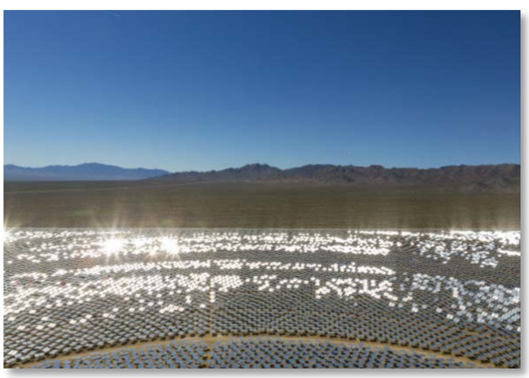
REGIONAL CONCENTRATING SOLAR PROJECTS

Ivanpah Solar Electric Generating Station

IVANPAH AT A GLANCE

- **Location:** Ivanpah Dry Lake, CA
- **Size:** Approx. 3,500 acres (federal land)
- **Power Production:** 377 MW nominal (392 MW gross)
- **Homes Served Annually:** 140,000
- **Construction Commenced:** October 2010
- **Expected Completion Date:** 2013

The Ivanpah Solar Electric Generating System is comprised of three separate units with a total capacity of 392 MW. Ivanpah is a joint effort between NRG Energy, Google, Bechtel, and BrightSource Energy. The station uses over 300,000 software controlled mirrors to concentrate sunlight on three 459-foot towers. Four types of heliostats are used depending on the distance from the tower; the furthest out are more than half a mile away. The heliostats are capable of withstanding 85-mph winds.

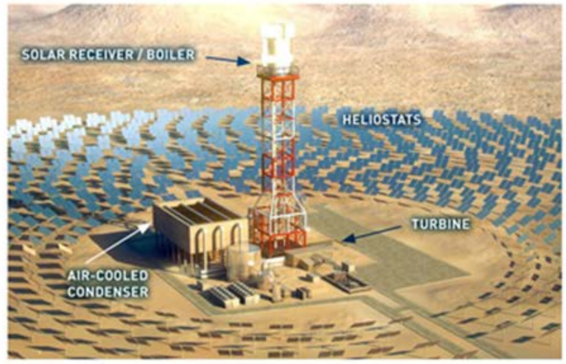


Ivanpah Computer Controlled Heliostats

Ivanpah Solar Receiver and Condensers

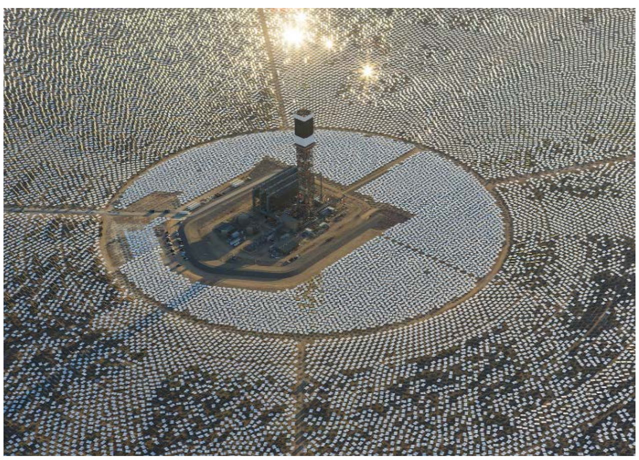
Each tower holds a 2,100-ton boiler that directs steam into a turbine generator at ground level (Figure 2). Natural gas is used to bring the boiler up from a cold start, but in normal use, it retains enough heat from the previous day to start up on sunlight alone. A 110-ton counterweight is continually repositioned to keep the tower stable. The concentrated sunlight generates steam in the tower-top boilers. The facility relies on air-cooled condensers to condense the turbine exhaust, allowing it to use as much as 95% less water than a wet-cooled thermal plant. The plant's only water needs are boiler makeup and cleaning. Water is sourced from two wells on the site.

TECHNOLOGY

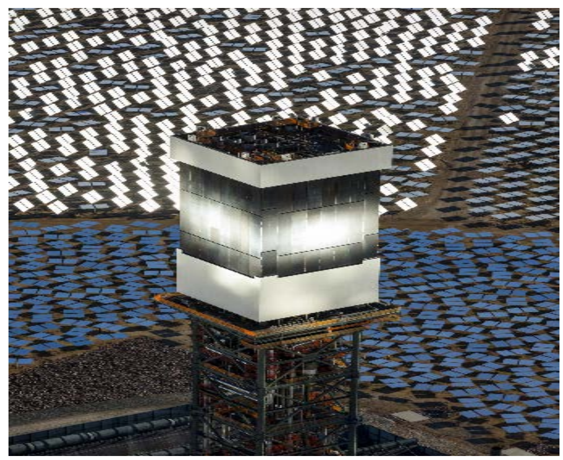


- Ivanpah will produce electricity the same way that most of the world's electricity is produced – by creating high-temperature steam to turn a conventional turbine. However, instead of burning fossil fuels to create the steam, we use the clean and infinite sun as fuel.
- At the heart of BrightSource's proprietary power-tower solar thermal system is an innovative solar field design, optimization software and a control system that allow for the creation of high temperature steam.
- At Ivanpah, over 300,000 software-controlled mirrors will track the sun in three dimensions and reflect the sunlight to boilers that sit atop three 459 foot tall towers. When the concentrated sunlight strikes the boilers' tubes, it heats the water to create superheated steam.
- This high-temperature steam is then piped from the boiler to a standard turbine where electricity is generated. From here, transmission lines carry the power to homes and businesses.

The 3,500 acre facility is located in Ivanpah Dry Lake, Calif., about 40 miles southwest of Las Vegas. BrightSource began development in 2006, and construction commenced in October 2010, led by engineering, procurement, and construction partner Bechtel. The station was first synced to the grid in September 2013 and went into commercial operation at the end of 2013. It is selling its power to Pacific Gas & Electric (Units 1 and 3) and Southern California Edison (Unit 2) under long-term power purchase agreements.



One of Three 130 MW Solar Power Blocks



Close up of Solar Receiver

Ivanpah's $2.2 billion cost was supported by $1.6 billion in loan guarantees from the DOE's Loan Programs Office (LPO). The plant is just a portion of the 2.8 GW of LPO-financed large-scale solar (CSP and photovoltaic) that is currently operating or under construction. The LPO currently oversees a portfolio of more than $30 billion that supports more than 30 closed and committed projects. LPO-supported facilities include one of the world's largest wind farms as well as several of the world's largest solar generation and thermal energy storage systems.

Solana Generating Station

Solana solar thermal plant, a parabolic trough concentrating solar power (CSP) plant and the first in the U.S. with thermal energy storage began commercial operations in October 2013.

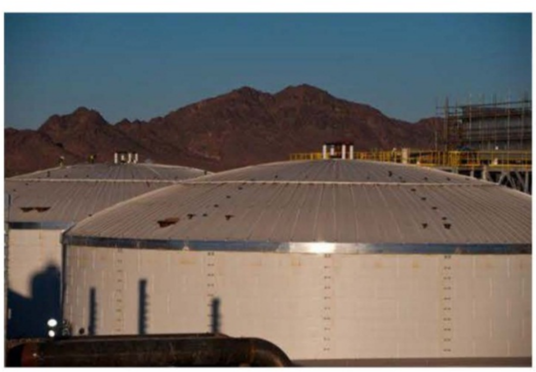
The 280-MW plant, near Gila Bend in Arizona about 70 miles southwest of Phoenix, employs molten salt to store about six hours of thermal energy at full power, allowing the facility to continue operating during periods of peak evening demand. The addition of thermal storage also allows the facility to smooth out any intermittency in generation as a result of cloudy periods during the day.

The three-square mile facility employs 2,700 parabolic trough mirrors and a pair of 140-MW steam turbines. Heated oil from the mirrors is used to heat molten salt in six pairs of hot and cold tanks with a capacity of 125,000 metric tons.

Solana will sell all its power to Arizona Public Service, the state's largest utility, through a 30-year power purchase agreement. The facility cost approximately $2 billion to build, and was financed in part with a $1.45 billion loan guarantee from the Department of Energy (DOE).

Aerial View of Solona Solar Field

Parabolic Trough Collector



Thermal Energy Storage Tanks

Solona's Power Blocks

Solana – Solar CSP with Storage

As shown in the conceptual layout of the Solana plant below, large insulated buildings containing molten salt will be located next to the steam boilers. At select times, instead of immediately creating steam, the heat transfer fluid will heat the molten salt. Then, if electricity is needed when the sun is not shining, the fluid can be heated by running it through the hot salt instead of through the mirrors. Using this process, electricity can be made from heat energy that was created up to six hours earlier.

Conceptual Layout of Solana Plant (Abengoa Solar, 2009)

A) Solar Field
B) Thermal Energy Storage (Hot & Cold Tanks)
C) Heat Transfer Fluid Expansion Vessels
D) Heat Transfer Fluid Pumps
E) Heat Transfer Fluid Supply Headers
F) Solar Steam Generators
G) Steam Turbines and Generators
H) Operations Control Building
I) Cooling Towers
J) Switchyards
K) Water Treatment System
L) Cooling Tower Make up Tank
M) Evaporation Ponds
N) Raw Water Tank

Mojave Solar Project

The Mojave Solar Project consists of two 140 megawatt parabolic trough plants. The Mojave Solar technology uses mirrors to concentrate the thermal energy of the sun to drive a conventional steam turbine. The plant is located 100 miles northeast of Los Angeles, near Barstow, California. Construction has begun and the Mojave Solar Project will come online in mid-2014. Abengoa Solar received a federal loan guarantee from the U.S Government in the amount of $1.2 billion, which facilitated the financial closing with the Federal Financing Bank (FFB) and the start of the plant´s construction. Pacific Gas & Electric (PG&E) will purchase the power generated from the solar thermal facility, as part of a 25 year power purchase agreement (PPA) with Abengoa Solar.

Aerial View of Mohave Solar Fields

Mohave Solar Collectors

Research and Development Test Sites

In addition to these "utility scale" projects TEP is evaluating numerous solar manufacturers' products at four test sites in the Tucson area. TEP and UES are working together in partnership with The University of Arizona (UA) on advancing solar and renewable technology. The focus of the UA research group includes building advanced system components that allow for more solar energy collection and distribution. This partnership remains critical not only for technological improvements but also for the research data used in creating economic policies that benefit communities.

Irvington Test Site # 1

Over 600 PV modules from 20 different manufacturers are grid-tied at the TEP solar test site #1. TEP is field-testing 90 kW peak of PV systems here. Since 2003, AC power measurements have been recorded every 5 minutes from individual PV systems. Since 2009, University of Arizona researchers have monitored AC power, DC power, irradiance and temperature every second, and continue to provide real time performance data for TEP.

PV Module Manufacturer	PV Module Model	Inverter	Peak Power per Module	System Capacity (kWDC)
Sharp	NE-Q5E2U	Aurora	165 W	2.97
BP	3150U	Xantrex Suntie	150 W	1.5
Uni-Solar	Uni-Solar 64W	Fronius	64 W	1.536
Sanyo	HIP-G751BA2	SMA	167 W	1.336
Solyndra	SL-001 Black Roof	KACO	182 W	1.6
Solyndra	SL-002 White Roof	KACO	182W	1.6
GSE	GG-112	Xantrex Suntie	45 W	1.44
Shell	ST40	Xantrex Suntie	40 W	1.52
Sanyo	HIP-J54BA2	Fronius	180 W	1.44
BP	MST50	Solectria	50 W	3
Astro	Api-165-MCB	Xantrex Suntie	165 W	1.485
Millennium/Solarex	MST-43MV	Solectria	43 W	2.58
Evergreen Solar	EC-115-GL	Soleil 2000	115 W	1.955
BP	SX140X	Xantrex Suntie	140W	1.4
BP	MST-50	Beacon Power	50W	7.5
BP	4170	Xantrex Suntie	170W	3.6
Shell	SQ150	SHARP	150W	3
Shell	SQ 150-PC	PV Powered	150W	3
Kyocera	KC150G	Xantrex Suntie	150W	1.35
Sunpower	SPR-215-WHT-U	Sunpower 3000	215W	1.935
ASE	ASE 300	Fronius (2)	300W	21.6
Prism Solar	Custom	SMA	50W	1.6
Skyline	Custom SAT	KACO	37.5W	1.2

Note: Skyline SAT is the only tracker system installed at this site. Total capacity installed for testing is approximately 30kW.

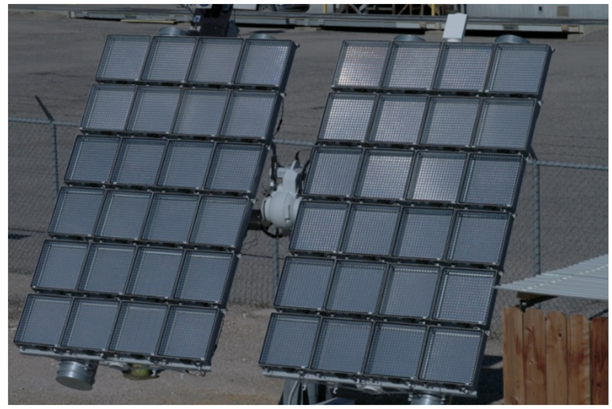
Irvington Test Site # 2

SOLON Corp. has developed a PV test site to demonstrate and perform R&D for Solon's various PV technologies starting in 2009. This site is one of three in the world using the exact same technologies that are being tested for geographic and climate diversity. SOLON has three types of PV systems in place including two fixed axis systems, a single axis tracker, and a dual axis tracker.

PV Module Manufacturer	PV Module Model	Inverter	Peak Power per Module	System Capacity (kWDC)
Solon	Fixed 0 Deg – C-Si Test	KACO	230	1.61
BP	3150U	Xantrex Suntie	150 W	1.5
Brand X	Fixed 32 Deg – C-Si Test	KACO	230	1.61
Brand Y	Fixed 32 Deg – C-Si Test	KACO	180	1.26
Brand Z	Fixed 32 Deg – C-Si Test	KACO	220	1.54
Brand X1	Fixed 32 Deg – C-Si Test	KACO	230	1.61
Solon	Single Axis Tracker – C-Si Test	KACO	220	1.54
Brand Y1	Single Axis Tracker – C-Si Test	KACO	230	1.61
Brand Z1	Single Axis Tracker – C-Si Test	KACO	230	1.61
Brand X2	Single Axis Tracker – C-Si Test	KACO	230	1.61
Brand Y2	Single Axis Tracker – C-Si Test	KACO	230	1.61
Brand Z2	Single Axis Tracker – C-Si Test	KACO	230	1.61
Solon	Single Axis Tracker – C-Si Test	KACO	220	1.61
Brand X3	Dual Axis Tracker – C-Si Test	KACO	200	1.54
Brand Y3	Dual Axis Tracker – C-Si Test	KACO	210	1.4
Brand A1	Dual Axis Tracker – Thin Film Test	KACO	190	1.47
Brand A2	Dual Axis Tracker – Thin Film Test	KACO	230	1.33

Irvington Test Site # 3

This site is in the early stages of development, and will focus on small scale advanced PV technologies, including Concentrating PV and newer planned tracking systems. This site will also be used for testing larger modules on the order of 1kW in capacity.



PV Module Manufacturer	PV Module Model	Inverter	Peak Power per Module	System Capacity (kWDC)
Petra Solar	Concentrating PV	Petra Micro	200W	1

DMP Test Site

There is currently over 200 kW of fixed PV installed at the DeMoss Petrie station. This installation occurred in 2001, and uses ASE 300 watt modules. This station is a smaller model of our Springerville Generating Station, where the same ASE modules are being tested to provide comparison data at different locations.

PV Module Manufacturer	PV Module Model	Inverter	Peak Power per Module	System Capacity (kWDC)
ASE	ASE 300	PV Powered	300W	108
ASE	ASE 300	Fronius CL	300W	54
ASE	ASE 300	Fronius CL	300W	54

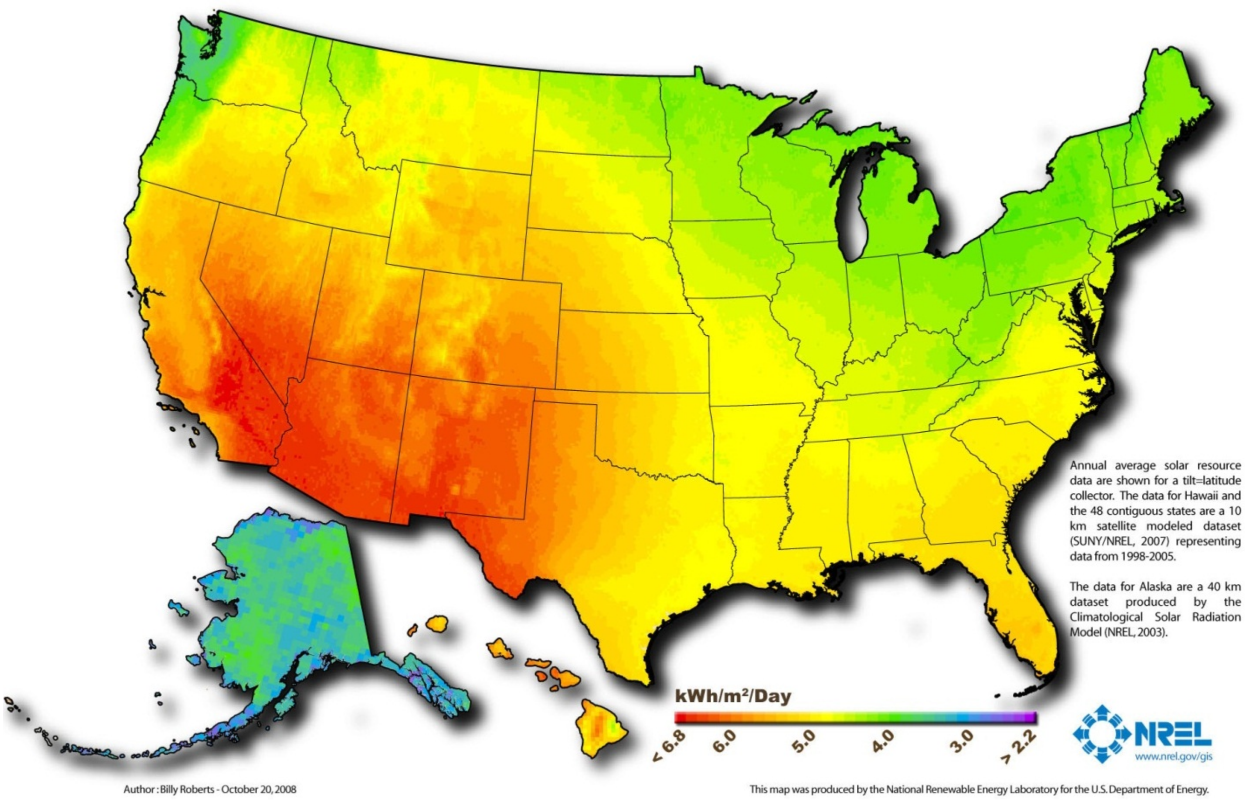
Other R&D Efforts

TEP is planning to continue its subscription with the Electric Power Research Institute ("EPRI") in 2014. Previous studies conducted in 2013 and carried forward into 2014, as well as new programs for 2014, will provide necessary data and application information for the implementation of variable generation ("VG") into utility grids, both for transmission and distribution systems. The total estimated cost of subscription is $191,000. TEP will contract with either the National Renewable Energy Laboratory ("NREL) or EPRI to provide continued solar generation resource integration information at a subtransmission and higher system wide level. The impacts of large VG penetration on TEP's system will be studied, including capacity limitations, operational requirements, and the assessment of TEP's operations relative to incorporating large renewable capacity into the system. Study information from the 2011 Grid Stability Study will be used to model various transmission system penetration levels. The models will support analysis consisting of residential and commercial DG solar penetration up to and including utility scale solar generation systems. NREL or EPRI will model different levels of penetration based on future DG integration over the next 2-5 years. TEP's Transmission Planning group will evaluate the various models to determine the impact on system dispatch criteria, regulation, and reserves. This information will also provide the Transmission Planning group with several dynamic models to analyze various intermittency cases with solar applications on the grid.

U.S. SOLAR MAP

This map shows the national solar photovoltaic (PV) resource potential for the U.S. This map is based on the monthly average daily total solar resource potential on grid cells. The insolation values represent the resource available to a flat plate collector, such as a photovoltaic panel, oriented due south at an angle from horizontal to equal to the latitude of the collector location. This is typical practice for PV system installation, although other orientations are also used.

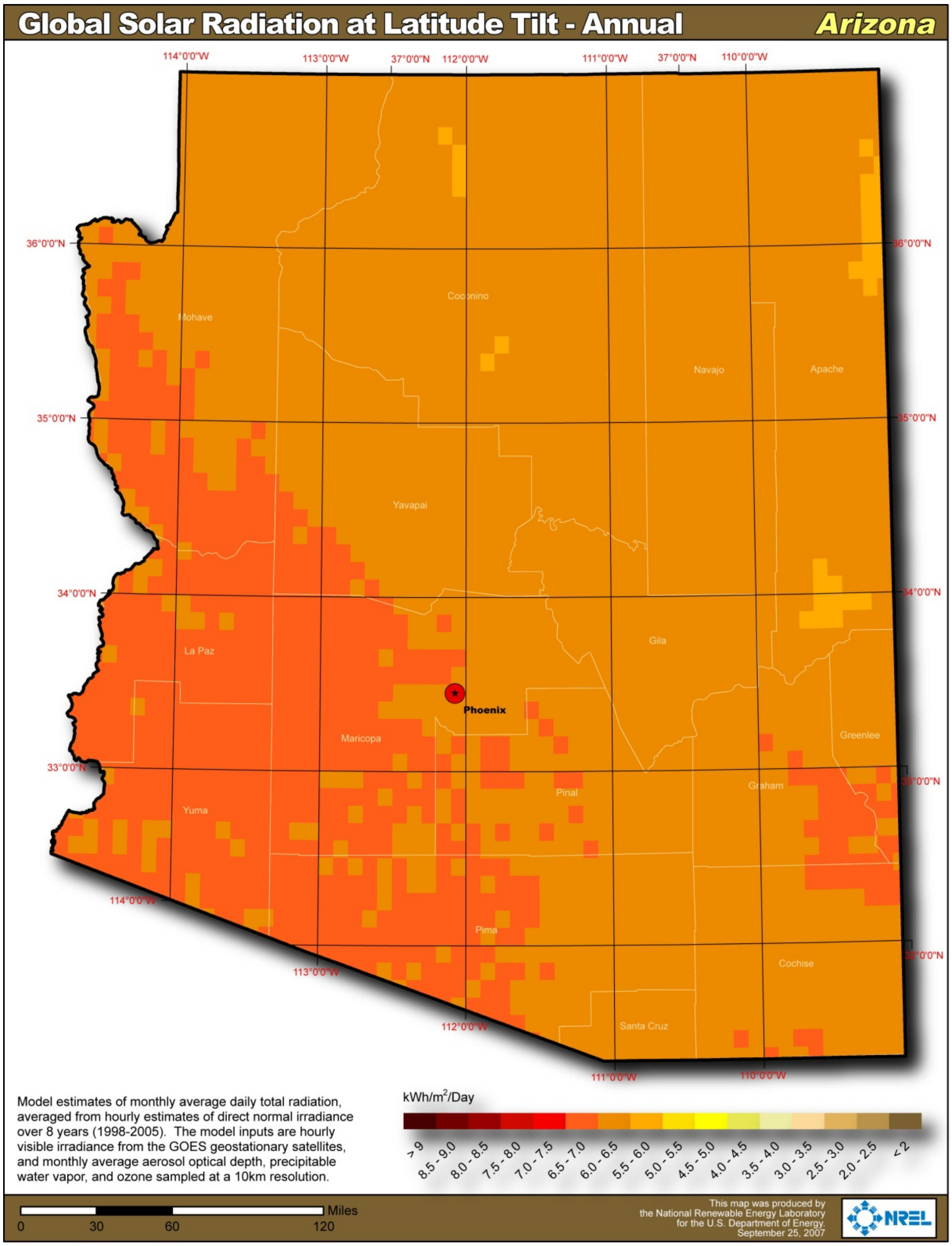
Map 17 – U.S. NREL Solar Radiation Map



ARIZONA SOLAR POWER MAP

The Arizona NREL Solar Insolation Map is based on estimates monthly daily total radiation, averaged from hourly estimates of direct normal irradiance over eight years. The inputs are based on hourly visible irradiance from the GOES geostationary satellites, and month average aerosol optical depth, precipitable water vapor, and ozone sampled at a 10km resolution.

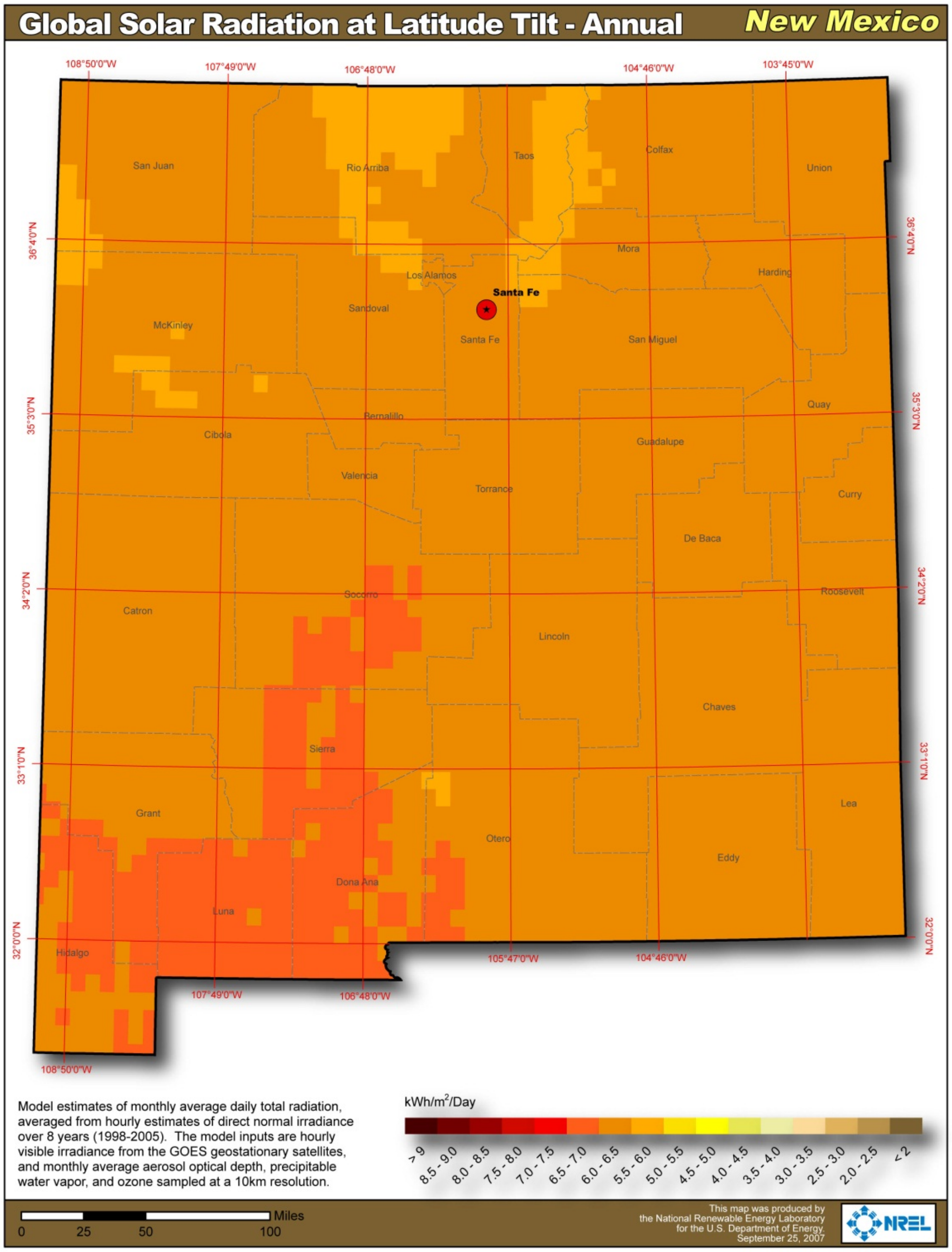
Map 18 - Arizona NREL Solar Insolation Map



NEW MEXICO SOLAR POWER MAP

The New Mexico NREL Solar Insolation Map is based on estimates monthly daily total radiation, averaged from hourly estimates of direct normal irradiance over eight years. The inputs are based on hourly visible irradiance from the GOES geostationary satellites, and month average aerosol optical depth, precipitable water vapor, and ozone sampled at a 10km resolution.

Map 19 – New Mexico NREL Solar Insolation Map



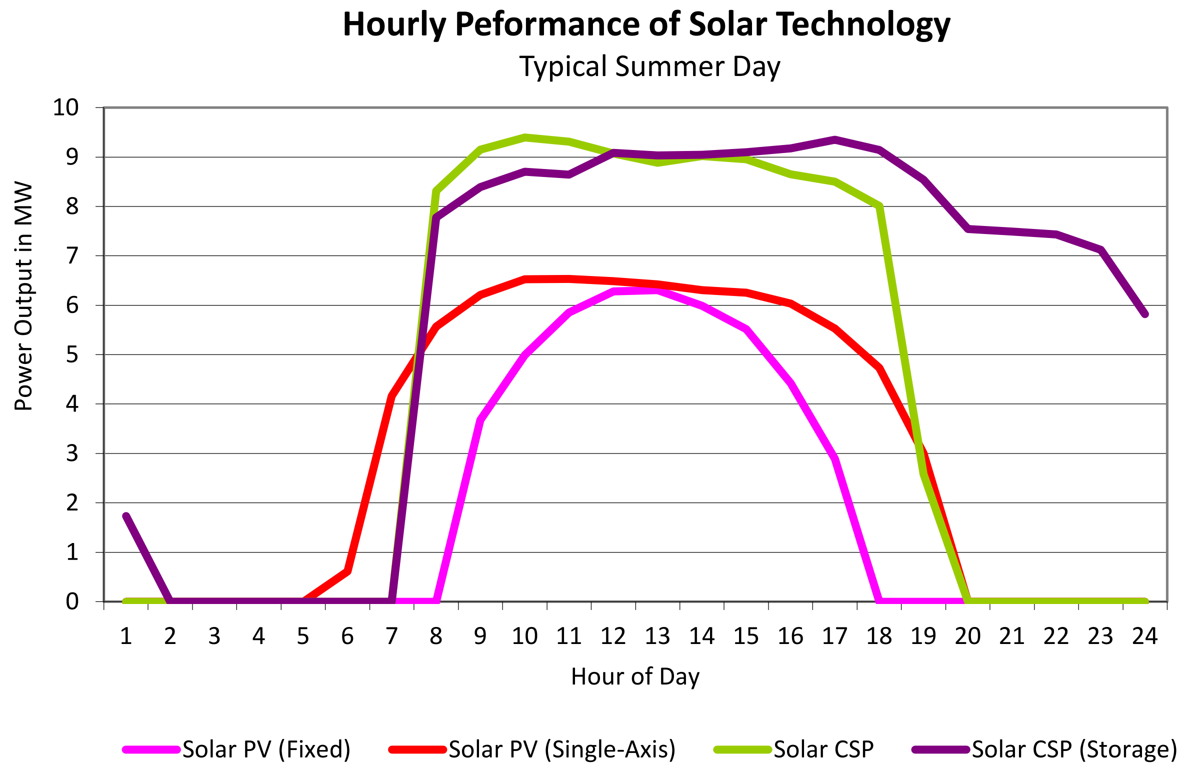
SOLAR RESOURCES MODELED

There are four types of solar electric generating technologies considered for cost modeling: solar parabolic trough (without energy storage), solar parabolic trough (with energy storage), and solar photovoltaic (Fixed) and solar photovoltaic (Single Axis).

Cost and Operating Characteristics	Units	Solar PV (Fixed)	Solar PV (Single Axis)	Solar CSP	Solar CSP (Storage)
Project Lead Time	Years	2	2	2	2
Installation Years	First Year Available	2014	2014	2014	2014
Peak Capacity	MW	20	20	50	50
Construction Cost	2014 $/kW	$1,941	$3,161	$5,384	$6,937
EHV/Interconnection Cost	2014 $/kW	$52	$52	$207	$207
Total Construction Cost	2014 $/kW	$1,993	$3,313	$5,591	$7,144
Construction Cost with ITC	2014 $/kW	$1,493	$2,549	$4,142	$5,336
Fixed O&M	2014 $/kW-yr	$15	$27	$35	$70
Variable O&M	2014$/MWh	$0	$0	$0	$5.00
System Integration Costs	2014 $/MWh	$5.20	$5.20	$3.80	$3.80
Levelized Cost of Energy	$/MWh	$166	$186	$206	$212
Typical Capacity Factor	Annual %	17%	24%	30%	38%
Net Coincident Peak Contribution	NCP %	33%	51%	70%	87%
Water Usage	Gal/MWh	0	0	800	800
30% Federal ITC	Qualify	YES	YES	YES	YES
Tax Depreciation	Qualify	5-Year	5-Year	5-Year	5-Year

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 POWER

Resource Characteristics

Wind power is the process of mechanically harnessing kinetic energy from the wind and converting it into electricity. The most common form of utility-scale wind technology uses a horizontal-axis rotor with turbine blades to turn an electric generator mounted at the top of a tall tower. For utility-scale wind power production, dozens of wind turbines may be grouped together at a wind farm project. Power generated by the wind turbines is collected at a substation where transformers increase the voltage and the power is then fed into the transmission system.

Because air has low mass, the wind itself has low energy density. The amount of wind power that can be produced at a given project site is dependent on the strength and frequency of wind. Wind velocity determines quantity of power that can be produced. For example, a doubling of wind speed allows roughly eight times as much power to be produced

Over the last decade, the use of wind power has increased rapidly, making it the predominant form of new renewable generation resource, with many large-scale installations around the world. Major advances in wind power technology were achieved in the 1990s and 2000s, allowing much larger turbines to be developed. Today wind turbines are generally considered to be the most mature form of renewable energy technology, with industrial giants such as Siemens and GE amongst the leading manufacturers. For example, wind turbines with a capacity of 1.5 megawatts to 2.5 megawatts are now common and wind turbines as large as 6 megawatts are being developed. This has created economies of scale, driving down the unit cost of energy from wind power resources.

Picture 11 - Kingman Wind Farm (10 MW Project)

Unisource Energy Wind Project
A small wind farm outside of Kingman, Arizona developed by Western Wind Energy Corporation.

Wind Resource Technology

As the wind starts to blow, yaw motors turn a turbine's nacelle so that the rotor and blades face directly into wind. The blades are shaped with an aerofoil cross section (similar to an aircraft wing) and this causes air to move more quickly over one side than the other. This difference in speed causes a difference in pressure which in turn causes the blade to move, the rotor to turn and a rotational force (or torque) to be generated.

The rotor is connected to a gearbox (on most turbines) and in turn to a generator housed in the nacelle that converts the torque into electricity. The electricity is then fed into a transformer located either inside or just outside the turbine which steps up the voltage to reduce losses in transportation. From there the electricity travels through underground cables to a small sub-station, usually on the wind farm site, where the voltage is stepped up through further transformers and exported to the local grid.

Typically turbines start to generate electricity in wind speeds of 3-4 m/s (7-9 mph). The amount of torque (and so electricity) generated increases with wind speed up to around 15 m/s (34 mph) where the maximum (or rated) capacity of the turbine is reached. Output is then maintained at this level until a turbine is shut down when the wind reaches high speeds of around 25m/s (57 mph) to protect it from excessive loads - though the turbines are in fact designed and certified to withstand wind speeds up to 70 m/s (157 mph).

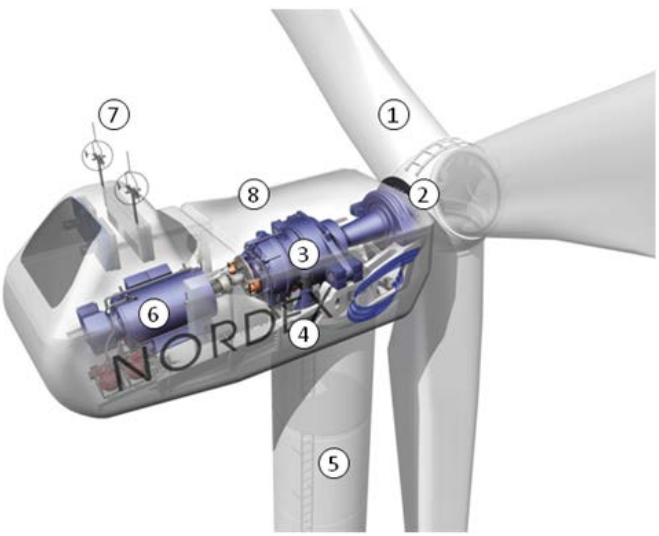


Figure 29 - 3D Drawing of Nordex N80/2500kW Wind Turbine

HOW A WIND TURBINE WORKS

1. Rotor assembly of three blades mounted on a hub which is connected via the main shaft to the gearbox.

2. Pitch motors change the angle of attach of the blades so as to control rotational speed and torque.

3. Gearbox converts the rotational speed of the rotor to a suitable speed for the generator.

4. Yaw motors continually turn the nacelle so as to ensure the rotor faces into the wind.

5. Tower supports the nacelle and rotor. The tower contains electrical cables and access ladders.

6. Generator converts the torque generated by the rotor to electrical energy.

7. Anemometers measure the wind speed and direction, used as inputs to the wind turbine control system.

8. Nacelle is the housing in which the main components are located.

Existing Wind Resources

Resource-Counterparty	Owned/PPA	Technology	Location	Operator-Manufacturer	Completion Date	Capacity MW
Macho Springs	PPA	Wind	Deming, NM	Element Power	Oct 11	50
Red Horse 2 (Future)	PPA	Wind	Wilcox, AZ	Torch Renewables	Q4 2015	50

Macho Springs

Element Power, a global renewable energy developer, has started construction on the Macho Springs Wind Farm located in Luna County, NM. The wind farm is located approximately 20 miles northeast of Deming, NM. Construction is expected to be completed in August. The 50 MW (megawatt) wind farm, consisting of 28 Vestas V100-1.8 MW wind turbines, will generate enough clean energy to provide electricity for more than 20,000 homes.

The project is situated on approximately 1900 acres of privately owned land. Each of the 28 turbines will be situated on an 80-meter (264 feet) tower, with a rotor diameter of 100-meters (328 feet). The energy output from the project is contracted to Tucson Electric Power through a long term power purchase agreement. The project's output will be delivered via El Paso Electric's existing line that runs through the project area.

Picture 12 – Macho Springs Wind Farm in New Mexico (50 MW Project)

The project will provide over $8 million in revenue to Luna County through the County's taxing authority over the 20 year life of the project. The money will be split between the Luna County School District and Luna County, where it will support public services.

Element Power is also developing a second phase of Macho Springs, located 6 miles to the north in Sierra County. This phase is also 50 MW and would connect with the grid at the same location.

Prior to construction, the company performed a host of environmental studies to ensure the wind farm minimizes impacts to the surrounding landscape and wildlife. Element Power is also committed to investing its people and resources in working with communities in New Mexico to build additional renewable energy projects that maximize clean power production while minimizing environmental impacts. Element Power is a leader in working with local stakeholders in designing facilities that meet the highest standard of environmental stewardship while avoiding pollution associated with traditional energy.

Table 38 – Macho Springs Project Details

Project Details	
Owner	Element Power PPA (Purchase Power Agreement)
System Name	Macho Springs Power 1
Developer	Element Power
Location	Deming, New Mexico
Capacity	51 MW
In Service	10/31/11
System Type	28 – 1.8 MW Vestas V-100 turbines on 80 meter Towers
Estimated Yearly Energy Output	134, 000 MWh

Red Horse 2 Wind Project (Future)

The Red Horse 2 wind project is a 40-megawatt wind farm including twenty eight 1.4 megawatt wind turbines sited on 220 acres. Each turbine will stand more than 450 feet high and will be owned by Red Horse 2 LLC which was formed by Torch Renewables Energy. The project will be located at Allen Flat, about 20 miles west of Wilcox, AZ and is scheduled to go on line in the fourth quarter of 2015. TEP will take power from this project under a 20-year purchase power agreement.

WIND RESOURCES MODELED

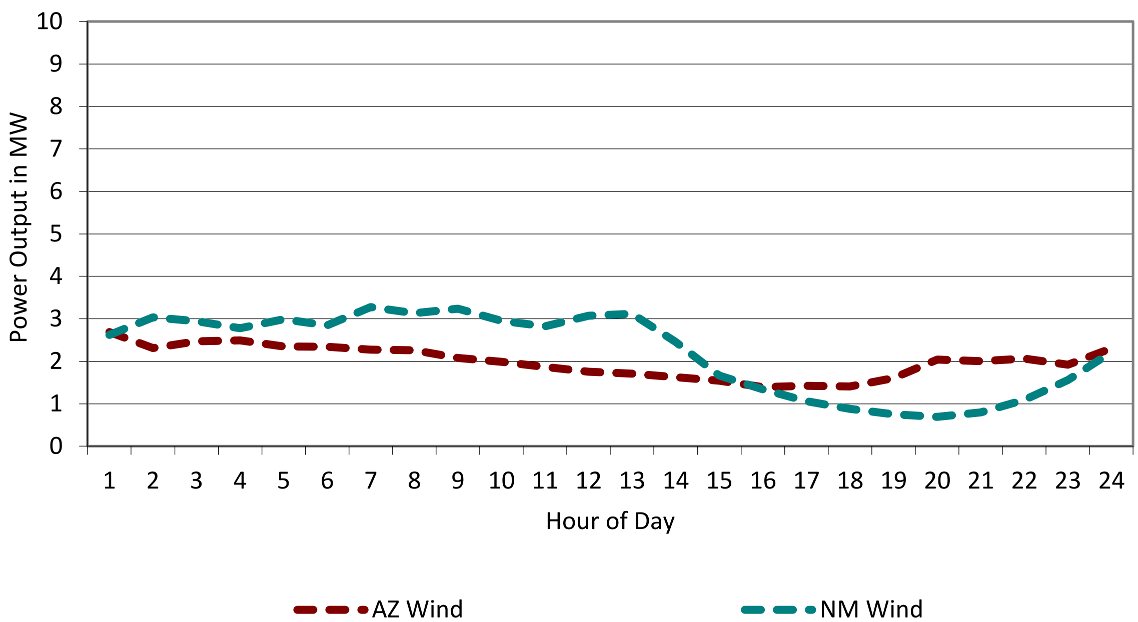
The resource plan modeled wind resources that reflected the seasonal and hourly wind profiles that were sited in either New Mexico or Arizona.

Cost and Operating Characteristics	Units	NM Wind	AZ Wind
Project Lead Time	Years	2	2
Installation Years	First Year Available	2014	2014
Peak Capacity	MW	50	50
Construction Cost	2014 $/kW	$1,864	$2,071
EHV/Interconnection Cost	2014 $/kW	$414	$207
Total Construction Cost	2014 $/kW	$2,278	$2,278
Fixed O&M	2014 $/kW-yr	$52.00	$52.00
System Integration Costs	2014 $/MWh	$1.40	$1.40
Levelized Cost of Energy	$/MWh	$146	$177
Typical Capacity Factor	Annual %	38%	30%
Net Coincident Peak Contribution	NCP %	13%	9%
Water Usage	Gal/MWh	0	0
30% Federal ITC	Qualify	NO	NO

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.

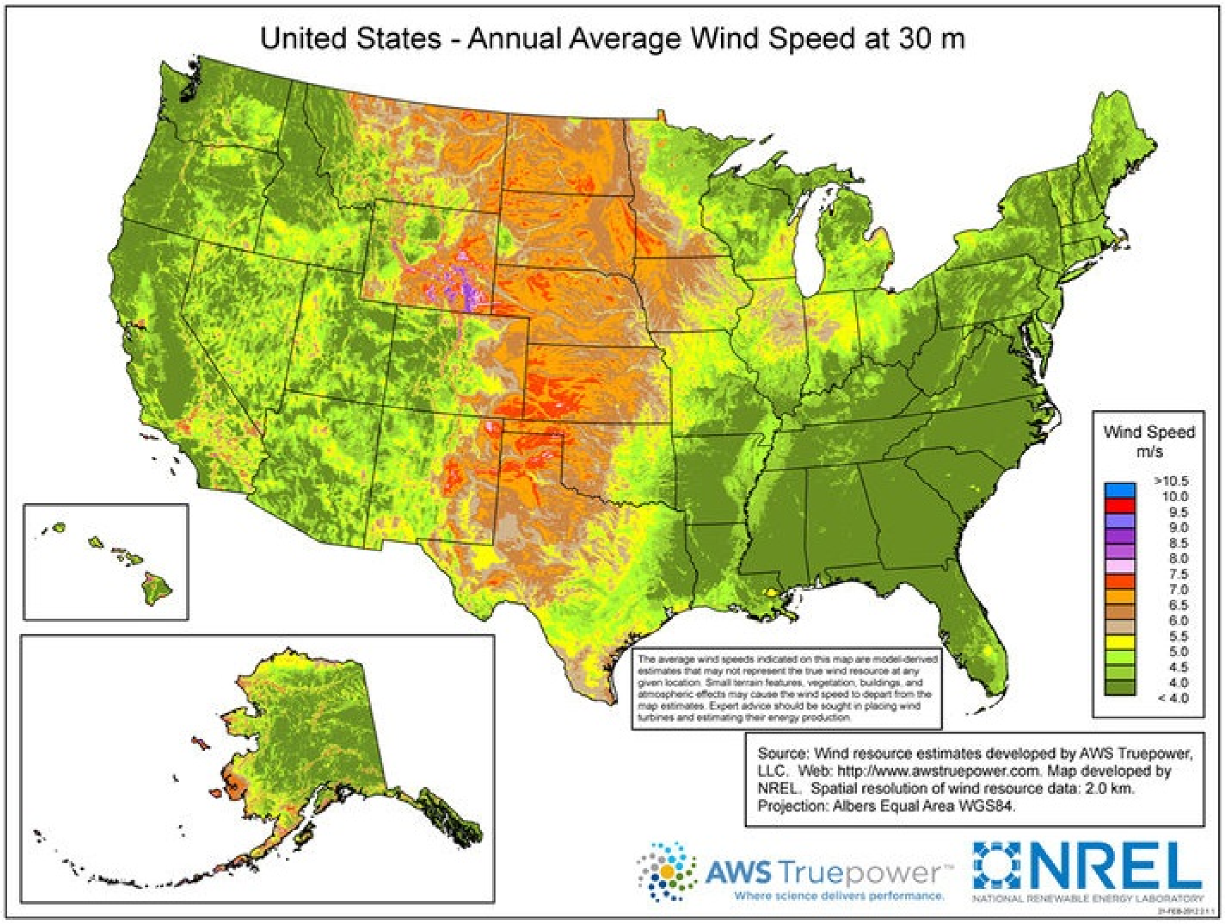
Hourly Peformance of Wind Technology
Typical Summer Day



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

U.S. WIND RESOURCE MAP

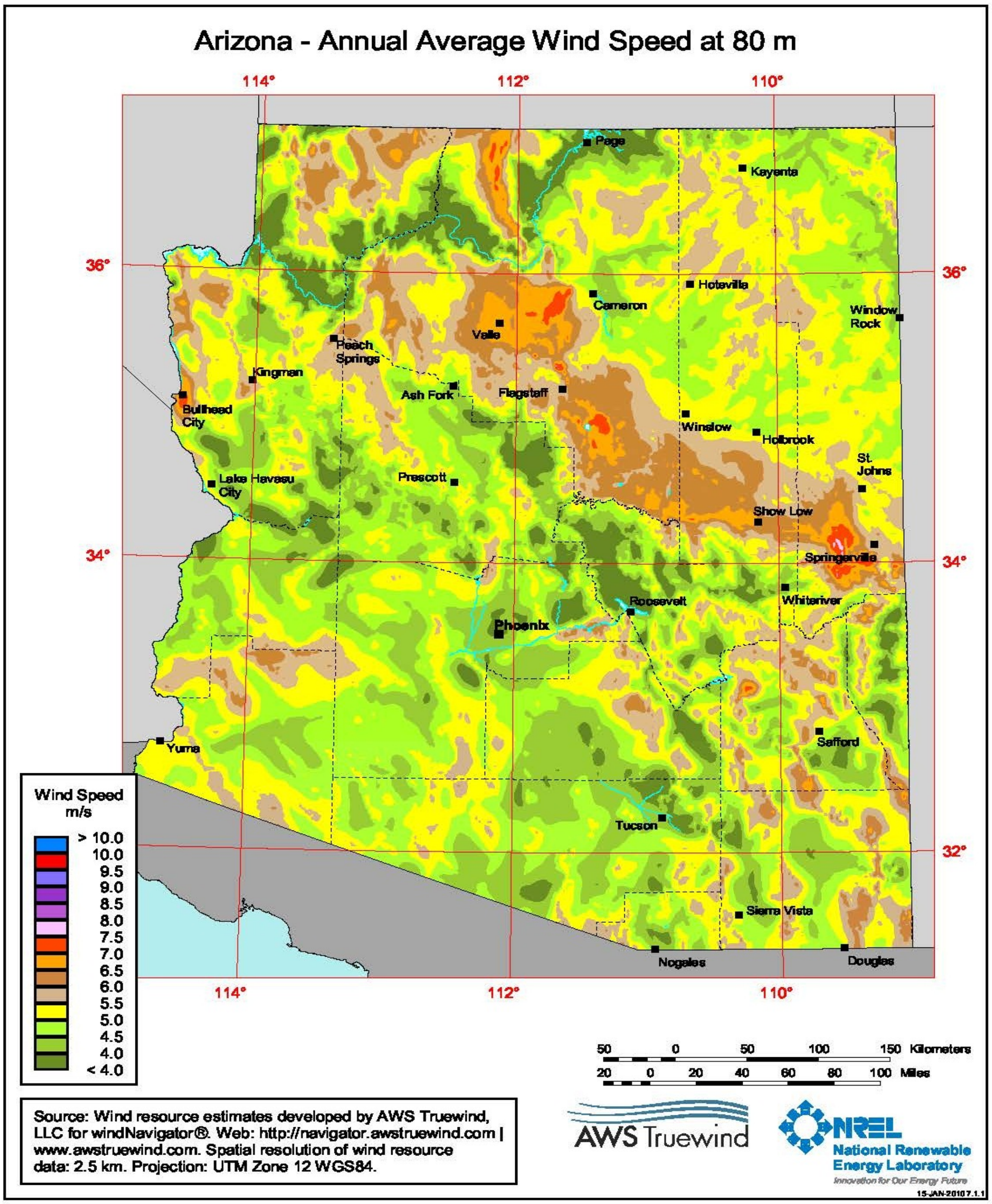
Map 20 - U.S. Wind Resource Map



ARIZONA WIND RESOURCE MAP

The U.S. Department of Energy's Wind Program and the National Renewable Energy Laboratory (NREL) published an 80-meter (m) height wind resource map for Arizona. The Arizona Wind Resource Map shows the predicted mean annual wind speeds at an 80-m height. Areas with annual average wind speeds around 6.5 meters per second and greater at 80-m height are generally considered to have a resource suitable for wind development. Utility-scale, land-based wind turbines are typically installed between 80m and 100m high.

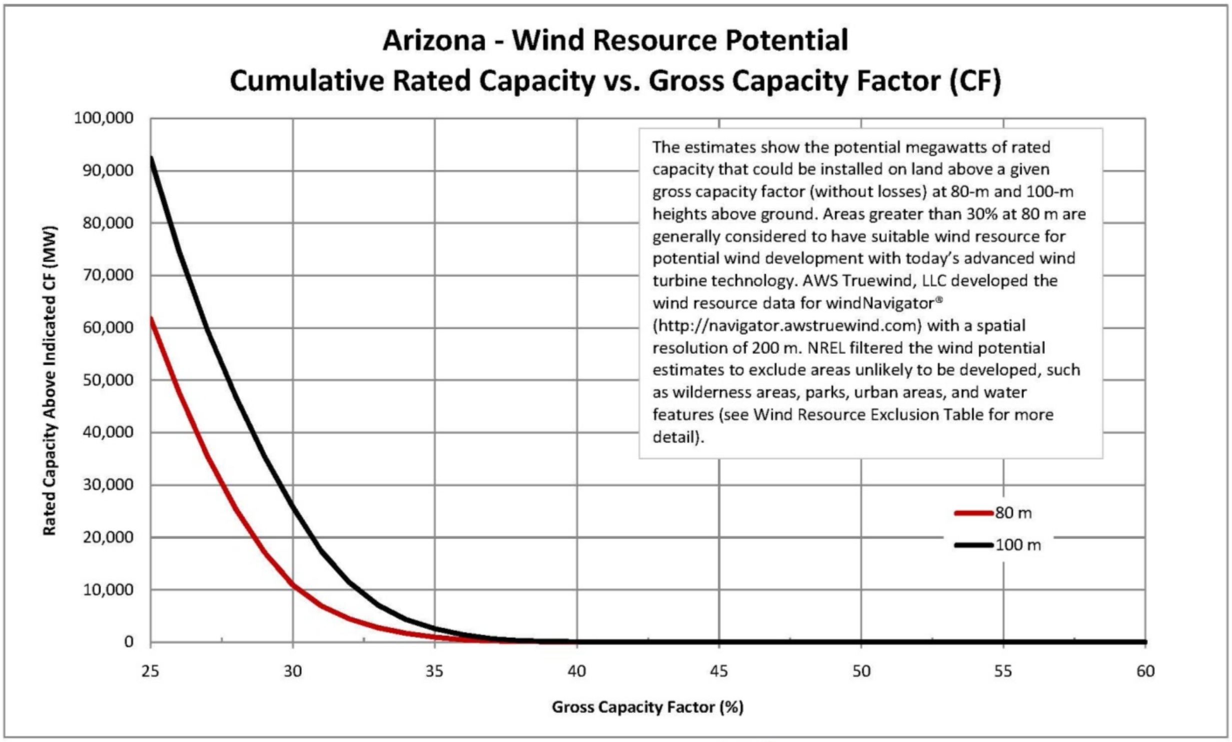
Map 21 - Arizona NREL Wind Resource Map



ARIZONA WIND RESOURCE POTENTIAL

It is estimated that Arizona's wind resource capacity potential is approximately 10,900 MW based on an annual capacity factor of 30%. On an annual basis this results in 30,600 GWh of potential annual wind generation for the state.

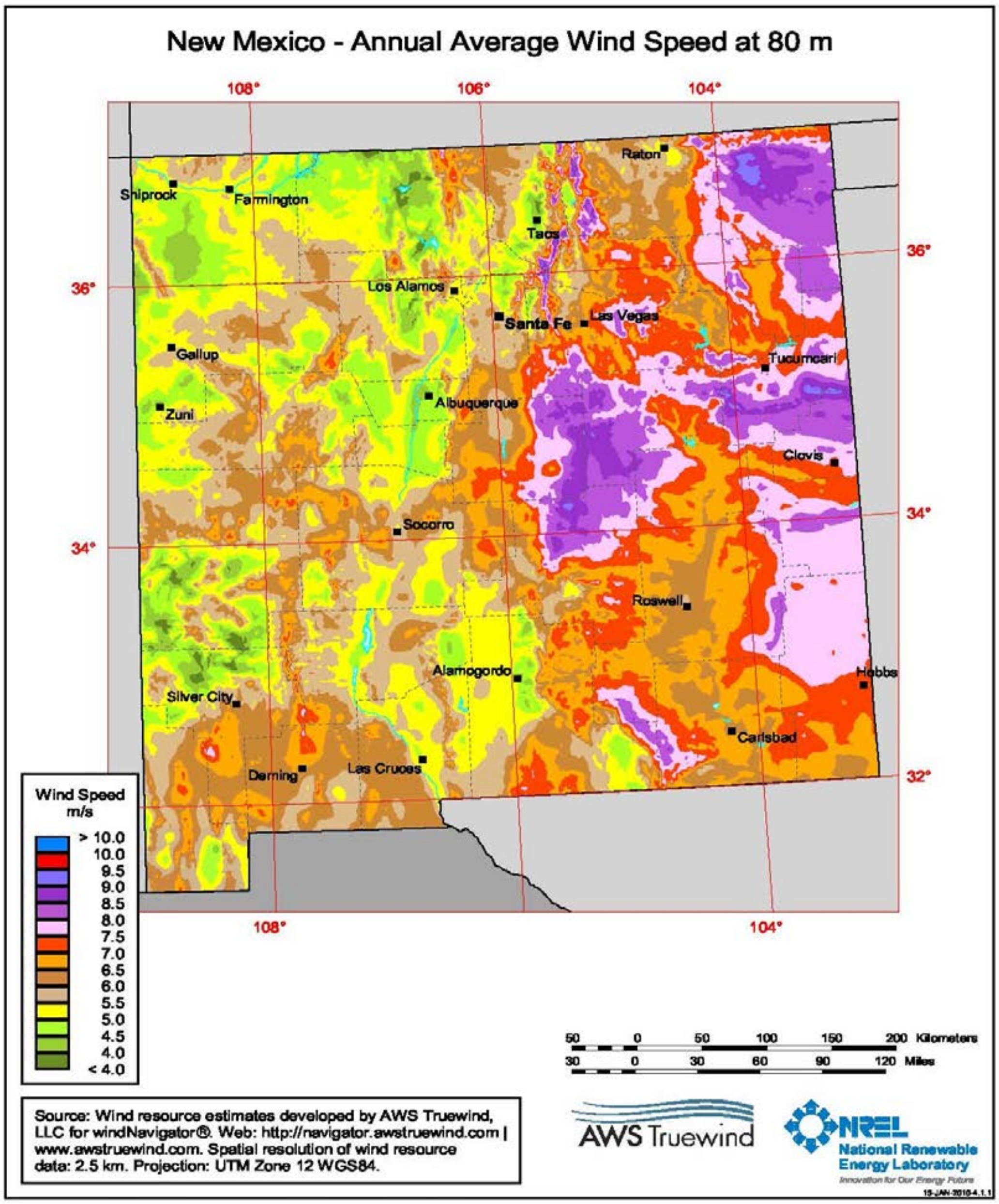
Map 22 - Arizona NREL Wind Resource Potential



NEW MEXICO WIND RESOURCE MAP

The U.S. Department of Energy's Wind Program and the National Renewable Energy Laboratory (NREL) published an 80-meter (m) height wind resource map for New Mexico. The New Mexico Wind Resource Map shows the predicted mean annual wind speeds at an 80-m height. Areas with annual average wind speeds around 6.5 meters per second and greater at 80-m height are generally considered to have a resource suitable for wind development. Utility-scale, land-based wind turbines are typically installed between 80 and 100 m high.

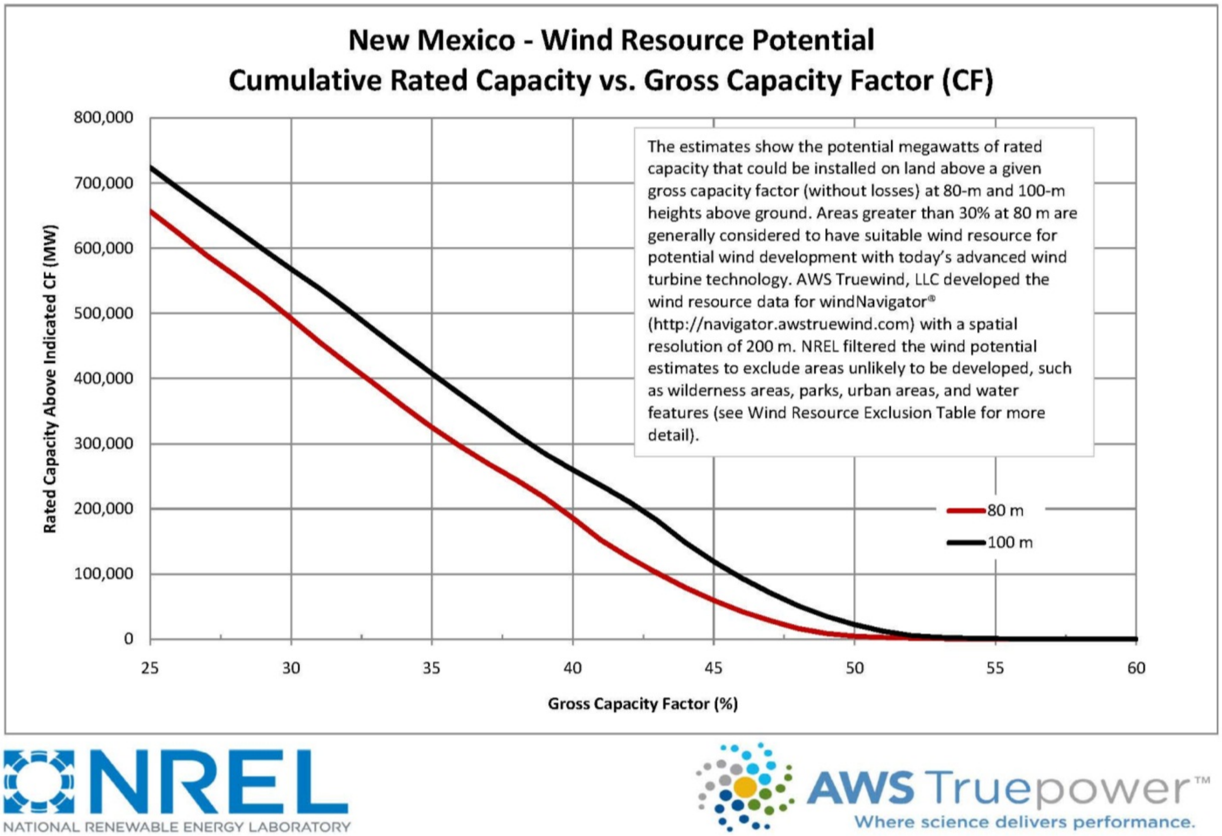
Map 23 - New Mexico NREL Wind Power Map



NEW MEXICO WIND RESOURCE POTENTIAL

It is estimated that New Mexico's wind resource capacity potential is approximately 492,000 MW based on an annual capacity factor of 30%. On an annual basis this results in 1,645,000 GWh of potential annual wind generation for the state.

Map 24 – New Mexico Wind Resource Potential



Bio-Resources (Biofuels)/ Land Fill Gas

Biofuel power plants utilize the heat produced from the combustion of biological materials to produce electricity. In contrast to many other potential renewable energy sources, biofuel generation from multiple sources is a relatively mature, proven technology. In addition, biomass resources have the advantage of being carbon-neutral. Being carbon-neutral refers to achieving net zero carbon emissions by balancing a measured amount of carbon released with an equivalent amount sequestered or offset. These attributes merit the consideration of biofuel resources as part of TEP's generation portfolio, and as such they were analyzed in the IRP process. However, the favorable carbon emissions characteristics and technological reliability must also be weighed against some significant disadvantages (most significantly economic considerations as well as the environmental impact of significant emissions of several pollutants).

Technology Overview

Biofuel energy sources can be divided into two broad categories: biomass and biogas.

Biomass: This category includes all solid biological materials. The most common source of biomass fuel is wood. However this category can also include manure, sewage sludge, agricultural waste, and even cultivated biomass agricultural products such as grasses.

Biomass plants operate in a manner very similar to coal plants. In general, the heat produced from combusting the biomass is used to produce steam which is in turn used to turn a turbine to produce electricity. In addition to dedicated biomass plants, there is also the potential for using biomass sources as a co-firing fuel with traditional resources such as coal.

Biogas: This category includes the capture of gas naturally produced as a part of biological processes. The most common fuel falling into this category is methane collected from the process of decay at landfills. Another potential source is the methane produced from bacterial digestion of manure.

Biogas resources may be used to produce electricity as part of a dedicated plant in the same manner as a traditional natural gas plant or used as a cofiring fuel.

Transmission and Siting Requirements

Biofuel resources may or may not require significant transmission upgrades depending on the location of the source of fuel. For instance, plants utilizing urban wood waste or gas produced as a part of sewage treatment would likely be located near load centers and require minimal additional transition resources. On the other hand, a plant utilizing agricultural waste or waste from forest thinning would likely be a significant distance from load centers and require transmission upgrades.

Dispatch Characteristics

One of the potential major advantages to the deployment of biomass is that it can be used as a stable, reliable, baseload resource (in contrast to many other renewables). Direct fired biomass facilities typically operate at capacity factors of 85% and above.

Environmental Attributes

The biggest environmental advantage of the use of biofuels is that they are considered to be carbon-neutral. While the process of burning biofuels does release CO_2, a nearly equal amount of CO_2 is absorbed from the atmosphere as the biological source of the fuel grows. While the burning of biofuels is carbon-neutral, it does entail significant emissions of nitrous oxides and particulate matter, requiring the use of scrubbing technology. In addition to some unfavorable emissions, the use of biomass also risks other negative environmental impacts if the fuel is not collected in a sustainable manner. In general, however, biofuels are harvested from waste sources, and sustainability is not a significant issue.

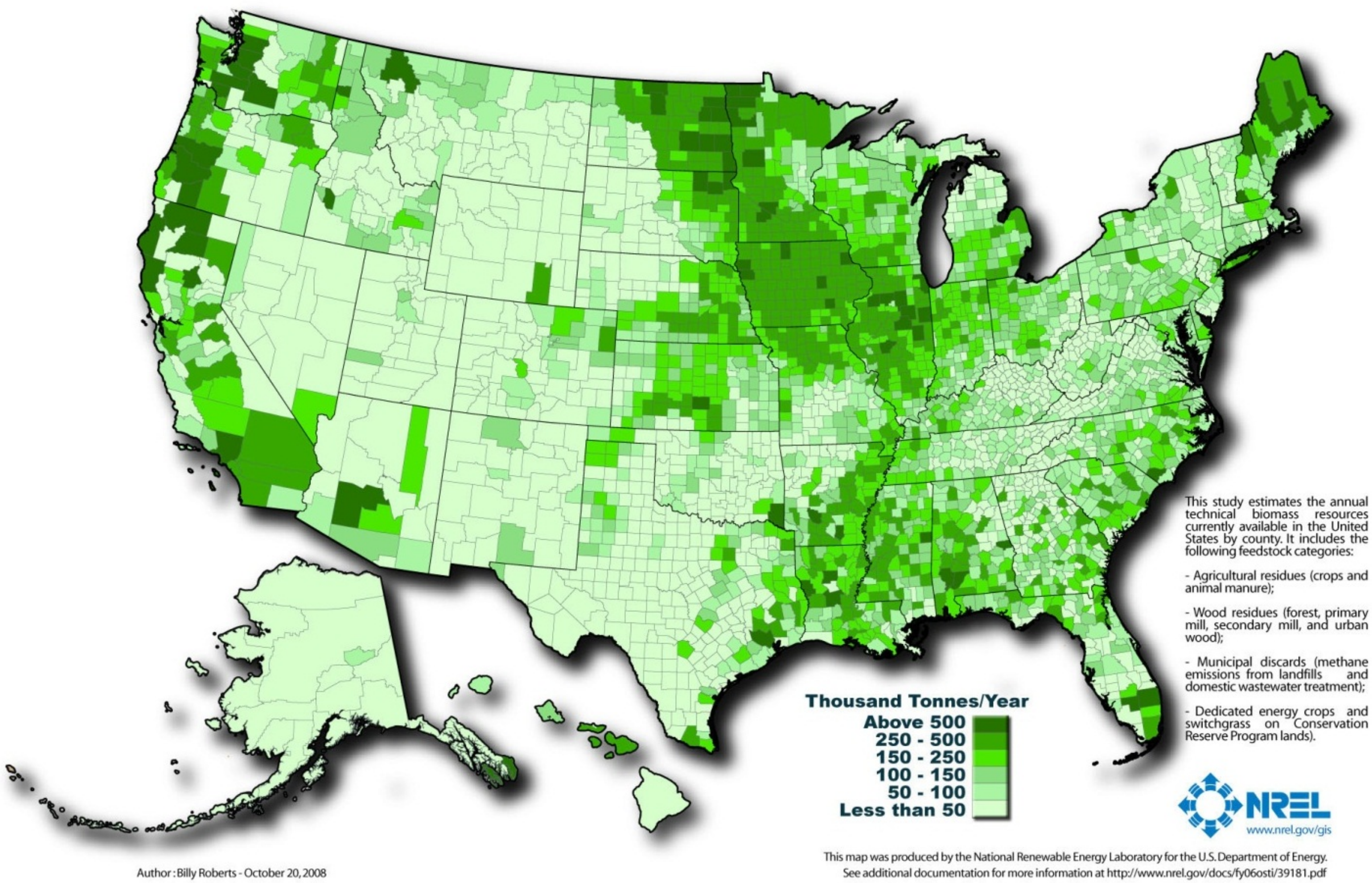
Modeling Assumptions

For the IRP process at TEP, a direct fired biomass facility with the following characteristics was considered.

Coincident System Peak Capacity	100%
Heat Rate Btu/kWh	11,000
Capacity Cost $/kW	$3,313
Fixed O&M Cost $/kW-Year	$85
Annual Capacity Factor, %	85%
CO2 Rate, lbs/MMBtu	Carbon-Neutral
SO2 Rate, lbs/MMBtu	0.0006
NOX Rate, lbs/MMBtu	0.033
HG Rate, Mlbs/MMBtu	2.55
Water, Gal/MWh	90
Levelized Cost $/MWh	$120

U.S. BIOMASS MAP

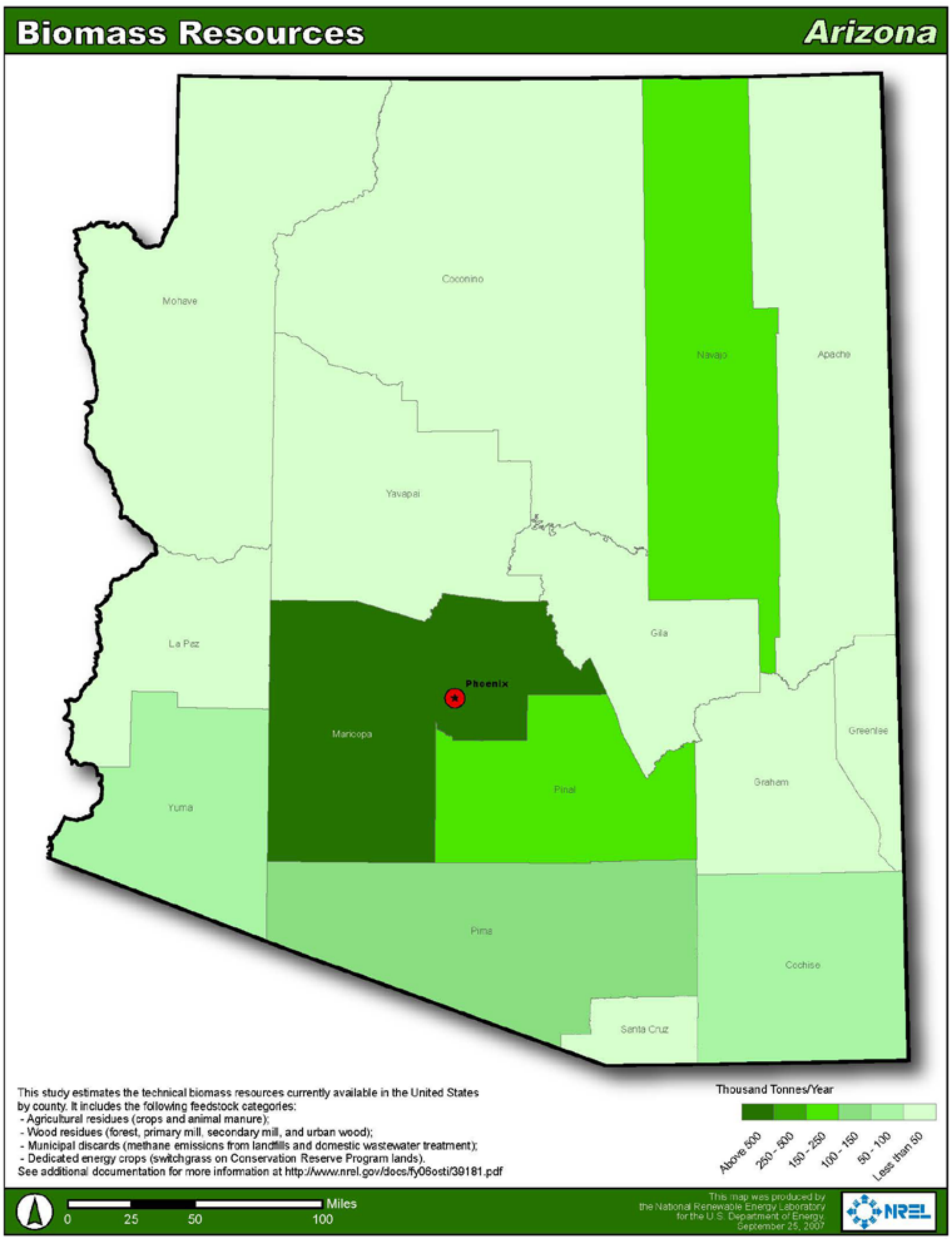
Map 25 – U.S. NREL Biomass Map



ARIZONA BIOMASS MAP

The Arizona NREL Biomass Map illustrates the biomass resources available in the United States by county. Biomass feedstock data are analyzed both statistically and graphically using a geographic information system (GIS). The following feedstock categories are evaluated: crop residues, forest residues, primary and secondary mill residues, urban wood waste, and methane emissions from manure management, landfills, and domestic wastewater treatment.

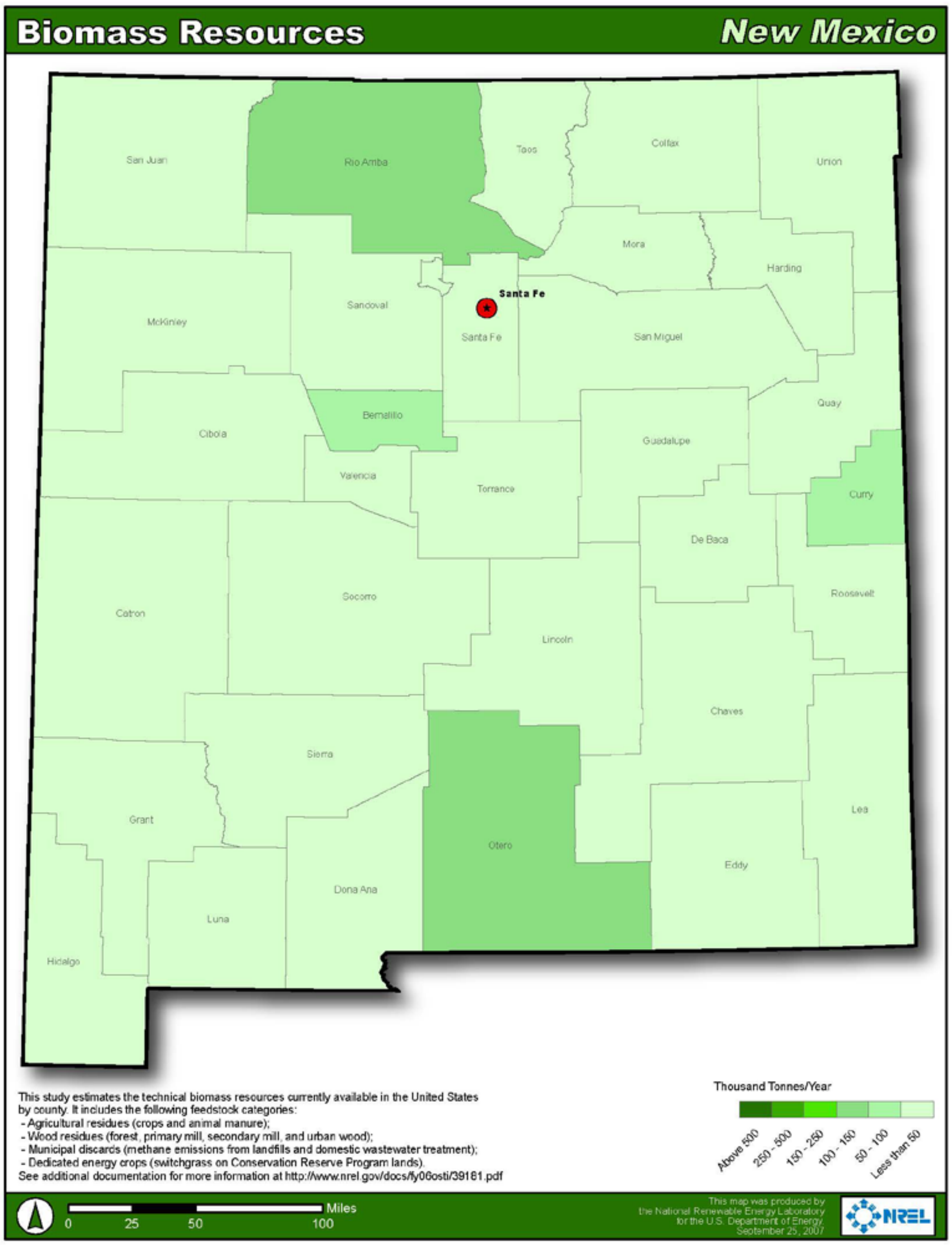
Map 26 – Arizona NREL Biomass Map



NEW MEXICO BIOMASS MAP

The New Mexico NREL Biomass Map illustrates the biomass resources available in the United States by county. Biomass feedstock data are analyzed both statistically and graphically using a geographic information system (GIS). The following feedstock categories are evaluated: crop residues, forest residues, primary and secondary mill residues, urban wood waste, and methane emissions from manure management, landfills, and domestic wastewater treatment.

Map 27 – New Mexico NREL Biomass Map



EXISTING BIOMASS PROJECTS

Table 39 – TEP's Existing Biomass Resources

Resource-Counterparty	Owned/PPA	Technology	Location	Operator-Manufacturer	Completion Date	Capacity MW
Sundt Biogas	PPA	Landfill Gas	Tucson, AZ	City of Tucson	1999	5
Sexton Energy	PPA	Landfill Gas	Tucson, AZ	Sexton Energy	Dec 11	2.2

Sexton Landfill Gas Project

The 2.2 MW Sexton Energy Landfill gas project collects methane from Tucson's 80 acre Tangerine Landfill. The methane will be burned by TEP with Pima county receiving royalties on the resulting electricity.

Sundt Biogas

TEP uses methane gas from the Los Reales Landfill in Tucson and burns it in place of coal to produce electricity. Gas from the Los Reales Landfill is piped 3.5 miles to TEP's Sundt Generating Station to co-fire a boiler. Methane gas is a byproduct of decay in landfills, and it has a Global Warming Potential (GWP) that is 22 times more than carbon dioxide.

Picture 13 – Los Reales Landfill

The Los Reales Landfill covers approximately 370 acres in Tucson, Arizona and is owned and operated by the city of Tucson's Department of Environmental Service

TEP measures actual emissions and tracks them as part of it monitoring performance. This data is available on line at the following website. http://www.tep.com/Green/GreenWatts/PerfMon.asp

Renewable Resource Integration Costs

Table 40 below reflects the renewable integration modeling assumptions used in the 2014 IRP for Tucson Electric Power. The scenarios below were calculated with the AuroraXMP® model (by EPIS, Inc.). The costs were estimated by calculating the marginal difference between a 7x24 purchase and each representative renewable technology shown in the table. The reference scenarios each represent 100 MWs of their respective technology for wind and solar as shown in the table. The 'Existing TEP Renewables' scenario consists of 70 MWs of a mix of fixed PV and single-axis PV along with 50 MWs of wind generation at Macho Springs in Luna county New Mexico. For each scenario in Table 7, an 8760 hourly profile was created from actual generation for wind and solar data in 2013. Additionally, actual hourly retail load for 2013 was represented. The average annual natural gas price was set to $6/MMBtu.

The four scenarios studied resulted in integration costs ranging from $1.40/MWh for Wind generation and up to $5.20/MWh for Solar PV generation. Since TEP is a summer peaking utility and wind resources in Arizona and New Mexico are prominent in the shoulder and off-peak months (and hours), the integration costs for wind are the lowest. Tucson Electric Power dispatches coal resources on the margin more often in the off season, while gas resources are on the margin during the summer and diurnal hours. This accounts for the lower integration costs observed for wind resources.

Table 40 - System Integration Costs

System Integration Costs ($/MWh)			
Renewable Technology	Reference ($6/MMBtu Permian)	Increase per 100 MW	Increase per $1/MMBtu Permian
Wind	$1.40	$1.00	$0.60
Solar PV	$5.20	$1.10	$1.60
Solar CSP	$3.80	$1.40	$1.40
Existing TEP Renewables	$2.90		$0.80

As stated above, the PV hourly shape was comprised of TEP's existing blend of fixed panel and single-axis panel PV systems. The Solar PV scenario yielded an integration cost of $5.20/MWh and $3.80/MWh for the scenario Solar CSP. The hybrid scenario is "Existing TEP Renewables". The profile of the existing solar and wind resources for TEP were combined and modeled in this scenario. The resulting cost of $2.90/MWh is a blend of the Wind and Solar PV scenarios. It's observed that 100 MWs of each technology contributes an additional $1/MWh to $1.40/MWh of costs. The variability of natural gas also has an impact on the integration costs. An increase for Permian natural gas ranges from 60 cents to $1.60 for each additional $1/MMBtu increase in gas.

This methodology captures the energy costs (fuel and purchased power) for the TEP system which are associated with inter-hour fluctuations of wind and solar technology. Alternatively stated, the performance of the renewable scenarios was compared to a block purchase which is available for every hour. This study does not address sub-hourly variability of renewables that can contribute to additional system regulation costs.

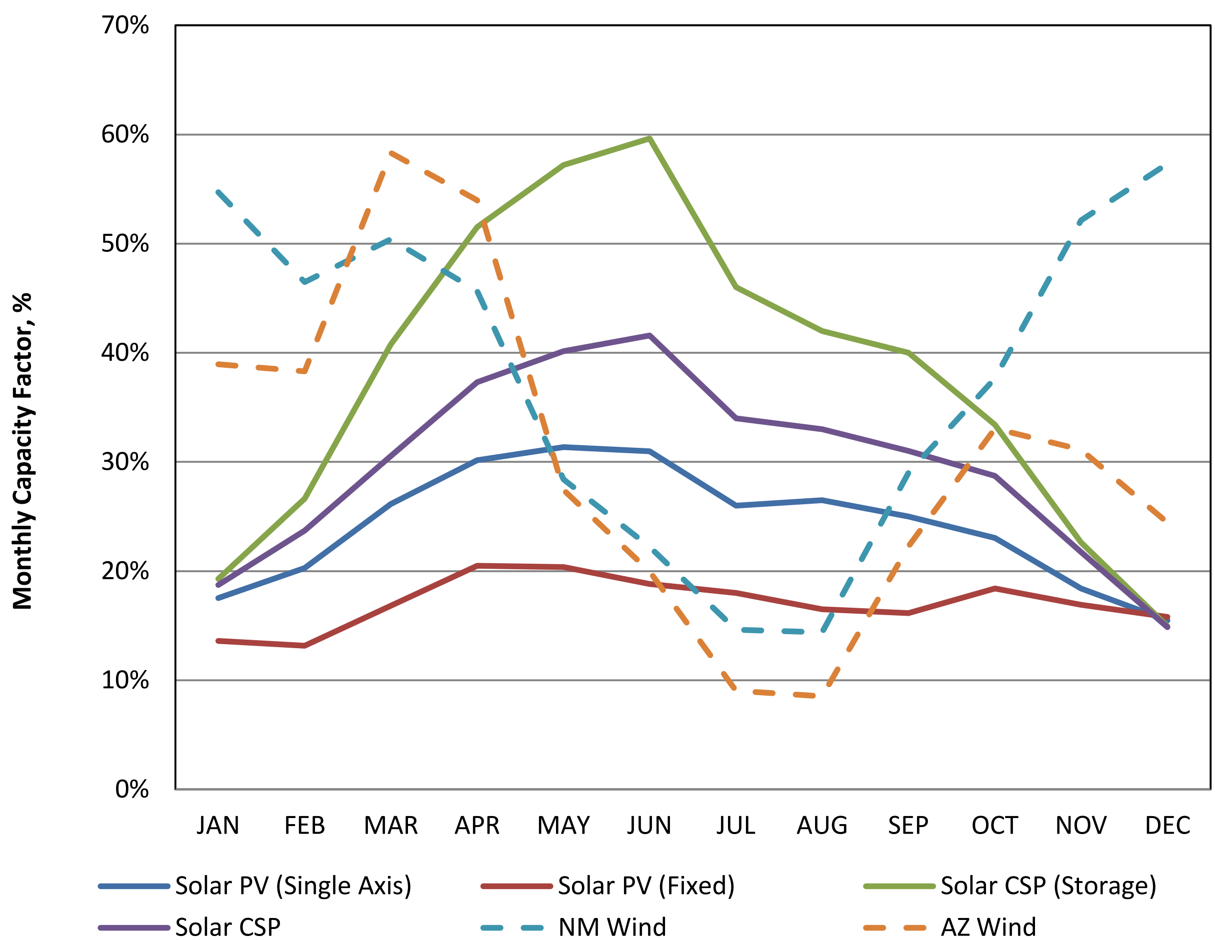
The integration costs calculated for wind resources were compared to the APS Wind Integration Cost Impact Study conducted by NAU, September 2007.(NAU, Northern Arizona University) Integration costs for solar resources were compared to the Solar Integration Study for Public Service Company of Colorado, prepared by Xcel Energy, February 9, 2009. (EnerNex Corporation, 2009). In addition, a study that was completed in mid-2011, titled Large-Scale PV Integration Study conducted by Navigant Energy was used to validate these integration cost calculations.

TEP's methodology for calculating integration costs compares most with the Public Service Company of Colorado (PSC) study. The PSC natural gas assumptions and inputs were considerably higher in 2009 but, it's worth noting that they calculate integration cost increase of $1.40/MWh for each $1.00/MMBtu change in average annual gas price. This is consistent with TEP's findings. The reference costs will differ between the two companies due to seasonal difference and resource fleet mix.

Seasonal Profiles for Renewable Resources

Chart 51 shown below provides a monthly comparison of the expected capacity factors by renewable technology types. Wind resources provide more output during the winter season whereas solar resources tend to have higher capacity factors during the summer season.

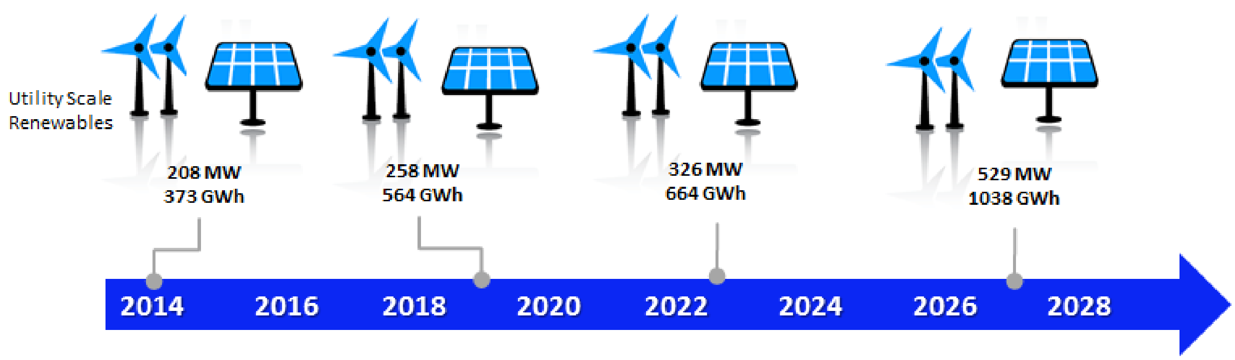
Chart 51 - Renewable Resource Seasonal Profiles



Projected Utility Scale Requirements in the 2014 IRP

The Reference Case plan also includes a diverse portfolio of renewable resources that complies with the Arizona Renewable Energy Standard (RES). The Reference Case plan meets the renewable energy standard goals. The RES requires TEP to utilize renewable energy resources to serve 4.5% of its 2014 retail load requirement, growing to 15% by 2025. By 2028, the Reference Case plan includes approximately 529 MW of utility scale renewable nameplate capacity. These utility scale renewable resources are expected to supply approximately 373 GWh of energy in 2014 growing to 1038 GWh by 2028.

Figure 30 – Utility Scale Renewable Capacity



Below is a forecast summary of the utility-scale renewable resources that comply with the Arizona RES targets.

Table 41 – 2014-2028 Projected Utility Scale Resources

REST Utility Scale Program, Energy	2014	2015	2016	2017	2018	2019	2020	2021
Utility Scale Solar, GWh	239.2	298.2	299.0	298.1	298.1	298.2	298.9	298.2
Utility Scale Wind, GWh	133.4	266.3	267.3	266.3	266.4	266.3	267.3	266.3
Total Utility Scale Renewables, GWh	372.6	564.5	566.3	564.5	564.5	564.4	566.2	564.5

REST Utility Scale Program, Energy	2022	2023	2024	2025	2026	2027	2028
Utility Scale Solar, GWh	398.2	398.2	615.7	690.8	710.1	729.2	747.8
Utility Scale Wind, GWh	266.4	266.3	302.6	310.0	306.2	308.3	310.3
Total Utility Scale Renewables, GWh	664.5	664.5	918.3	1,000.8	1,016.3	1,037.5	1,058.1

Table 42 – 2014-2028 Projected Utility Scale Resource Costs

REST Utility Scale Program Costs	2014	2015	2016	2017	2018	2019	2020	2021
PPFAC Cost, Renewables, $000	$25,090	$31,668	$31,206	$30,273	$29,433	$28,580	$27,781	$26,800
REST Program - Utility Scale, $000	$16,350	$26,033	$26,677	$27,425	$28,260	$29,117	$30,094	$30,908
Total Utility Scale Renewables, $000	$41,440	$57,701	$57,883	$57,698	$57,693	$57,698	$57,875	$57,708

REST Utility Scale Program Costs	2022	2023	2024	2025	2026	2027	2028
PPFAC Cost, Renewables, $000	$26,010	$25,044	$24,495	$23,532	$26,132	$24,934	$23,734
REST Program - Utility Scale, $000	$31,844	$32,805	$33,908	$34,829	$39,777	$40,994	$42,274
Total Utility Scale Renewables, $000	$57,854	$57,850	$58,403	$58,362	$65,909	$65,929	$66,008

CHAPTER 13

RENEWABLE RESOURCE INTEGRATION AND ENERGY STORAGE

The Future of Renewable Resource Integration

In order to maintain system reliability, real time system operators maintain a constant balance between customer retail demand and system generation capability. Conventional thermal generation resources are dispatched throughout the day, ramping up and down as load conditions change. However, in the case of renewable resources, the output from these resources is weather dependent and typically non-dispatchable. As higher percentages of renewable resources are added to the TEP resource portfolio over the next few years, system dispatchers will have to rely on more stringent scheduling requirements and new grid technologies to successfully manage real time operations. In preparation for these changes, TEP is conducting on-going studies and reviewing work being conducted by other utilities to access the potential costs and system upgrades that will be necessary to support higher penetrations of intermittent resources.

Some common recommendations that are starting to emerge from recent studies include the following:

- Successful integration of intermittent renewable resources requires additional investments in transmission and distribution resources.
- Generation fleet flexibility is critical. Existing thermal resources need quick start capabilities, fast ramp rates and the ability to cycle more frequently.
- Updates to utility reliability criteria should be modified with higher penetrations of renewables. (i.e., higher reserve margins).
- State-of-the-art forecasting and dispatching tools need to be integrated with the real-time operations.
- Renewable resources should be implemented with adequate investments in grid storage technologies that provide low voltage ride through, voltage control, and reactive power control capabilities.
- Optionally for renewable resources to provide curtailable schedules or set ramp rate limits is critical to system reliability.
- Quick-start combustion turbines with low unit minimums and fast ramping resources such as pumped-storage plants are good complements to integrating intermittent renewable resources into existing power systems.
- Customer load shifting and DR programs provide additional dispatch support.
- Integration of utility-scale energy storage devices will play a critical role in renewable integration. This chapter provides an overview of some of these emerging technologies.

For purposes of the 2014 Resource Plan, TEP shows the need to develop a portfolio of future storage technologies that will support long-term grid reliability. For purposes of the 2014 IRP, the need for future storage technologies is focused on supporting the need for quick response time ancillary services. These services are listed below:

- Load Following / Ramping
- Regulation
- Voltage Support
- Power Quality
- Frequency Response

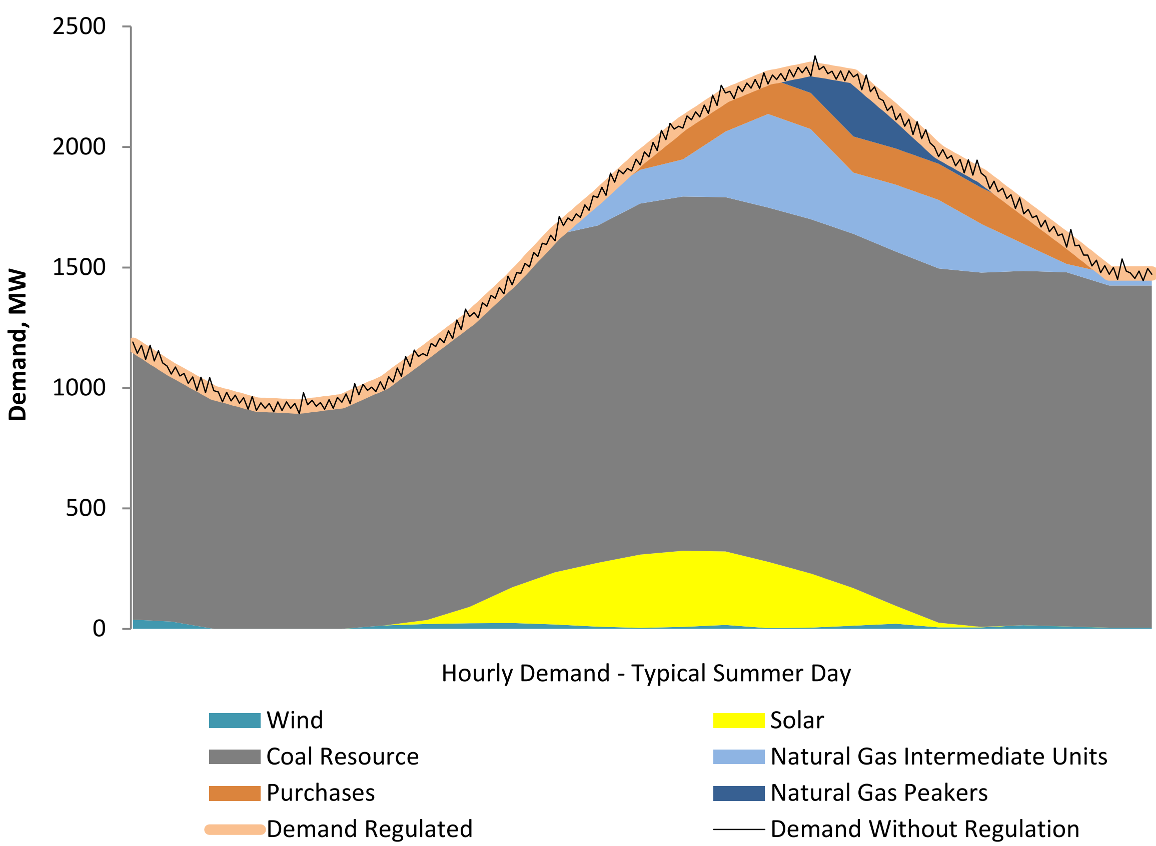
Load Following

Load following is generally characterized by a utility's ability to regulate power output changes that over a five to ten minute timeframe. Load following is required to respond to the changing conditions of electric supply and demand. Historically, utilities relied on a mix of conventional generation resources tied into a utilities' energy management system (EMS) that provided automated generation control (AGC) to manage their load following requirements. However, as renewable resources become a larger part of the resource portfolio, changes in supply and demand conditions will become more extreme and will happen more frequently.

Regulation

Regulation is used to reconcile momentary differences caused by fluctuations in generation and loads. The primary reason for controlling regulation in the power system is to maintain grid frequency requirements that comply with the North American Electric Reliability Council's (NERC's) Real Power Balancing Control Performance and Disturbance Control Performance Standards. The benefit of regulation from storage technologies with a fast ramp rates are on the order of two to three times that of regulation provided by conventional generation. This is due to the fact that storage technologies have the ability to react to changes in system conditions in a matter of a minute or two rather than several minutes. The black load demand line in Chart 52 shows numerous fluctuations depicting the imbalance between generation and load without regulation. The thicker orange line in the plot shows a smoother system response after damping of those fluctuations with regulation.

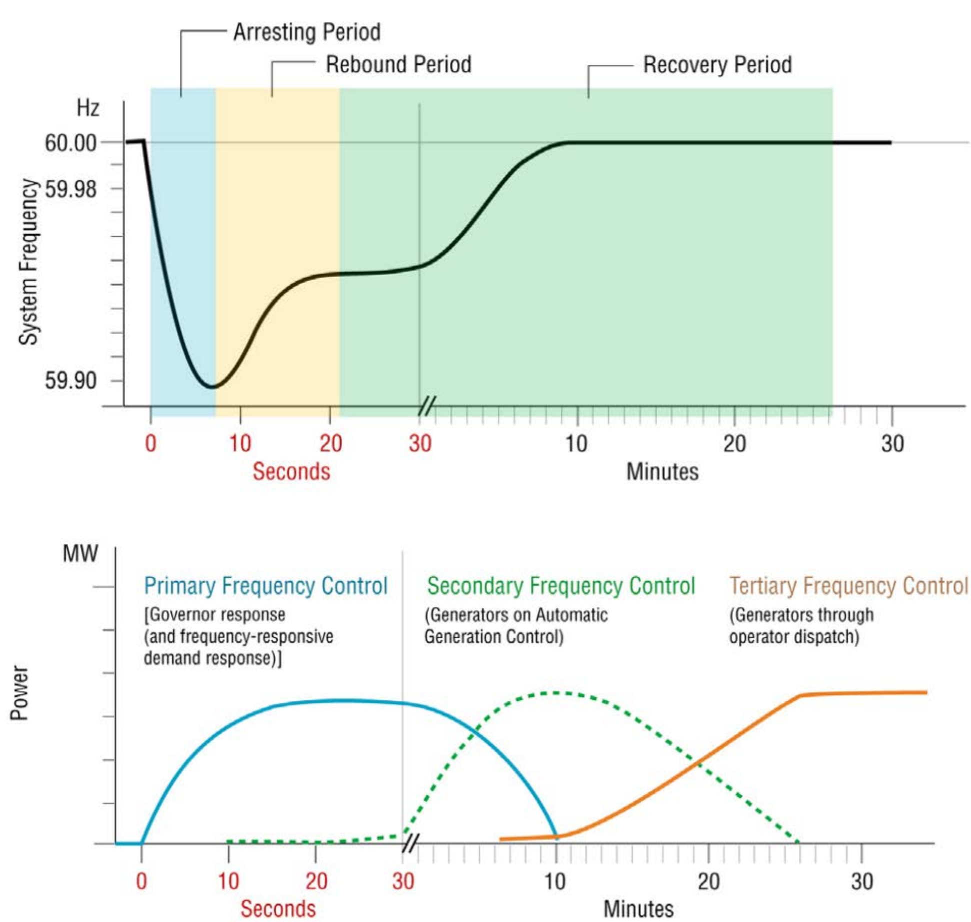
Chart 52 – Effects of Load Regulation



Frequency Response

Frequency response is an ancillary service requirement that is similar to regulation except frequency response requires a response to a system disturbance in time periods of seconds rather than minutes. These types of disturbances occur when there is a sudden loss of a generation unit or a transmission line outage. As a result, other generating resources that are online must respond to counteract this sudden imbalance between load and generation and to maintain the system frequency and stability of the grid. The first response within the initial seconds is called the primary frequency control. This response is the result of the governor action on the generation units automatically increasing their power output as shown in the lower portion of Figure 31 below. This is followed by the longer duration of secondary frequency controls. These responses are initiated by AGC that spans a half a minute to several minutes shown by the dotted line in the lower portion of Figure 31. The combined effect of inertia and the governor actions of online generation units determines the rate of frequency decay and recovery shown in the arresting and rebound periods in the upper portion of Figure 31. This is also the window of time in which the fast-acting response of flywheel and battery storage systems excels in stabilizing the frequency. The presence of fast-acting storage assures a smoother transition to normal operation returning grid frequency back to its normal range.

Figure 31 – Sequential Actions of Frequency Controls



Voltage Support

Another reliability requirement for electric grid operators is to maintain grid voltage within specified limits. To manage reactance at the grid level, system operators need voltage support resources to offset reactive effects so that the transmission and distribution system networks can be operated in a stable manner. Normally, designated power plants are used to generate reactive power (VAR) to offset reactance in the grid. These power plants could be displaced by strategically placed energy storage within the grid at central locations or taking the distributed approach and placing multiple VAR-support storage systems near large loads.

Power Quality

The electric power quality service involves using storage to protect customer on-site loads downstream (from storage) against short-duration events that affect the quality of power delivered to the customer's loads. Some manifestations of poor power quality include the following:

- Variations in voltage magnitude (e.g., short-term spikes or dips, longer term surges, or sags).
- Variations in the primary 60-hertz (Hz) frequency at which power is delivered.
- Low power factor (voltage and current excessively out of phase with each other).
- Harmonics (i.e., the presence of currents or voltages at frequencies other than the primary frequency).
- Interruptions in service, of any duration, ranging from a fraction of a second to several seconds.

Typically, the discharge duration required for the power quality use ranges from a few seconds to a few minutes. Distributed storage systems can monitor grid power quality and discharge to smooth out disturbances so that it is transparent to customers.

Table 43 – Ancillary Services Technical Consideration for Storage Technologies

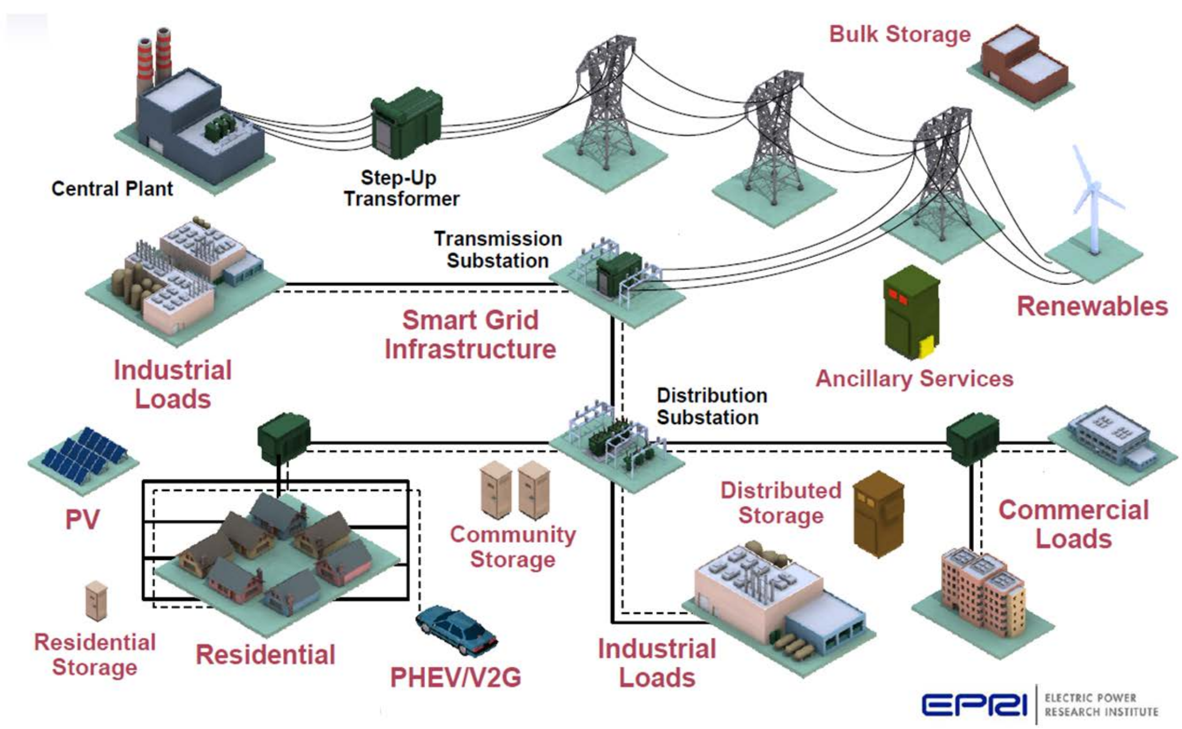
Ancillary Services	Storage System Size	Target Discharge Duration	Minimum Cycles/Year
Load Following / Ramping	1 – 100 MW	Range: 15 minutes to 60 minutes	Not Applicable
Regulation	Range: 10 – 40 MW	Range: 15 minutes to 60 minutes	250 – 10,000
Voltage Support	1 – 10 (MVAR)	Not Applicable	Not Applicable
Distribution Deferral	500 kilowatts (kW) – 10 MW	Range: 1 – 4 hours	50 - 100
Power Quality	100 kW – 10 MW	10 seconds – 15 minutes	10 - 200
Frequency Response	10 – 100 MW	5 seconds – 2 hours	20 - 100

ELECTRIC ENERGY STORAGE (EES) TECHNOLOGY

Electric energy storage (EES) technology has the potential to facilitate the large-scale deployment of variable renewable electricity generation, such as wind and solar power. EES promises other benefits unrelated to renewable energy, such as improved grid reliability and stability, deferral of new generation and transmission investments, and other grid benefits

EES technologies vary by method of storage, the amount of energy they can store, and how quickly and for how long they can release stored energy. Some EES technologies are more appropriate for providing short bursts of electricity for power quality applications, such as smoothing the output of variable renewable technologies from hour to hour (and to a lesser extent within a time scale of seconds and minutes). Other EES technologies are useful for storing and releasing large amounts of electricity over longer time periods (for peak-shaving, load-leveling, or energy arbitrage). These EES technologies could be used to store variable renewable electricity output during periods of low demand and release this stored power during periods of higher demand.

Figure 32 –Role of Storage within a Distributed Grid

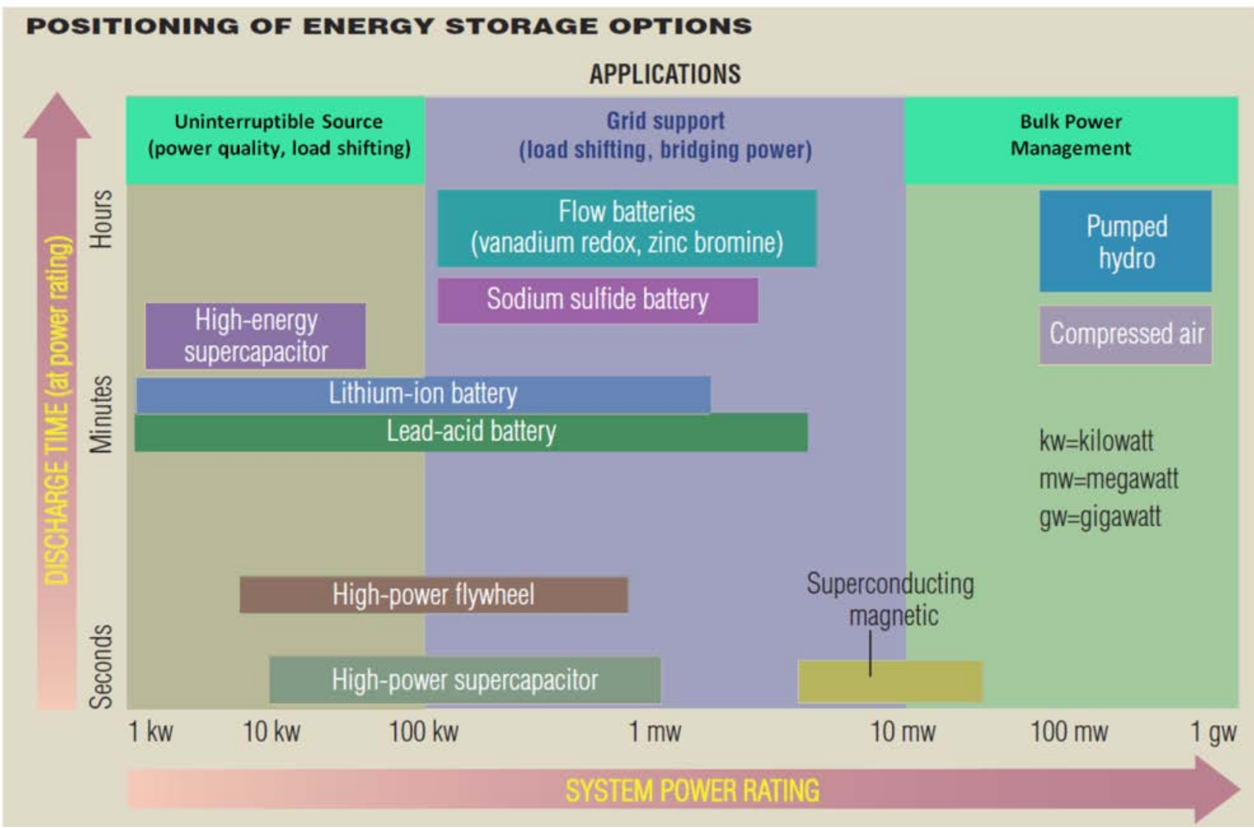


Energy Storage Options

Some of the major technology options being researched by TEP include the following:

- Pumped Hydro
- Compressed Air Energy Storage
- Rechargeable Batteries
- Flywheels
- Ultracapacitors
- Fuel Cells

Figure 33 – Positioning of Energy Storage Options



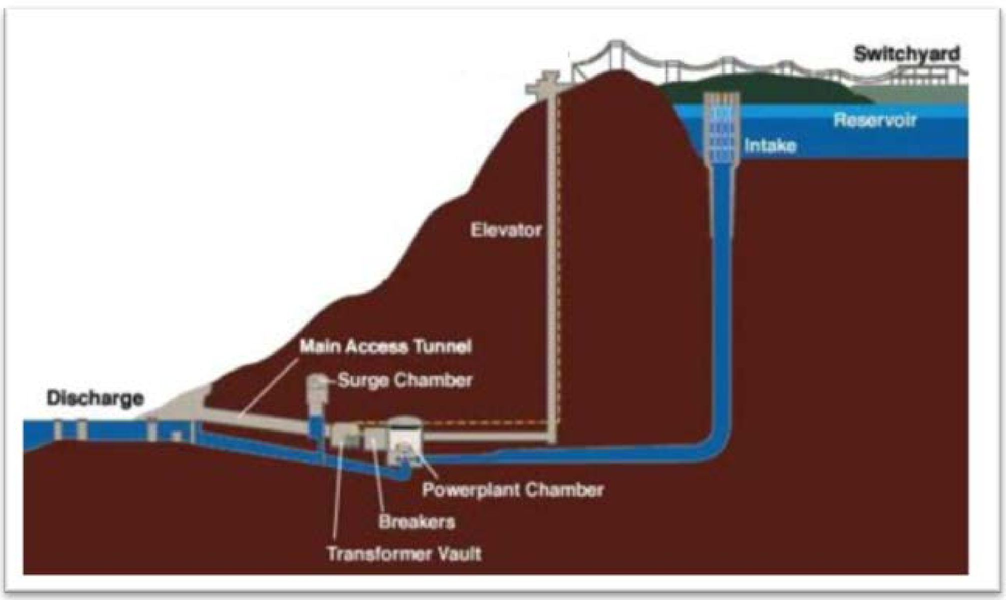
Pumped Hydro

Pumped hydro has been in use for nearly a century worldwide. Pumped hydro accounts for most of the installed storage capacity in the United States. Pumped hydro plants use off-peak electricity to pump water from a low-elevation reservoir to a higher reservoir. When the utility needs the electricity, the plant releases the water to flow through hydro turbines to generate power.

Typical pumped hydro facilities can store up to 10 or more hours of energy storage. Pumped hydro plants can absorb excess electricity produced during off-peak hours, provide frequency regulation, and help smooth the fluctuating output from other sources. Pumped hydro requires sites with suitable topography where reservoirs can be situated at different elevations and where sufficient water is available. Pumped hydro is economical only on a large (250-2,000 MW) scale, and construction can take several years to complete.

The round-trip efficiency of these systems usually exceeds 70 percent. Installation costs of these systems tend to be high due to siting requirements and obtaining environmental and construction permits presents additional challenges.

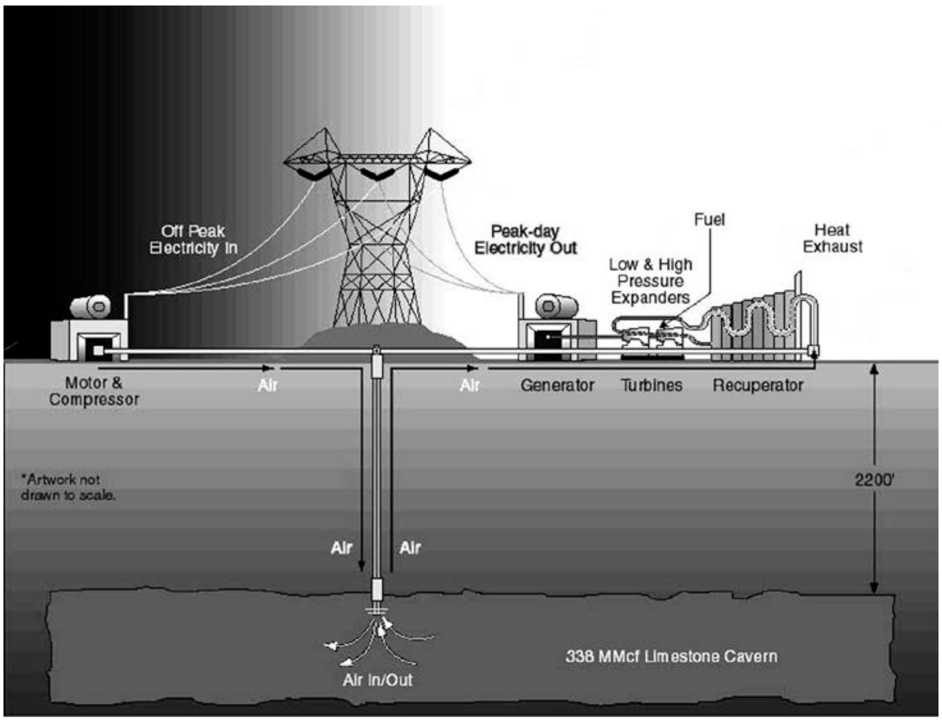
Figure 34 – Pumped Storage Project



Compressed Air Energy Storage

A leading alternative for bulk storage is compressed air energy storage (CAES). CAES is a hybrid generation/storage technology in which electricity is used to inject air at high pressure into underground geologic formations. CAES can potentially offer shorter construction times, greater siting flexibility, lower capital costs, and lower cost per hour of storage than pumped hydro. A CAES plant uses electricity to compress air into a reservoir located either above or below ground. When the utility needs the electricity, the compressed air is withdrawn, heated via combustion, and run through an expansion turbine to drive a generator.

Figure 35 - Compressed Air Energy Storage (CAES)



CAES plants are in operation today— a 110-MW plant in Alabama and a 290-MW unit in Germany. Both plants compress air into underground caverns excavated from salt formations. The Alabama facility stores enough compressed air to generate power for 26 hours and has operated reliably since 1991.

CAES plants can use several types of air-storage reservoirs. In addition to salt caverns, underground storage options include depleted natural gas fields or other types of porous rock formations. EPRI studies show that more than half the United States has geology potentially suitable for CAES plant construction. Compressed air can also be stored in above-ground pressure vessels or pipelines. The latter could be located within right-of-ways along transmission lines. Responding rapidly to load fluctuations, CAES plants can perform ramping duty to smooth the intermittent output of renewable generation sources as well as provide spinning reserve and frequency regulation to improve overall grid operations.

Rechargeable Batteries

Several different types of large-scale rechargeable batteries can be used for EES including lead acid, lithium ion, sodium sulfur (NaS), and redox flow batteries. Batteries can be located in distribution systems closer to end users to provide peak management solutions. An aggregation of large numbers of dispersed battery systems in smart-grid designs could even achieve near bulk-storage scales.

In addition, if plug-in hybrid electric vehicles (PHEVs) become widespread, their onboard batteries could be used for EES, by providing some of the supporting or "ancillary" services in the electricity market such as providing capacity, spinning reserve, or regulation services, or in some cases, by providing load-leveling or energy arbitrage services by recharging when demand is low to provide electricity during peak demand.

Lead Acid Batteries

Deep-cycle lead acid batteries have been the mainstay for residential renewable energy storage for decades and advanced versions of lead acid technology are under development for many storage applications. It remains the lowest-cost battery technology and continues to have multiple applications in the transportation sector.

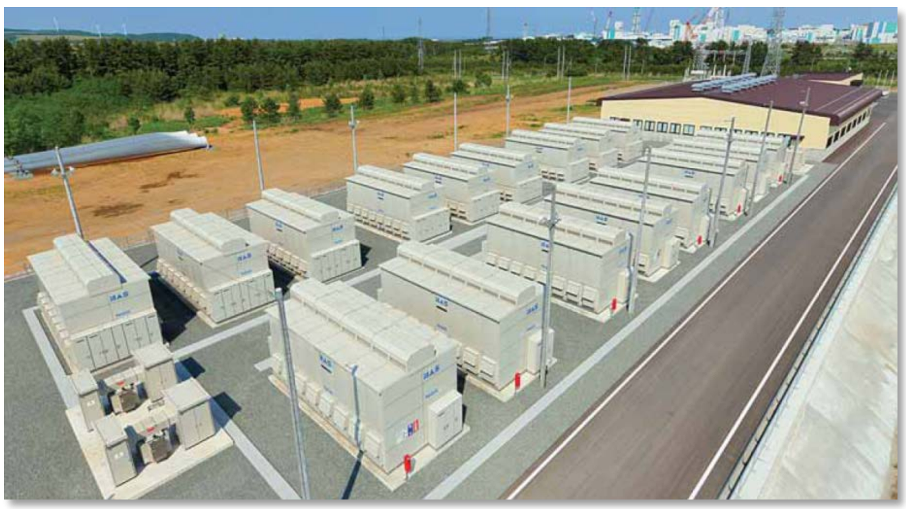
Picture 14 – PNM Prosperity Energy Storage Project

This project integrates an Advanced VRLA (Valve-Regulated Lead-Acid) and UltraBattery energy storage solution with a separately installed 500 kW solar plant. Its purpose is to provide simultaneous voltage smoothing for consistent energy levels and peak shifting

Sodium Sulfur (NAS) Batteries

NAS batteries have proved a better match for utility applications because of its high storage capacity; its ability to handle a large number of charge-recharge cycles as would be incurred with an intermittent renewable energy resource; its large scale and potential for even larger scalability; its dynamic response to system changes; and its demonstrated commercial performance and availability. Additionally, the longer cycle life translates to lower replacement costs and thus low maintenance costs.

NaS batteries must operate at about 450°C (850°F) and must be maintained at this high temperature by appropriate thermal insulation. Since NaS batteries consist of reactive materials maintained at high-temperatures, engineering measures are required to ensure safe operations. Notwithstanding these challenges, large-scale NaS battery installations have been demonstrated worldwide, with the largest installed unit being able to store about 245 MWh of electricity, with a charge/discharge capacity of 34 MW for a wind power stabilization application in Northern Japan by NGK Insulators Inc.



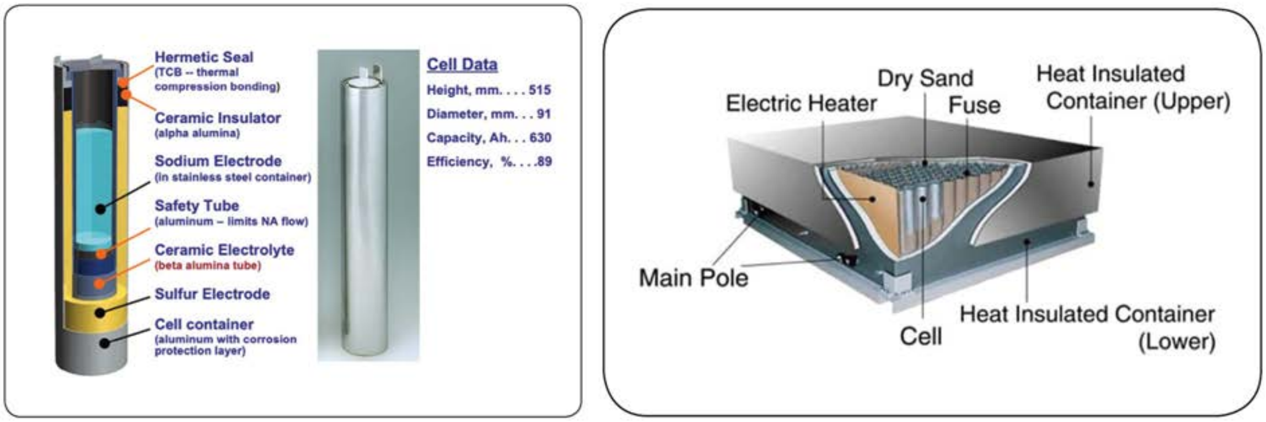
Picture 15 - EPRI –Sodium Sulfur Battery Plant

Tokyo Electric Power Company's sodium sulfur battery plants developed in partnership with NGK Insulators.

Several utilities are putting NAS technology to work in the United States. In 2008 Xcel Energy announced plans to test energy storage devices as part of its smart grid strategy to modernize and upgrade the grid to allow for integration of renewable energy sources. Xcel Energy is testing a one MW wind energy battery-storage system, using NaS battery technology. The test will demonstrate the system's ability to store wind energy and move it to the electricity grid when needed, and to validate energy storage in supporting greater wind penetration on the Xcel Energy system.

The Wind to Battery project is made up of twenty 50 kW modules. It is roughly the size of two semi trailers and weighs approximately 80 tons. The battery is able to store about 7.2 MWh of electricity, with a charge/discharge capacity of one MW. When the wind blows, the batteries are charged. When the wind calms down, the batteries supplement the power flow. Fully charged, the battery could power 500 homes for over 7 hours.

Figure 36 - Xcel Energy – Wind to Battery Project



(Left) Schematic of single battery cell
(Right) Cross section of battery components

Picture 16 – Xcel Energy – Wind to Battery Project

To date in the U.S., about 40 MWs have been deployed for grid support and integration with wind energy systems. General Electric has plans to develop and manufacture NaS batteries for renewable energy system integration.

Lithium-Ion Batteries

Lithium ion batteries are widely used in consumer electronics for such applications as cell phones and portable computers. There are a number of different combinations and mixtures of cathode materials used that compete on the basis of their power and energy density, safety, and reliability. Because of the tradeoffs in these areas, no one formulation has become the standard one. Lithium ion batteries are the main focus for transportation energy storage and the economies of scale provided by the growth of those applications is the primary reason to seriously consider the technology for the grid. The 1980s saw the introduction of the nickel metal hydride (NiMH) battery, which has been the mainstay for hybrid electric vehicles since they entered the market. Although both NiMH and lead acid batteries continue to improve, one or another type of lithium-ion battery is likely to power a growing percentage of electric vehicles throughout the next decade. The energy density of lithium-based batteries is about twice that of NiMH batteries (which themselves have twice the density of lead acid batteries.)

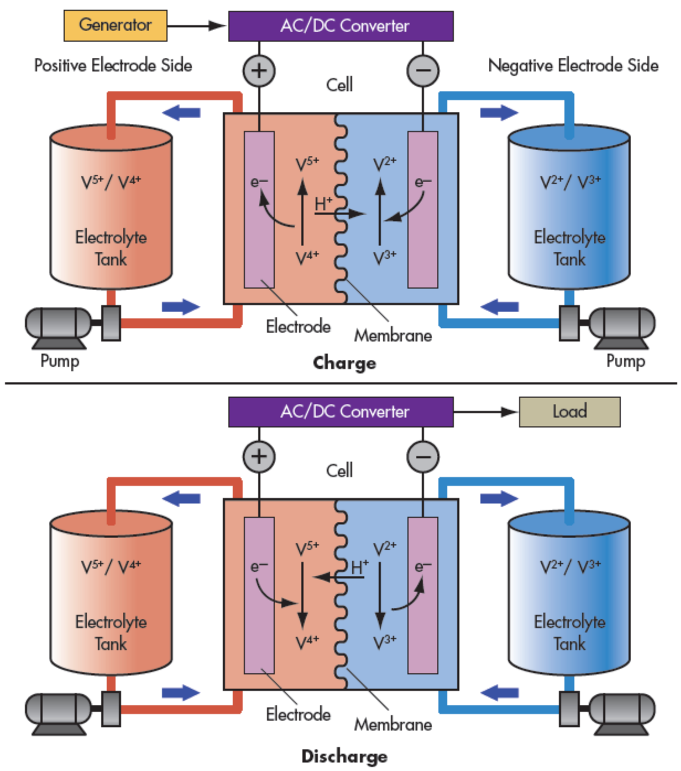
Advanced Lithium-ion (Li-ion) batteries have demonstrated energy storage capacities much higher than those of conventional lead-acid batteries of equal weight and can last through 5-10 times more deep-discharge cycles (operational life of about five years). For utility purposes characteristics of the Li-ion battery make it ideal for commercial and residential applications including load shifting and photovoltaic integration. PHEVs may eventually serve as distributed energy storage units that could support not only the home but the electricity grid as well.

Picture 17 - AES Storage LLC's Laurel Mountain Energy Storage
Supplies 32 MW of regulation using Li-ion batteries

Vanadium Redox Batteries

The vanadium redox flow battery (VRB) has a range of utility applications. VRBs have already been used in a number of demonstrations in small-scale utility applications, and the technology is close to being viable for more widespread use. In a VRB, energy is stored chemically in different ionic forms of vanadium (a metallic element) in an electrolyte, which is pumped from separate storage tanks across an ion exchange membrane, where a reduction/oxygen—redox—reaction takes place, changing the oxidation number of the atoms and creating a current. VRBs are a "large" battery technology, ranging in capacity from 1 KW to several MWs. Characteristics such as long life, high energy density, and flexible power and energy sizing make VRBs suitable for long-duration utility-scale use.

Figure 37 - EPRI – Diagram of Vanadium Redox Flow Battery (VRB)



The storage potential of flow batteries, such as the vanadium redox battery, resides in the fluid electrolyte rate rather than in expensive electrodes. Thus the discharge time can be upgraded by simply using larger electrolyte tanks. When the battery is being charged, the V4+ ions in the positive half-cell are converted to V5+ ions when electrons are taken up by the positive electrode, and electrons from the negative electrode convert the V3+ ions to V2+ in the negative half cell. During the discharge process this is reversed, resulting in voltage to load.

Picture 18 – Prudent Energy Vanadium Redox Flow Battery Project
The system consists of 200-kW modules providing a total of 6 hours of electrochemical energy storage

The Vanadium Redox Battery (VRB) is one of the best known examples of a redox flow battery that has been scaled up to MWh sizes; systems with the power level of 2 MW and storage capacity of 12 MWh have been demonstrated. Many units based on VRB technologies are in operation worldwide. Some of the flow battery systems have been in operation for over 30 years with minimal maintenance. The life cycle emission from these batteries is less than 25 percent of that of lead-acid batteries.

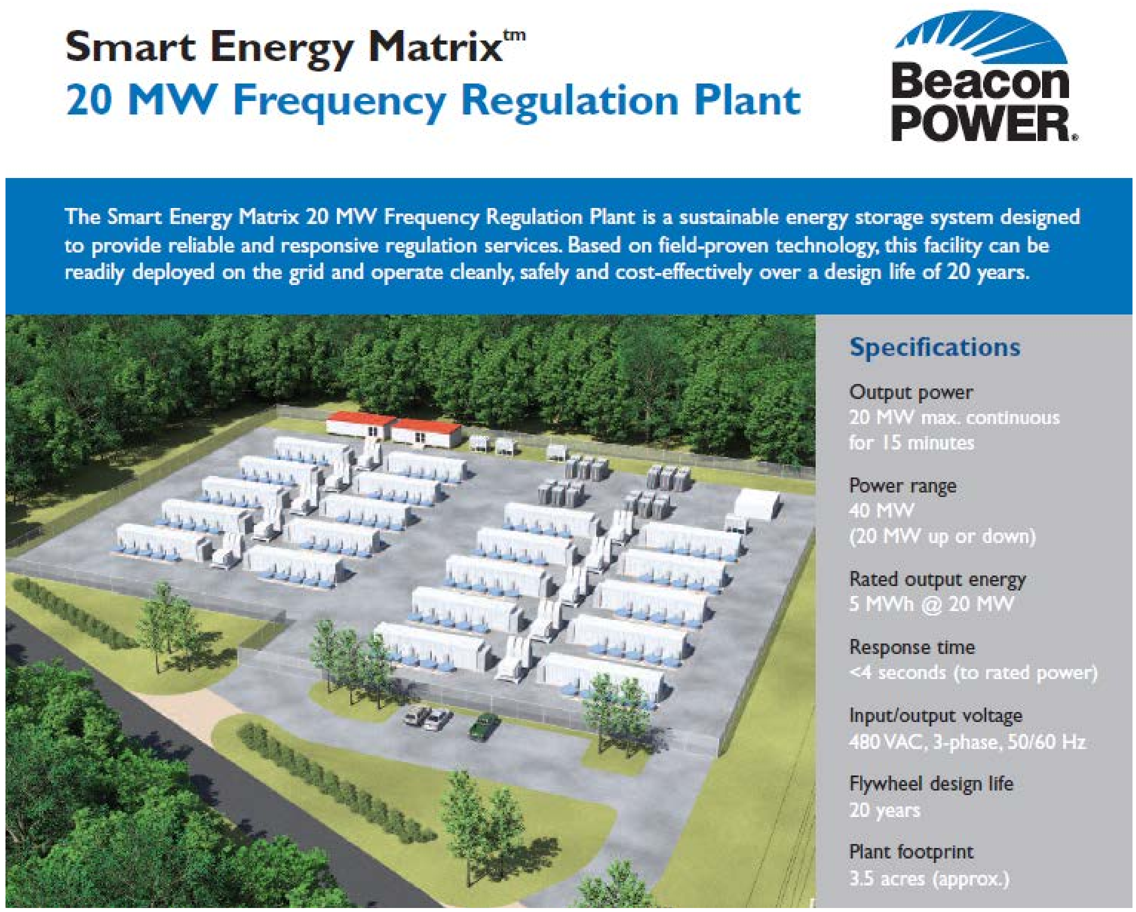
Grid Technologies

Flywheels

Flywheels can be used for power quality applications since they can charge and discharge quickly and frequently. In a flywheel, energy is stored by using electricity to accelerate a rotating disc. To retrieve stored energy from the flywheel, the process is reversed with the motor acting as a generator powered by the braking of the rotating disc.

Flywheel systems are typically designed to maximize either power output or energy storage capacity, depending on the application. Low-speed steel rotor systems are usually designed for high power output, while high-speed composite rotor systems can be designed to provide high energy storage. A major advantage of flywheels is their high cycle life—more than 100,000 full charge discharge cycles.

Scale-power versions of the system, a 100 kW version using modified existing flywheels which was a proof of concept on approximately a 1/10th power scale, performed successfully in demonstrations for the New York State Energy Research and Development Authority and the California Energy Commission.



Picture 19 - EPRI - Beacon Power Flywheel Facility

Rendering of a 20 MW flywheel facility - 200 high energy flywheels and associated electronics will be able to provide 20 MW of up and down regulation.

Ultracapacitors

Ultracapacitors are electrical devices that consist of two oppositely charged metal plates separated by an insulator. The ultracapacitor stores energy by increasing the electric charge accumulation on the metal plates and discharges energy when the electric charges are released by the metal plates. Ultracapacitors could be used to improve power quality because they can rapidly provide short bursts of energy (in under a second) and store energy for a few minutes. Utracapacitors are still in the demonstration phase.

Chart 53 – Storage Technology Installed Cost, $/kW

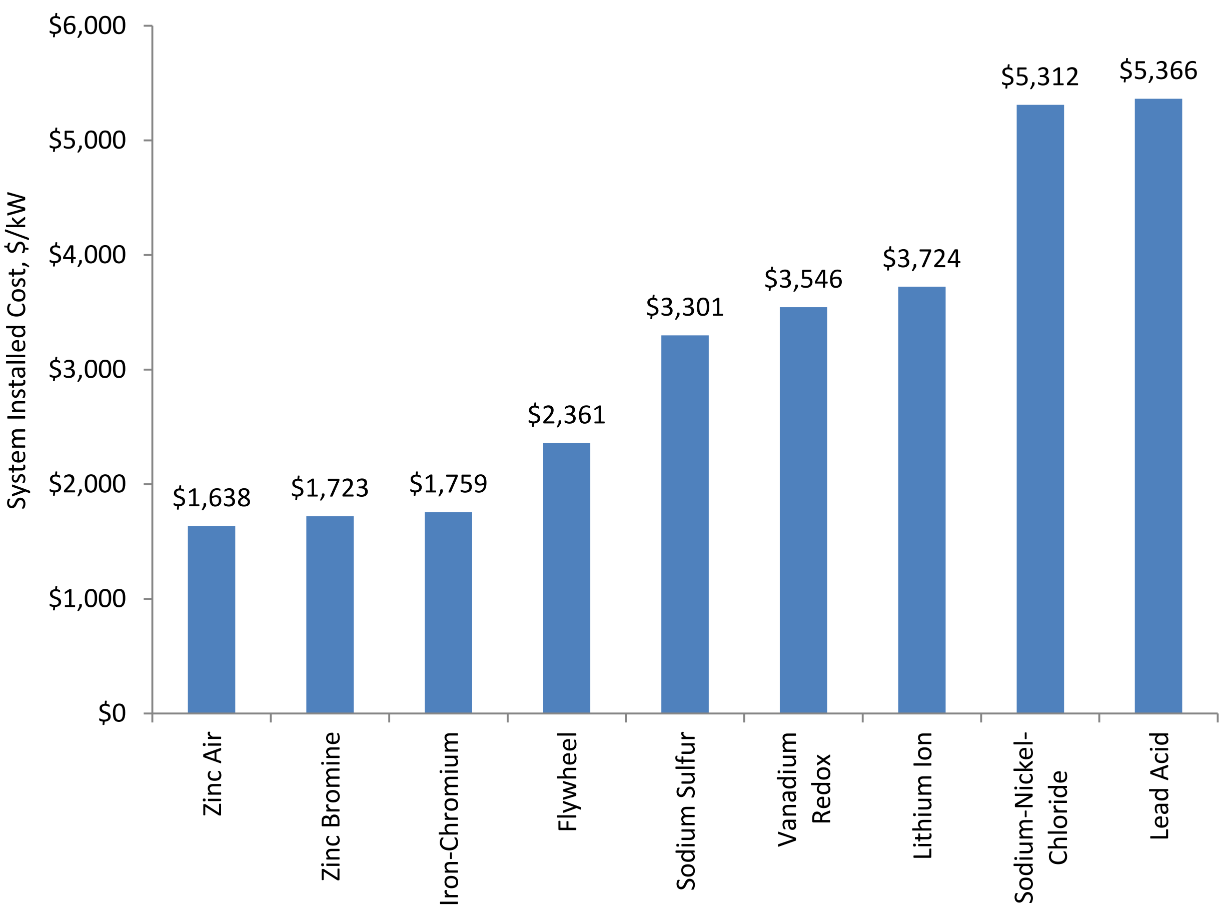


Table 44 - Summary of Energy Storage Systems (ESS)

Energy Storage Systems	Capacity	Storage Capacity	Discharge Time	Installed Cost, $/kW	Energy Cost, $/kWh	Technology Development
Bulk Power Systems						
Pumped Hydro	250 MW to 2000 MW	1500 MWh to 20 GWh	6 - 12 Hours	$5000 to $8,000 / kW	$150 to $250/kWh	Mature
CAES	100 MW to 500 MW	150 MWh to 750 MWh	4 - 10 Hours	$1,000 to $2,000 / kW	$150 to $300/kWh	Commercial
Rechargeable Batteries						
Lead-Acid	< 1MW	0.1 kWh to 1 MWh	1 - 5 Hours	$4,500 to $7,000 / kW	$700 to $900/kWh	Commercial
Flow Battery	< 1 MW	1.5 MWh to 4 MWh	2 - 4 Hours	$6,000 to $8,500 / kW	$400 to $800/kWh	Deployment
Lithium-Ion (Li-on)	< 1MW	0.1 MWh to 0 .5 MWh	2 - 4 Hours	$3,500 to $4,500 / kW	$1100 to $1,300/kWh	Deployment
Sodium Sulfur (NaS)	< 40 MW	< 250 MWh	6 - 10 Hours	$3,000 to $4,000 / kW	$400 - $600/kWh	Mature
Grid Technologies						
Flywheels	< 20 MW	< 5 MWh	< 15 minutes	$2,000 to $5,500 / kW	$4000 to $5000/kWh	Deployment
Ultracapacitors	< 1 MW	< 100 kWh	< 1 minute	$500 to $1,000 / kW	$20,000 to $30,000/kWh	Demonstration

Fuel Cell Systems

Fuel cell technology has been developed by government agencies and private corporations. Fuel cells are an important part of space exploration and are receiving considerable attention as an alternative power source for automobiles. In addition to these two applications, fuel cells continue to be considered for power generation for permanent power and intermittent power demands.

Operating Principles

Fuel cells convert hydrogen-rich fuel sources directly to electricity through an electrochemical reaction. Fuel cell power systems have the promise of high efficiencies because they are not limited by the Carnot efficiency that limits thermal power systems. Fuel cells can sustain high efficiency operation even under part load. The construction of fuel cells is inherently modular, making it easy to size plants according to power requirements.

There are four major fuel cell types under development: phosphoric acid, molten carbonate, solid oxide, and proton exchange membrane. The most developed fuel cell technology for stationary power is the phosphoric acid fuel cell (PAFC). PAFC plants range from around 200 kW to 11 MW in size and have efficiencies on the order of 40 percent. PAFC cogeneration facilities can attain efficiencies approaching 88 percent when the thermal energy from the fuel cell is utilized for low grade energy recovery. The potential development of solid oxide fuel cell/gas turbine combined cycles could reach electrical conversion efficiencies of 60 to 70 percent.

Applications

Most fuel cell installations are less than 1 MW. Commercial stationary fuel cell plants are typically fueled by natural gas, which is converted to hydrogen gas in a reformer. However, if available, hydrogen gas can be used directly. Other sources of fuel for the reformer under investigation include methanol, biogas, ethanol, and other hydrocarbons.

In addition to the potential for high efficiency, the environmental benefits of fuel cells remain one of the primary reasons for their development. High capital cost, fuel cell stack life, and reliability are the primary disadvantages of fuel cell systems and are the focus of intense R&D. The cost is expected to drop significantly in the future as development efforts continue, partially spurred by interest by the transportation sector.

Performance and Cost Characteristics

A significant cost is the need to replace the fuel cell stack every 3 to 5 years due to degradation. The stack alone can represent up to 40 percent of the initial capital cost. Most fuel cell technologies are still developmental and power produced by commercial models is not competitive with other resources.

Comparison of Utility Scale Fuel Cell Technologies

U.S. DEPARTMENT OF ENERGY | Energy Efficiency & Renewable Energy

FUEL CELL TECHNOLOGIES PROGRAM

Comparison of Fuel Cell Technologies

Fuel Cell Type	Common Electrolyte	Operating Temperature	Typical Stack Size	Efficiency	Applications	Advantages	Disadvantages
Polymer Electrolyte Membrane (PEM)	Perfluoro sulfonic acid	50-100°C 122-212° typically 80°C	< 1kW–100kW	60% transportation 35% stationary	• Backup power • Portable power • Distributed generation • Transporation • Specialty vehicles	• Solid electrolyte reduces corrosion & electrolyte management problems • Low temperature • Quick start-up	• Expensive catalysts • Sensitive to fuel impurities • Low temperature waste heat
Alkaline (AFC)	Aqueous solution of potassium hydroxide soaked in a matrix	90-100°C 194-212°F	10–100 kW	60%	• Military • Space	• Cathode reaction faster in alkaline electrolyte, leads to high performance • Low cost components	• Sensitive to CO_2 in fuel and air • Electrolyte management
Phosphoric Acid (PAFC)	Phosphoric acid soaked in a matrix	150-200°C 302-392°F	400 kW 100 kW module	40%	• Distributed generation	• Higher temperature enables CHP • Increased tolerance to fuel impurities	• Pt catalyst • Long start up time • Low current and power
Molten Carbonate (MCFC)	Solution of lithium, sodium, and/or potassium carbonates, soaked in a matrix	600-700°C 1112-1292°F	300 kW-3 MW 300 kW module	45-50%	• Electric utility • Distributed generation	• High efficiency • Fuel flexibility • Can use a variety of catalysts • Suitable for CHP	• High temperature corrosion and breakdown of cell components • Long start up time • Low power density
Solid Oxide (SOFC)	Yttria stabilized zirconia	700-1000°C 1202-1832°F	1 kW–2 MW	60%	• Auxiliary power • Electric utility • Distributed generation	• High efficiency • Fuel flexibility • Can use a variety of catalysts • Solid electrolyte • Suitable for CHP & CHHP • Hybrid/GT cycle	• High temperature corrosion and breakdown of cell components • High temperature operation requires long start up time and limits

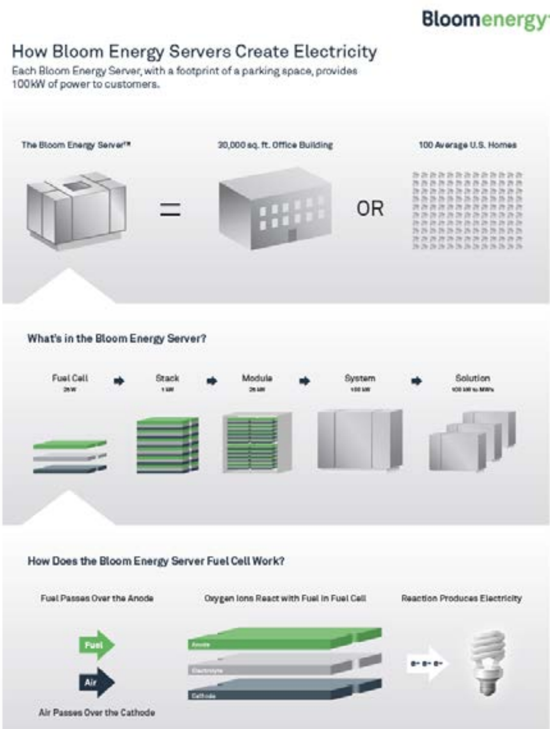
For More Information

More information on the Fuel Cell Technologies Program is available at http://www.hydrogenandfuelcells.energy.gov.

Bloom Energy Corporation

Bloom Energy Corporation, a silicon Valley-based company has successfully developed a DG fuel cell technology to meet the needs of the retail market. Bloom Energy' Bloom Energy Server, a patented solid oxide fuel cell (SOFC) technology provides a clean, reliable, source of power that is being embraced by many large companies. Some of Bloom Energy customers include Bank of America, The Coca-Cola Company Cox Enterprises, eBay, FedEx, Google, Staples, and Wal-Mart.

With the Bloom Energy Server, customers can efficiently generate their own electricity on site, reducing their carbon footprint while lowering energy costs and mitigating power outage risks. Each Bloom Energy Server provides 100 kW of electricity.



Typical Installation of Bloom Box Units
Source: Bloom Energy

CHAPTER 14

Distributed Generation Resources

Overview

Distributed Generation (DG) resources are small-scale renewable resources sited on customer premises. The Renewable Energy Standard requires that a portion of renewable energy requirements be obtained from residential and commercial DG systems. The required DG percentage in the Arizona REST standard is 30% of the total renewable energy requirement.

Distributed Generation Resources

For the 2014 IRP, all of TEP's proposed resource plans comply with the RES specified DG targets. For modeling purposes, TEP assumes the majority of DG resources will be based on solar PV and solar hot water systems. This section provides a brief overview on both residential PV systems and solar hot water heating technologies.

Typical residential distributed photovoltaic (PV) systems

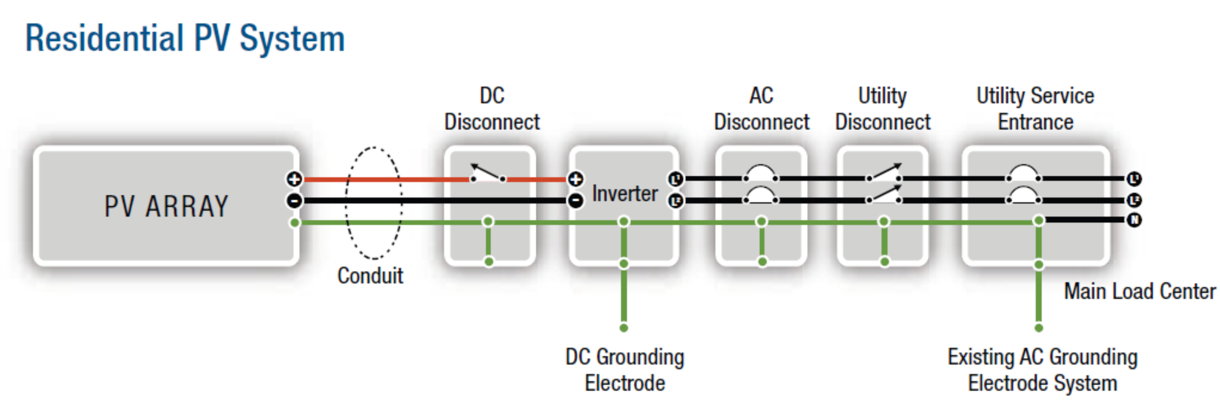
Solar Photovoltaic DG Systems Overview

Solar Photovoltaic DG systems convert sunlight directly into electricity. A residential PV power system enables a homeowner to generate some or all of their daily electrical energy demand on their own roof. The house remains connected to the utility grid at all times, so any power needed above the installed solar capacity can be drawn from the utility. PV systems can also include battery backup or uninterruptible power supply (UPS) capability to operate selected circuits in the residence for hours or days during a utility outage.

Every house that is connected to the electric utility has a main service panel, an electrical meter and a line to the utility grid. Power flows from the grid through the meter to the service panel where it is distributed throughout the house. When PV generation is added to a residence, additional power from that source will also flow to the Main Service Panel to be distributed throughout the house. In the event of a utility outage, the PV system is designed to shut down until utility power is restored.

A simple grid-tied PV system diagram is show below:

Figure 38 – Residential PV System Schematic



Typical System Components:

PV Array: PV systems use solar cells to convert sunlight directly into electricity. The most commonly used solar cells are made from highly purified crystalline silicon. Groups of solar cells are packaged into PV modules, which are sealed to protect the cells from the environment. Modules are wired together in series and parallel combinations to meet the voltage, current, and power requirements of the system. This grouping is referred to as a PV array. The PV array produces DC power, which is then converted to AC power by an inverter to produce electricity. PV modules typically range in size from 5-to-25 square feet and weighs about 3-4 lbs/ft^2.

Balance of System (BOS): The remainder of the PV system, aside from the PV modules, is called the balance-of-system. BOS includes mounting systems and wiring systems used to integrate the solar modules into the structural and electrical systems of the home. The wiring systems include disconnects for the DC and AC sides of the inverter, ground-fault protection, and overcurrent protection for the solar modules. Most PV systems include a circuit combiner to integrate each module source circuit. Some inverters include this fusing and combining function within the inverter enclosure.

Configuration of Typical PV Systems

Figure 39 – Typical Grid Tied PV System

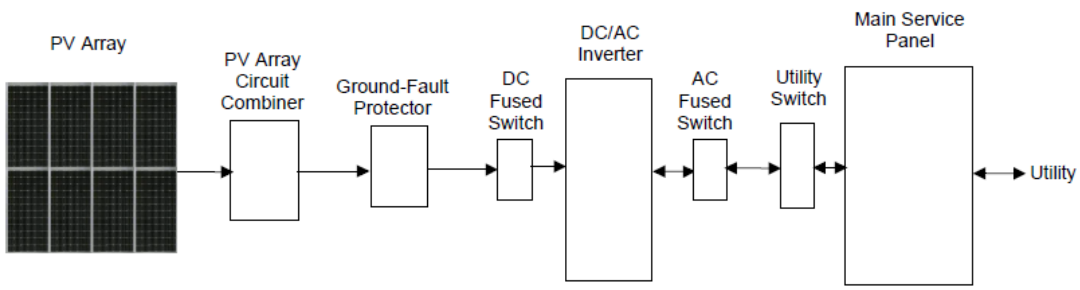
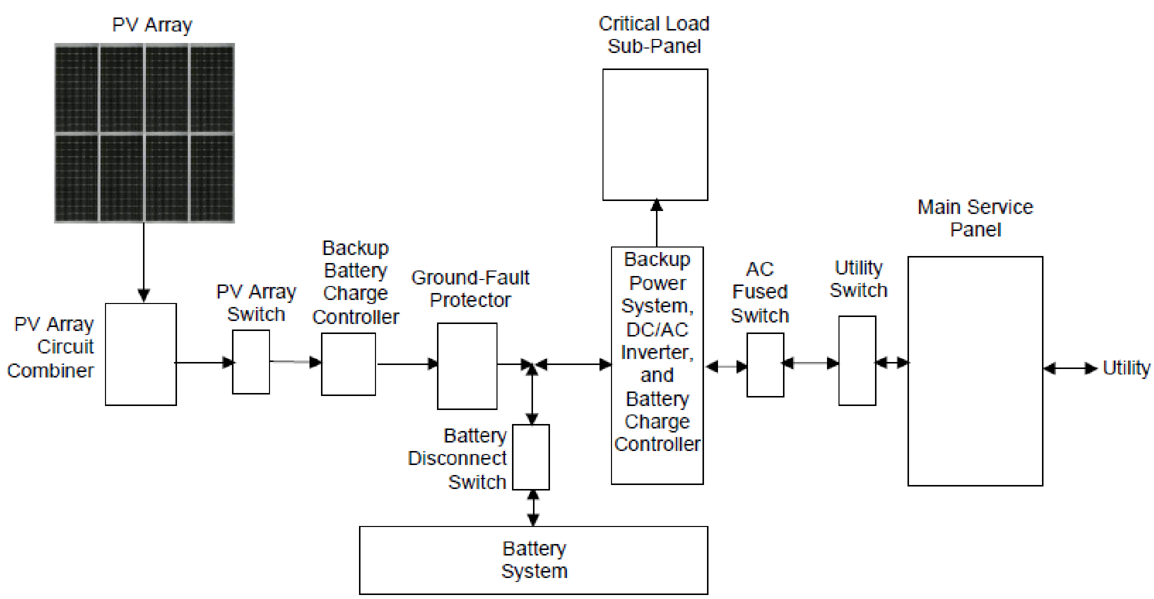


Figure 40 – Typical Grid Tied PV System with Battery Backup



Davis Monthan Air Force Base Distributed Generation Project

The February 2014 completion of a 16 megawatt solar addition at Davis Monthan Air Force Base (DM) has expanded the total solar resources for the base to 21 megawatts making Davis Monthan Air Force Base the Department of Defense's largest solar site. The February addition is comprised of over 57,000 fixed tilt panels on 170 acres. Owned by SunEdison, it is contracted to supply the Air Force base with power over the next 25 years for an expected taxpayer savings of $ 500,000 per year.

Picture 20 – Davis Monthan Air Force Base Distributed Generation Project

Solar PV Load Profiles

Chart 54 – Typical Summer Customer Load Profile, Net Solar PV

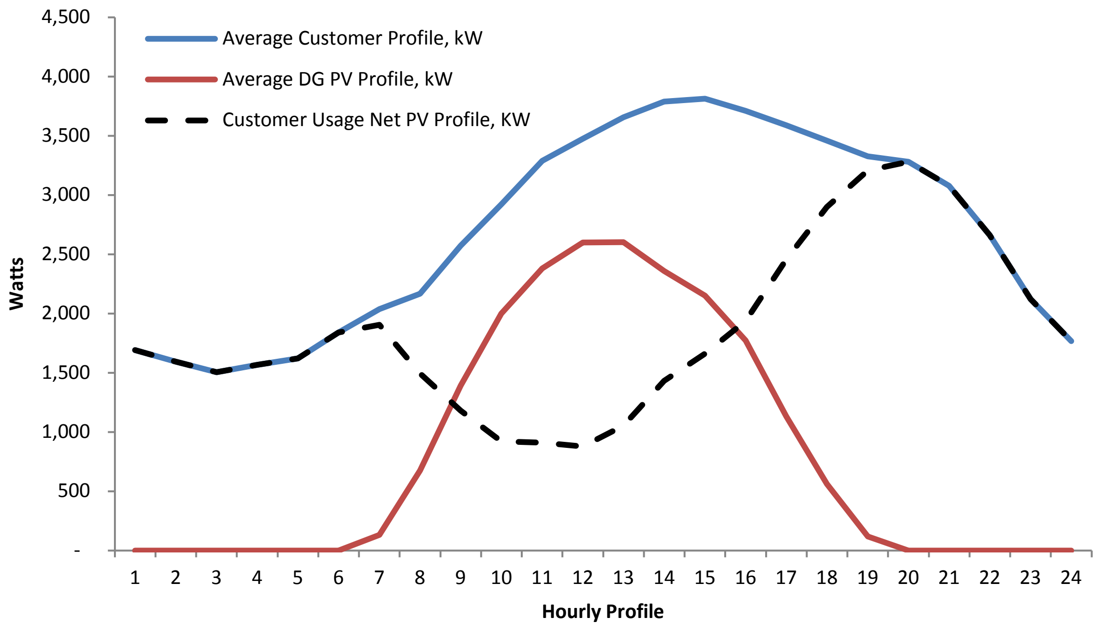
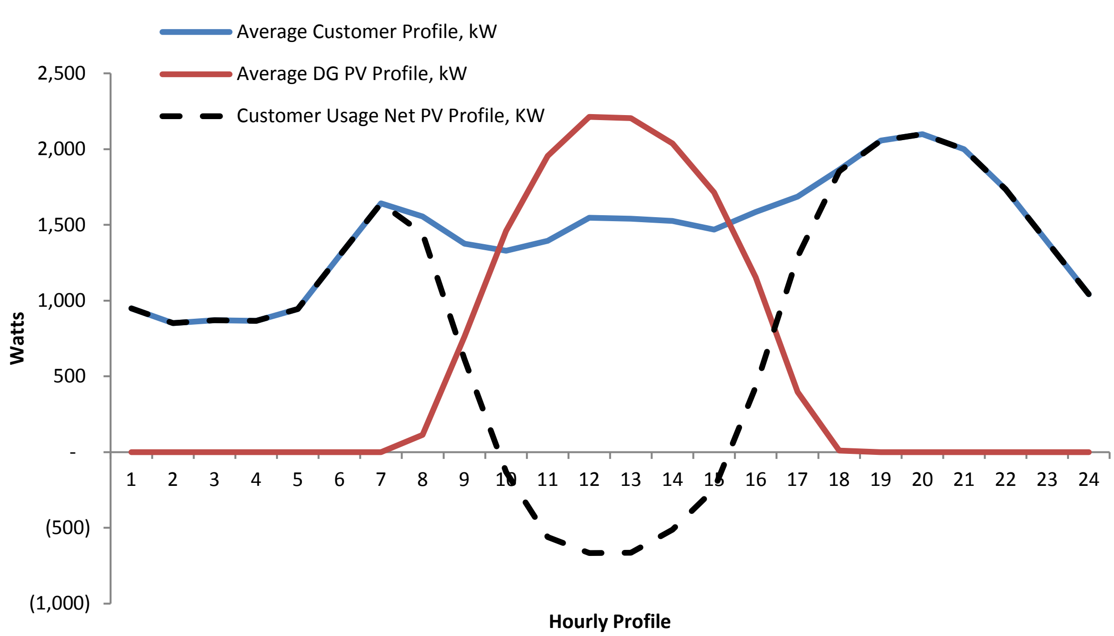


Chart 55 – Typical Winter Customer Load Profile, Net Solar PV



Solar Hot Water Heater Overview

Solar water heating systems include storage tanks and solar collectors. There are two types of solar water heating systems: active, which have circulating pumps and controls, and passive, which don't. Most solar water heaters require a well-insulated storage tank. Solar storage tanks have an additional outlet and inlet connected to and from the collector. In two-tank systems, the solar water heater preheats water before it enters the conventional water heater. In one-tank systems, the back-up heater is combined with the solar storage in one tank. Solar water heating systems are described using four common terms:

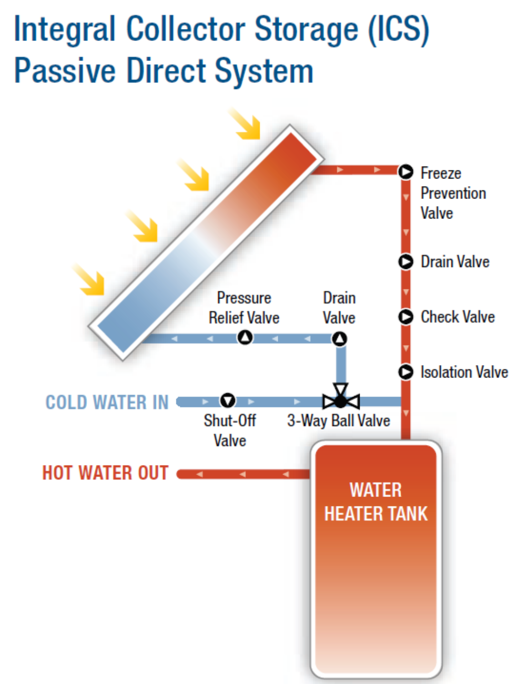
- Active systems use pumps to move fluids through the system.
- Passive systems rely on the buoyancy of warm water and gravity to move fluids through the system without any pumps.
- Direct systems heat water that feeds directly into the domestic hot water system. Direct systems always use potable water as the heat transfer fluid. In areas with dissolved minerals, carbon dioxide, or other water quality problems, these systems may require water softeners or other treatments.
- Indirect systems have independent piping and use heat exchangers to isolate solar fluids from potable domestic hot water. Systems using propylene glycol must use heat exchangers, however, water may also be used in indirect systems with heat exchangers.

Typical solar hot water heater system

The following system descriptions include example illustrations of system designs. In practice, systems may be configured in many different ways.

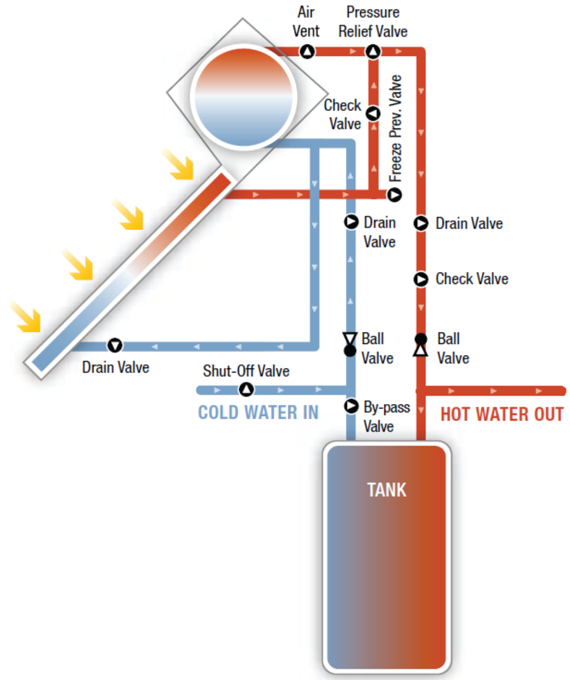
Integral Collector Storage (ICS) Passive Direct System

ICS systems are passive and direct. The tank and collector are combined. Potable water is heated and stored in the ICS collector. As hot water is used, cold water fills the collector from the bottom. These systems work best when hot water demands are in the late afternoon and evening. Heat gained during the day may be lost at night if not used depending on local weather conditions. A check valve or the arrangement of pipe runs stops reverse thermosiphoning where heat is lost from the domestic hot water system to the night sky. These systems are the least expensive of solar thermal options and one of the most popular systems on the world market. However, they may only be used in areas that do not experience many hard freezes. ICS collectors have more depth than flat plate collectors to accommodate integral tanks. Some builders have placed these collectors directly on the roof deck and built up around them with parapets or tile roof systems.



Source: NREL – Department of Energy

Thermosiphon Passive Direct System



Thermosiphon systems are passive with a storage tank located higher than the solar collector. Some systems come prepackaged with tanks pre-mounted to collectors. In these systems the tank sits on the outside of the roof. Other systems have tanks located inside attic spaces above the collectors. These systems are direct, using potable water as the heat transfer fluid. Water pipes and tanks containing water must be protected from freezing or located in a conditioned space in climates that freeze.

Typical Installations

In general, SHW systems are mounted on a south-facing roof, or adjacent to the house at ground level. In either case, the SHW system is generally remote from the backup and supplementary storage water heater and its tank. This distance, or the amount of finished space the loop must traverse in a retrofit installation, impacts the method and cost of installation. The most fundamental distinction is between systems that must resist freezing (closed-loop systems), and those located in climates where freezing is very rarely severe enough to threaten the integrity of the system (open-loop systems). Because closed-loop systems require either drain-back provisions or a separate freeze-protected loop to indirectly heat water in the storage tank, they generally have active components (pumps) and are more complex.

Solar Hot Water Heating Load Profiles

Chart 56 – Typical Summer Customer Load Profile, Net Solar Hot Water Heating

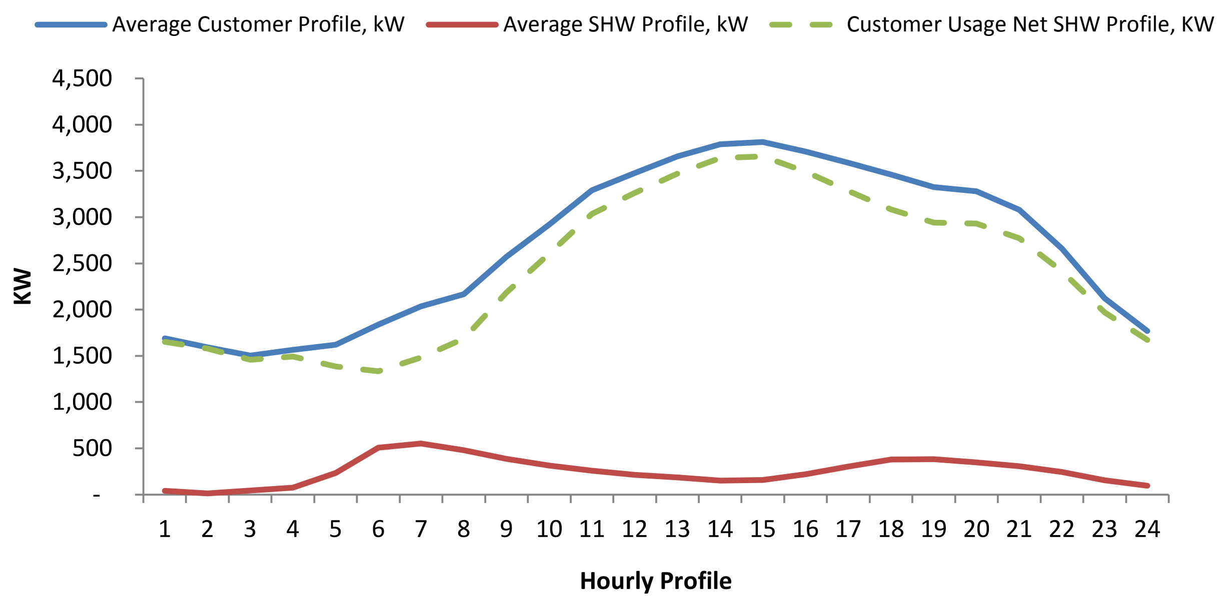
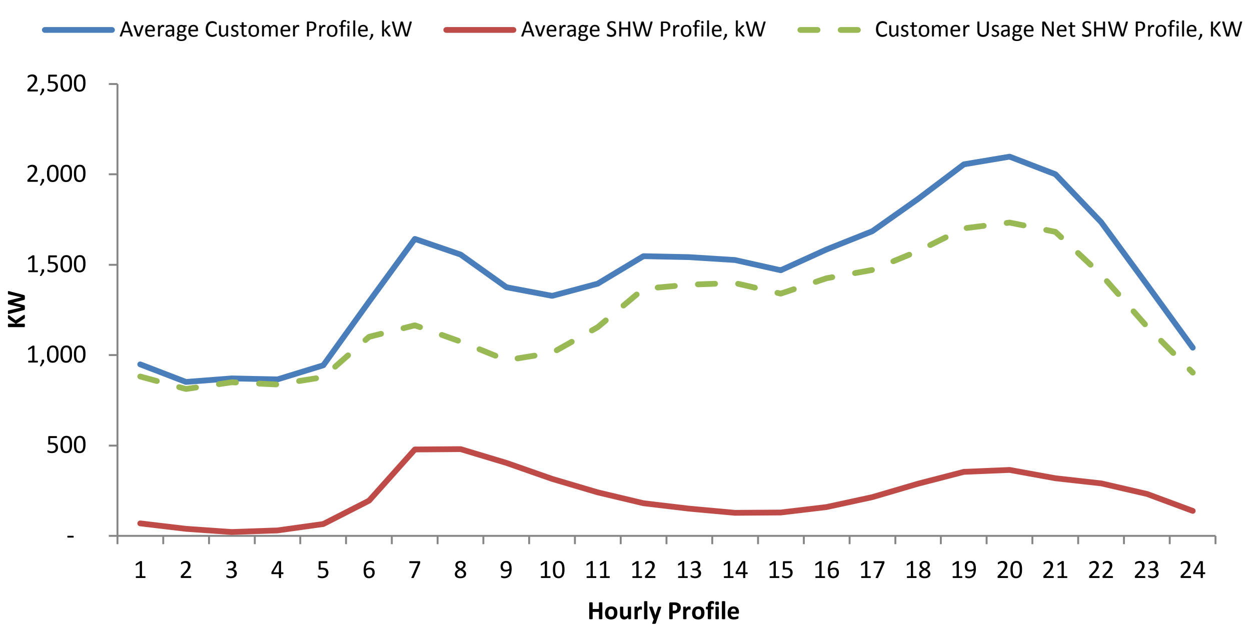


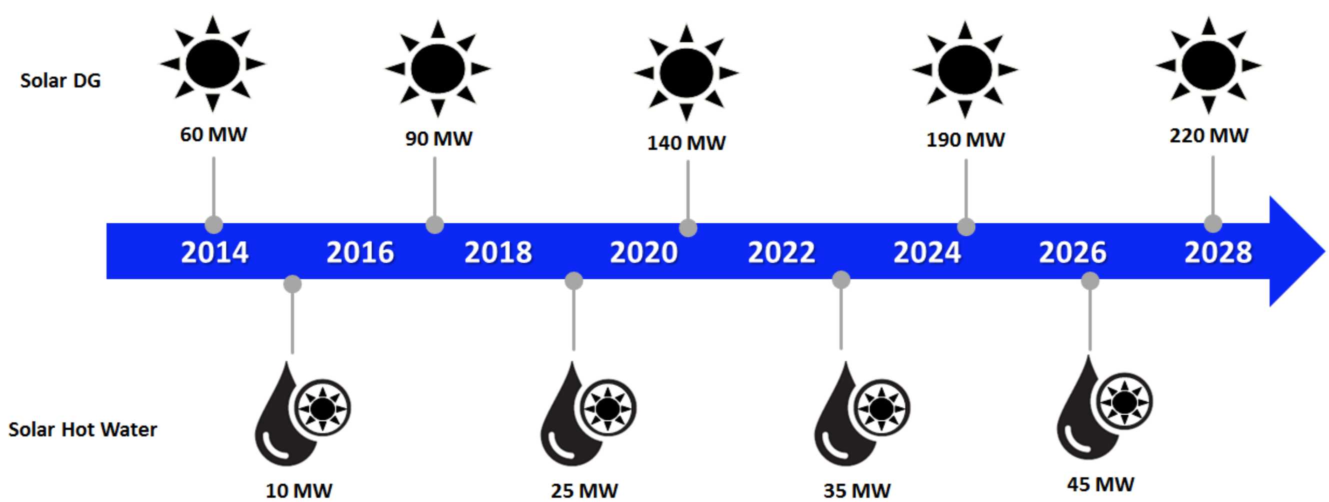
Chart 57 – Typical Winter Customer Load Profile, Net Solar Hot Water Heating



Projected Distributed Generation Requirements in the 2014 IRP

The Reference Case plan meets the distributed generation requirement based on Arizona's Renewable Energy Standard. The annual distributed generation requirement is 30% of the total renewable energy standard. By the end of 2014, the Reference Case plan will include approximately 71 MW of rooftop solar PV and solar hot water heating capacity. Distributed generation resources are expected to supply at least 123 GWh of energy on an annual basis in 2014 growing to approximately 455 GWh by 2028. Figure 41 below shows the expected cumulative nameplate capacity of both rooftop solar PV and solar hot water heating that will be installed in TEP's service territory from 2014 through 2028.

Figure 41 - Distributed Generation Resource Capacity



Below is a forecast summary of the estimated grid offsets related to customer-sited DG systems that comply with the Arizona RES targets.

Table 45 – 2014-2021 Projected Distributed Generation for TEP

Distributed Generation GWh	2014	2015	2016	2017	2018	2019	2020	2021
Solar Photovoltaic Systems	100.1	110.5	120.6	145.4	170.1	194.4	218.9	243.3
Solar Hot Water Systems	11.1	12.3	13.4	16.2	18.9	21.6	24.3	27.0
Total Portfolio Energy	111.2	122.8	134.0	161.5	189.0	216.0	243.2	270.3

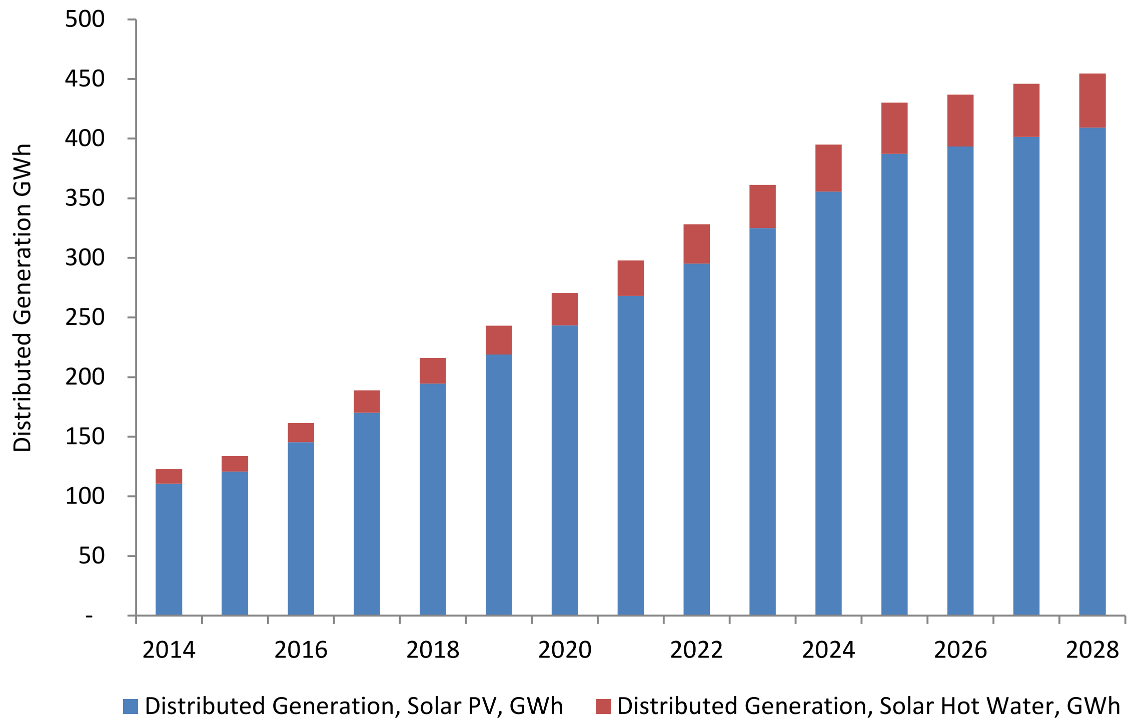
Distributed Generation MW	2014	2015	2016	2017	2018	2019	2020	2021
Nameplate Capacity, AC	56	66	75	84	101	117	134	151
System Coincident Peak	15	17	20	22	27	31	35	40

Table 46 – 2022-2028 Projected Distributed Generation for TEP

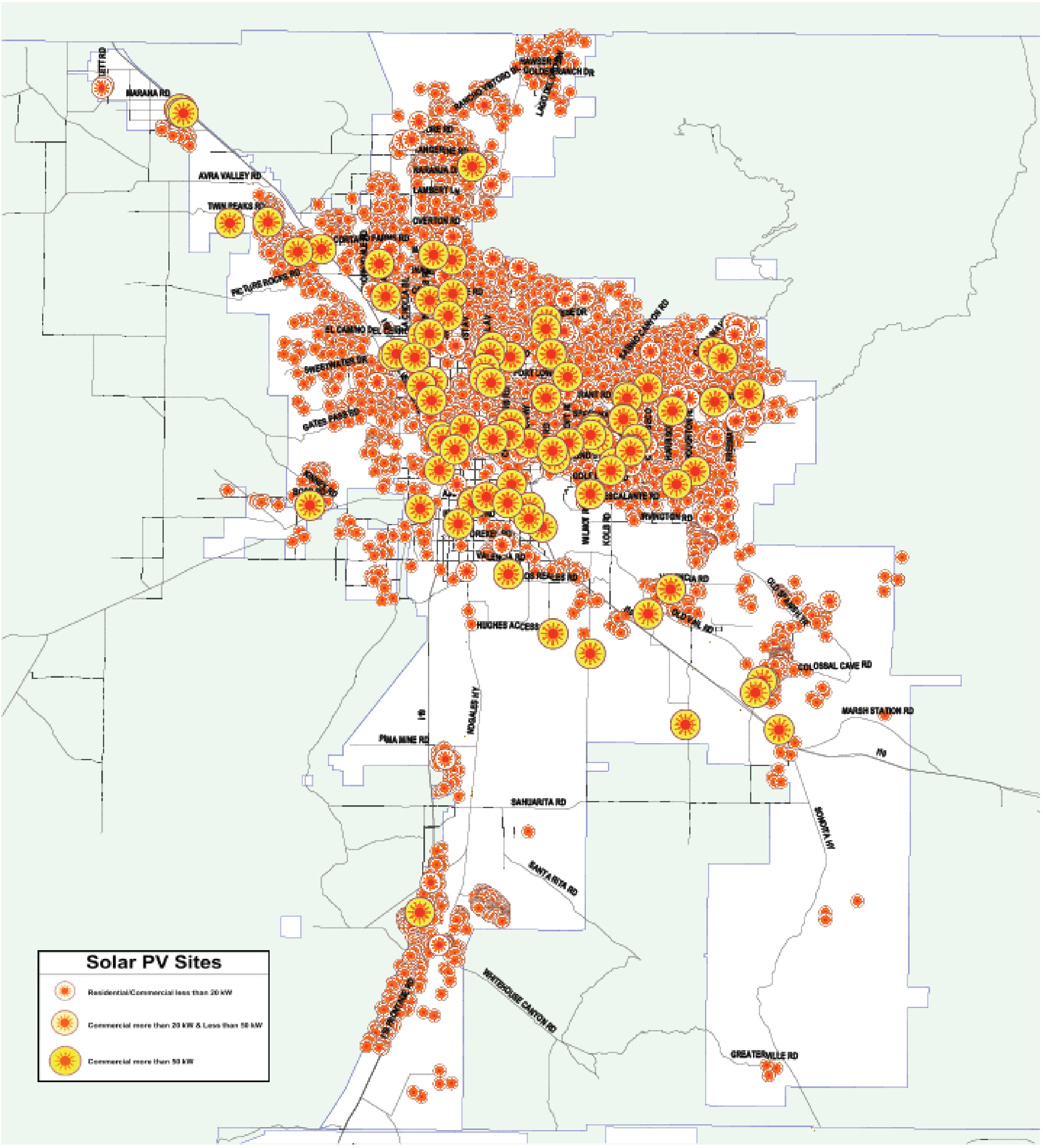
Distributed Generation GWh		2022	2023	2024	2025	2026	2027	2028
Solar Photovoltaic Systems		295.2	325.0	355.4	387.2	393.2	401.4	409.2
Solar Hot Water Systems		32.8	36.1	39.5	43.0	43.7	44.6	45.5
Total Portfolio Energy		328.1	361.1	394.9	430.2	436.9	446.0	454.6

Distributed Generation MW		2022	2023	2024	2025	2026	2027	2028
Nameplate Capacity, AC		190	210	229	250	254	259	264
System Coincident Peak		50	55	61	66	67	68	71

Chart 58 – TEP's Distributed Generation by Technology Type



Map 28 – TEP's Distributed Solar Resources Sites



CHAPTER 15

REFERENCE CASE PLAN ASSUMPTIONS

Reference Case Plan Market Assumptions

In developing its fifteen year market forecast, the resource planning team relied on Wood MacKenzie to provide a comprehensive set of correlated market, fuel, and emission price forecasts. These forward price projections for wholesale power, coal, natural gas and emission prices were based on a comprehensive set of market fundamentals for the WECC Region. As a general planning rule, TEP compares its input assumptions against multiple third party sources to validate the range of potential forecast values for developing its Reference Case plan and sensitivities.

- 2013 Wood MacKenzie Long Term View (Fall 2013)
- 2013 IHS Global Long Term Forecast (Spring 2013)
- 2013 U.S. Energy Information Administration (EIA) Outlook (January 2013)
- 2013 Ventyx Spring Reference Case

Market Reference Case Plan Assumptions

This section details the Reference Case plan market assumptions for the following IRP inputs.

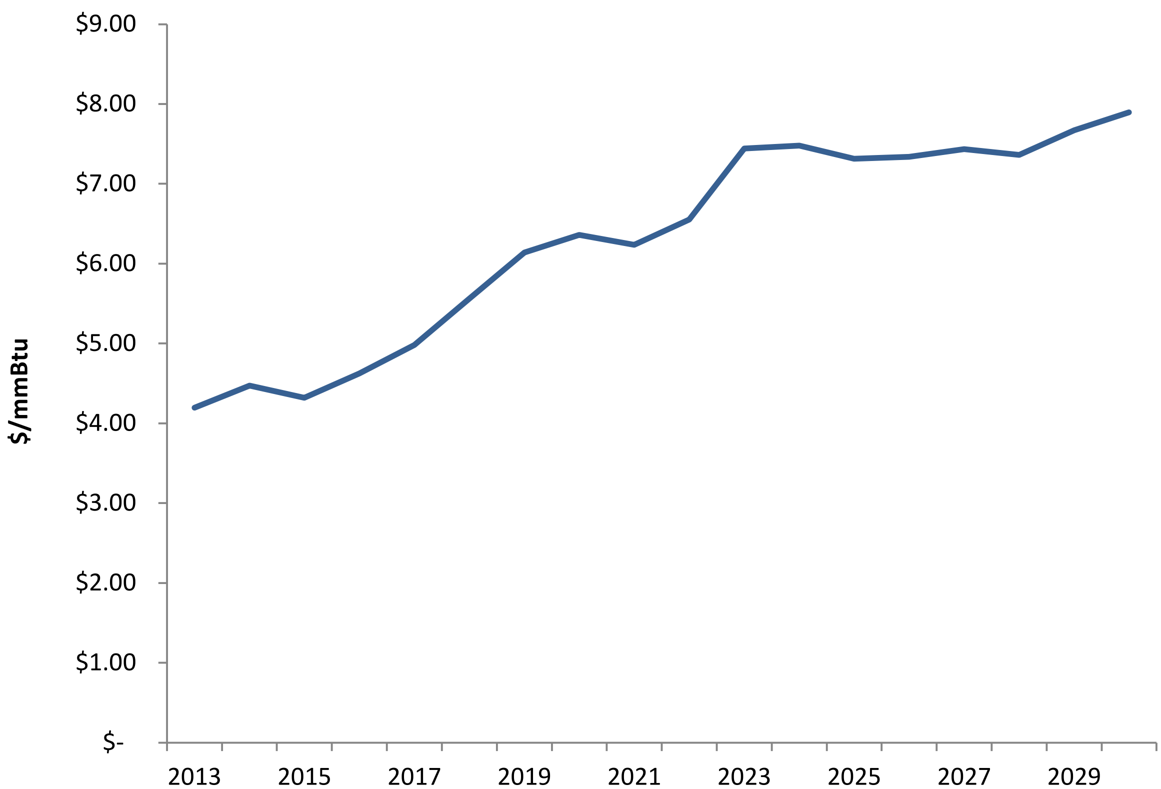
- Natural Gas Prices
- Wholesale Power Prices
- Delivered Coal Prices
- Emissions Prices

NATURAL GAS PRICE FORECAST

Permian Natural Gas

The Wood-Mackenzie forecast for Permian natural gas starts at $4.47/MMBtu in 2014, and escalates to $7.36/MMBtu in 2028. Chart 59 - Permian Basin Natural Gas Prices shows the 15 year natural gas price projections in nominal dollars.

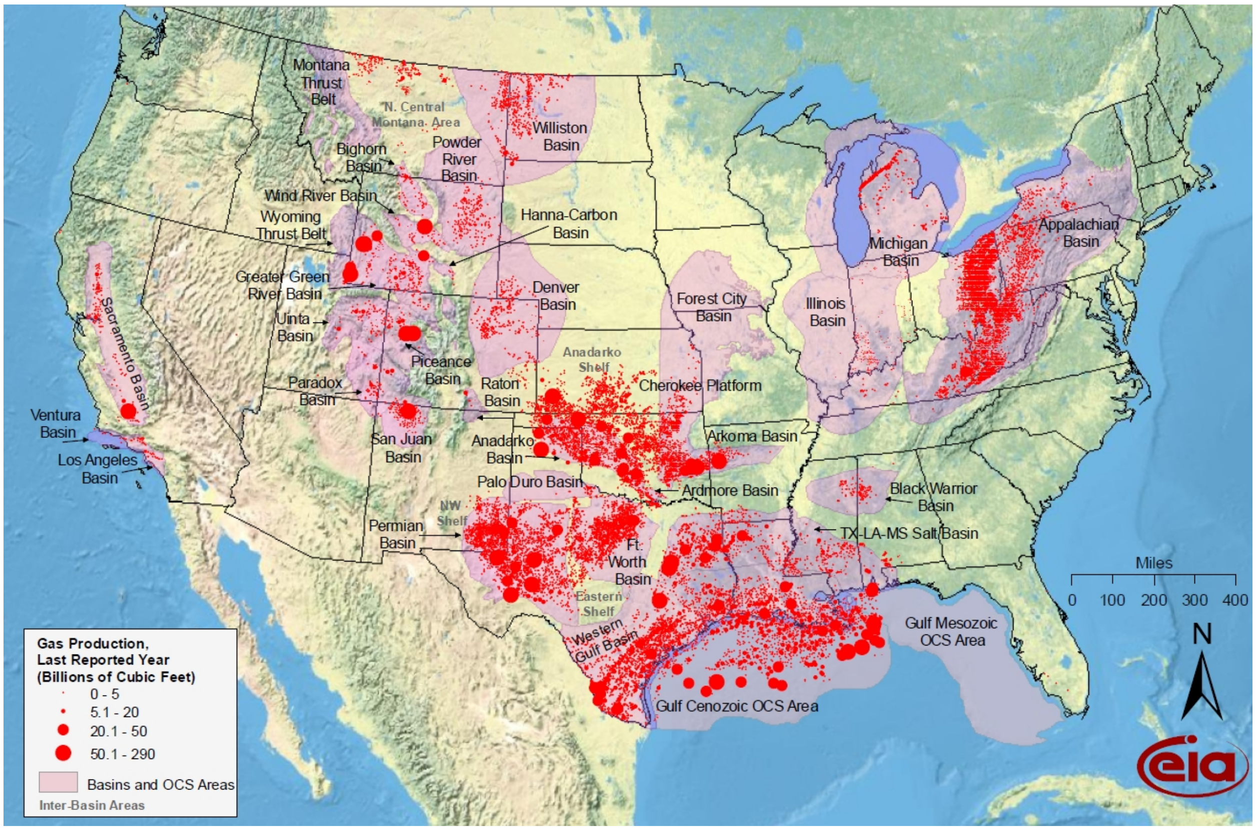
Chart 59 - Permian Basin Natural Gas Prices



Natural Gas Supply Basins

TEP's forward natural gas price projections are based on deliveries from the Permian and San Juan Basins. Primary and secondary supply basins are shown along with key market hubs in Map 29.

Map 29 - Natural Gas Production in Conventional Fields in the U.S.

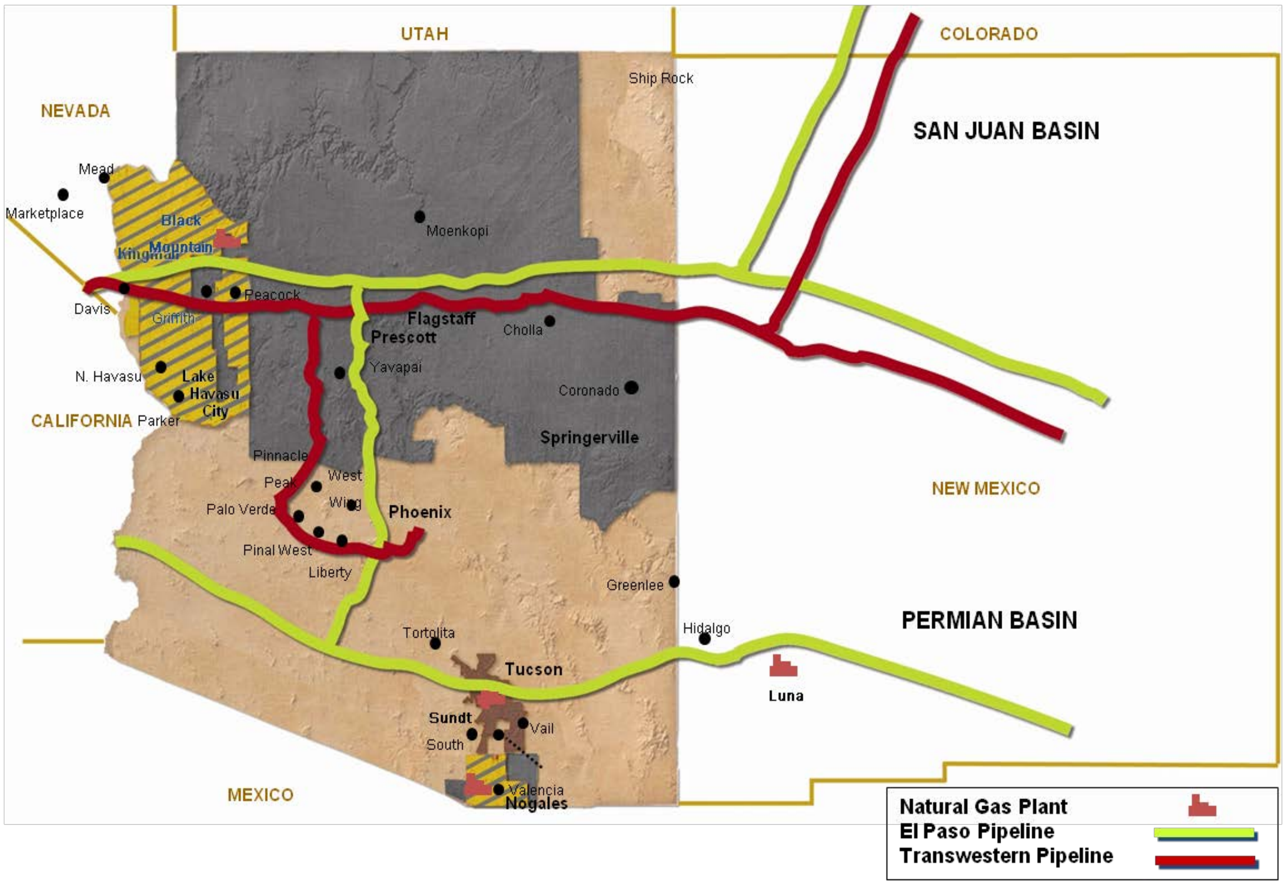


Source: Energy Information Administration (EIA) based on data from HPDI, IN Geological Survey, USGS

NATURAL GAS PIPELINE INFRASTRUCTURE

Map 30 - Natural Gas Pipeline Infrastructure below provides an overview of TEP's natural gas fired generation facility in relationship to both the El Paso and Transwestern pipeline infrastructure.

Map 30 - Natural Gas Pipeline Infrastructure

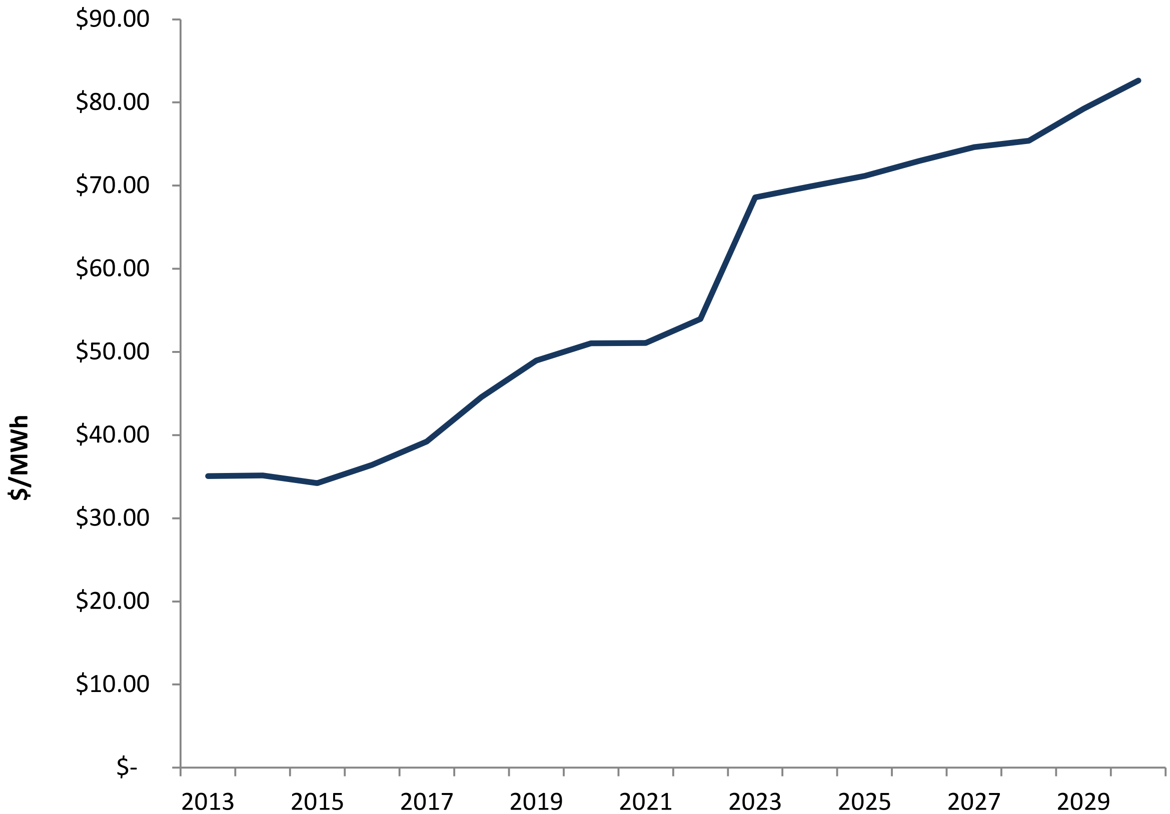


WHOLESALE MARKET PRICE FORECAST

Palo Verde (On-Peak) Market Prices

The Wood-Mackenzie forecast for 7x24 Palo Verde market prices starts at $35.13/MWh in 2014, and escalates to $75.40/MWh in 2028. Chart 60 - Palo Verde (7x24) Market Prices shows the 15 year wholesale power price projections in nominal dollars.

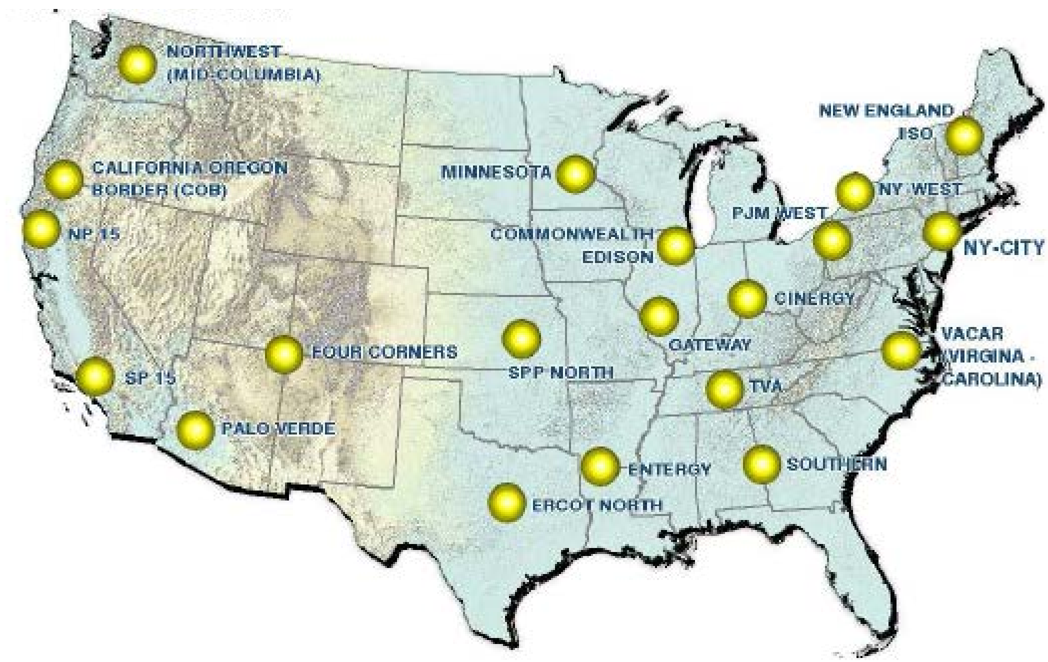
Chart 60 - Palo Verde (7x24) Market Prices



Wholesale Power Market Price Zones

TEP's forward wholesale market power price projections are based on Palo Verde and Four Corner market hubs as shown below in Map 31 - Wholesale Power Market Price Zones.

Map 31 - Wholesale Power Market Price Zones



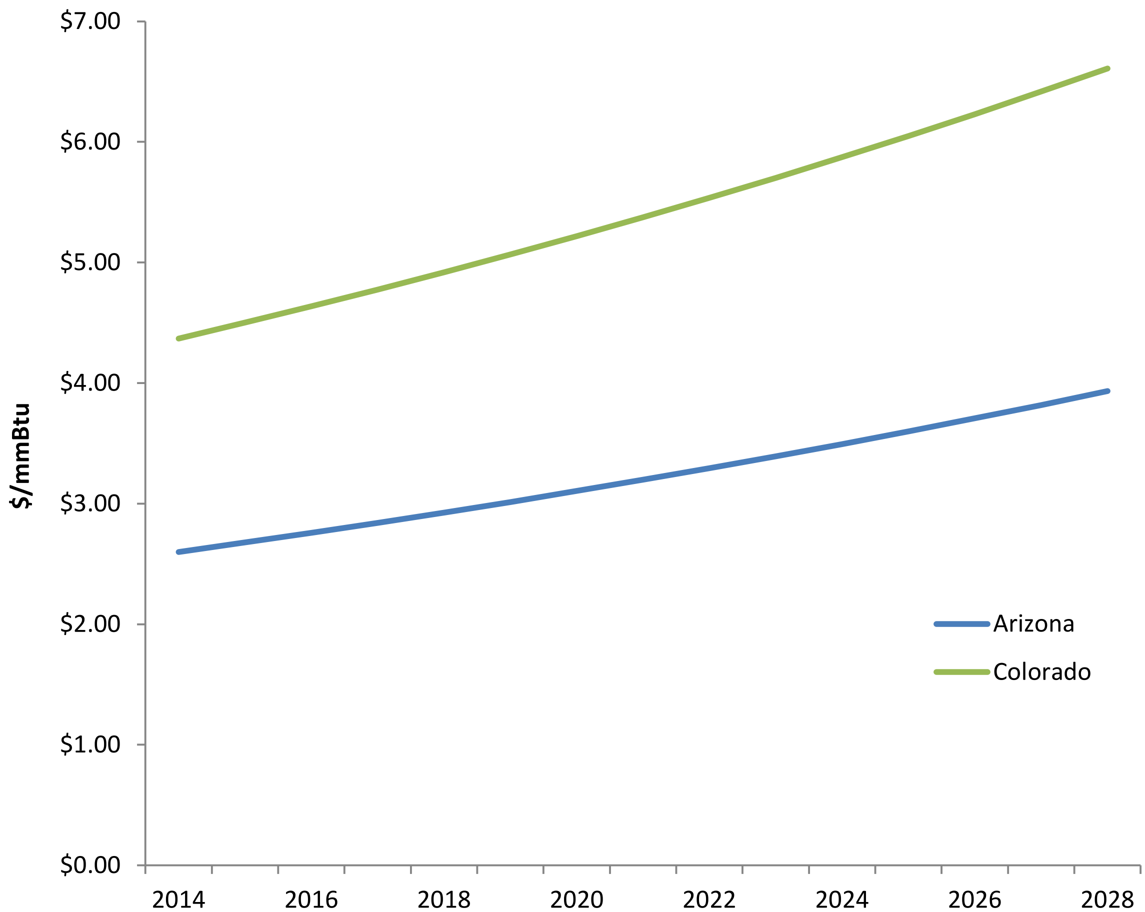
SOURCE: Ventyx.

COAL PRICE FORECAST

Coal Market Prices

Chart 61 shows the average delivered coal price for TEP existing coal-fired facilities for source out of Arizona and Colorado. For the 2014 Reference Case plan delivered coal from Arizona starts at $2.60/MMBtu in 2014, and escalates to $3.93/MMBtu by 2028. Chart 61 shows the 15 year coal price projections in nominal dollars.

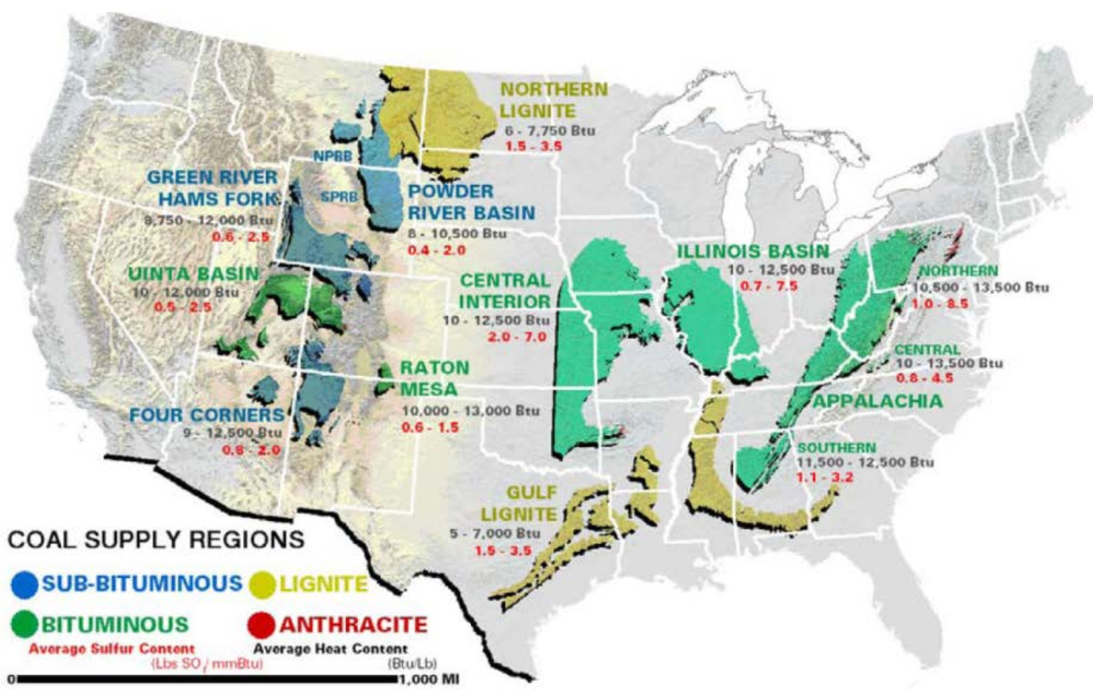
Chart 61 - Coal Price Forecast



Coal Supply Regions

TEP's existing coal facilities rely on long-term coal contracts that are sourced from either Arizona or New Mexico mining operations. For purposes of the resource planning process, it was assumed that any new resources which required a coal fuel supply (Pulverized Coal or IGCC) would be based on price projections from the Four Corners or Powder River Basin coal regions. The U.S. Coal Supply Regions are shown in Map 32 below:

Map 32 - U.S. Coal Supply Regions



SOURCE: Ventyx.

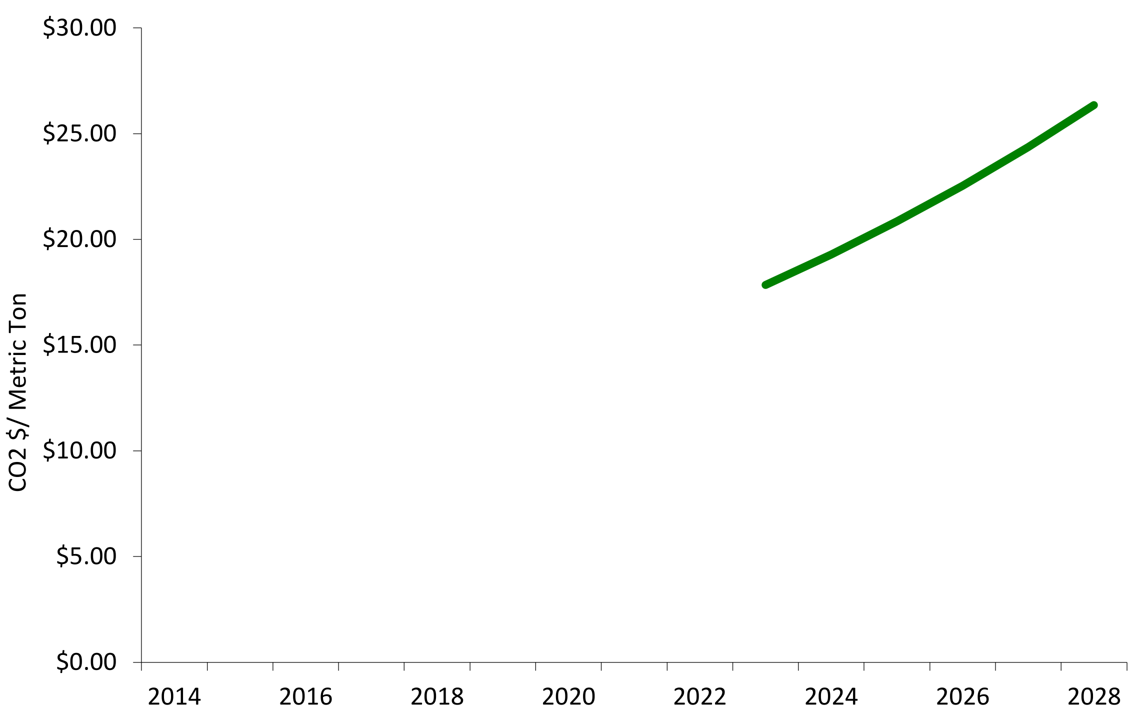
EMISSION PRICES

Carbon Price Assumptions Used in the 2014 IRP

For the 2014 IRP, we assume a federal carbon price, beginning in 2023 at $17.26/metric ton and escalating at 6% annually in real terms. While the current political environment is unlikely to yield substantive legislation in the near term, rising emission levels over the coming years are expected to provide the political backing for carbon policy to re-emerge around 2020. We assume a three-year window to implement such policy and have chosen a price path that reflects the middle ground of two previous proposals (Bingaman-Specter in 2007 and Kerry-Lieberman in 2010) that garnered some political backing. This assumes that a price containment mechanism would be imposed if and when such legislation is passed.

Beyond the legislative approach, potential new regulatory rules could limit carbon emissions. A key difference between a legislative and a regulatory approach is how compliance is monetized-whether through a tax or allowance price, or via capital expenditures needed to meet potential efficiency or emission rate limits. An upcoming proposal to regulate emissions from existing sources is expected in June 2014 with a final rule coming one year later. While EPA has publicly indicated that it will take a flexible approach it remains difficult to project potential impacts until the proposal is issued.

Chart 62 - CO_2 Emission Prices, $/ Metric Ton



Financial and Capital Structure Assumptions

Table 47 below details the financial and capital structure assumptions used for the 2014 IRP. The weighted average cost of capital is based on assumptions from TEP's approved rate order in June 2013.

Table 47 - Financial and Capital Structure Assumptions

Cost Of Capital	
Debt	5.18%
Common Equity	10.00%
Composition	
Debt	56.50%
Common Equity	43.50%
Average Cost Of Capital	
Weighted Average Cost of Capital (WACC)	7.26%
Inflation, Insurance & Property Taxes	
Inflation Rate	2.50%
Property Taxes & Insurance	1.90%
Federal & State Income Tax Rates	
Federal Tax Rate	35.00%
State Tax Rate	7.10%
Composite Rate	39.60%

RISK ANALYSIS

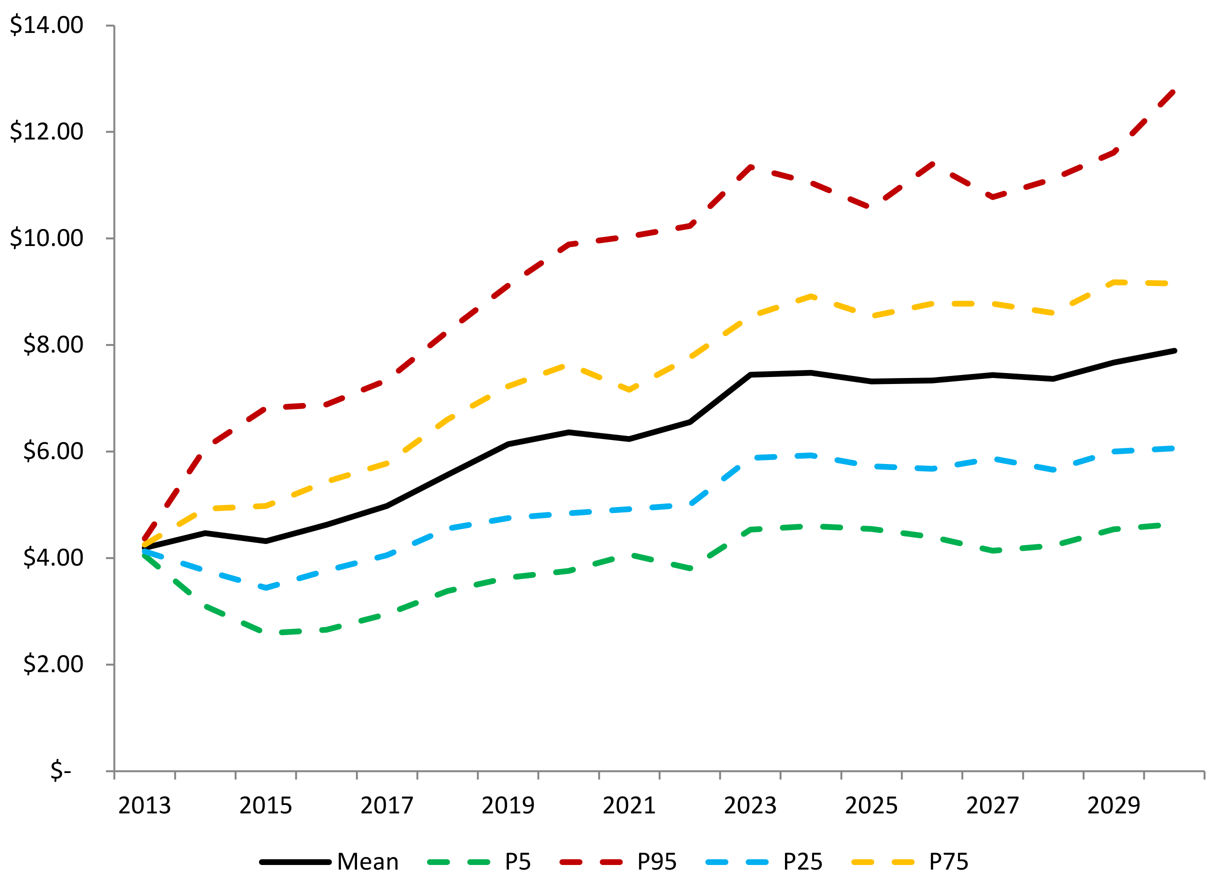
For the 2014 IRP, TEP developed explicit market risk analytics for each candidate portfolio through computer simulation analysis. Specifically, a set of 100 iterations, each representing a possible future set of correlated, consistent inputs for natural gas prices, wholesale prices, and retail loads was developed using a stochastic model. Each potential resource portfolio was then evaluated against the same 100 iterations. The resulting risk profiles for each portfolio were then developed. This analysis ensures that the selected preferred portfolio not only has the lowest expected cost, but is also robust enough to perform well against a wide range of possible load and market conditions.

NATURAL GAS AND WHOLESALE POWER SIMULATIONS

Permian Natural Gas

The Wood-Mackenzie forecast for Permian natural gas starts at $4.47/MMBtu in 2014, and escalates to $7.36/MMBtu in 2028. Chart 63 - Permian Basin Natural Gas Price Simulation Statistics shows both the expected forward market prices as well as summary statistics for the 100 Permian Basin price paths against which each portfolio was evaluated.

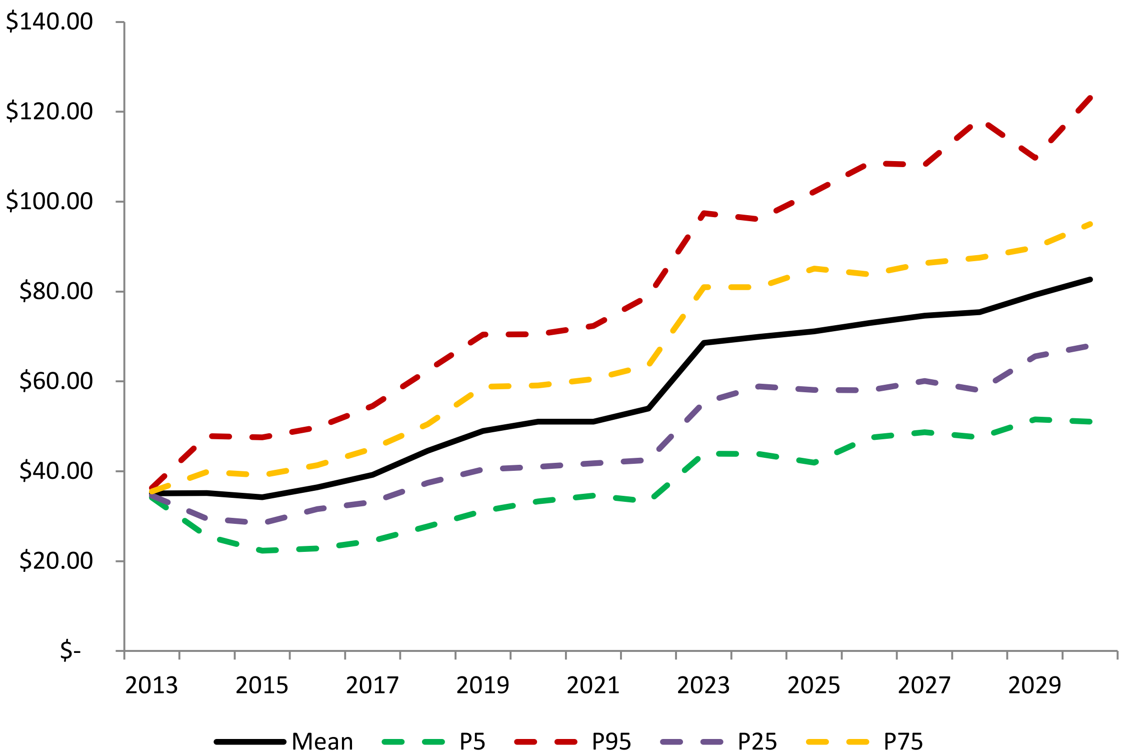
Chart 63 - Permian Basin Natural Gas Price Simulation Statistics



Palo Verde (7x24) Market Prices

The Wood-Mackenzie forecast for 7x24 Palo Verde market prices starts at $35.13/MWh in 2014, and escalates to $75.40/MWh in 2029. Chart 64 - Palo Verde (7x24) Market Price Simulation Statistics shows both the expected forward market prices as well as summary statistics for the 100 Palo Verde hub price paths against which each portfolio was evaluated.

Chart 64 - Palo Verde (7x24) Market Price Simulation Statistics



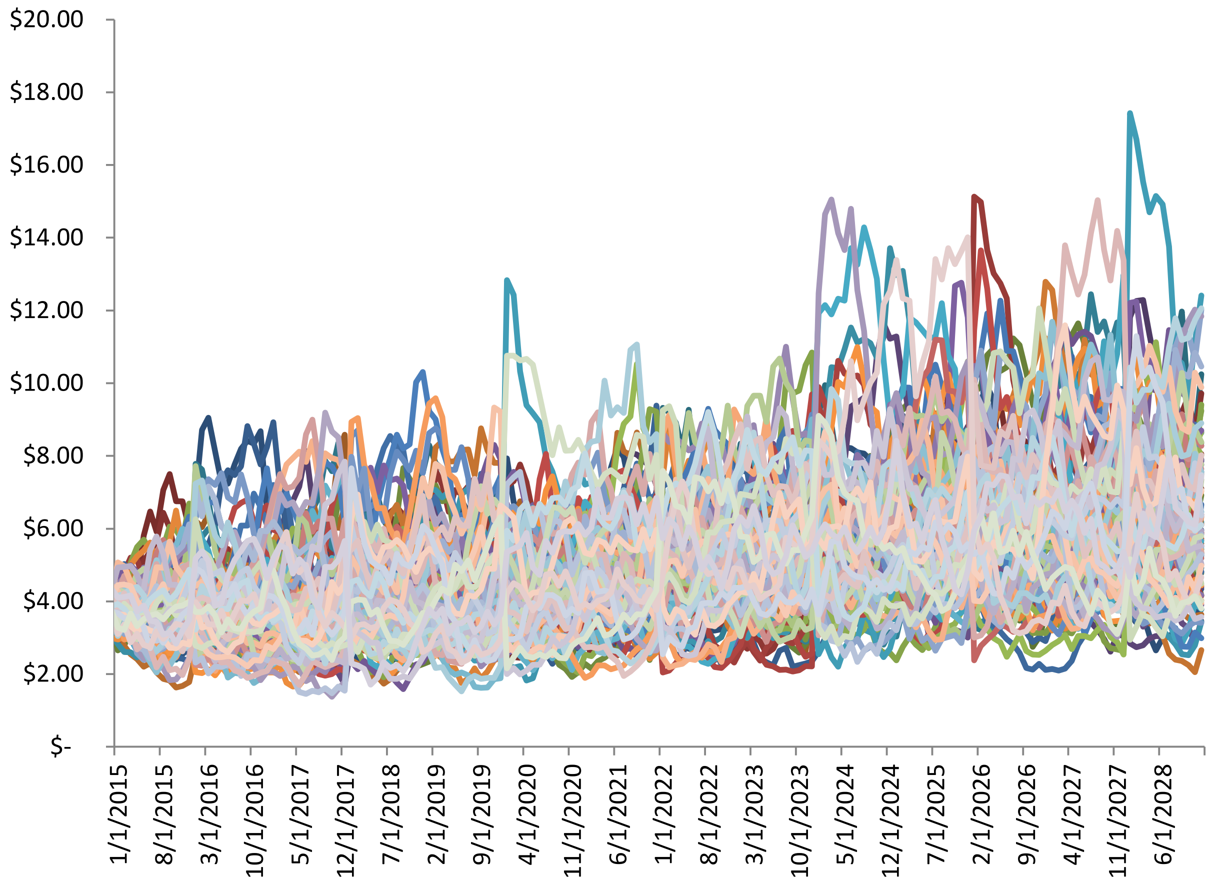
When considering Chart 63 and Chart 64 from above, it is important to note that the summary statistics are aggregations rather than individual price paths. For instance the P95 number for a given year represents the point which 95% of simulated values fall below.

Individual price paths mimic realistic behavior by being subject to the price "spikes," mean reversion, and uneven trend observed in actual markets. As an example, Chart 65 on the following page shows 100 individual Permian Basin price paths.

Permian Natural Gas

Chart 65 details the 100 Permian Basin price paths against which each portfolio was evaluated.

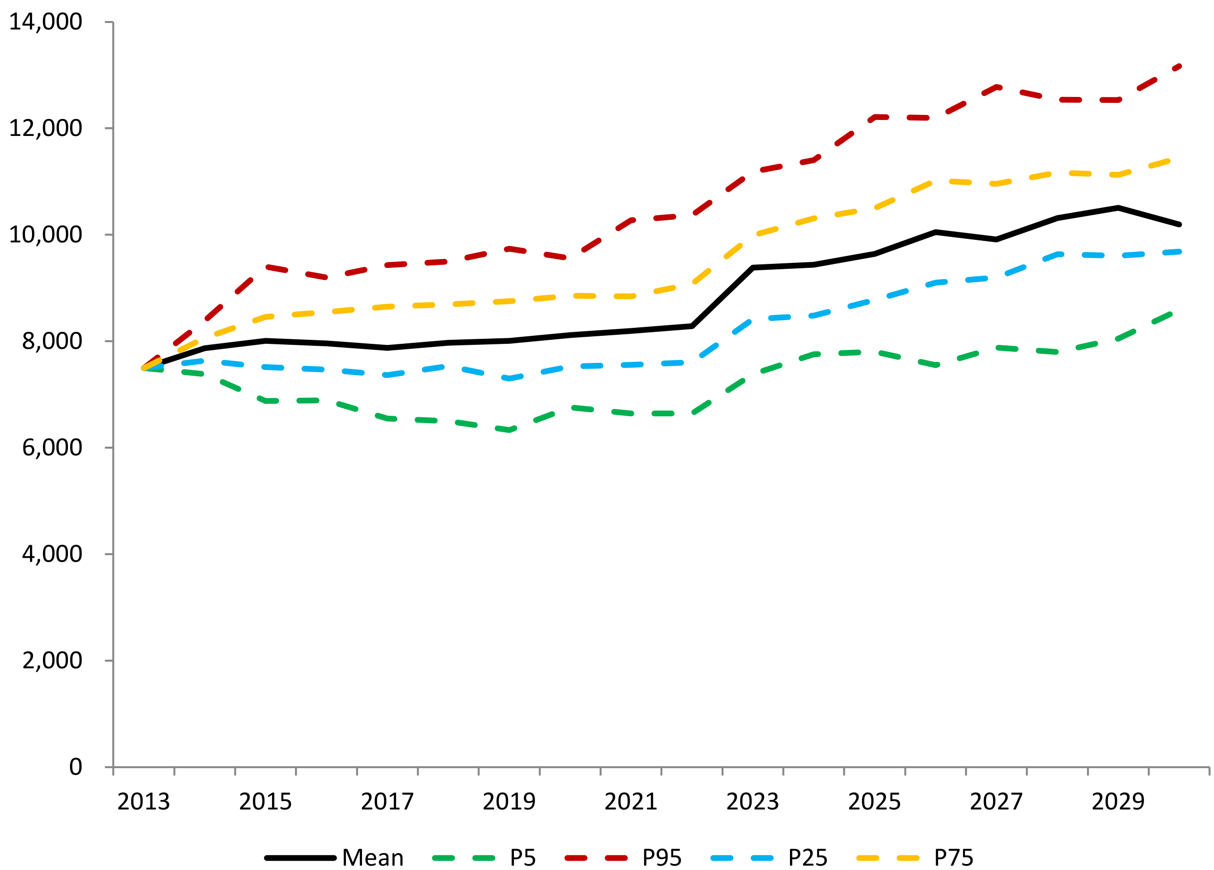
Chart 65 - Permian Basin Natural Gas Price Iterations ($/mmBtu)



Maintianing the Relationship Between Gas and Power

It is also important to note that reasonable relationships between gas, wholesale power, and loads are maintained within each iteration. In particular, simulations are constrained to maintain reasonable implied market heat rates. Chart 66 provides a summary of the annual implied market heat rates in the 100 iterations used in this analysis.

Chart 66 – Simulation Implied Market Heat Rate Summary Statistics (mmBtu/kWh)



As illustrated in Chart 66, the stochastic model allows for some variability in the relationship between gas and power (which is desirable), without still maintaining a reasonable correlation.

Load Variability and Risk

As outlined in the previous sections, load is also varied within each of the 100 iterations in accordance with the movement of gas and power. In this way, a wide variety of possible load growth scenarios are also considered in the simulation analysis and are therefore inherent in the resulting risk profiles.

In addition to this simulation analysis, load scenarios addressing specific situations were developed and evaluated on a case by case basis. Results of this scenario analysis along with changes that would be required in the Preferred Portfolio resource additions are summarized below.

Load Growth Scenarios

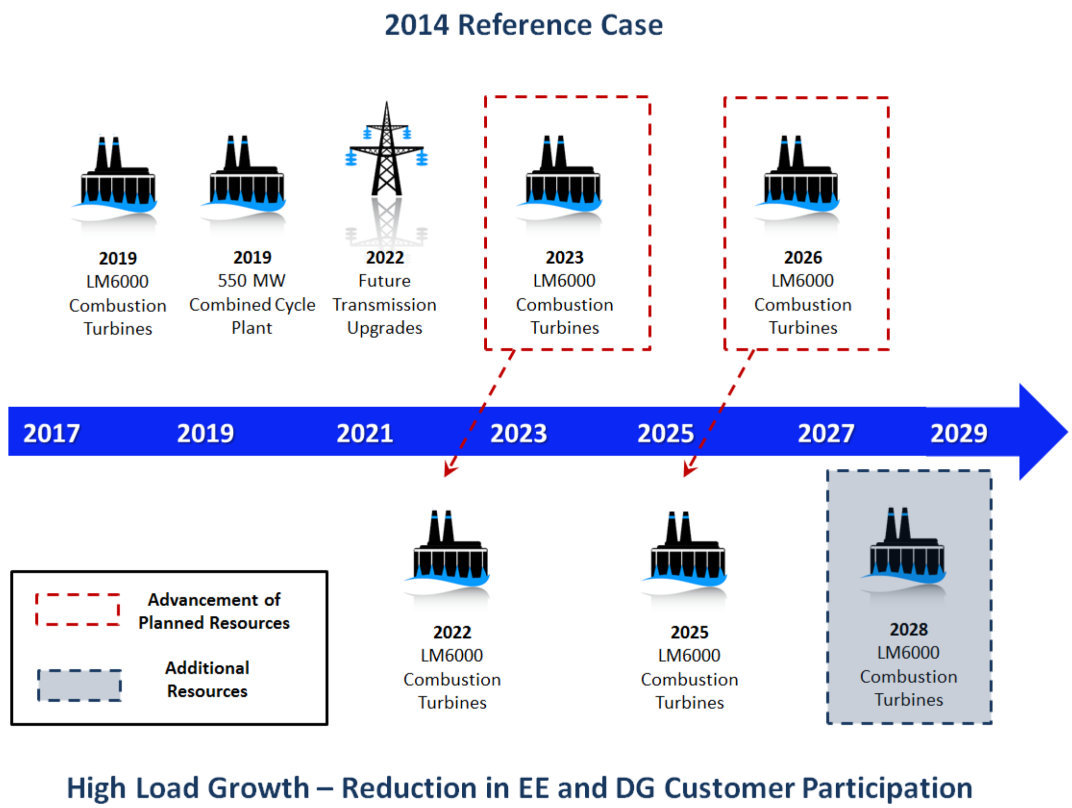
The 2014 Reference Case plan projects TEP peak demand growing between 1.0% and 1.5% per year. This change in growth assumes no significant expansions in TEP's large industrial and mining customers and assumes that targets for energy efficiency (22% by 2020) and distributed generation (30% of 15% by 2025) are realized per Arizona state standards.

For purposes of the 2014 IRP, TEP modeled two additional load growth scenarios that reflect two potential scenarios that may affect TEP's long-term expansion plans. The first scenario considers the potential reductions in customer participation in TEP's energy efficiency and distributed generation programs. The second scenario contemplates a new large industrial customer or a facility expansion at an existing mining customer within TEP's service territory.

Reduction in Energy Efficiency or Distributed Generation

For purposes of this scenario, it is assumed that TEP only realizes about 50% of the energy efficiency and distributed generation targets. Under this scenario, TEP's peak demand grows between 1.5% and 2.0% per year. This change in the forecast has only moderate impacts on TEP's 2014 Reference Case plan. As shown in Figure 42 below, TEP would have to advance the installation of its planned combustion turbines in 2023 and 2026 by one year. In addition, by the end of the 15-year planning period, TEP would need to install additional combustion turbines in 2028 as the result of this increased load growth.

Figure 42 – Reduction in EE or DG Load Scenario



Large Industrial / Mining Expansions

Given TEP's geographic proximity to Southern Arizona mining operations, TEP coordinates it planning strategies around potential mine shutdowns or expansions. Rosemont and Twin Buttes mines are two potential mining projects that may expand operations in the near future.

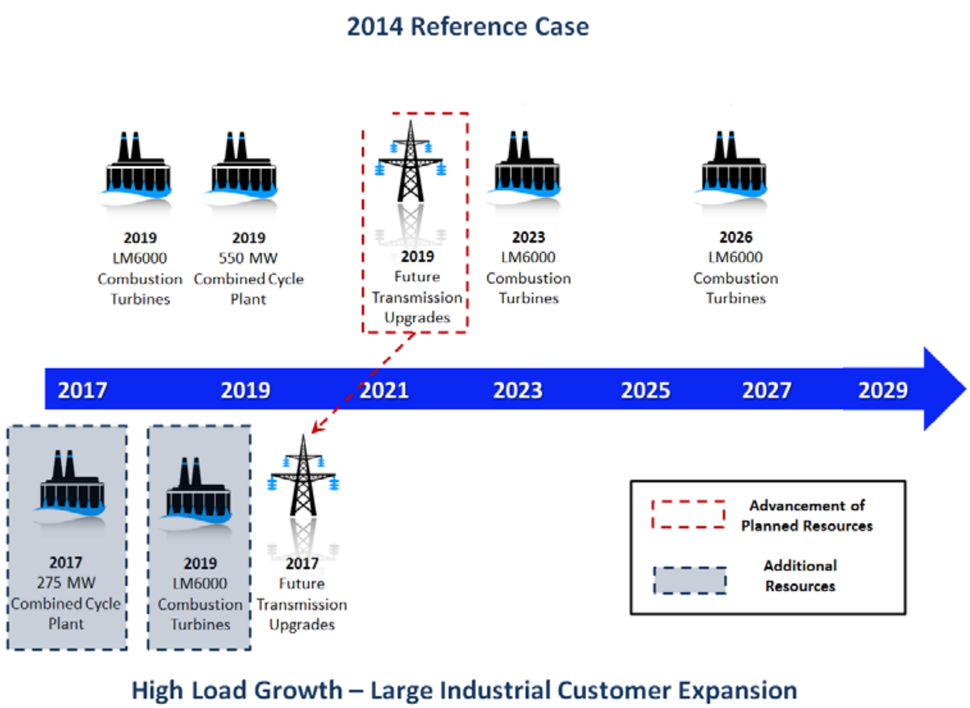
Rosemont Mine – The proposed copper mine is located 30 miles south of Tucson in the Santa Rita Mountains. Augusta Resource Corporation, a Vancouver, BC-based mining company is hopeful to begin building the mine in the near future.

Twin Buttes Mine – TEP is also monitoring the Twin Buttes mine project. In late 2009, Freeport-McMoRan bought the Twin Buttes mine site, near Sahuarita. The Twin Buttes Mine adjoins Freeport's existing Sierrita Mine, which is seven miles west of Green Valley. Freeport needs to conduct studies to determine the property's best use, but the purchase gives Freeport-McMoRan the potential to expand their current operations.

Large Industrial Customer Expansion

For purposes of this scenario, it is assumed that TEP's peak demand increases significantly over the next five years due to an expansion of a new or existing large industrial customer. Under this scenario, TEP's peak demand increases by 125 MW in 2017 and again in 2019 by 125 MW (for a total of 250 MW, a 10% increase in retail demand). This change in the forecast would result in the advancement of both transmission and generation resources in the near term. As shown in Figure 43Figure 11 below, TEP would have to advance work on future transmission and system upgrades by two years from 2019 to 2017. In addition, TEP would have to procure additional generation resources starting in 2019 to cover the load and reserve margin requirements under this scenario. Given the high load factors associated with these types of customers, this scenario shows the need for additional combined cycle and combustion turbines resources as early as 2019.

Figure 43 – Large Industrial Customer Expansion



CHAPTER 16

FUEL SUPPLY

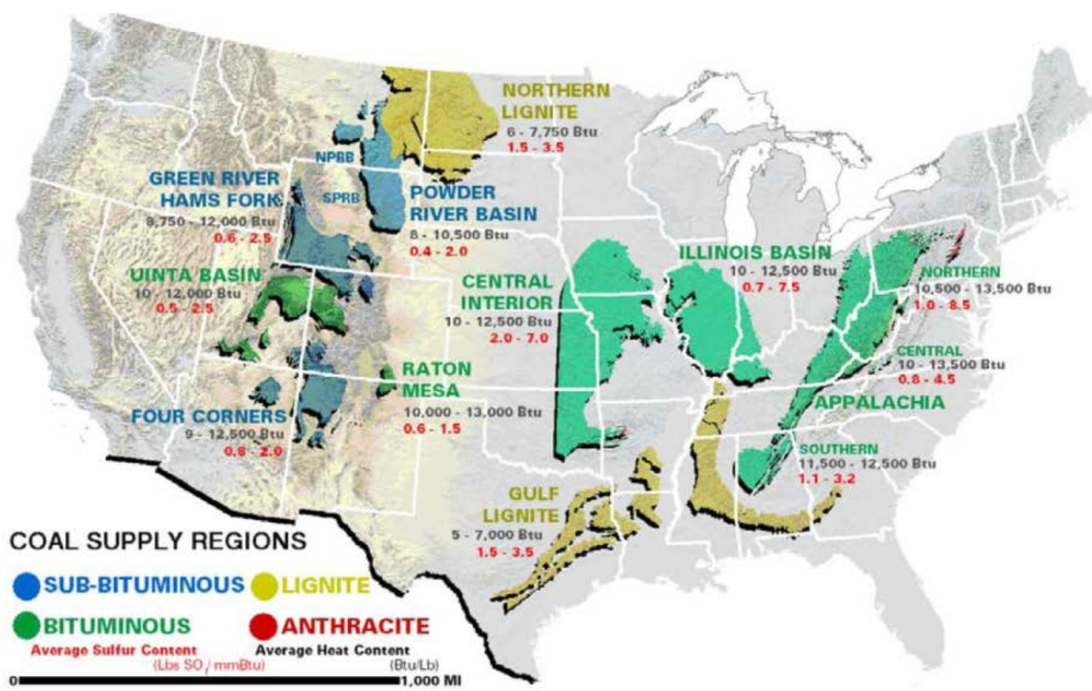
Coal Supply

For the 2014 IRP, TEP relied on publicly available data related to projected recoverable coal reserves to quantify future coal supply. These data sources included reports compiled by the U.S. Energy Information Administration and British Petroleum (BP).

- U.S. Energy Information Administration, 2013 Annual Coal Report
- BP Statistical Review of World Energy (June 2013)

Due to its low cost and ample supply, coal remains the dominant fuel source for power generation in the U.S. Domestic coal for electricity generation is produced throughout the country. The major producing regions are Central Appalachia (CAPP), Northern Appalachia (NAPP), and the Illinois Basin (ILLB), jointly described as Eastern coal; the Powder River Basin (PRB) and the Rocky Mountain Basin (RCKY), jointly described as Western coal. Lignite is produced in Texas and neighboring states (Gulf Lignite). Production of Northern Lignite is centered in North Dakota. The quality of coal is heterogeneous within each producing region and even more so among producing regions. Map 33 - Domestic Coal Producing Regions depicts U.S. coal producing regions and typical qualities of the coal produced.

Map 33 - Domestic Coal Producing Regions



SOURCE: Ventyx.

There are four major ranks of coal in the U.S. classification scheme. In the United States, coal rank is classified according to its heating value, its fixed carbon and volatile matter content, and, to some extent, its caking properties during combustion. The coal ranks from highest to lowest in heating value are:

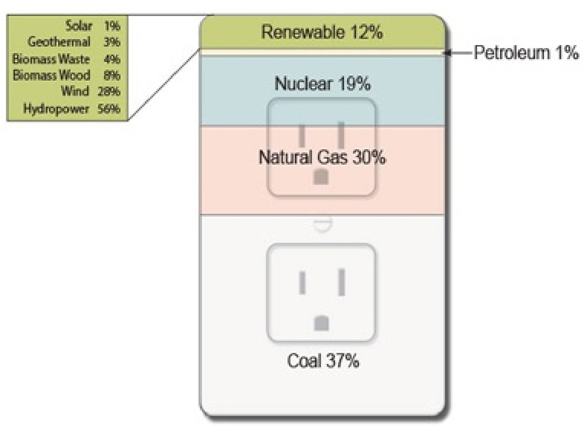
- anthracite
- bituminous
- subbituminous
- lignite

Of the four ranks, bituminous coal accounts for over half (53.1 percent) of the demonstrated reserve base (DRB). Bituminous coal is concentrated primarily east of the Mississippi River, with the greatest amounts in Illinois, Kentucky, and West Virginia. All subbituminous coal (36.5 percent of the DRB) is west of the Mississippi River. Most subbituminous coal is in Montana and Wyoming. Lignite, the lowest-rank coal, accounts for about 8.8 percent of the DRB. Lignite is found mostly in Montana, Texas, and North Dakota. Anthracite, the highest-rank coal, makes up only 1.5 percent of the DRB. Anthracite is concentrated almost entirely in northeastern Pennsylvania.

U.S. Energy Information Administration

The United States holds the world's largest estimated recoverable reserves of coal and is a net exporter of coal. In 2012, our nation's coal mines produced more than a billion short tons of coal, and more than 81% of this coal was used by U.S. power plants to generate electricity. The United States has around 1,400 coal-fired electricity generating units in operation at almost 600 plants across the country. While coal has been the largest source of electricity generation for over 60 years, its annual share of total net generation declined from 50% in 2007 to 37% in 2012 as some power producers switched to lower-priced natural gas.

Figure 44- Sources of U.S. Electricity Generation, 2012

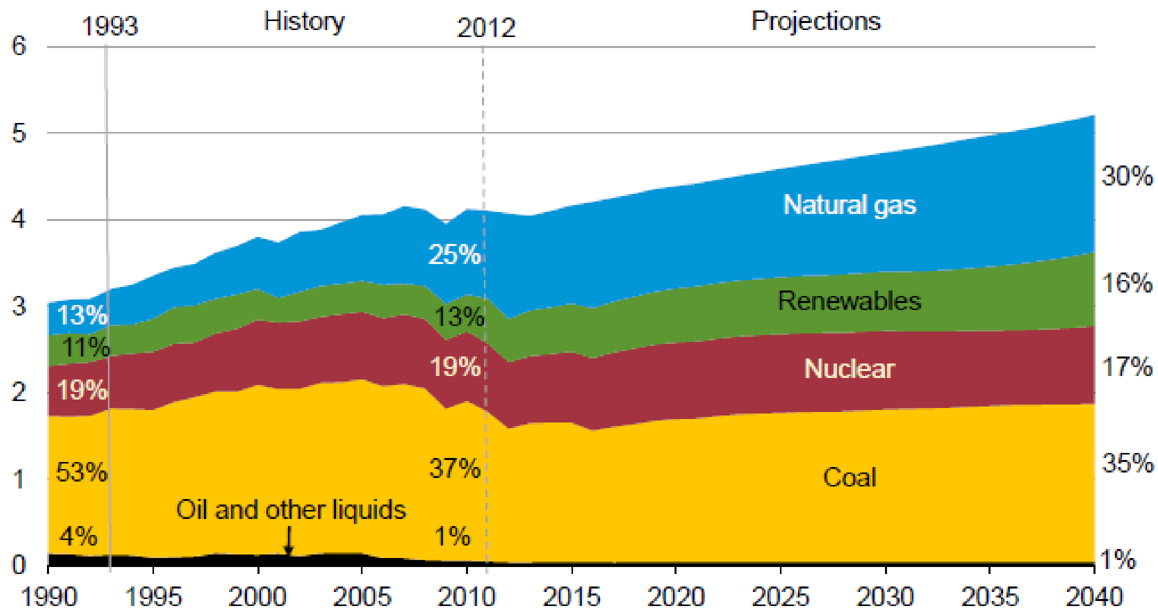


Source: U.S. Energy Information Administration, *Electric Power Monthly* (March 2013). Percentages based on Table 1.1 and 1.1a; preliminary data for 2012.

This shift was largely driven by an increase in natural gas development, particularly in recent years due to significant increase in production from shale gas.

While the share of our total net electricity generated from coal is expected to decrease by 2040, the amount of coal used to meet growing demand for power is expected to increase in the absence of new policies to limit or reduce emissions of carbon dioxide and other greenhouse gases. Revised emissions policies, however, could significantly change the outlook for domestic coal use.

Chart 67 - U.S. Electricity Net Generation (trillion kilowatthours)



Source: EIA, Annual Energy Outlook 2013

As of January 1, 2013, the demonstrated reserve base (DRB) was estimated to contain 481 billion short tons. In the United States, coal resources are larger than remaining natural gas and oil resources, based on total British thermal units (Btus). Annually, EIA reports remaining tons of coal in the DRB, which is comprised of coal resources that have been identified to specified levels of accuracy.

Between 1990 and 1999, EIA obtained updated coal reserves information and data largely through its Coal Reserves Data Base (CRDB) program. That program encouraged state agencies to revise coal resource and reserves estimates in their respective states. These revised coal reserves estimates include improved analyses of coal quality, accessibility, and recoverability in the study areas. EIA used these new data to revise the DRB.

Recovery rates vary greatly between underground and surface mining. The actual proportion of coal resources that can be recovered from undisturbed deposits varies from less than 40% in some underground mines to more than 90% at some surface mines. In some underground mines, by design a portion of the coal is left intact as pillars to protect against surface collapse. Adverse geologic features in a mining area, such as folding, faulting, and inter-layered rock strata, can limit the amount of coal recovered at some underground and surface mines.

Access to some coal is limited. Because of property rights, land use conflicts, and physical and environmental restrictions, EIA has estimated that only about 54% of the DRB may be available or accessible for mining.

EIA annually estimates recoverable coal reserves by adjusting the DRB to reflect accessibility and recovery rates in mining. As of January 1, 2013, EIA estimated that the remaining U.S. recoverable coal reserves totaled over 257 billion short tons, from a DRB of 481 billion short tons.

Recoverable coal reserves at producing mines represent the quantity of coal that can be recovered (i.e. mined) from existing coal reserves at producing mines. These reserves essentially reflect the working inventory at producing mines. In 2012, the recoverable reserves at producing mines were 18.7 billion short tons. EIA conducts an annual survey, form EIA-7A, "Coal Production and Preparation Report," to gather and report the quantity of recoverable coal reserves at producing mines.

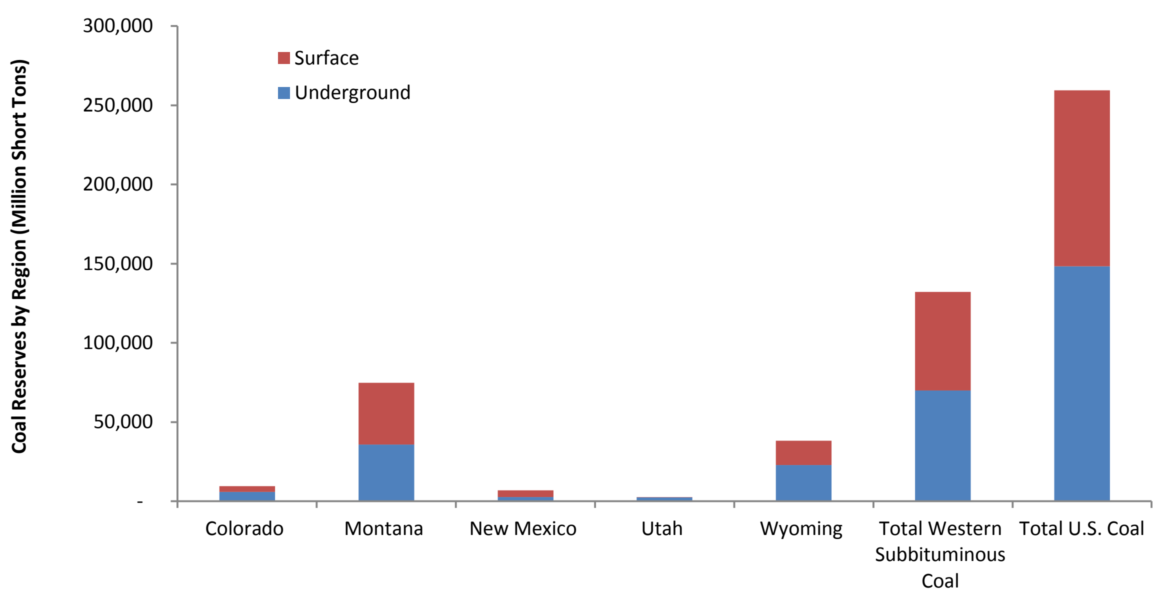
Table 48 – EIA Coal Reserves Data, 2012 Annual Coal Report

Recoverable Coal Reserves at Producing Mines, Estimated Recoverable Reserves, and Demonstrated Reserve by Mining Method, 2012

(Million Short Tons)	Underground - Minable Coal			Surface - Minable Coal			Total		
Coal-Resource	Recoverable Reserves at Producing Mines	Estimated Recoverable Reserves	Demonstrated Reserve Base	Recoverable Reserves at Producing Mines	Estimated Recoverable Reserves	Demonstrated Reserve Base	Recoverable Reserves at Producing Mines	Estimated Recoverable Reserves	Demonstrated Reserve Base
U.S. Total	6,656	147,750	329,814	12,008	109,898	151,571	18,664	257,648	481,385

	Underground - Minable Coal			Surface - Minable Coal			Total		
Coal-Resource State	Recoverable Reserves at Producing Mines	Estimated Recoverable Reserves	Demonstrated Reserve Base	Recoverable Reserves at Producing Mines	Estimated Recoverable Reserves	Demonstrated Reserve Base	Recoverable Reserves at Producing Mines	Estimated Recoverable Reserves	Demonstrated Reserve Base
Arizona	-	-	-	w	-	-	w	-	-
Colorado	w	5,811	11,073	w	3,744	4,759	300	9,555	15,832
Georgia	-	1	2	-	1	2	-	2	4
Montana	w	35,906	70,925	w	38,738	47,927	960	74,644	118,851
New Mexico	w	2,763	6,073	w	4,075	5,819	497	6,838	11,892
South Dakota	-	-	-	-	277	366	-	277	366
Utah	w	2,365	4,825	w	211	267	199	2,576	5,091
Wyoming	w	22,926	42,456	w	14,487	17,495	6,932	37,413	59,951
Western Coal Sources		69,771	135,352		61,255	76,267	8,888	131,026	211,617
Percentage of US Total		47%	41%	0%	56%	50%	48%	51%	44%

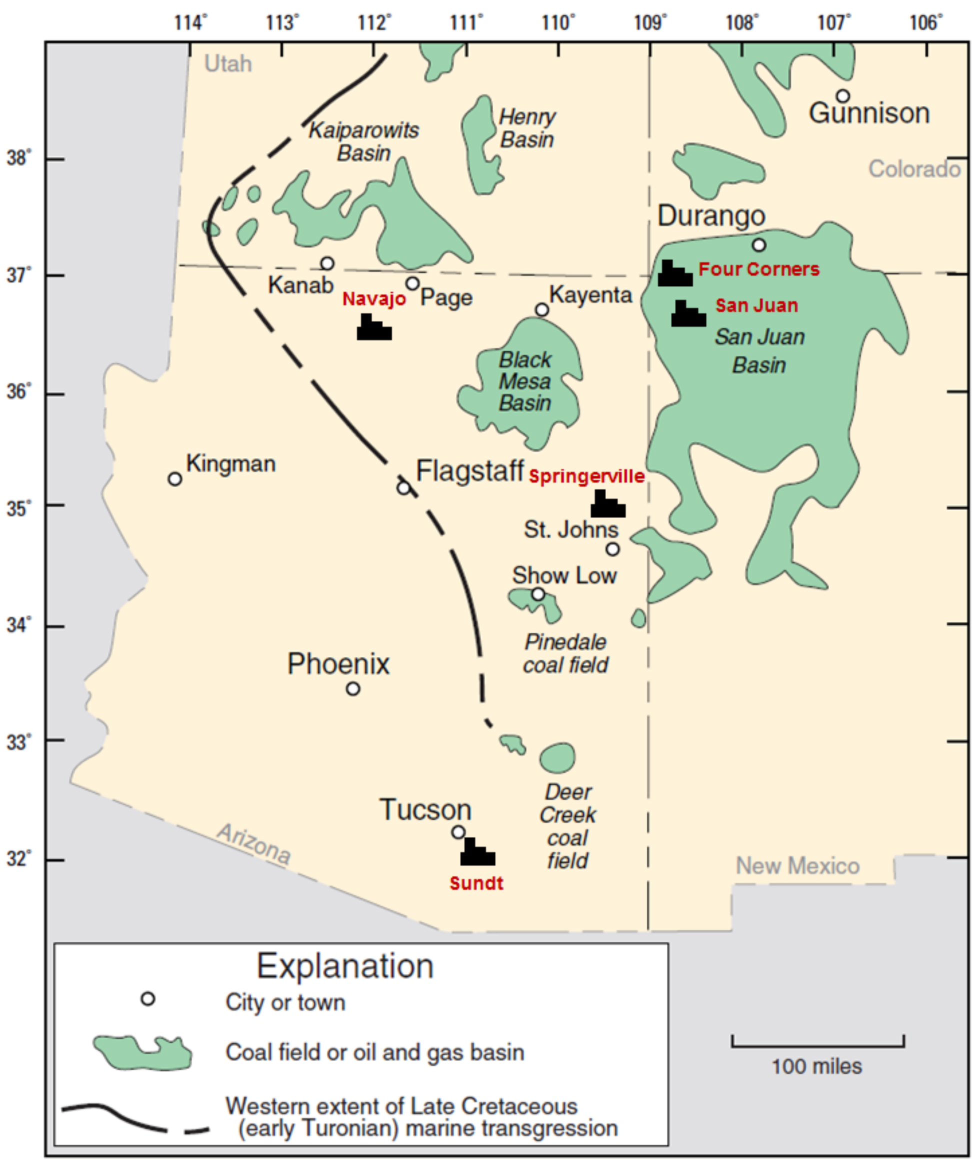
Chart 68 – EIA Coal Reserve Report (2012)



TEP's Coal Sources

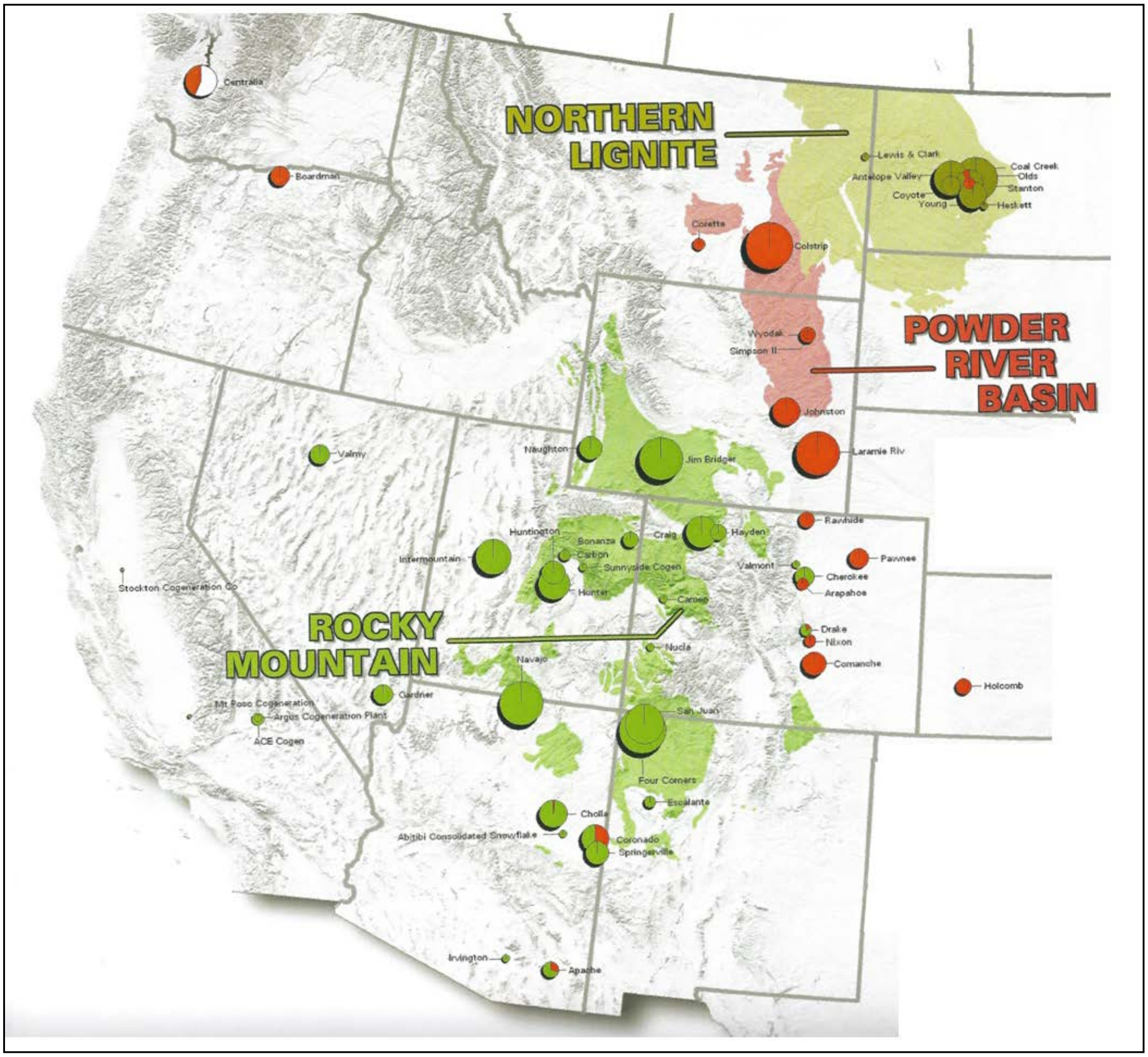
The three remote coal stations that TEP is a minority participant in, San Juan, Four Corners and Navajo, are sourced from mine mouth coal operations. All three plants have adequate coal reserves to fuel the stations for the expected lives of the plants. The two coal stations that TEP owns and operates Springerville and Sundt, have rail lines to the station and therefore have access to several sources of coal in both Colorado and Powder River basin. TEP's forecast price of coal is shown in Chapter 16.

Map 34 - Arizona Coal Fields



Source: Geologic Assessment of Coal in the Colorado Plateau: Arizona, Colorado, New Mexico, and Utah

Map 35 - WECC Coal Regions and Relative Coal Consumption by Plant



Source: Ventyx

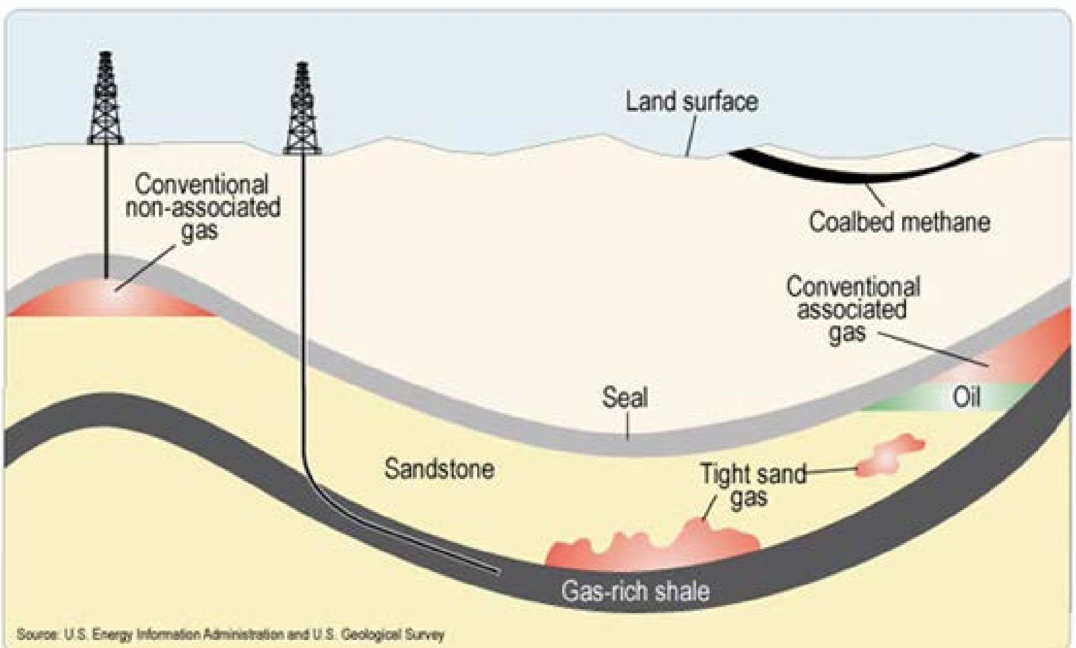
Natural Gas Supply

For the 2014 IRP, TEP relied on a number of data sources to compile the supply and demand fundamentals related to natural gas supply. These data sources included reports compiled by:

- EIA's 2013 Annual Energy Outlook – 2013
- Wood MacKenzie, Regional Gas and Power Service Insight – 2013

Natural gas comes from both conventional and unconventional geological formations. The key difference between conventional and unconventional natural gas is the manner, ease and cost associated with extracting the resource. Conventional gas is typically "free gas" trapped in multiple, relatively small, porous zones in various naturally occurring rock formations such as carbonates, sandstones, and siltstones. However, most of the growth in supply from today's recoverable gas resources is found in unconventional formations. Unconventional gas reservoirs include tight gas, coal bed methane, gas hydrates, and shale gas. The technological breakthroughs in horizontal drilling and fracturing hat have made shale and other unconventional gas supplies commercially viable have revolutionized the production of natural gas.

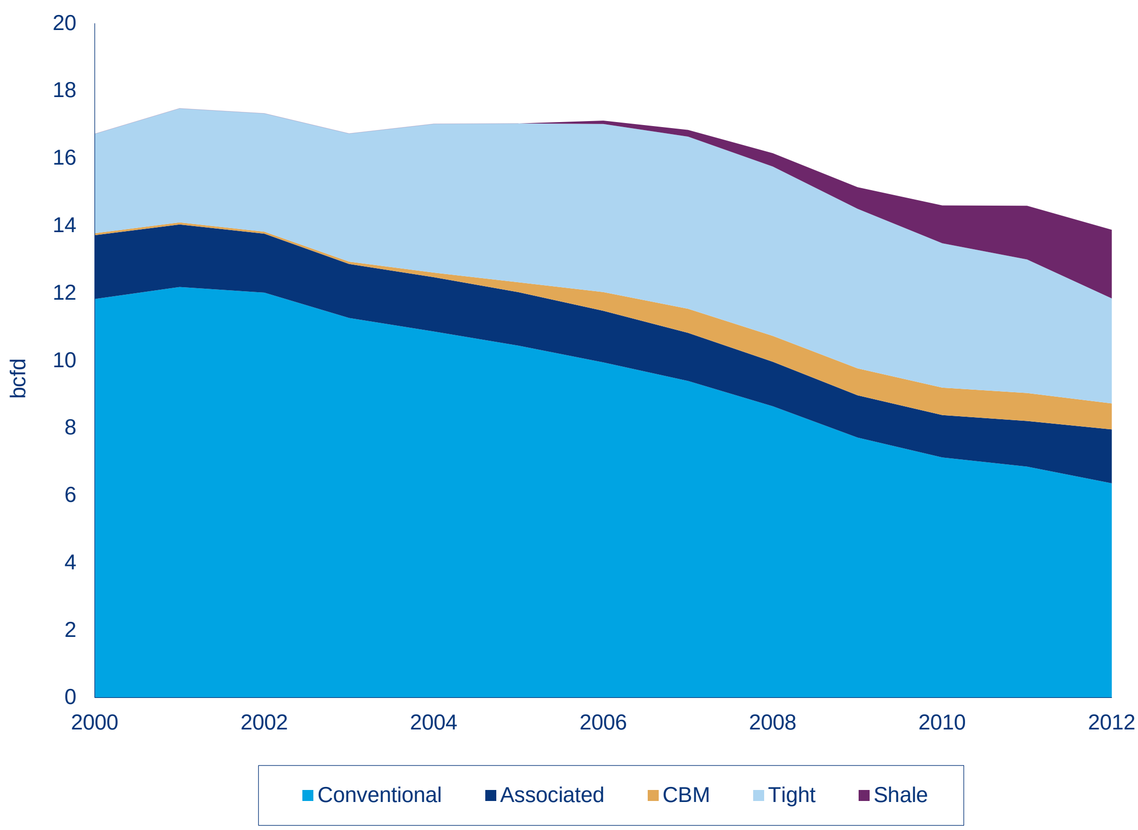
Figure 45 - Natural Gas Geological Formations



Conventional Gas Production

Historically conventional natural gas accounted for 40 -55% of all U.S. supply. Over the last decade, conventional natural gas production has declined from 26 bcfd in 2003 to 12bcfd in 2013. This decline was largely offset by tight sand gas production and more recently by shale gas production. Today, conventional natural gas production accounts 17% of total supply where as tight gas and shale gas production account for 65% of U.S. supply.

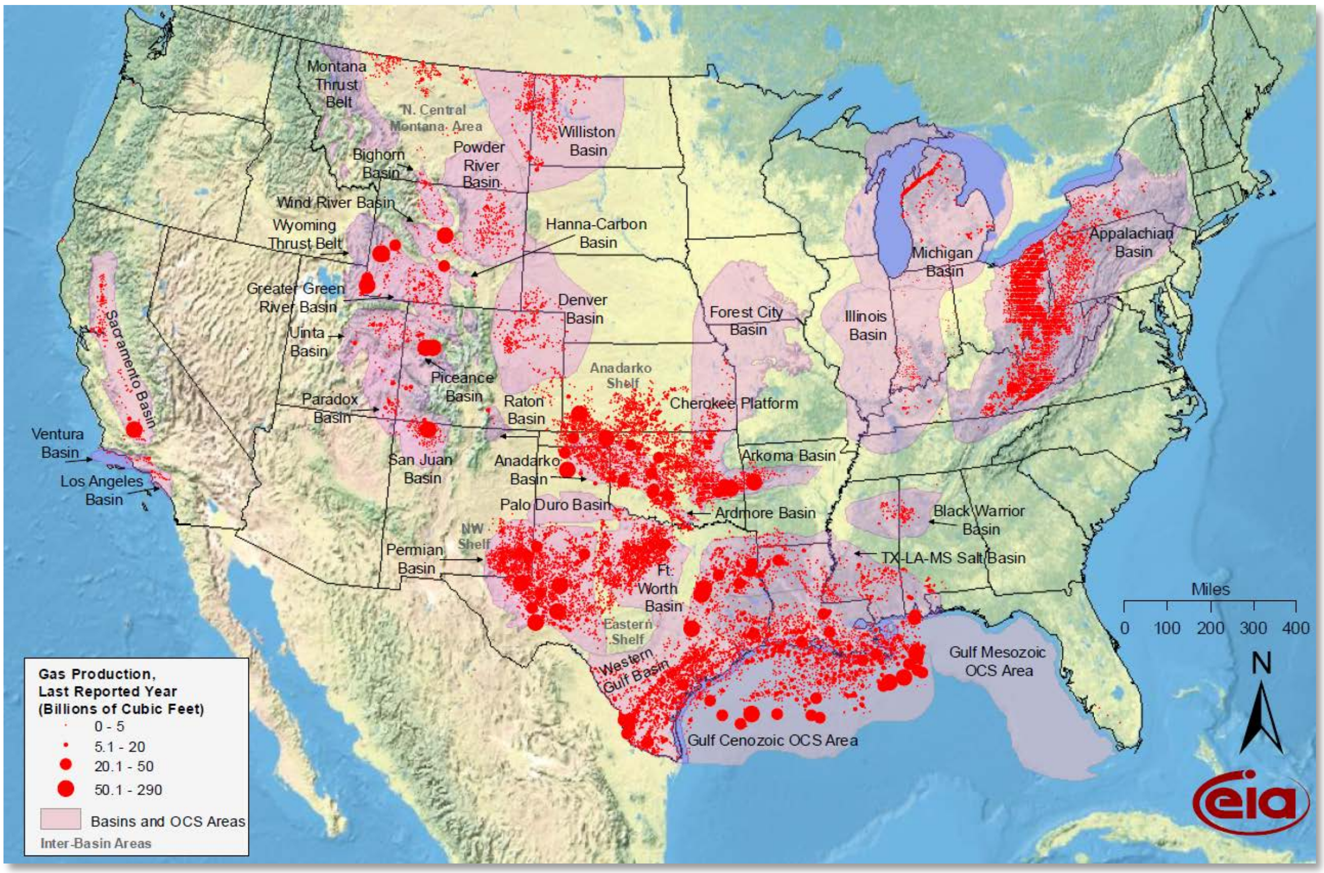
Figure 46 – Historical U.S. Gas Production, 2012 (bcfd)



Conventional Gas Locations

Map 36 below provides an overview on conventional U.S. natural gas production.

Map 36 - U.S. Conventional Gas Production

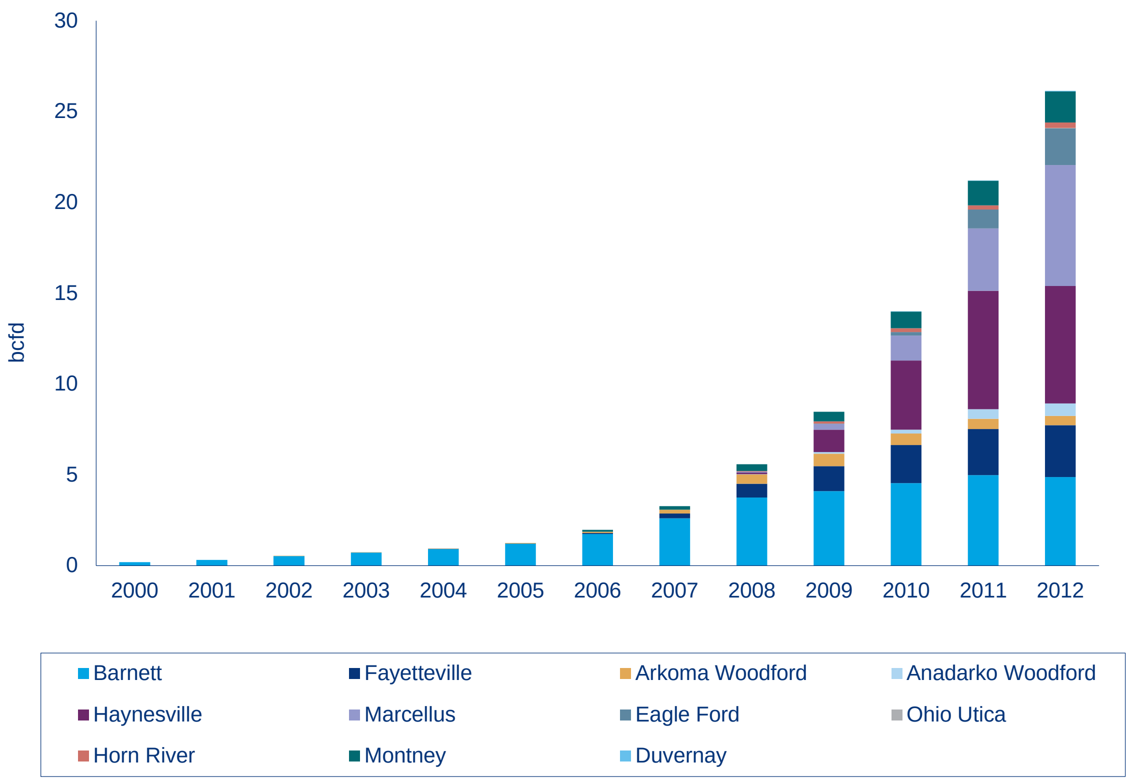


Source: EIA Energy Information Administration

Unconventional Gas Production

The sharp growth in unconventional gas production in North America has changed the supply dynamics on a global basis. In addition to making North America increasingly self-sufficient in gas, it has removed the need to import LNG and, in so doing, has contributed to the surplus of LNG available for export markets. This has helped depress spot prices globally. Unconventional gas (coal bed methane (CBM), tight gas and shale gas) is present in large volumes throughout the U.S. and the world. Production from these new sources is having far reaching consequences for global gas trade and pricing, by reducing import requirements and providing additional export sources. This has helped depress spot prices globally. The primary cause for the downward trend in U.S. natural gas prices is the robust production growth from several emerging shale gas plays. Natural gas production from shale has grown to over 26 Bcfd as illustrated in Chart 69.

Chart 69 - U.S Shale Natural Gas Production 2000-2012, (bcfd)



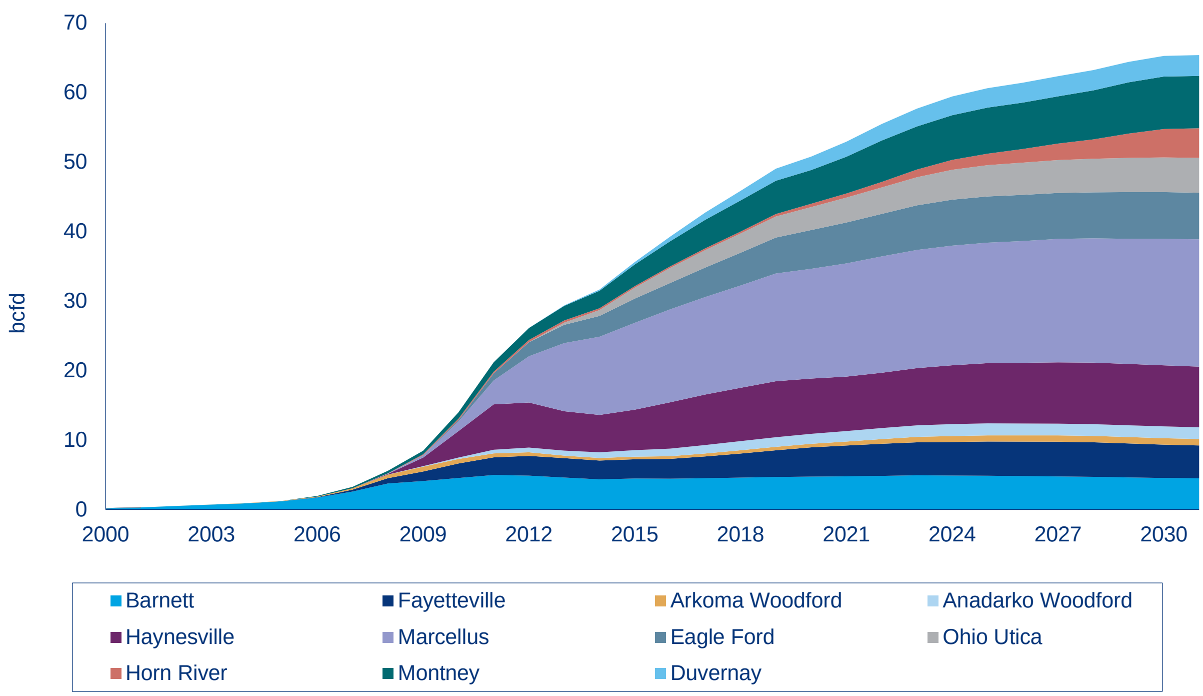
U.S. Shale Gas Plays

Over the past decade, the combination of horizontal drilling and hydraulic fracturing has allowed access to large volumes of shale gas that were previously uneconomical to produce. The production of natural gas from shale formations has rejuvenated the natural gas industry in the United States.

Of the natural gas consumed in the United States in 2013, about 95% was produced domestically; thus, the supply of natural gas is not as dependent on foreign producers as is the supply of crude oil, and the delivery system is less subject to interruption. The availability of large quantities of shale gas should enable the United States to consume a predominantly domestic supply of gas for many years and produce more natural gas than it consumes.

It is projected that U.S. natural gas production will increase from 66 bcfd in 2013 to 100 bcfd in 2028, a 50% increase. Almost all of this increase in domestic natural gas production is due to projected growth in shale gas production, which grows from 27 bcfd in 2013 to 56 bcfd in 2028.

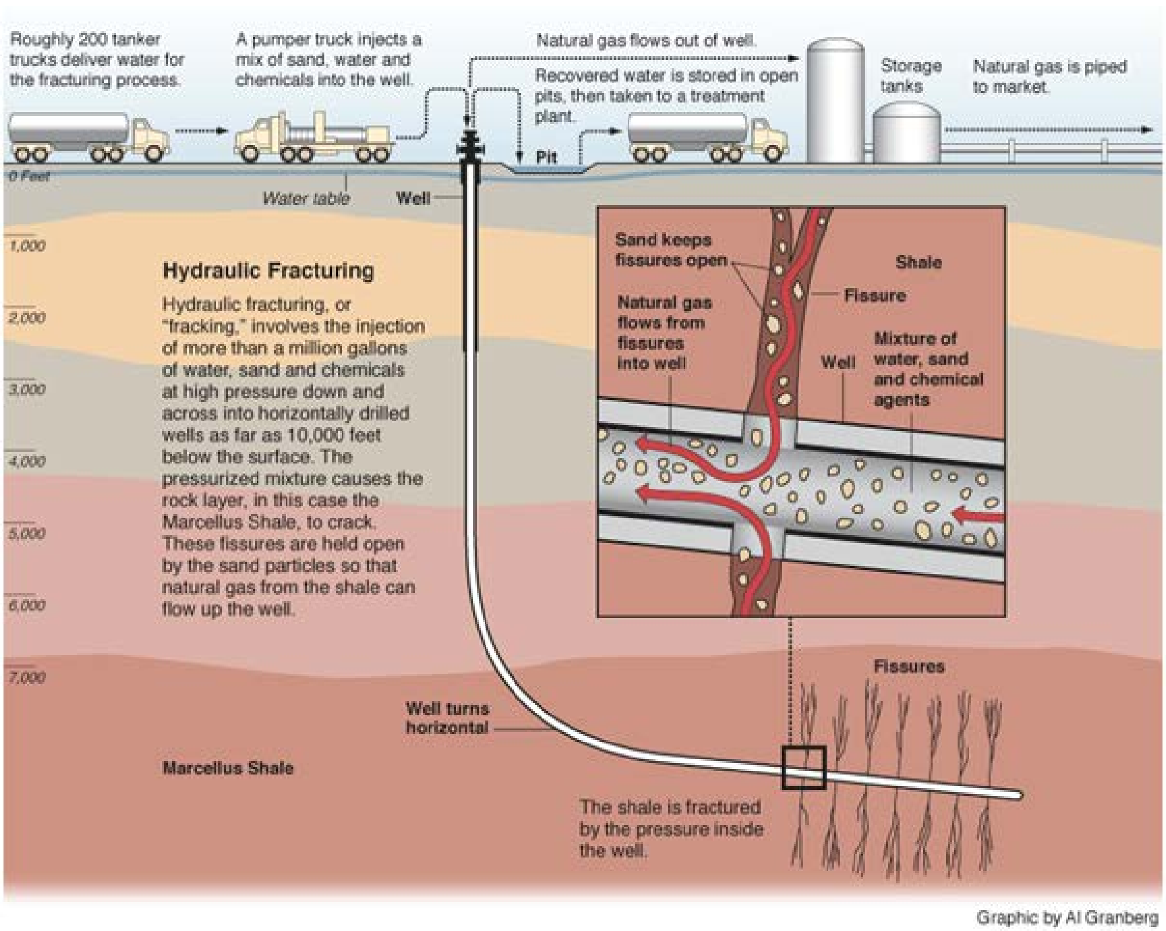
Chart 70 – Shale Plays Forecast (bcfd)



Hydraulic Fracturing

Hydraulic fracturing commonly called "fracking" is a technique in which water, chemicals, and sand are pumped into the well to unlock the hydrocarbons trapped in shale formations by opening cracks (fractures) in the rock and allowing natural gas to flow from the shale into the well. When used in conjunction with horizontal drilling, hydraulic fracturing enables gas producers to extract shale gas economically. Without these techniques, natural gas does not flow to the well rapidly, and commercial quantities cannot be produced from shale.

Figure 47 - Hydraulic Fracturing

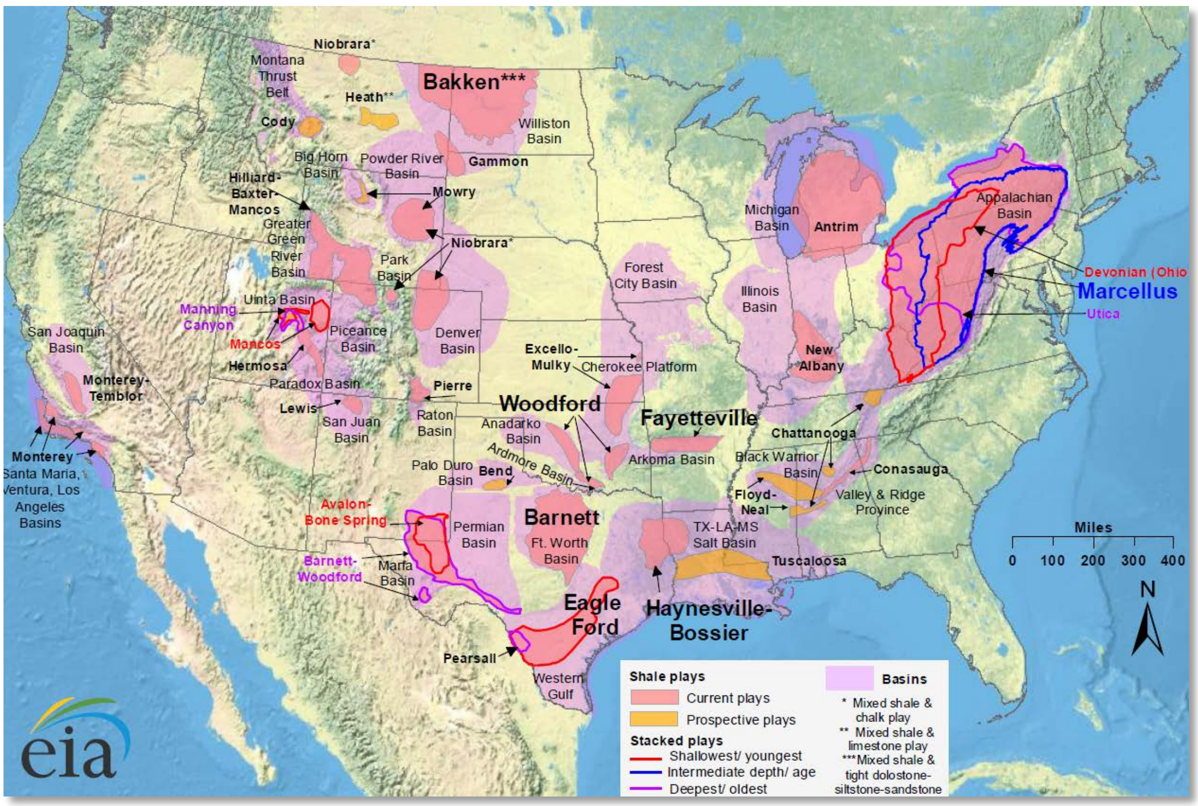


Source: EIA Energy Information Administration

Shale Gas Plays

Shale gas is found in shale "plays," which are shale formations containing significant accumulations of natural gas and which share similar geologic and geographic properties. A decade of production has come from the Barnett Shale play in Texas. Experience and information gained from developing the Barnett Shale have improved the efficiency of shale gas development around the country. Another important play is the Marcellus Shale in the eastern United States. Geophysicists and geologists identify suitable well locations in areas with potential for economical gas production by using surface and subsurface geology techniques and seismic techniques to generated maps of the subsurface. Map 37 below provides an overview on U.S. shale gas plays.

Map 37 - U.S. Shale Gas Plays

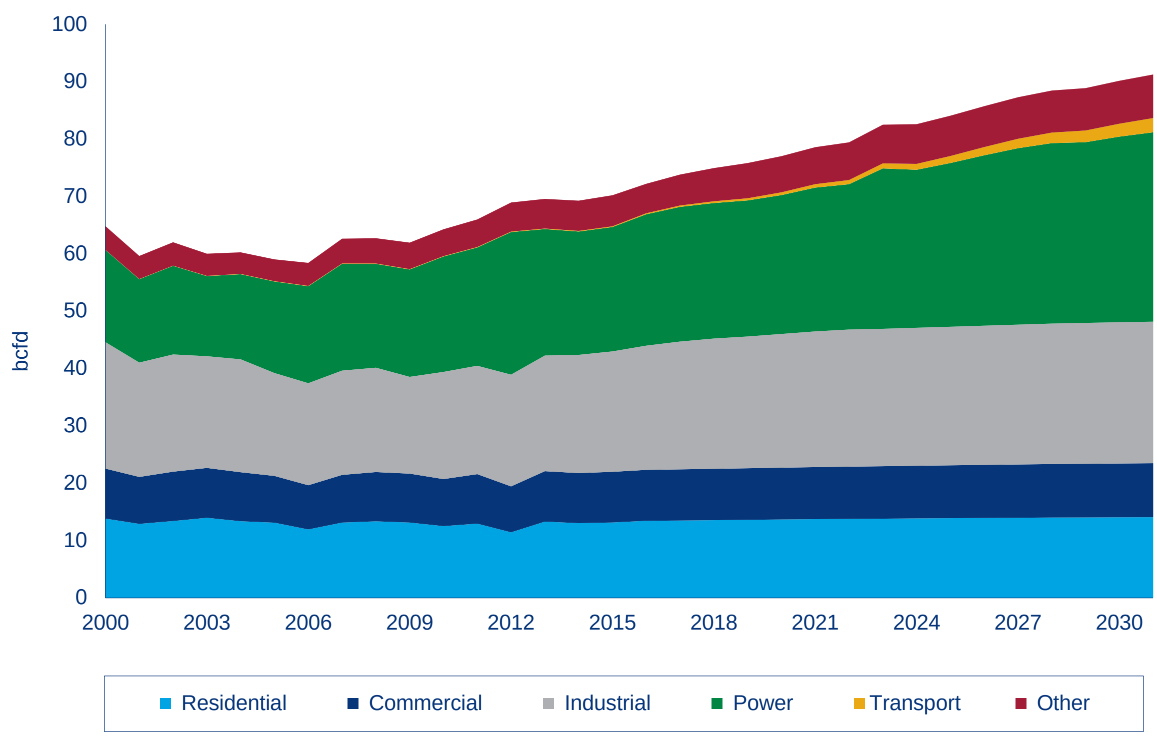


Source: EIA Energy Information Administration

Natural Gas Demand Forecast

Natural gas use increases in all the end-use sectors except residential and commercial, where consumption is expected to be essentially flat over the forecast period as a result of improvements in appliance efficiency and falling demand for space heating, attributable in part to population shifts to warmer regions of the country. The current forecast projection for U.S. natural gas demand (by sector) is depicted in Chart 71. As shown, U.S. gas demand for power generation remains relatively flat through 2015 at approximately 21 bcfd. An important inflection point in the gas markets should arrive in 2016 when new Mercury and Air Toxics Standards (MATS) bring about the final tranche of coal retirements and the ramp up of LNG exports at Sabine Pass, Freeport, and Cameron between 2016 and 2019. New gas-fired industrial facilities continue to come online, as does the build out of Mexican export pipelines to facilitate further export growth. As shown, U.S. gas demand for all sectors increases from 70 bcfd in 2013 to 73 bcfd in 2016. Domestic demand ramps up 12.5 bcfd between 2016 and 2022 climbing to 100 bcfd by 2028.

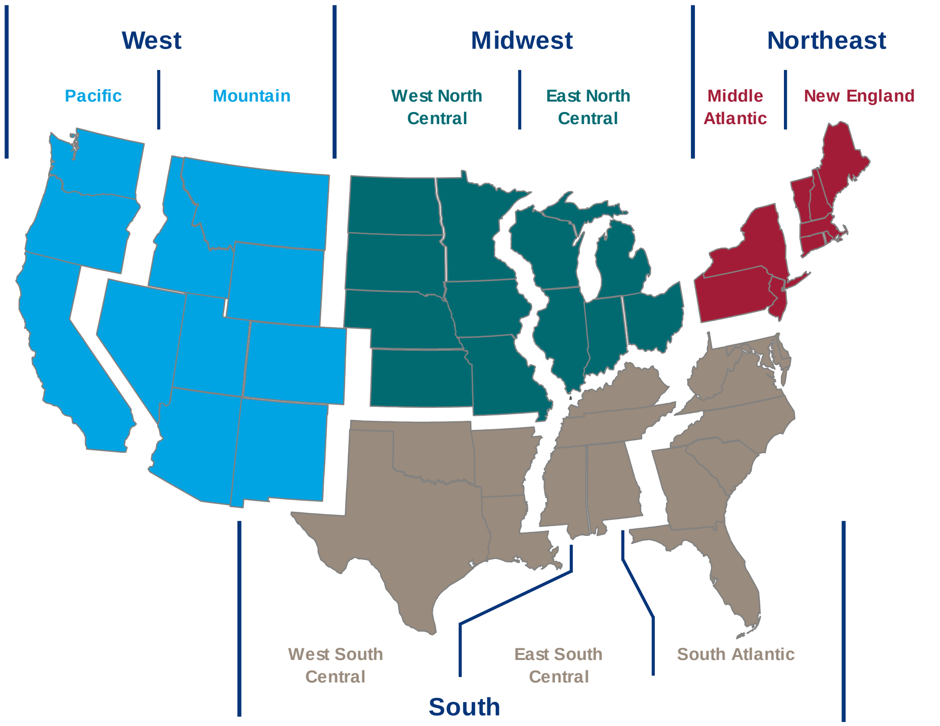
Chart 71 - U.S. Natural Gas Demand Forecast (bcfd)



Natural Gas Demand Forecast

The power generation sector forecast is built up from projections for unit-level dispatch in four regions; South, Northeast, and West. These regions are depicted in the Map 38 - Regional State Groupings.

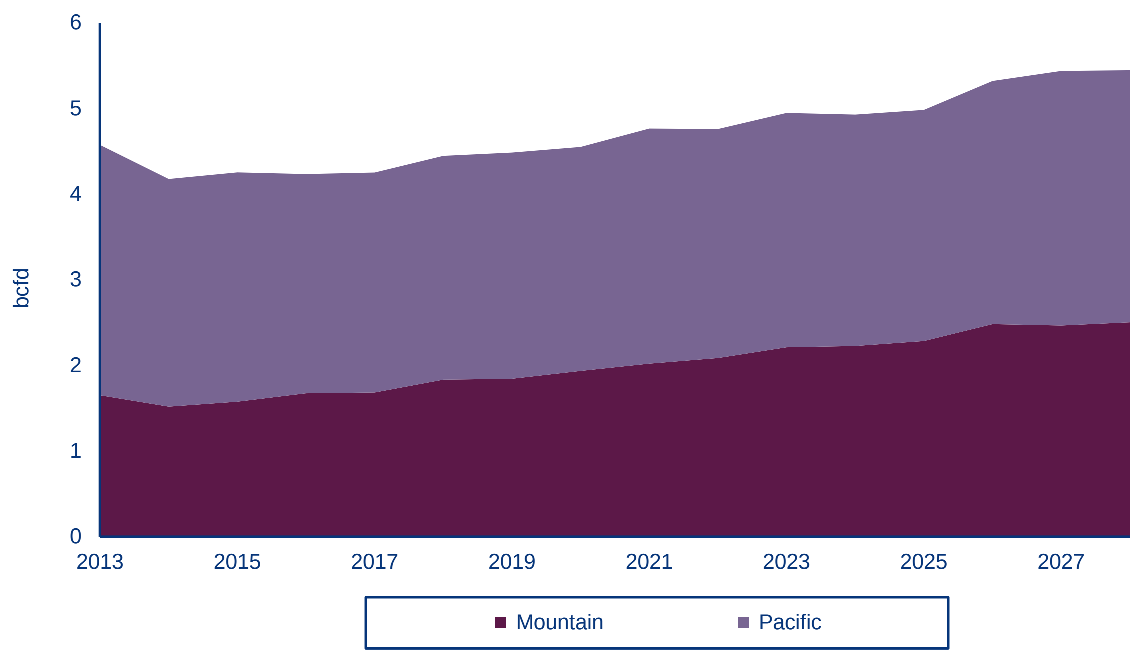
Map 38 - Regional State Groupings



Natural Gas Demand Forecast

As shown in Chart 72, natural gas demand in WECC for the power sector falls early in the projection period from a spike in 2012, which resulted from very low natural gas prices relative to coal. Consumption of natural gas for power generation increases by an average of 0.8 percent per year, with more natural gas used for electricity production as relatively low prices make natural gas more competitive with coal. Increases in power sector gas consumption are modest for the period 2014 to 2028 with about 1.3 bcfd of incremental consumption which is expected to occur in aggregate for both the Mountain and Pacific regions of WECC. The relatively slow growth rates for power sector gas consumption during these years is largely a result of state level energy efficiency and renewable energy mandates that are expected to meet a large portion of incremental power demand over the next ten years. Beyond that, power sector gas consumption is expected to grow at a much quicker pace driven by additional environmental regulations.

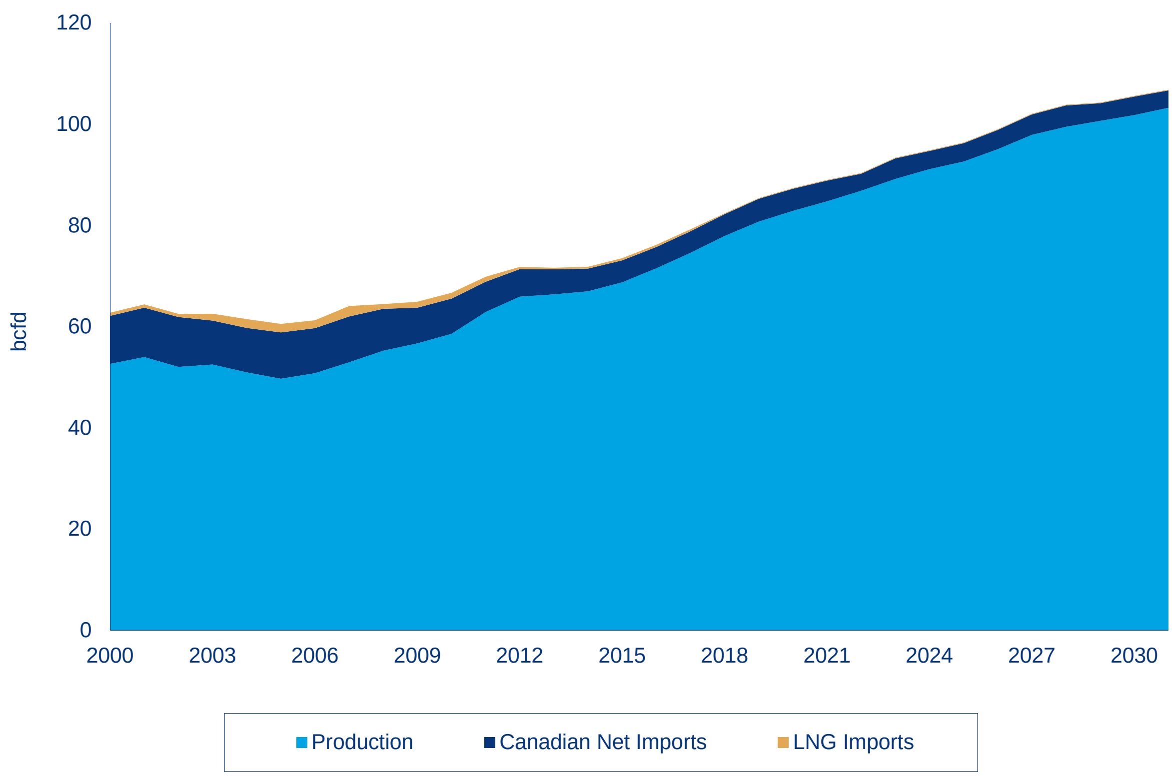
Chart 72 – WECC Regional Gas Demand Forecast (bcfd)



Natural Gas Supply Forecast

In 2013, U.S. natural production made up 94% of the natural gas supply while the remaining 6% resulted in imports from Canada. The future outlook on U.S. natural gas production is expected to grow from 65 bcfd in 2013 to 100 bcfd by 2028.

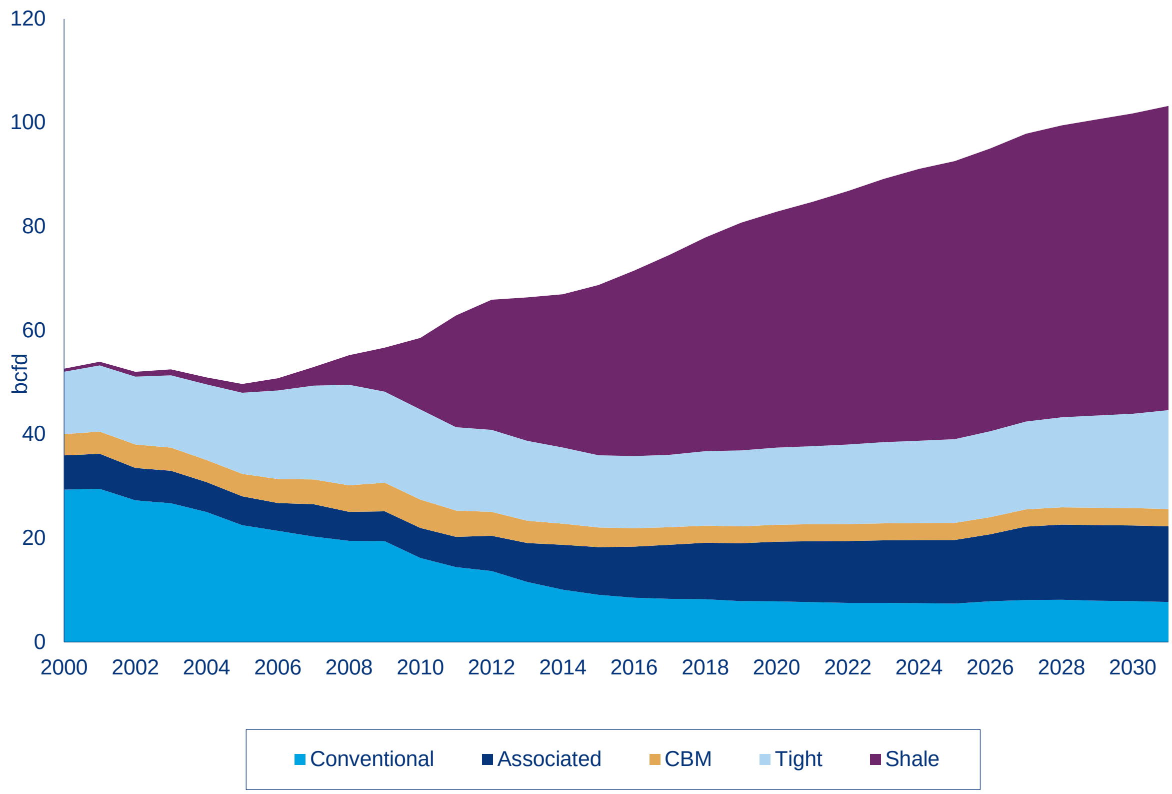
Chart 73 – U.S. Natural Gas Production Balances Net Imports (bcfd)



Natural Gas Supply Forecast

Over the time period 2013 to 2028, conventional gas production is expected to decrease from current levels of about 17% of the domestic supply to about 8% of domestic supply as lower cost shale gas production continues to displace higher cost conventional production. Production levels from Coal Bed Methane (CBM) and tight gas are relatively constant over time, dropping slightly during the early period of rapid growth in shale gas production and increasing modestly in the later years of the forecast period.

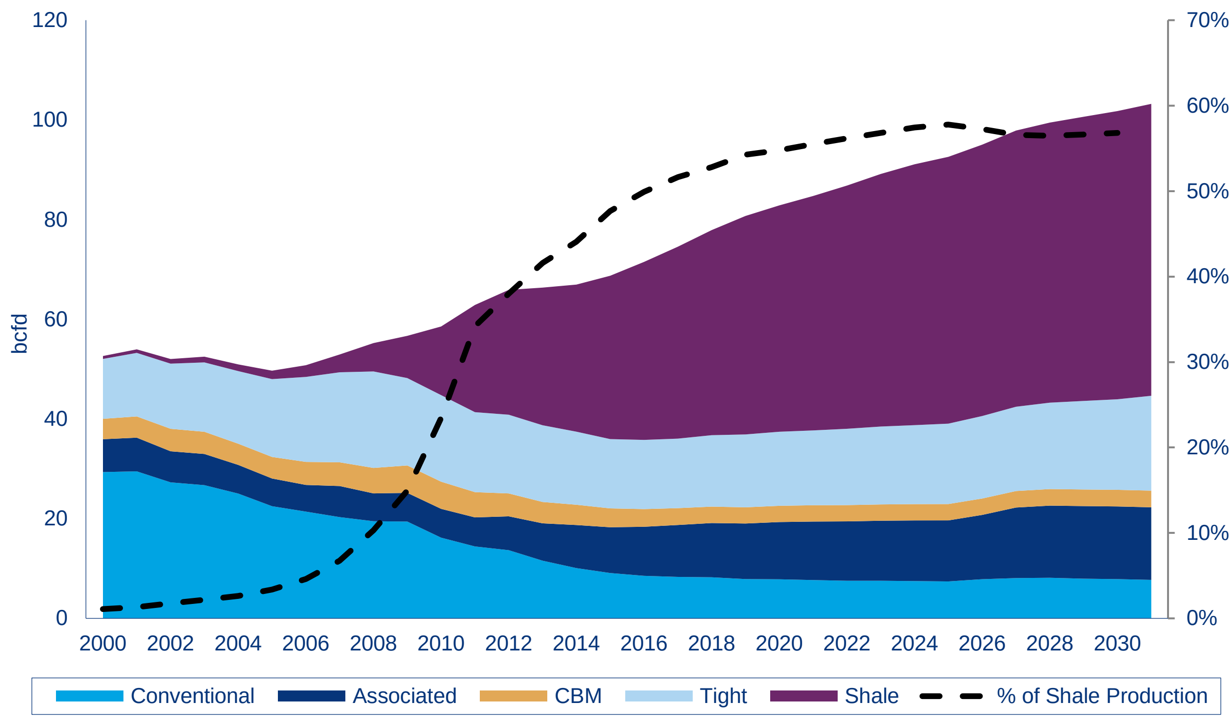
Chart 74 – U.S. Natural Gas Production by Source (bcfd)



Shale Gas Production

Shale gas production represents the largest incremental supply source for the U.S. market with production growing at a rate that displaces conventional production. Shale gas production is estimated to grow from current levels of about 42% of domestic supply to about 57% of domestic supply by 2028. This represents an increase of about 30 bcfd over current levels of shale gas production.

Chart 75 - U.S. Natural Gas Supply Forecast (bcfd)



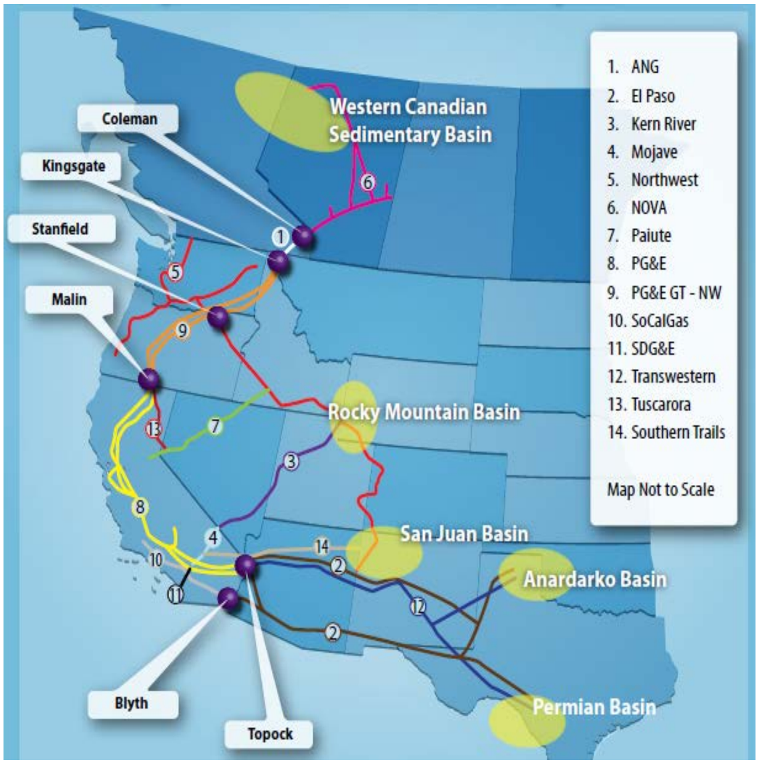
Natural Gas Transportation

The largest capacity natural gas pipeline within the region is the El Paso Natural Gas Company system. It has the capability to transport up to 6.2 billion cubic feet (Bcf) per day from natural gas production areas located in the Permian Basin of western Texas and the San Juan Basin of southern Colorado. While the destination of a major portion of its deliveries is the California State border, this natural gas pipeline system also provides substantial service to customers in Arizona, especially to the growing natural gas fired electric power generation market. It is also a secondary source of supply for the Southwest Gas Company (at the Arizona/Nevada State border), a major supplier of natural gas to southern Nevada and the Las Vegas metropolitan area.

Transwestern Pipeline Company's 2.4 Bcf per day natural gas pipeline system almost parallels the northern route of the El Paso Natural Gas Company system from West Texas through the San Juan Basin of northern New Mexico. It also delivers a large portion of its transported supplies to the California border and is a major participant within the Arizona marketplace.

Both the Transwestern Pipeline Company and El Paso Natural Gas Company systems deliver supplies to the three major intrastate natural gas pipelines operating in California: Southern California Gas Company (SoCal), California Gas Transmission Company (formerly PG&E Gas Transmission), and San Diego Gas & Electric Company (via the Southern California Gas Company system).

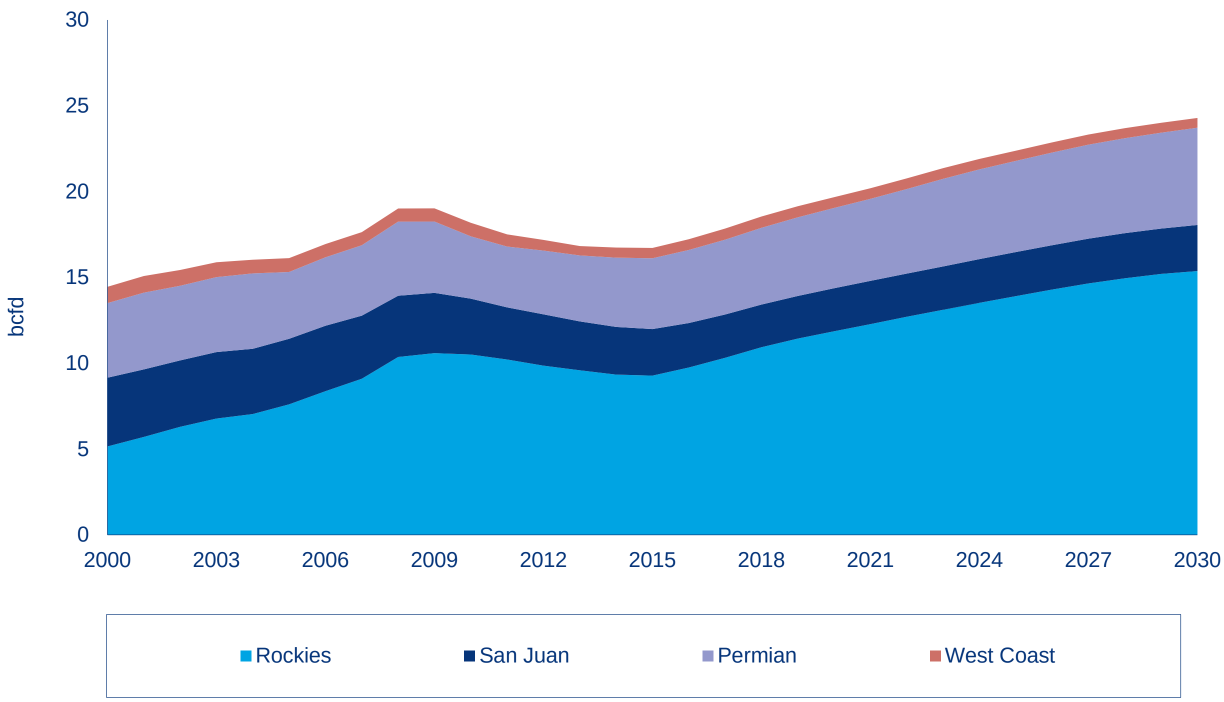
In addition, both Transwestern Pipeline Company and El Paso Natural Gas Company deliver to the Mojave Pipeline Company (0.4 Bcf per day) system, which enters the region at the northern Arizona/California border and crosses to Kern County, where it then merges with the Kern River Transmission Company system. The Mojave Pipeline Company and Kern River Transmission Company systems were the first interstate natural gas pipelines (in 1992) to extend into the State of California, which previously limited its territory to intrastate pipelines service only.



Regional Natural Gas Production

The San Juan Basin production levels are expected to remain relatively flat over the next several years with increases occurring in both the Permain Basin and Rockies region. Permian production levels are expected to grow by about 2.5% per year. The Rockies region is expected to increase production at 3.7% per year. As shown in Chart 76, regional gas supply sources with access to the Arizona markets will increase current production levels from 17 bcfd in 2013 to 24 bcfd by 2028 (40% increase over current levels).

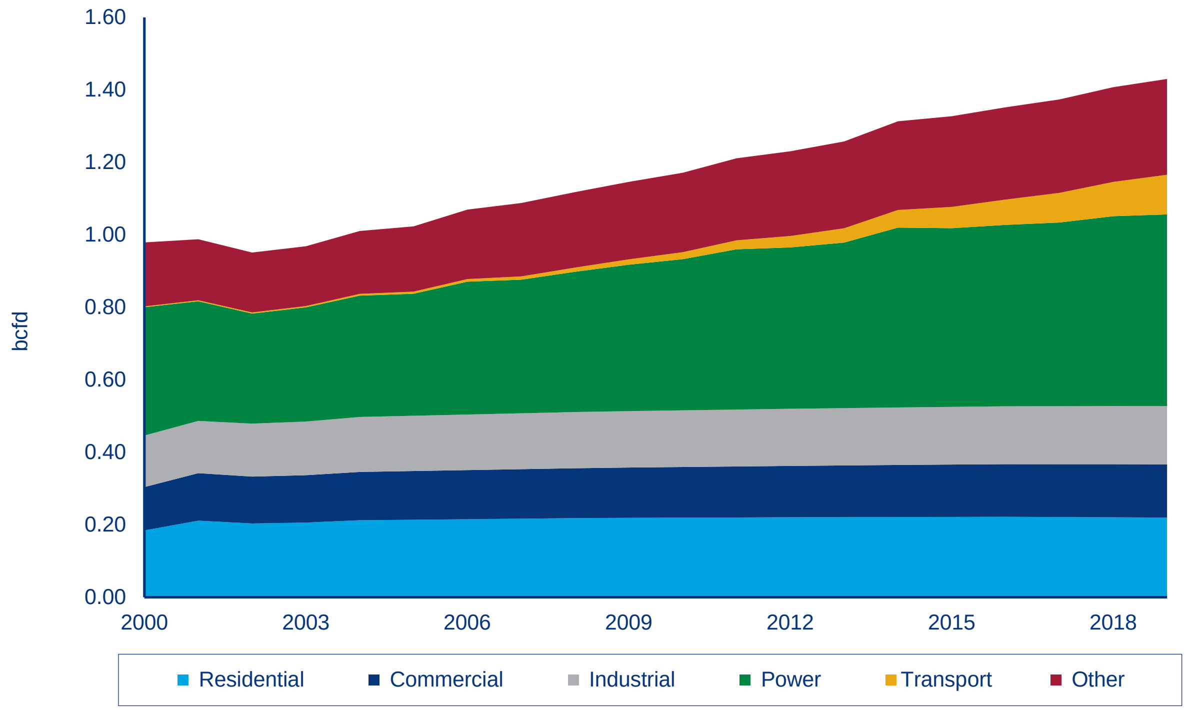
Chart 76 - Future Regional Natural Gas Production



Target Market End-Use Demand for Arizona

End-demand in Arizona is expected to rise from 1.0 bcfd in 2013 to 1.35 bcfd in 2028. New gas-fired generation and new industrial facilities are seen as main growth drivers, as does the build out of Mexican export pipelines to facilitate further export growth. Chart 77 below shows the Arizona natural gas demand by six major use sectors.

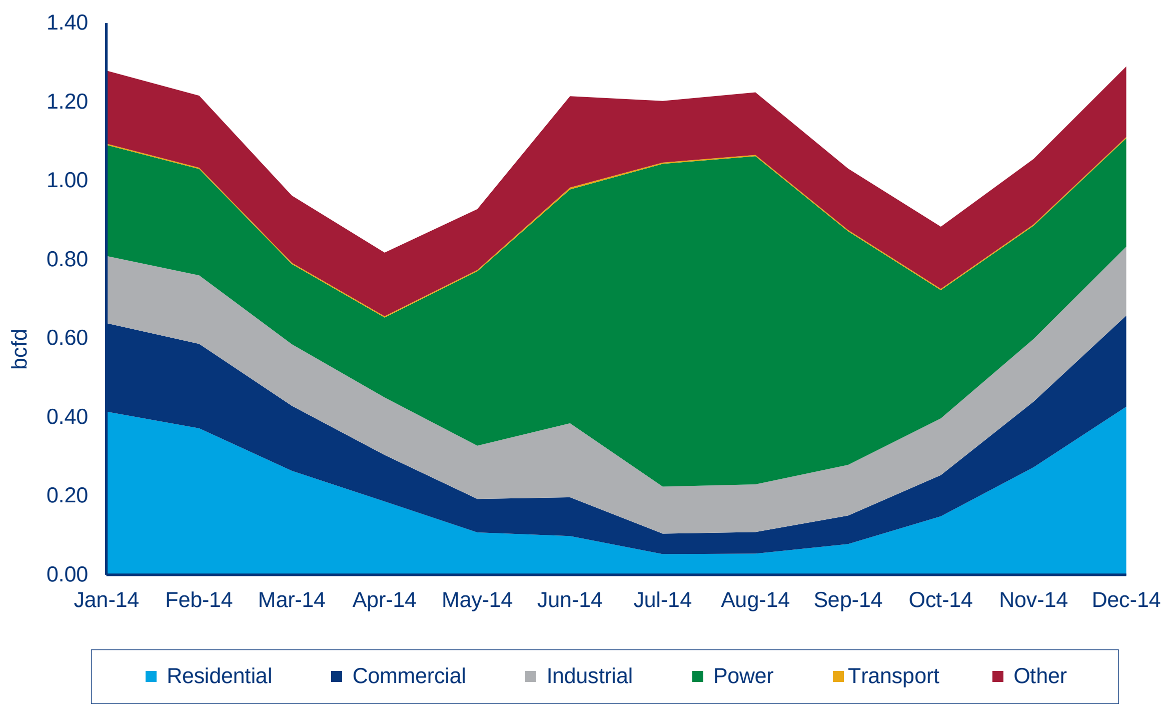
Chart 77 - Arizona Natural Gas Demand by Sector (bcfd)



Arizona Seasonal Natural Gas Demand

Arizona experiences a dual-peaking annual demand, with the highest rate of natural gas demand occurring in the summer (June – September) as a result of increased gas-fired generation. A slightly smaller peak in occurs in the winter (December – February) spurred by residential demand for heating coupled with gas-fired generation. Chart 78 below show the seasonality demand for Arizona natural gas.

Chart 78 - Arizona Seasonal Natural Gas Demand (bcfd)



CHAPTER 17

INTEGRATED RESOURCE PLANNING RESULTS

Introduction

The resource planning process starts with a set of input assumptions. These assumptions include a forecast of customer demand, resource operating characteristics, resource costs, and assumptions on future regulatory and environmental policies. These assumptions provide input to a detailed planning simulation model used to develop an understanding of the financial requirements, risk factors and externalities associated with each resource portfolio. The goal of the planning process is to develop a resource acquisition strategy that balances a number of objectives, such as affordability, system reliability, and environmental compliance. The results of this process present a resource strategy that balances competing objectives while allowing for flexibility to execute contingency plans as future conditions evolve.

Overview of the 2014 Reference Case Plan

The 2014 IRP presents the Reference Case plan as TEP's recommended resource plan. The Reference Case plan provides a starting point for comparisons against other resource portfolio alternatives. The 2014 IRP Reference Case plan highlights a plan for long term portfolio diversification while maintaining cost effective operations at our existing generation stations which result in lower annual NO_X, Mercury and CO_2 emissions with a focus on future development of energy efficiency, demand response, renewables and natural gas resources.

In addition, the 2014 Reference Case plan provides an in-depth analysis on the complex issues associated with our near-term coal plant decisions. Based on the known and reasonable planning assumptions as of this filing, the 2014 Reference Case plan shows TEP's commitment to maintaining its full participation at the Four Corners Power Plant and Navajo Generation Station. These commitments support the proposed "Better-than-BART" alternatives which result in lower overall emissions at these stations while protecting the economic welfare of the Navajo and Hopi tribes, and Central Arizona Water (CAP) users. The 2014 Reference Case plan also makes commitments to a portfolio diversification strategy that reduces TEP's overall utilization of coal fired generation by one-third over the next five years.

Finally, the 2014 IRP presents some potential contingency options to deal with unforeseen changes in load growth, higher renewable energy standards, higher environmental compliance costs, and opportunities to acquire merchant generation assets below current new-build construction cost. In the end, the 2014 Reference Case plan strikes a balance between minimizing costs to customers and mitigating environmental impacts while maintaining TEP's high level of system reliability. This chapter presents an overview of the 2014 IRP Reference Case plan and provides the associated timeline for future resource decisions.

Overview on TEP's Environmental Compliance

Over the last several years, TEP's coal-fired facilities have faced a number of complex environmental challenges that were likely to result in TEP having to invest approximately $467 million dollars in pollution control upgrades by 2018 to maintain environmental compliance. These environmental challenges included regulations such as the Clean Air Act's Regional Haze Rule (requiring Best Available Retrofit Technologies (BART) to reduce haze in national parks and wilderness areas), Coal Combustion By-Products regulation and strict emission limitations for Mercury and other Hazardous Air Pollutants (HAPs). In addition, the announcement of the President's Climate Action Plan in June 2013, increases the likelihood that the EPA will need to mandate new carbon pollution standards for both new and existing generation sources.

In an effort to comply with these regulations and minimize potential rate impacts on customers, TEP worked with various stakeholders of Four Corners Power Plant (Four Corners), Navajo Generating Station (NGS), and San Juan Generating Station (SJGS) to sort through the legal, technical and financial implications associated with continued operations in its existing coal plants. As a result of these negotiations, there are a number of potential proposals being considered by the EPA that will reduce TEP's near term investment in pollution control upgrades to approximately $161 million dollars. A savings of $306 million dollars over the EPA's original proposed implementation plans.

Table 49 – Environmental Capital Comparisons (Original EPA Proposals vs. Reference Case Plan)

Based on EPA's Original Proposals (2012 IRP)

Capital	BART	MACT	Total
Four Corners	$45	$1	$46
Navajo	$85	$1	$86
San Juan	$200	-	$200
Springerville	-	$5	$5
Sundt 4	$130	$0	$130
CapEx 2014-2019	$460	$7	$467
CapEx 2020-2028	$0	-	$0
Total CapEx	$460	$7	$467

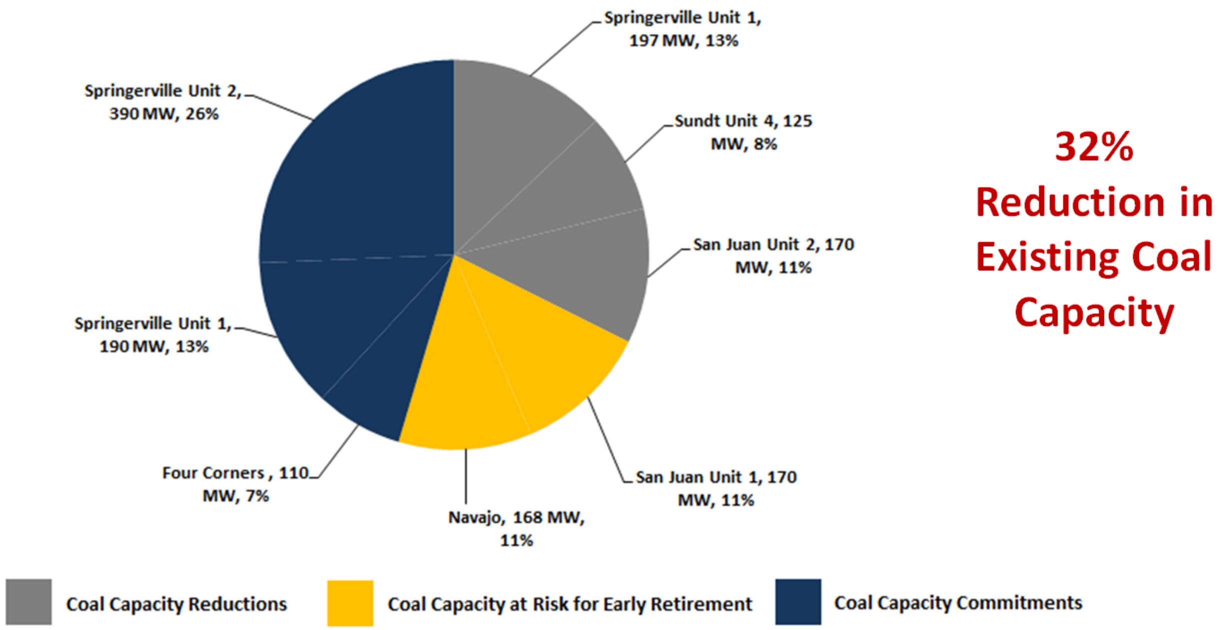
TEP 2014 Reference Case Plan

Capital	BART	MACT	Total	Savings
Four Corners	$35	$1	$36	$10
Navajo	$85	$1	$86	$0
San Juan	$35	-	$35	$165
Springerville	-	$4	$4	$1
Sundt 4	-	$0	$0	$130
CapEx 2014-2019	$70	$6	$76	$391
CapEx 2020-2028	$85	-	$85	-$85
Total CapEx	$155	$6	$161	$306

TEP's Portfolio Diversification Strategy for the 2014 IRP

As part of the 2014 Reference Case plan, TEP is committed to moving forward with a portfolio diversification strategy to reduce its risks associated with investments in coal fired generation. This strategy results in lower cost outcomes for TEP's customers while reducing it longer term carbon risk in its generation resource portfolio. Chart 79 below shows the current status of TEP's commitments regarding its coal generation resources. The coal resources in grey reflect TEP's planned commitments to reduce its overall coal capacity by 492 MW (32% of TEP's existing coal fleet) over the next five years at Springerville, San Juan and Sundt Generating Stations. The coal resources shown in yellow reflect the proposed "Better than BART" alternatives that are still pending final approval from the EPA. The coal resources shown in dark blue reflect TEP's current commitment to maintain its participation in these generation facilities.

Chart 79 – 2014 IRP Planned Coal Capacity Reductions and Commitments



To replace this lost coal capacity from TEP's existing resource mix, TEP conducted a Request for Proposal (RFP) in May 2013 to evaluate the potential alternatives for the capacity reductions that were being considered at the Springerville and San Juan Generating Stations. As a result, TEP received fourteen different proposals from nine different bidders. Based on TEP's bid analysis, the Entegra Power Group LLC (Entegra) was chosen as the final bidder due the economic and operational advantages of their proposal.

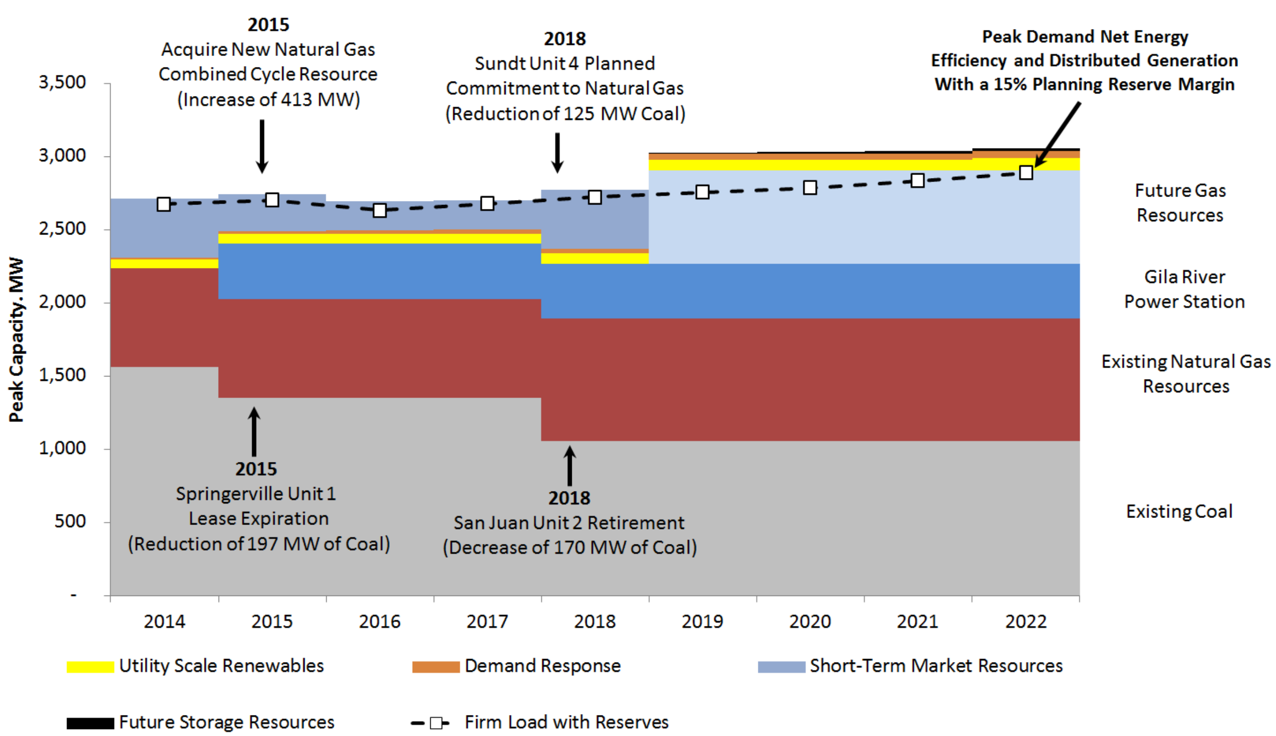
Picture 21 – Gila River Power Station

In December 2013, TEP and its affiliate UNS Electric, Inc. (UNS Electric) entered into a purchase agreement with a subsidiary of Entegra Power Group LLC (Entegra) to purchase Power Block 3 of the Gila River Generating Station (Gila River Unit 3). Gila River Unit 3 is a gas-fired combined cycle unit with a capacity rating of 550 MW, located in Gila Bend, Arizona. The purchase price is set at $219 million ($398/kW) subject to adjustments to prorate certain fees and expenses through the closing and in respect of certain operational matters. It is anticipated that TEP will purchase a 75% undivided interest in Gila River Unit 3 for approximately $164 million and UNS Electric will purchase the remaining 25% undivided interest for approximately $55 million, although TEP and UNS Electric may modify the percentage ownership allocation between them. TEP and UNS Electric expect the transaction to close in December 2014.

Reference Case Plan - Coal Capacity Reductions

Figure 48 shows the Reference Case plan timing of the expected coal reductions as well as the acquisition of the Gila River Power Station that are planned to occur over the next five years.

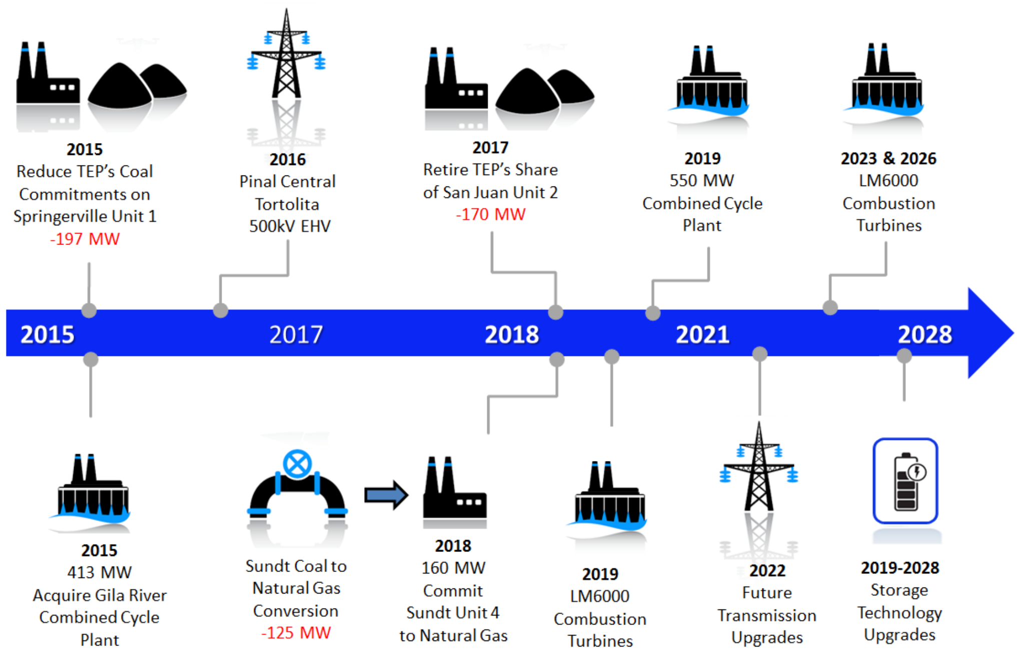
Figure 48 – Reference Case Plan - Coal Capacity Reductions by Year



Reference Case Plan Timeline

Figure 49 shows the Reference Case plan timing on expected resource retirements, additions and improvements by year and resource type.

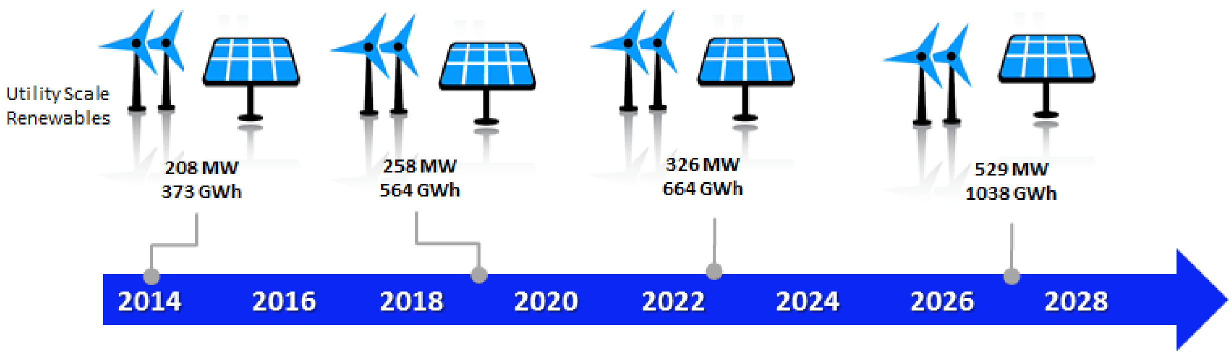
Figure 49 – 2014 IRP Reference Case Plan Timeline



Projected Utility Scale Requirements in the 2014 IRP

The Reference Case plan also includes a diverse portfolio of renewable resources that complies with the Arizona Renewable Energy Standard (RES). The Reference Case plan meets the renewable energy standard goals. The RES requires TEP to utilize renewable energy resources to serve 4.5% of its 2014 retail load requirement, growing to 15% by 2025. By 2028, the Reference Case plan includes approximately 529 MW of utility scale renewable nameplate capacity. These utility scale renewable resources are expected to supply approximately 373 GWh of energy in 2014 growing to 1,038 GWh by 2028.

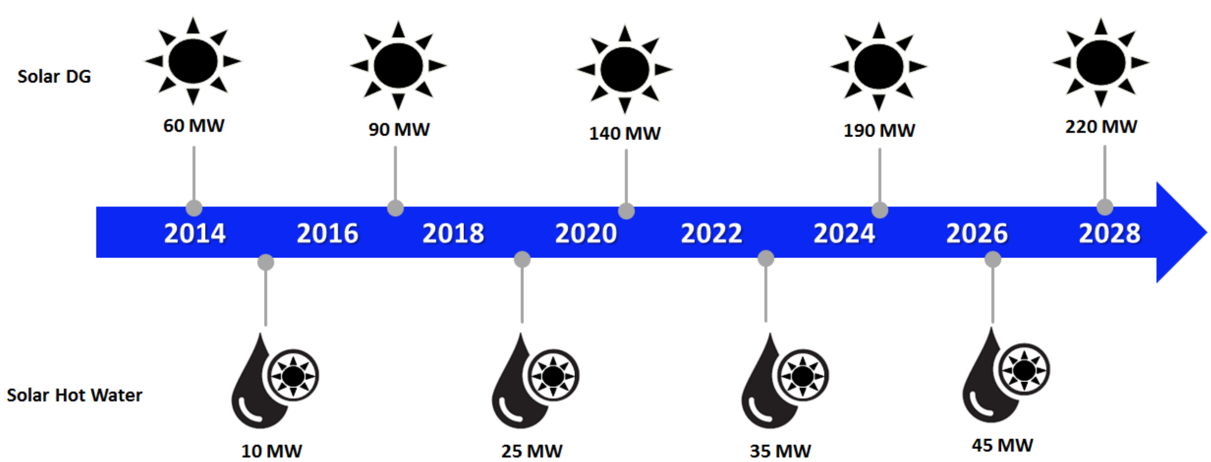
Figure 50 – Utility Scale Renewable Capacity



Projected Distributed Generation Requirements in the 2014 IRP

The Reference Case plan meets the distributed generation requirement based on Arizona's Renewable Energy Standard. The annual distributed generation requirement is 30% of the total renewable energy standard. By the end of 2014, the Reference Case plan will include approximately 71 MW of rooftop solar PV and solar hot water heating capacity. Distributed generation resources are expected to supply at least 123 GWh of energy on an annual basis in 2014 growing to approximately 455 GWh by 2028. Figure 51 below shows the expected cumulative nameplate capacity of both rooftop solar PV and solar hot water heating that will be installed in TEP's service territory from 2014 through 2028.

Figure 51 - Distributed Generation Resource Capacity



Projected Energy Efficiency Requirements in the 2014 IRP

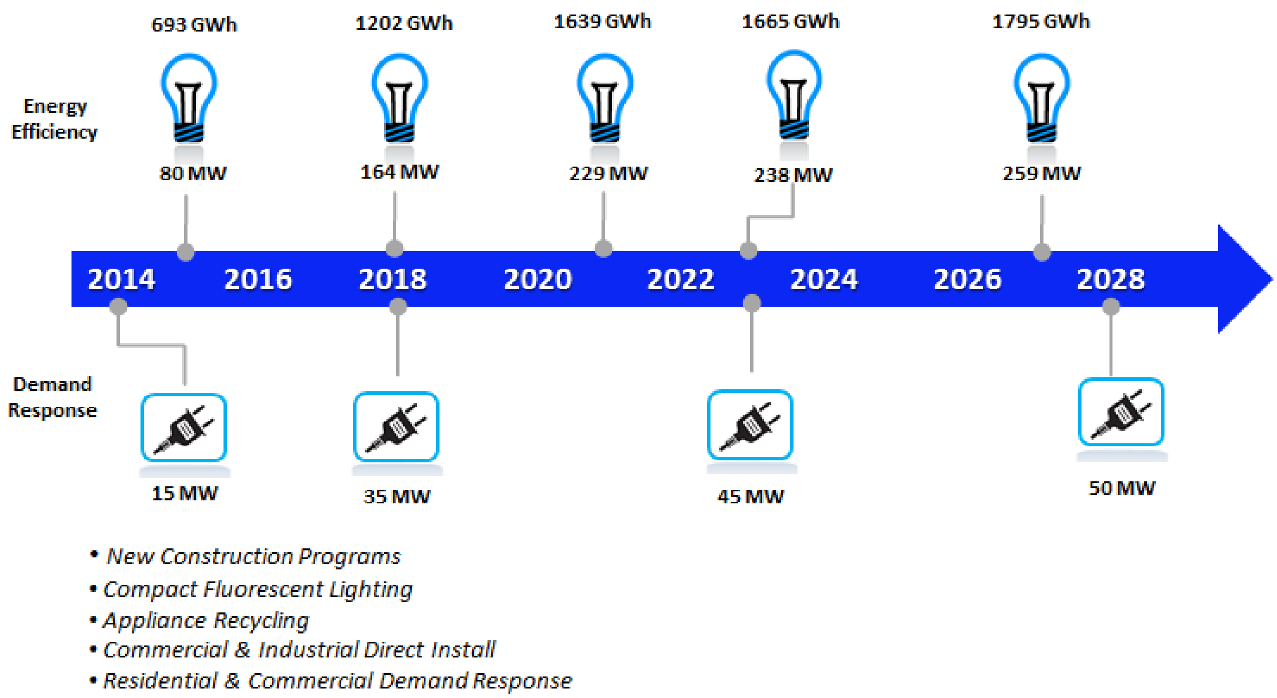
Energy Efficiency

TEP proposes to pursue a range of cost-effective and industry-proven programs to meet future energy efficiency targets. TEP's proposed energy efficiency portfolio maintains compliance with the Arizona Energy Efficiency Standard which targets cost effective programs that reach a 22% cumulative energy reduction by 2020. By 2020, this offset to future retail load growth is expected to reduce TEP's annual energy requirements by approximately 1,816 GWh and reduce TEP's system peak demand by 312 MW.

Demand Response

The Reference Case plan targets dispatchable demand response programs that reduce TEP's summer peak loads. TEP's future demand response programs are expected to reduce TEP's system peak demand by 50 MW by 2028. Figure 52 shows the equivalent capacity reductions installed under future energy efficiency and demand response programs for the Reference Case plan from 2014 through 2028.

Figure 52 - Energy Efficiency and Demand Response (Equivalent Capacity Reductions)



STATUS UPDATES FOR THE 2014 REFERENCE CASE PLAN

This section provides an overview on the status of TEP's resource planning decisions for its existing coal plants and discusses the planned acquisition of Power Block 3 at the Gila River Power Station. The following provides background on events that have led up to the current status and describes the assumptions that were modeled as part of the 2014 IRP Reference Case plan.

- Status of the Planned Environmental Upgrades for the Four Corners Power Plant
- Status of the Planned Unit Retirements at the San Juan Generating Station
- Status of the Planned Fuel Conversion on Sundt Unit 4
- Status of the Planned Environmental Upgrades for the Navajo Generating Station
- Status of the Planned Ownership Changes on Springerville Unit 1
- Status of the Planned Acquisition on Power Block 3 at the Gila River Power Station

Four Corners Power Plant

Picture 22 - Four Corners Power Plant

Prior to 2014, the Four Corners Plant was configured as a 5-unit coal plant with 2,100 MW of capacity. On December 31, 2013, APS permanently shut down Units 1-3 (560 MW). Today, Units 4-5 remain open with 1,540 MW of capacity shared between five owner participants. The plant is located on the Navajo Indian Reservation west of Farmington, New Mexico, and is operated by APS. The plant utilizes coal from the nearby Navajo mine that is operated by BHP Billiton. TEP owns 110 MW or a 7% interest in units 4 and 5.

Table 50 – Four Corners Participation

Four Corners Participation	Units 4-5	Ownership
Arizona Public Service	970	63%
Public Service of New Mexico	200	13%
Salt River Project	150	10%
Tucson Electric Power	110	7%
El Paso Electric	110	7%
Plant Capacity	1,540	100%

Four Corners – Regional Haze Status

Under the 1999 Regional Haze rule, FCPP must install BART for visibility impairing pollutants. Current controls for SO_2 and particulates will satisfy BART for those pollutants. BART for NO_x will require the installation of additional controls.

In August 2012, EPA issued a final FIP for FCPP, which called for the installation of SCR on all five units within five years as BART for NOx. The FIP also included an alternative to BART, based on a proposal offered by APS, which called for the closure of Units 1-3 (owned by APS) by 2014, and a delay in the installation of SCR on Units 4 and 5 to 2018. Under the FIP, APS was required to notify the EPA by the end of 2013 which option would be implemented at FCPP. In December 2013, APS notified EPA that it would implement the alternative to BART, and that same month, Units 1-3 permanently ceased operation. TEP's estimated share of the capital costs to install SCR technology on Units 4 and 5 is approximately $36 million ($327/kW). TEP's share of incremental annual operating costs for SCR is estimated at $2 million.

Four Corners – Mercury and Air Toxics Standards Status

Based on the EPA's final Mercury and Air Toxics Standards (MATS) rule, mercury emission control equipment may be required at FCGS by 2015. TEP's share of the estimated capital cost of this equipment is less than $1 million. The annual operating cost associated with the mercury emission control equipment is expected to be less than $1 million for TEP.

Four Corners Coal Supply

The Four Corners Plant purchases all of its coal from the Navajo mine, which is a mine mouth facility located adjacent to the plant. Prior December 2013, the mine was owned and operated by BHP Billiton, the parent company of BHP Navajo Coal Company (BNCC) which held long-term leases for the coal reserves with the Navajo Nation. However, as part of the on-going fuel negotiations with the plant participants, BHP announced that the mine would be sold to the Navajo Nation. As part of the ownership transition, BHP Billiton would be retained by BNCC under contract as the mine manager and operator through July 2016.

On December 30, 2013, the ownership of BHP Navajo Coal Company was transferred to Navajo Transitional Energy Company, LLC ("NTEC"), a company formed by the Navajo Nation to own the mine and develop other energy projects. On this same date, the Four Corners co-owners executed a long term fuel agreement for the supply of coal to Four Corners from July 2016, when the current coal supply agreement expires, through 2031.

El Paso Electric Company, a 7% owner in Units 4 and 5 of Four Corners, did not sign the 2016 Coal Supply Agreement. Under the 2016 Coal Supply Agreement, APS has agreed to assume the 7% ownership obligation. APS has also granted NTEC an option to purchase the 7% interest in the plant within a certain timeframe. The 2016 Coal Supply Agreement contains alternate pricing terms for the 7% ownership obligations in the event NTEC does not purchase the 7% interest.

Land Lease Status

Four Corners is located on land held under easements from the United States and also under leases from the Navajo Nation. In March 2011, APS, on behalf of the Four Corners participants, negotiated amendments to an existing facility lease with the Navajo Nation that would extend the leasehold interest in the plant to 2041. The amendments were approved by the Navajo Nation Council and the Nation's President. The Department of the Interior (DOI) must also approve the amendments as well as a related federal rights-of-way grant that the Four Corners participants will pursue. An environmental impact study (EIS) will be conducted as part of the DOI review process.

2014 IRP Four Corners Power Plant Assumptions

For purposes of the 2014 IRP, the Reference Case plan assumes that participants at Four Corners proceed with the alternative BART compliance strategy and install selective catalytic reduction controls on Units 4 and 5 by July 31, 2018. In addition, the Reference Case plan assumes that additional mercury controls are put in place to comply with MATS by 2015.

San Juan Generating Station

Picture 23 – San Juan Generating Station

San Juan Generating Station (SJGS), operated by Public Service Company of New Mexico (PNM), is a four unit coal-fired generating station located in Farmington, New Mexico with approximately 1,680 MW of capacity. There are nine owner participants within the plant. The plant serves customers in California, Colorado, New Mexico, Utah and Arizona. TEP owns 50% interests in each of Units 1 and 2 providing generating capacity of 170 MW each or 340 MW total.

Table 51 – San Juan Plant Participation

						Ownership				
San Juan Participation	Units 1	Units 2	Units 3	Units 4	Station MW	Units 1	Units 2	Units 3	Units 4	Station MW
Public Service of New Mexico	170	170	248	195	783	50%	50%	50%	39%	46%
Tucson Electric Power	170	170			340	50%	50%			20%
MSR Public Power Agency				146	146				29%	9%
Imperial Irrigation District			105		105			21%		6%
Anaheim				51	51				10%	3%
City of Farmington				43	43				9%	3%
Tri-State G & T			41		41			8%		2%
Los Alamos County				36	36				7%	2%
Utah Associated Power				35	35				7%	2%
City of Colton			30		30			6%		2%
Azusa			30		30			6%		2%
Banning			20		20			4%		1%
City of Glendale			20		20			4%		1%
Plant Capacity	340	340	495	506	1,680	100%	100%	100%	100%	100%

San Juan - Regional Haze Status

In August 2011, EPA Region VI issued a Regional Haze Federal Implementation Plan (FIP) establishing new emission limits for NOx, SO_2 and sulfuric acid emissions at the San Juan Generating Station. The FIP requires the installation of Selective Catalytic Reduction (SCR) technology with sorbent injection on all four units within five years to reduce NOx and control sulfuric acid emissions. Based on two cost analyses commissioned by PNM, TEP's share of the cost to install SCR with sorbent injection is estimated to be between $180 million and $200 million.

In February 2013, the State of New Mexico, the EPA, and PNM signed a non-binding agreement that outlines an alternative to the FIP. The proposed plan includes: the retirement of San Juan Units 2 and 3 by December 31, 2017 and the installation of selective non-catalytic reduction (SNCR) technology on San Juan Units 1 and 4 by January 31, 2016. The New Mexico Environmental Department (NMED) prepared a revision to the regional haze SIP incorporating the provisions of the agreement, and in September 2013, the New Mexico Environmental Improvement Board approved the SIP revision. TEP estimates its share of the cost to install SNCR technology on San Juan Unit 1 would be approximately $35 million. TEP's share of incremental annual operating costs for SNCR is estimated at $1 million. The SIP revision now awaits final EPA approval. The EPA is expected to issue a final BART determination by the third quarter of 2014.

In connection with the implementation of the SIP revision and the retirement of San Juan Units 2 and 3, some of the San Juan owner participants have expressed a desire to exit their ownership in the plant. As a result, the participants are attempting to negotiate a restructuring of the ownership in San Juan, as well as addressing the obligations of the exiting participants for plant decommissioning, mine reclamation, environmental matters, and certain ongoing operating costs, among other items. The participants have engaged a mediator to assist in facilitating the resolution of these matters among the owners. The owners of the affected units also may seek approvals of their utility commissions or governing boards.

Any decision regarding early closure and replacement resources will require various actions by a number of third parties as well as federal and state regulatory approvals. In the event that the revised SIP is not approved by the EPA or the negotiations with the plant participants and coal supplier results in TEP pursuing other resource alternatives, TEP will file a supplemental update with the Commission regarding TEP's recommendation for engaging in an alternative resource plan for the San Juan Generating Station.

San Juan Generating Station – Mercury and Air Toxics Standards

San Juan's current emission controls are adequate to comply with the EPA's final MACT standards.

San Juan Coal Supply

The coal requirements for SJGS are supplied by San Juan Coal Company (SJCC), a subsidiary of BHP Billiton (BHP). The coal supply contracts for SJGS expire in 2017. Based on estimated reserve data, there is an adequate supply of coal to continue to operate SJGS for the remainder of the plant's life. Coal contract negotiations with BHP for future coal supply post-2017 continue and final terms have not been determined. It is expected that an extended or new contract will result in higher station fuel prices and these forecast projections are modeled in the Reference Case plan assumptions.

2014 IRP San Juan Generating Station Assumptions

Based the 2014 IRP Reference Case plan, TEP assumes that the EPA will approve the revised SIP and SJGS Units 2 and 3 will retire by the end of 2017. The owners who remain in the project will move forward with the installation of SNCRs on Units 1 and 4 which will occur by the later of January 31, 2016 or 15 months after EPA approval of a revised SIP.

TEP estimates its share of the cost to install SNCR technology on San Juan Unit 1 will be approximately $35 million, a savings of $165 million over the cost for SCR retrofits on Units 1 and 2. In addition, TEP's share of incremental annual operating costs for SNCR is estimated at $1 million rather than the $6 million for SCRs.

TEP owns 340 MW, or 50%, of San Juan Units 1 and 2. If San Juan Unit 2 is retired, TEP's coal-fired generating capacity would be reduced by 170 MW. The loss of the San Juan Unit 2 capacity is covered through the planned acquisition of Power Block 3 at the Gila River Power Station.

Sundt Generating Station

Sundt Generating Station (Sundt) is a four unit generating station located in Tucson, Arizona. Units 1, 2, and 3 are natural gas or oil burning generating units with capacities of 81 MW, 80 MW and 105 MW, respectively. Unit 4 is capable of burning natural gas or coal and landfill gas. Originally designed as a natural gas or oil-burning station, TEP was required to convert Unit 4 to coal by the Department of Energy (DOE) based on the U.S. Power Plant and Industrial Fuel Use Act of 1978 (PPIFUA) . TEP completed the conversion in January 1988. Unit 4 has a nominal capacity rating of 156 MW burning natural gas and a nominal capacity rating of 110 MW burning coal.

Picture 24 - Sundt Generating Station

In February 2011, the Arizona Department of Environmental Quality filed its Arizona State Implementation Plan (SIP) that concluded that Sundt Unit 4 was not BART eligible because the coal conversion project completed in 1988 was undertaken pursuant to the PPIFUA of 1978. However, in July 2013, the EPA rejected the Arizona State Implementation Plan (SIP) determination and concluded that Sundt Unit 4 was subject to the BART provisions of the Regional Haze Rule. EPA's determination found that although Sundt Unit 4 was converted to coal in 1988, it remained BART-eligible because the unit did not undergo a prevention of significant deterioration (PSD) review at the time of the coal conversion. As a result, EPA determined that Sundt Unit 4 was eligible for a BART analysis of the three haze-causing pollutants: NO_X, SO_2 and PM_{10}.

In January 2014, EPA issued a preliminary FIP that determined that Sundt Unit 4 was BART-eligible and subject to BART for sulfur dioxide (SO_2), nitrogen oxides (NO_X) and particulate matter (PM_{10}). For NO_X, EPA has proposed an emission limit of 0.36 lb/MMBtu as BART based upon the use of Selective Non-Catalytic Reduction (SNCR) as a control technology. For SO_2, EPA is proposed an emission limit of 0.23 lb/MMBtu as BART on a 30-day boiler operating day (BOD) rolling basis, which is consistent with dry sorbent injection (DSI) as a control technology. For PM_{10}, EPA is proposing a filterable PM_{10} emission limit of 0.030 lb/MMBtu as BART based on the use of the existing fabric filter baghouses.

Under this proposal TEP would be required to install SNCR for control of NO_X emissions and Dry Sorbent Injection (DSI) for control of SO_2 emissions to comply with the emission requirements above. The capital cost to install SNCR and DSI on Sundt Unit 4 is estimated to be $11.7 million. The incremental operating costs for these new controls are anticipated to be $6 million per year. Both controls would need to be implemented within three years of the effective date of the final rule. As an alternative, EPA proposed a better-than-BART alternative, based on a proposal offered by TEP, which calls for the elimination of coal as a fuel source for Sundt Unit 4 by December 31, 2017. Under this alternative proposal, TEP would be required to notify the EPA of its decision by July 31, 2015. EPA is expected to issue a final rule by June 2014.

2014 IRP Sundt Unit 4 Assumptions

Based on preliminary analysis of the EPA BART proposals and as part of TEP's overall coal diversification strategy, TEP plans to eliminate coal as a fuel source at Sundt and operate the Unit 4 on natural gas. Additional analysis will be conducted by TEP over the next two years to determine if any additional system upgrades will be needed to optimize Sundt Unit 4 for the permanent conversion to natural gas. For purposes of the 2014 IRP, the Reference Case plan assumes that Sundt Unit 4 is dispatched on coal through 2017 and then operated on natural gas for the duration of the IRP study period.

Navajo Generating Station

Picture 25 – Navajo Generating Station

The Navajo Generation Station (NGS) is configured as three separate 750 MW coal-fired generating units for a total of 2,250 MW. The plant is located in northern Arizona on the Navajo Indian Reservation. The plant serves customers in California, Nevada and Arizona. Salt River Project operates the plant and TEP owns a 7.5% interest in Navajo Units 1, 2 and 3. TEP has a total entitlement from the Navajo Plant of 168 MW. The other participants are shown below in Table 52.

Table 52 – Navajo Plant Participation

Navajo Plant Participation	Capacity MW	Ownership %
US Bureau of Reclamation	547	24.3%
Salt River Project	488	21.7%
Los Angeles Dept. Water & Power	477	21.2%
Arizona Public Service Co.	315	14.0%
Nevada Power Co.	254	11.3%
Tucson Electric Power Co.	168	7.5%
Plant Capacity	2,250	100.0%

Navajo Generating Station - Regional Haze Status

Under the 1999 Regional Haze rule, NGS must install BART for visibility impairing pollutants. Current controls for SO_2 will likely satisfy BART for that pollutant. BART for NO_X and particulates may require the installation of additional controls.

The EPA issued a proposed rule in February 2013 establishing BART requirements for NGS. The proposal called for the installation of SCR, for control of NO_X emissions from all three units by 2018. The proposal also included an “alternative to BART” which allows until 2023 for the installation of SCR in consideration of emission reductions achieved through the voluntary installation of controls in 2009 through 2011. In October 2013, EPA issued the supplemental proposal in response to a July 26, 2013, submittal from SRP, the operating agent for NGS, which described an agreement reached between members of a Technical Work Group (“TWG”)[1] formed to explore alternatives to EPA’s BART determination for NGS. The agreement contained a proposed BART alternative that achieves greater reductions in NO_X emissions than EPA’s BART, as well as commitments to reduce CO_2 emissions, to be achieved primarily through the closure of one of the units (or an equivalent curtailment in generation). The EPA is currently accepting public comment on the BART Determination and the alternatives. A final decision is expected sometime in 2014.

Navajo – Mercury and Air Toxics Standards (MATS) Status

Based on the EPA’s final MATS rule, NGS will need mercury emission control equipment by 2015, which may involve the installation of bag houses. TEP’s share of the estimated capital cost of this equipment is less than $1 million for mercury control and about $43 million if the installation of bag houses is necessary. TEP expects its share of the annual operating costs for mercury control and bag houses to be less than $1 million each. The operator of Navajo is currently analyzing the need for bag houses under various regulatory scenarios, which includes the regional haze final Best Available Retrofit Technology (BART) rules

Navajo Land Lease Extension

NGS is located on a site that is leased from the Navajo Nation. In addition to the lease, several rights-of-way are issued by federal agencies for additional facilities (i.e., railroad, transmission, ash disposal area, etc.).

The Navajo Council voted on July 18, 2013 to approve legislation that would extend the lease for Navajo Generating Station through 2044 and provide the Nation's consent to the renewal of the rights-of-way. The lease extension approved by the Council provides significant economic benefits to the Navajo Nation before the existing term of the lease expires in 2019, as well as millions of dollars in increased revenues for the Nation beginning in 2020. Those include contributions for education and community improvements.

The negotiations were initiated well in advance of 2019 in recognition that they would most likely require a significant amount of time and effort, and that the negotiated lease amendments would need to be included in

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[1] *The Technical Work Group consist of representatives from SRP (on behalf of itself and other NGS owners), Central Arizona Water Conservation District, Environmental Defense Fund, Navajo Nation, Gila River Indian Community, U.S. Department of Interior, and Western Resource Advocates*

the review that is required under the National Environmental Policy Act (NEPA) and Endangered Species Act (ESA) compliance processes. The lease ultimately needs to be approved by the Secretary of Interior, which cannot be done until the NEPA and ESA compliance processes are complete.

Navajo Coal Supply

The Navajo Plant's coal requirements are purchased from Peabody Energy from the Kayenta Mine. An electric railroad delivers coal to the plant from a mine on the Navajo and Hopi Indian Reservations at Black Mesa in northern Arizona. Peabody Energy holds long-term leases with the Navajo Nation and the Hopi Tribes. The Navajo Plant is under contract with Peabody through 2019. SRP is currently working with Peabody Energy to renegotiate contract terms post 2019. It is assumed that the extension of the Peabody coal contract will require a NEPA review and approval.

2014 IRP Navajo Generating Station Assumptions

For purposes of the 2014 IRP, the Reference Case plan assumes that participants at NGS proceed with the Alternative 1 BART compliance strategy and install selective catalytic reduction controls on two units by December 31, 2030. TEP estimates its share of the capital cost will be $42 million ($250/kW). The Reference Case plan also assumes that mercury controls and baghouses are installed to comply with both the MATS and Regional Haze regulations. TEP estimates that its share of the capital expenditure for mercury controls and baghouses would be about $44 million ($262/kW). TEP's share of annual operating costs for SCR controls, mercury controls and baghouses is estimated at less than $2 million per year. In the event that the alternative strategies are not approved by the EPA or the NGS participants pursue a different strategy, TEP will file a supplemental update with the Commission regarding TEP's recommendation for engaging in an alternative resource plan for the Navajo Generating Station.

Springerville Unit 1

Picture 26 – Springerville Generating Station

Springerville Generating Station

TEP currently leases 86% of Unit 1 of the Springerville Generating Station and holds an undivided one-half interest in certain Springerville Common Facilities under seven separate lease agreements that are accounted for as capital leases. The leases expire in January 2015 and include fair market value renewal and purchase options. TEP owns a 14.1% undivided ownership interest in Springerville Unit 1, representing approximately 55 megawatts (MW) of capacity.

Unit 2 of the Springerville Generating Station is owned by San Carlos Resources, Inc., a wholly-owned subsidiary of TEP. TEP's other interests in the Springerville Generating Station include leasehold interests in the Springerville Coal Handling Facilities and in a one-half interest in certain other facilities at Springerville used in common by all four Springerville units (Springerville Common Facilities).

During 2013, TEP agreed to purchase leased interests of 35.4% or 135 MW of Springerville Unit 1, for an aggregate purchase price of approximately $65 million. TEP expects to complete the purchases in December 2014 and in January 2015.

Springerville – Regional Haze Status

The BART provisions of the Regional Haze Rule do not apply to Springerville Units 1 and 2 since they were constructed in the 1980s which is after the timeframe as designated by the rules. Other provisions of the Regional Haze Rule requiring SGS to comply with future emission reductions are not likely to impact Springerville operations until after 2018.

Springerville – Mercury and Air Toxics Standards (MATS) Status

Based on the EPA's final standards, Springerville Generating Station may require mercury emission control equipment by 2015. The estimated capital cost of this equipment for Springerville Units 1 and 2 is about $5 million. TEP expects the annual operating cost of the mercury emission control equipment to be about $3 million. TEP will own 49.5% of Springerville Unit 1 upon close of the lease option purchases by early 2015; after the completion of such purchases, 50.5% of environmental costs attributed to Springerville Unit 1 will be reimbursed by the third party owners.

Springerville Coal Supply

Springerville currently purchases it coal supply from Peabody Energy's El Segundo Lee Ranch mine in New Mexico under a long-term contract. Currently, Springerville has the lowest coal supply costs within the TEP coal portfolio on a dollar per MMBtu basis. Springerville is located approximately 60 miles south of the Burlington Northern & Santa Fe Railroad Company (BNSF) main line on a private spur. This rail access gives Springerville the option to purchase from multiple suppliers and is not captive to a sole source supplier. Based on its air permit constraints, the coal sources that can feasibly supply fuel to Springerville are the mines in the Powder River Basin Region or the El Segundo, Lee Ranch mines in New Mexico. This ability to purchase coal from multiple sources will enable Springerville to acquire competitively priced coal over the remaining life of the plant.

2014 IRP Springerville Generating Station Assumptions

For purposes of the 2014 IRP, the Reference Case plan assumes TEP purchases 135 MW of Springerville Unit 1 for $65 million. As a result of this purchase, TEP will own 49.5% of Springerville Unit 1 for a total of 190 MW. The Reference Case plan also assumes that mercury controls are installed to comply with the MATS by 2015. TEP estimates that its share of the capital expenditure for mercury controls for its interests in units 1 and 2 will be about $4 million. TEP's share of annual operating costs for mercury controls is estimated at $2.5 million per year.

Gila River Power Station

Picture 27 – Gila River Power Station

In the 2012 Resource Plan, TEP made a commitment to actively monitor the wholesale merchant market for potential resource alternatives as part of its on-going decisions relative to its existing coal fleet. In May 2013, TEP conducted a Request for Proposal (RFP) soliciting the wholesale merchant market for 500 MW of firm resource capacity to replace the proposed capacity reductions that were being considered at the Springerville and San Juan Generating Stations. As a result, TEP received fourteen different proposals from nine different bidders. Based on TEP's bid analysis, the Entegra Power Group LLC (Entegra) was chosen as the final bidder due the economic and operational advantages of their proposal.

In December 2013, TEP and UNS Electric entered into a purchase agreement with a subsidiary of Entegra Power Group LLC (Entegra) to purchase Power Block 3 of the Gila River Generating Station (Gila River Unit 3). Gila River Unit 3 is a gas-fired combined cycle unit with a capacity rating of 550 MW, located in Gila Bend, Arizona. The purchase price is set at $219 million ($398/kW) subject to adjustments to prorate certain fees and expenses through the closing and in respect of certain operational matters.

It is anticipated that TEP will purchase a 75% undivided interest in Gila River Unit 3 for approximately $164 million and UNS Electric will purchase the remaining 25% undivided interest for approximately $55 million, although TEP and UNS Electric may modify the percentage ownership allocation between them. TEP and UNS Electric expect the transaction to close in December 2014.

2014 IRP Case Analysis

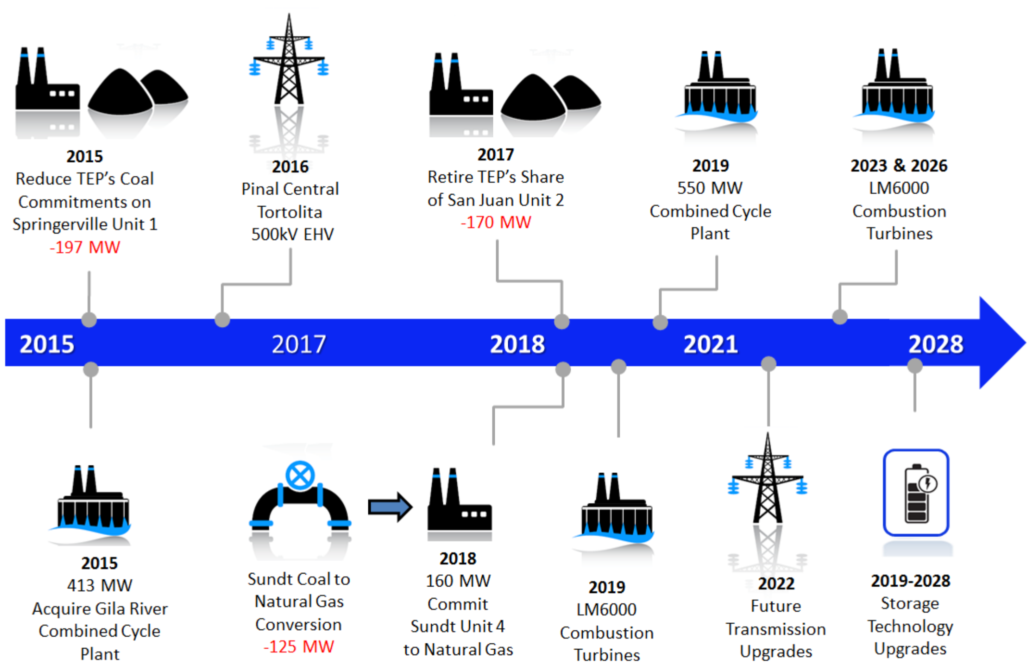
The following section provides a detailed analysis on the 2014 IRP cases analyzed for this report. The 2014 IRP presents the five cases below with an in depth analysis to support the recommend 2014 IRP Reference Case plan.

- Reference Case
- Coal Retirement Case
- Market Based Reference Case
- Coal Plant Retrofit Case
- High Renewable Case

Overview of the 2014 IRP Reference Case Plan

Figure 53 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 380 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 SIP and SNCR control technology is installed on San Juan Unit 1 and Unit 2 retires by the end of 2017. Finally, Sundt Unit 4 is committed to permanently eliminate coal as a fuel source at Sundt and operate on natural gas starting in 2018. As a result of this conversion, TEP will gain approximately 40 MW in additional capacity on Unit 4 from this conversion. 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 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 capacity, approximately 550 MW is assumed to be combined cycle technology while the remaining 270 MW is assumed to be local area combustion turbines.

Figure 53 – 2014 IRP Reference Case Plan Resource Timeline



In addition, the 2014 IRP Reference Case plan assumes that two new transmission upgrades will be required over the 15-year timeframe. The Pinal Central - Tortolita 500 kV transmission upgrade is planned for 2016 and will tie in the existing SRP Southeast Valley transmission project from Pinal Central into Tortolita. This upgrade will provide additional import capacity from wholesale merchant plants located near Palo Verde and increase TEP's load serving capabilities out through 2022. By 2022, it is expected that additional system upgrades will be required based on current load forecast projections. For purposes of the 2014 IRP Reference Case plan, a conceptual 345kV EHV project was assumed for modeling purposes. However, the exact project or required system upgrades are expected to be determining through the next series of Biennial Transmission Assessments that are coordinated with regional transmission providers and filed with the Arizona Corporation Commission. TEP will update these conceptual project descriptions in future IRP filings as they are determined. Finally, the 2014 IRP Reference Case plan recognizes the need for future storage technologies to support the integration of intermittent resources. For purposes of this filing, TEP assumes that approximately 50 MW of battery storage technology will be required by 2028 to support future ancillary service requirements for the grid.

Overview of the Full Coal Retirement Case

As a result of recommendations from the 2012 IRP planning process, the Commission required that TEP consider a full coal retirement scenario for the 2014 IRP. As a result of that order, TEP developed the Full Coal Retirement Case for consideration in the 2014 IRP. This Full Coal Retirement Case is based on potential alternative outcomes that potentially could develop as result of actions by the EPA or plant participants at the Four Corners, Navajo, San Juan and Springerville Generating Stations.

The Full Coal Retirement Case assumes for purposes of the 2014 IRP that TEP will replace approximately 1,500 MW of its existing coal capacity with natural gas combined cycle resources by the end of the 15-year planning period. Figure 54 shows the capacity and timing for each coal plant reduction. Figure 55 on the next page shows the corresponding timing of the natural gas combined cycle replacement capacity.

Figure 54 – Coal Retirement Case Resource Timeline for Existing Resources

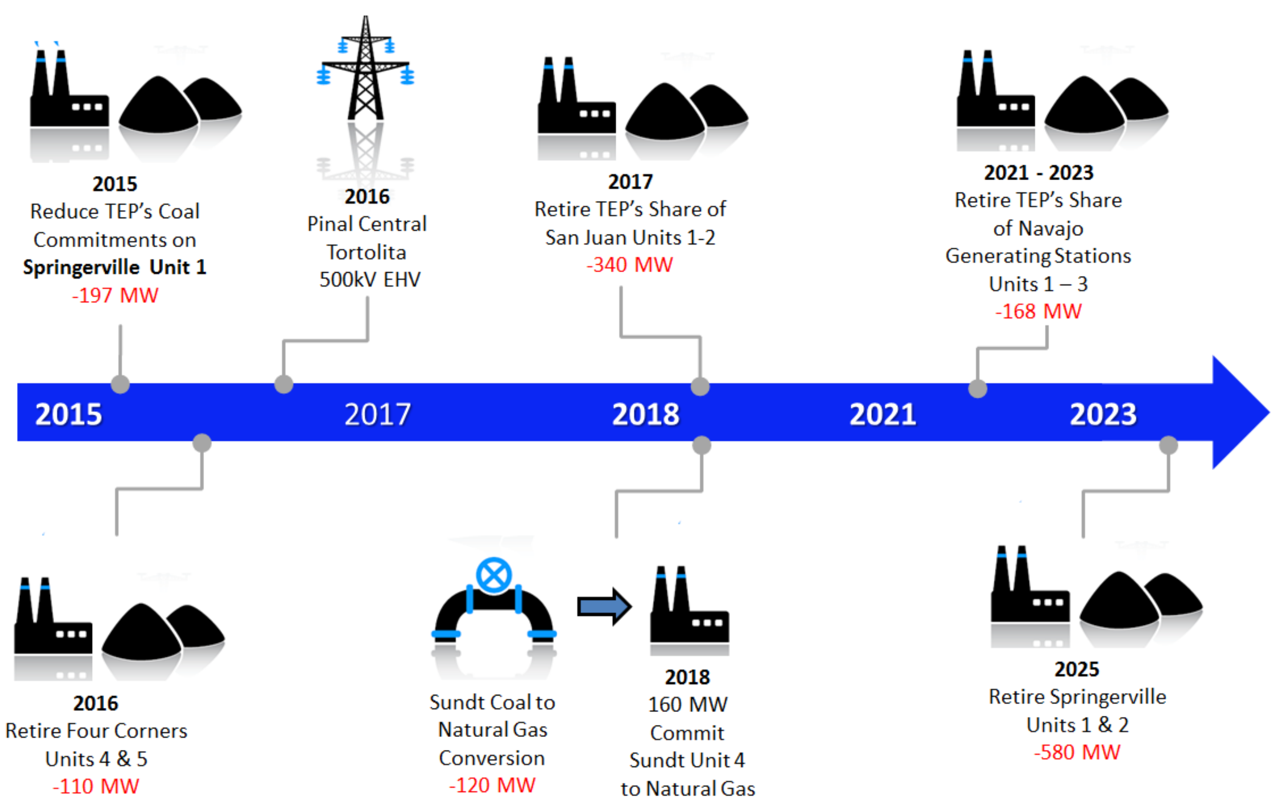
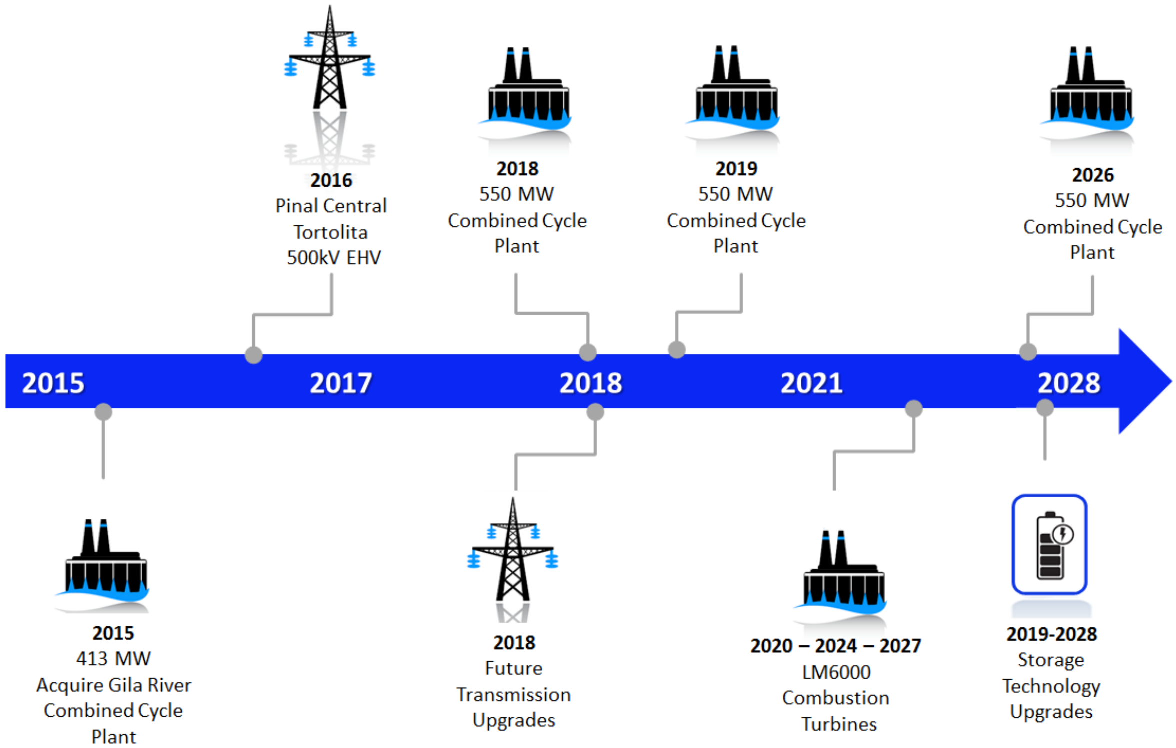


Figure 55 – Coal Retirement Case Resource Timeline for New Resources



Relative to the 2014 IRP Reference Case plan, the Full Coal Retirement case assumes that the planned Pinal Central to Tortolita 500kV upgrade is completed as scheduled in 2016. However, due to the assumed coal capacity reductions that occur at the Four Corners Power Plant in 2016 and San Juan Generating Station in 2018, TEP will have to advance upgrades on it transmission system prior to 2018 to be able to satisfy its load serving requirements. As a result of these plant retirements and the resulting transmission import limitations, TEP would have to site approximately 1,100 MW to 1,600 MW of new combined cycle generation resources either on the east side of its existing transmission system or within the Tucson metropolitan area. Finally, the Full Coal Retirement Case assumes that 270 MW of natural gas combustion turbines and 50 MW of battery storage technology are installed locally based on the same assumptions found within the 2014 IRP Reference Case plan.

Overview of the Market Based Reference Case Plan

For purposes of the 2014 IRP, TEP developed the Market Based Reference Case plan. Under this scenario, it is assumed that TEP relies on the wholesale market for limited amounts of firm wholesale purchase power agreements (PPA) to meet its future summer peaking requirements. This scenario provides some insights into how TEP's resource portfolio might look if there is adequate supply of merchant resource capacity within the Desert Southwest region over the long-term. For purposes of this scenario, it is assumed that TEP develops a portfolio of long and short-term purchase power agreements to cover its summer peaking requirements. It is assumed that TEP limits its reliance on firm market capacity purchases to 400MW per year. All other assumptions including transmission and storage technology upgrades are the same as the Reference Case plan.

Figure 56 – Market Based Reference Case Plan Timeline

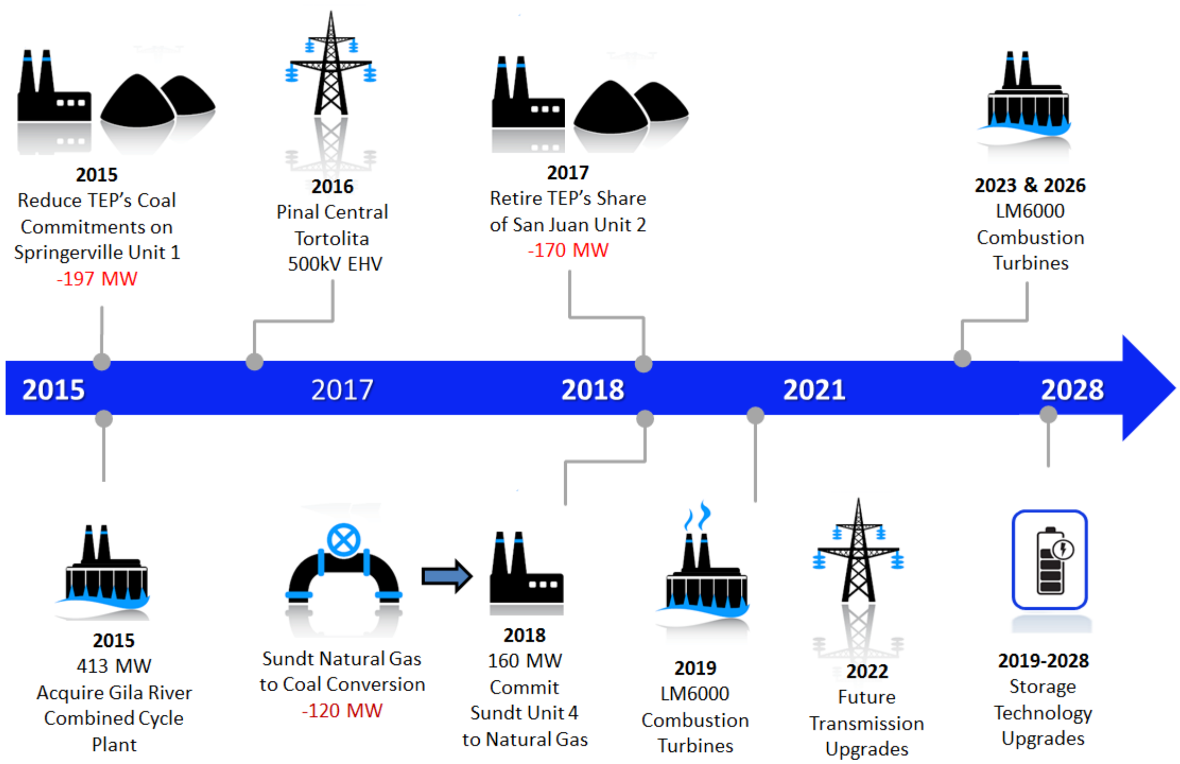


Table 53 – Market Capacity Requirements under the Market Based Reference Case Plan

Firm Capacity PPAs	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Firm Capacity Purchases, MW	375	200	125	175	175	275	300	350	375	300	325	350	325	375	400

Overview of the Coal Plant Retrofit Case

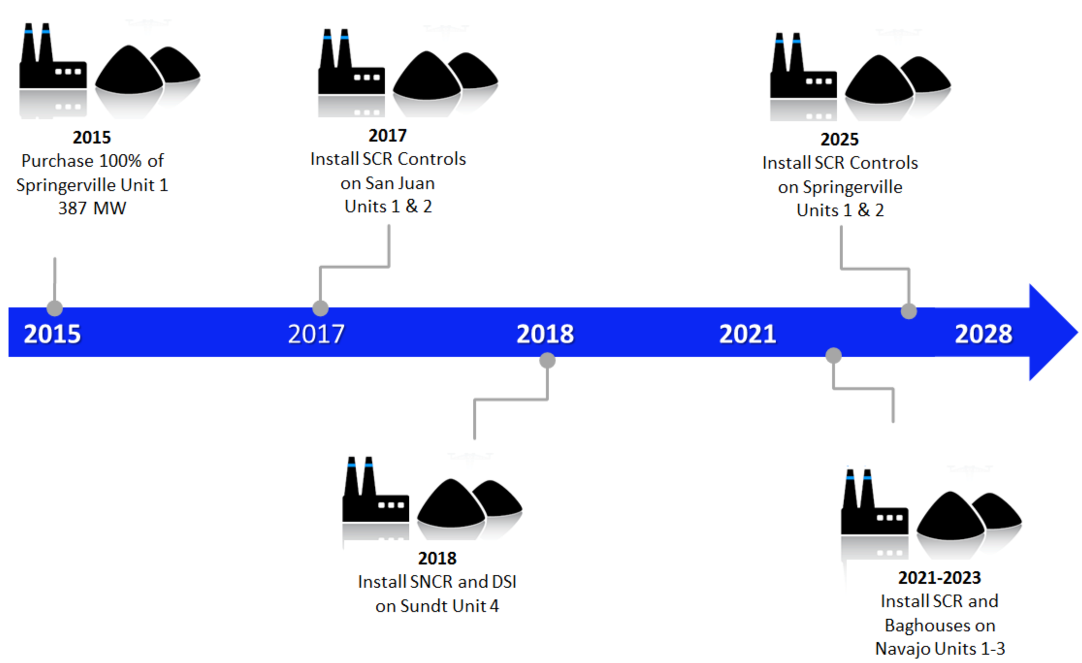
For purposes of the 2014 IRP, TEP developed the Coal Plant Retrofit Case. Under this case, it is assumed that the outcomes at TEP's coal fired generation facilities would have resulted in TEP having to comply with the EPA's preliminary Regional Haze proposals. As shown in Table 54, under these assumptions the following retrofits would have been installed at the following stations by the following years:

Table 54 – Coal Plant Retrofits

Station	Environmental Upgrades	Year in Service
Four Corners	SCR Controls	2016
San Juan	SCR Controls	2017
Navajo	SCR Controls and Baghouses	2021-2023
Sundt Unit 4	SNCR & DSI	2018
Springerville Units 1 & 2	SCR Controls	2026

For purposes of this case, TEP assumes that the EPA eventually mandates the installation of SCR control technology for Springerville Units 1 & 2 by 2026. The results of the Coal Plant Retrofit case provides some insights on how TEP's portfolio diversification strategy will achieve lower long-term resource costs while reducing risks associated with investment in coal fired generation resources.

Figure 57 – Coal Plant Retrofit Case Timeline



Overview of the High Renewable Case

For purposes of the 2014 IRP, TEP developed the High Renewable Case as a potential scenario. Under this scenario it is assumed that TEP develops a utility scale renewable portfolio that results in TEP serving 25% of its retail load by 2025 with renewable resources. Figure 58 and Figure 59 below show the comparison between the two utility scale renewable cases.

Figure 58 – 15% by 2025 REST Standard

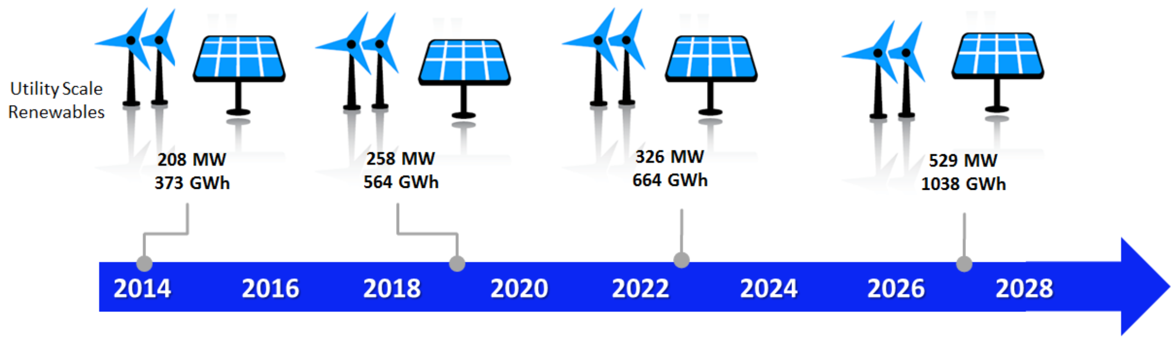
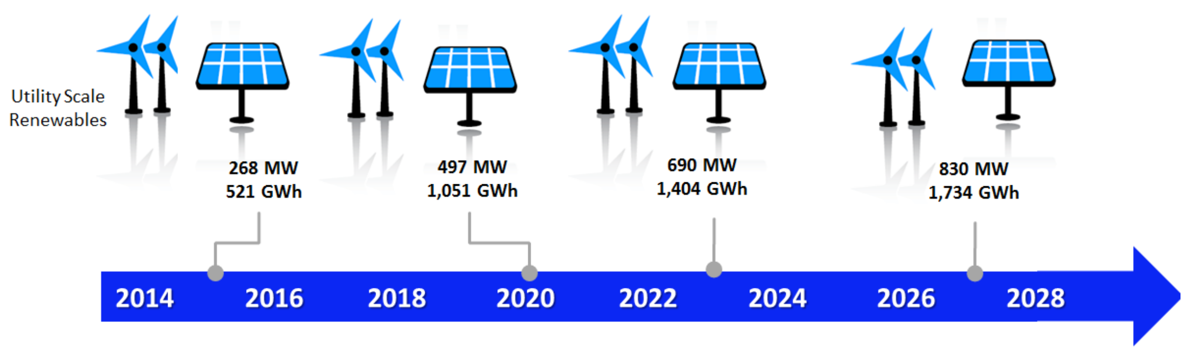


Figure 59 – 25% by 2025 – High Renewable Case



Overview of Major IRP Assumptions by Case

Figure 60 below summaries the major assumptions and environmental upgrades that are included in each case.

Figure 60 – Major IRP Assumptions by Case

Major Assumptions	Reference Case	Market Based Reference	Full Coal Retirement Case	High Renewable Case	Coal Plant Retrofit Case
Energy Efficiency Standard	Fully Compliant with Arizona Energy Efficiency Standard (22% by 2020)	Same as Reference Case	Same as Reference Case	Same as Reference Case	Same as Reference Case
Renewable Energy Standard	Fully Compliant with Arizona Renewable Energy Standard (15% by 2025)	Same as Reference Case	Same as Reference Case	Targets 25% by 2025 Difference from REST Target is Made Up with Utility Scale Resources	Same as Reference Case
Storage Resources	Approximately 50 MW In-Service by 2028	Same as Reference Case	Same as Reference Case	Approximately 80 MW In-Service by 2028	Same as Reference Case
Wholesale Market Firm Capacity	Rely on Wholesale Market for Firm Capacity through 2019	Rely on Wholesale Market for Firm Capacity through 2028 (Limited to 400 MW per Year)	Same as Reference Case	Same as Reference Case	Same as Reference Case

Environmental Upgrades	Reference Case	Market Based Reference	Full Coal Retirement Case	High Renewable Case	Coal Plant Retrofit Case
Four Corners	SCRs by 2018	SCRs by 2018	None	SCRs by 2018	SCRs by 2016
Navajo	SCRs by 2030	SCRs by 2030	None	SCRs by 2030	SCRs by 2023
San Juan	SNCR on Unit 1	SNCR on Unit 1	None	SNCR on Unit 1	SCRs by 2018
Springerville	None	None	None	None	SCRs by 2026
Sundt Unit 4	Gas Conversion	Gas Conversion	Gas Conversion	Gas Conversion	SNCR & DSI by 2018

Environmental CapEx & O&M	Reference Case	Market Based Reference	Full Coal Retirement Case	High Renewable Case	Coal Plant Retrofit Case
CapEx 2014-2019	$76	$76	5	$76	$349
CapEx 2020-2028	$42	$42	-	$42	92
Total CapEx	$118	$118	$5	$118	$441

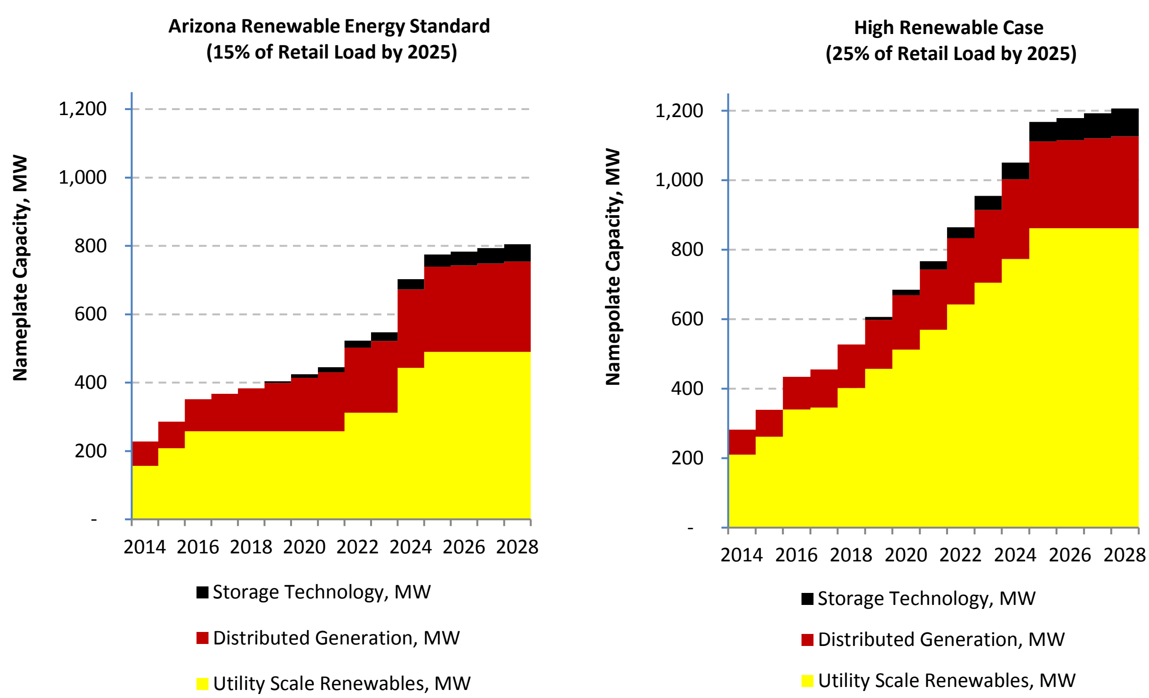
Incremental Annual O&M	$13	$13	$5	$13	$14

Overview of Renewable Energy Assumptions by Case

For purposes of the 2014 IRP, all of the scenarios modeled in the 2014 IRP assume that TEP is compliant with the Arizona REST standard. The REST standard requires TEP to utilize renewable energy resources to serve 15% of its retail load by 2025. However, for purposes of modeling TEP developed the High Renewable Case as a potential scenario. Under this scenario it is assumed that TEP utilizes 25% of renewable energy resources to serve its retail load by 2025.

Chart 80 shows the comparison between the compliant Renewable Energy Standard that results in a renewable resource portfolio with 755 MW of renewable nameplate capacity and 50 MW storage technologies by 2028 versus the High Renewable Case that that results in a renewable resource portfolio with 1127 MW of renewable nameplate capacity and 80 MW of storage technologies by 2028.

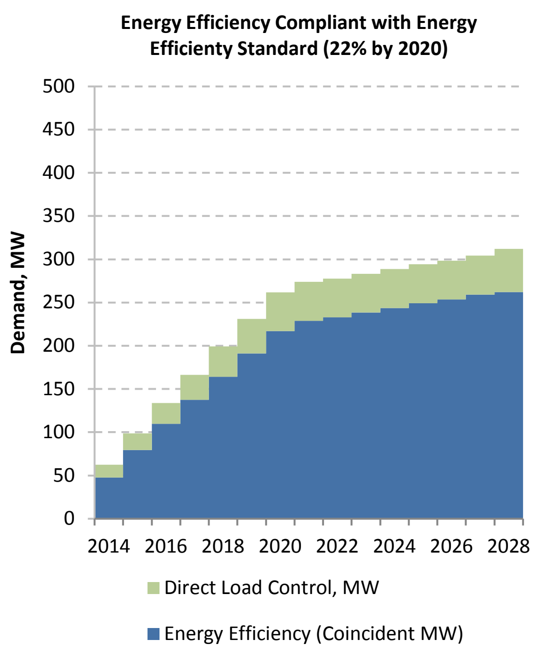
Chart 80 – Renewable Energy Scenario Charts

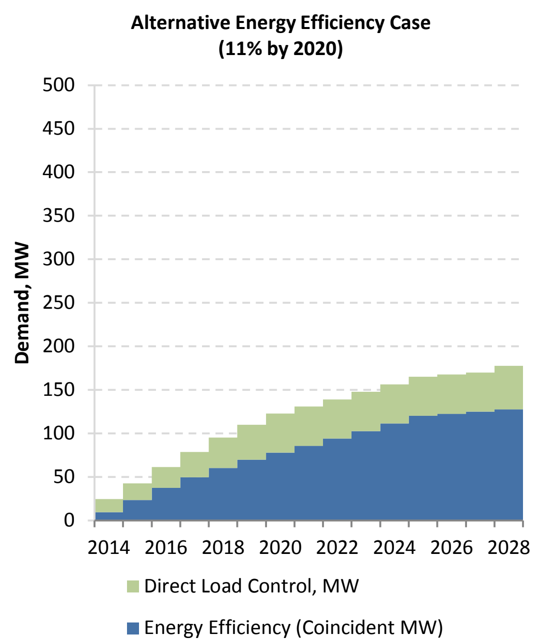


Overview of Energy Efficiency Assumptions in the 2014 IRP

For purposes of the 2014 IRP, all of the scenarios modeled in the 2014 IRP assume that TEP is compliant with the Arizona Energy Efficiency standard that achieves a cumulative 22% reduction in its retail load by 2020. However, for purposes of modeling potential future load sensitivities, TEP developed an Alternative Energy Efficiency Case that contemplates reduced levels of achieved Energy Efficiency as a result of changes in public policy or due to lower than expected customer participation. For purposes of modeling, the Alternative Energy Efficiency Case achieves approximately 1/2 of the current state standard (11% by 2020). Chart 81 shows the comparison between the compliant Energy Efficiency scenarios that achieves a 262 MW reduction in demand by 2020 versus the Alternative Energy Efficiency scenario that only realizes a 137 MW reduction in demand.

Chart 81 – Energy Efficiency Scenario Charts





Overview of New Resource Additions by Case

Figure 61 below summaries the new resource upgrades that are included in each case.

Figure 61 – New Resource Additions by Case

Reference Case	In-Service
Gila River Acquisition (413 MW)	2015
Springerville Purchase (135 MW)	2015
Pinal Central to Tortolita	2016
Transmission System Upgrade	2019
100% Combined Cycle Unit (550 MW)	2019
2 LM6000 CTs (90 MW)	2019
2 LM6000 CTs (90 MW)	2023
2 LM6000 CTs (90 MW)	2026
Battery Storage 5 MW per Year	2019-2028

Market Based Reference Case	In-Service
Gila River Acquisition (413 MW)	2015
Springerville Purchase (135 MW)	2015
Pinal Central to Tortolita	2016
Transmission System Upgrade	2019
2 LM6000 CTs (90 MW)	2019
2 LM6000 CTs (90 MW)	2023
2 LM6000 CTs (90 MW)	2026
Battery Storage 5 MW per Year	2019-2028

Full Coal Retirement Case	In-Service
Gila River Acquisition (413 MW)	2015
Springerville Purchase (135 MW)	2015
Pinal Central to Tortolita	2016
Transmission System Upgrade	2018
100% Combined Cycle Unit (550 MW)	2018
100% Combined Cycle Unit (550 MW)	2019
2 LM6000 CTs (90 MW)	2020
2 LM6000 CTs (90 MW)	2024
100% Combined Cycle Unit (550 MW)	2026
2 LM6000 CTs (90 MW)	2027
Battery Storage 5 MW per Year	2019-2028

High Renewable Case	In-Service
Gila River Acquisition (413 MW)	2015
Springerville Purchase (135 MW)	2015
Pinal Central to Tortolita	2016
Transmission System Upgrade	2019
100% Combined Cycle Unit (550 MW)	2019
3 LM6000 CTs (135 MW)	2019
2 LM6000 CTs (90 MW)	2023
2 LM6000 CTs (90 MW)	2026
Battery Storage 8 MW per Year	2019-2028

Coal Retrofit Case	In-Service
Springerville Purchase (387 MW)	2015
Pinal Central to Tortolita	2016
Transmission System Upgrade	2019
100% Combined Cycle Unit (550 MW)	2019
2 LM6000 CTs (90 MW)	2019
2 LM6000 CTs (90 MW)	2023
2 LM6000 CTs (90 MW)	2026
Battery Storage 5 MW per Year	2019-2028

Summary of NPV Revenue Requirements by Case

Figure 62 below summaries the Net Present Value (NPV) revenue requirement in detail for each case.

Figure 62 – NPV Revenue Requirements by Case

Non Fuel Revenue Requirements, $000	Reference	Market Based Reference	High Renewable	Full Coal Retirement	Coal Plant Retrofits
Existing T&D Resources	$3,630,009	$3,630,009	$3,630,009	$3,630,009	$3,630,009
Existing Generation Resources	$3,136,139	$3,136,139	$3,136,139	$2,831,771	$3,548,609
New Generation Resources	$765,489	$143,774	$804,178	$1,611,756	$765,489
Storage Resources	$19,270	$19,270	$30,831	$19,270	$19,270
New Transmission Resources	$196,076	$196,076	$261,088	$287,403	$196,076
Total Non-Fuel Revenue Requirements	$7,746,983	$7,125,267	$7,862,246	$8,380,209	$8,159,452

Fuel & Purchase Power, $000	Reference	Market Based Reference	High Renewable	Full Coal Retirement	Coal Plant Retrofits
PPFAC Cost, Fuel & Purchase Power	$3,233,216	$3,352,433	$2,999,684	$3,628,216	$2,991,438
PPFAC Cost, Renewable (Above MCCCG)	$264,742	$264,742	$270,470	$264,742	$264,742
Total Gas Transportation	$150,283	$92,600	$154,837	$222,260	$87,269
PPFAC Cost, Demand Charges	$12,936	$86,841	$12,936	$12,936	$15,869
Total PPFAC Costs	$3,661,177	$3,796,616	$3,437,926	$4,128,154	$3,359,319

Environmental Compliance	$488,929	$462,570	$486,029	$279,800	$592,241
PPFAC Cost including Environmental Compliance	$4,150,106	$4,259,187	$3,923,955	$4,407,954	$3,951,560

Energy Efficiency nad Renewables, $000	Reference	Market Based Reference	High Renewable	Full Coal Retirement	Coal Plant Retrofits
Energy Efficiency	$213,307	$213,307	$213,307	$213,307	$213,307
Demand Response	$37,689	$37,689	$37,689	$37,689	$37,689
Total Energy Efficiency	$250,995	$250,995	$250,995	$250,995	$250,995

Utility Scale Renewables	$518,752	$518,752	$1,135,457	$518,752	$518,752
Distributed Generation	$68,793	$68,793	$68,793	$68,793	$68,793
Total Renewables	$587,545	$587,545	$1,204,250	$587,545	$587,545

Total Energy Efficiency and Renewables	$838,540	$838,540	$1,455,245	$838,540	$838,540

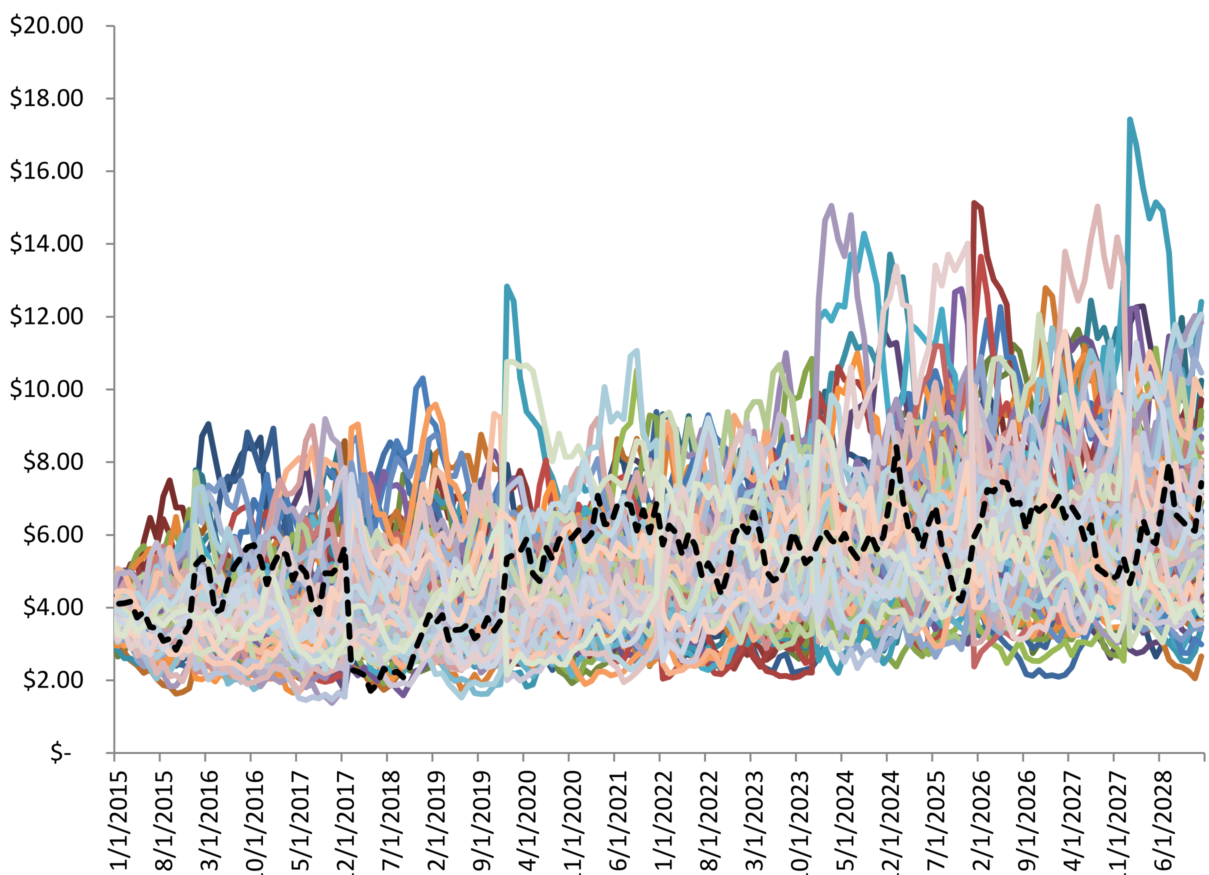
Total System Revenue Requirements	$12,735,629	$12,222,994	$13,241,446	$13,626,703	$12,949,553

NPV Delta from Reference Case		**-$512,635**	**$505,817**	**$891,075**	**$213,924**

RISK ANALYSIS RESULTS

For the 2014 IRP, TEP developed risk analytics for each candidate portfolio using computer simulation analysis. Specifically, a set of 100 iterations, each representing a possible future set of correlated inputs for natural gas prices, wholesale power prices, and retail loads were developed using a stochastic model. Each potential resource portfolio was then evaluated against the same 100 iterations. Risk profiles for each portfolio were then developed. This analysis ensures that the selected preferred portfolio not only results in the lowest expected cost, but is also robust enough to perform well against a wide range of possible load and market conditions. Chart 82 below provides a graphical illustration on how each gas price iteration is generated within a given simulation. The black dashed line illustrates one example of a gas price simulation over the 15-year study. A detailed discussion of this simulation methodology is presented in Chapter 15.

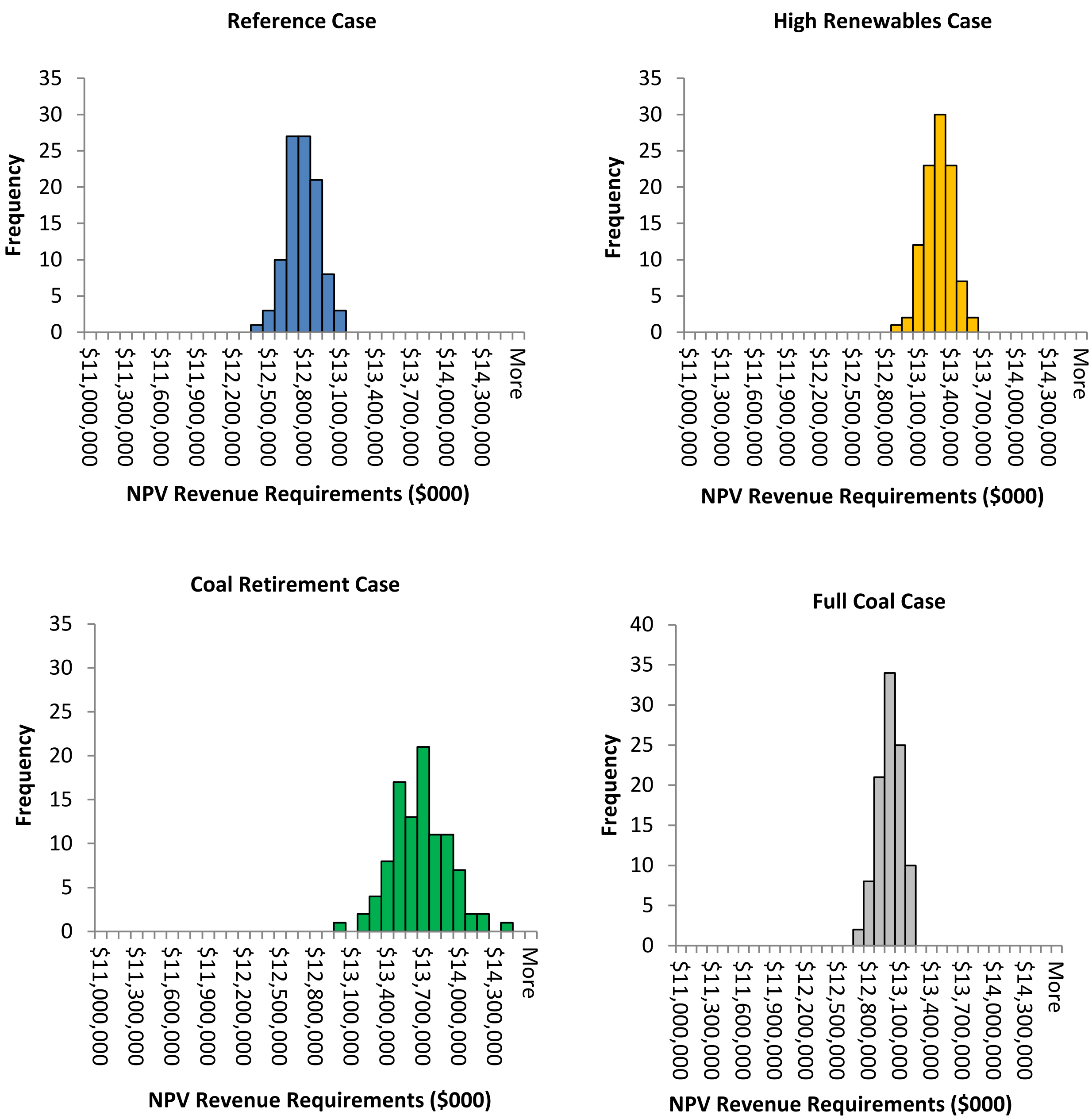
Chart 82 – Permian Gas Prices Iterations



DISTRIBUTION OF NPV REVENUE REQUIREMENTS BY CASE

The degree to which each portfolio is able to adequately serve customer load at a reasonable price can be gauged by examining the distribution of its Net Present Value Revenue Requirements (NPVRR) outcomes for each portfolio across all iterations. The performance of each portfolio is summarized in the following charts. Chart 83 shows each histogram comparing the frequency of outcomes for each of the candidate portfolios. All histograms are represented on the same scale. Portfolios showing a large number of outcomes (higher bars) on the right side of the graph represent high cost/risk options relative to the others resource plans.

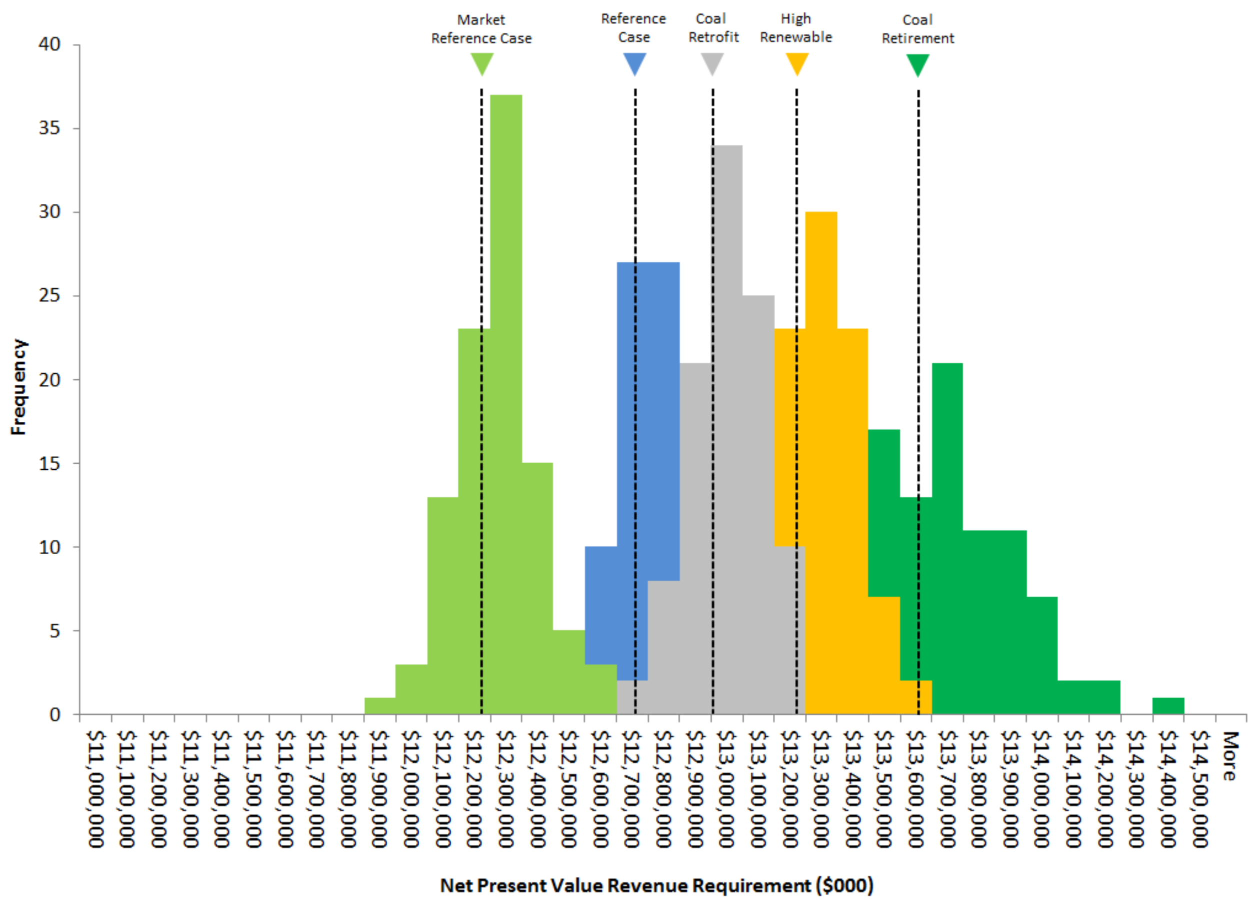
Chart 83 – Distribution of NPVRR by Case



DISTRIBUTION OF NPV REVENUE REQUIREMENTS BY CASE

Chart 84 below shows distribution of Net Present Value Revenue Requirements (NPVRR) on the same chart.

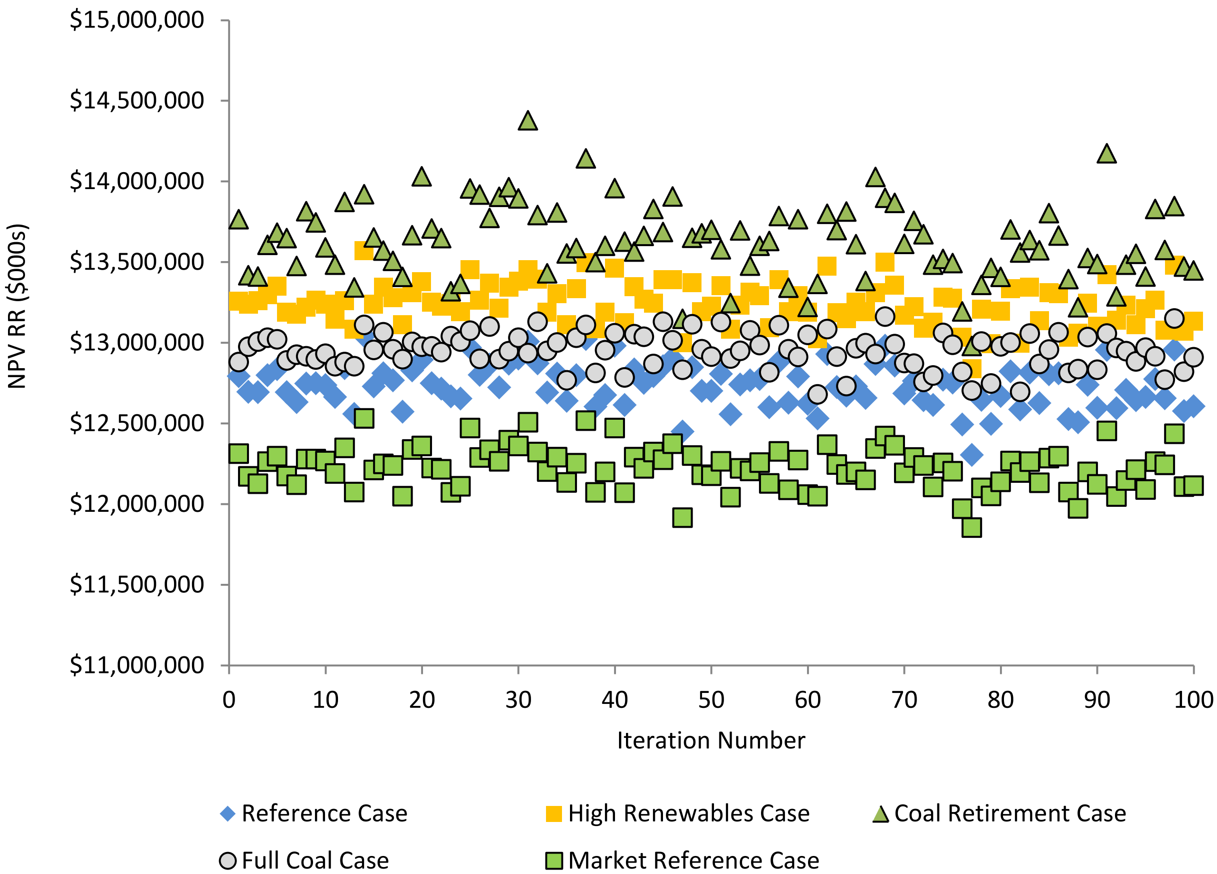
Chart 84 – Aggregated NPVRR by Case



NPVRR SUMMARY OF CASES BY ITERATION

Chart 85 shows a scatterplot summarizing the results of the individual iterations for each candidate portfolio. Portfolios showing a large number of values (points) higher on the chart represent higher cost/risk options relative to the others.

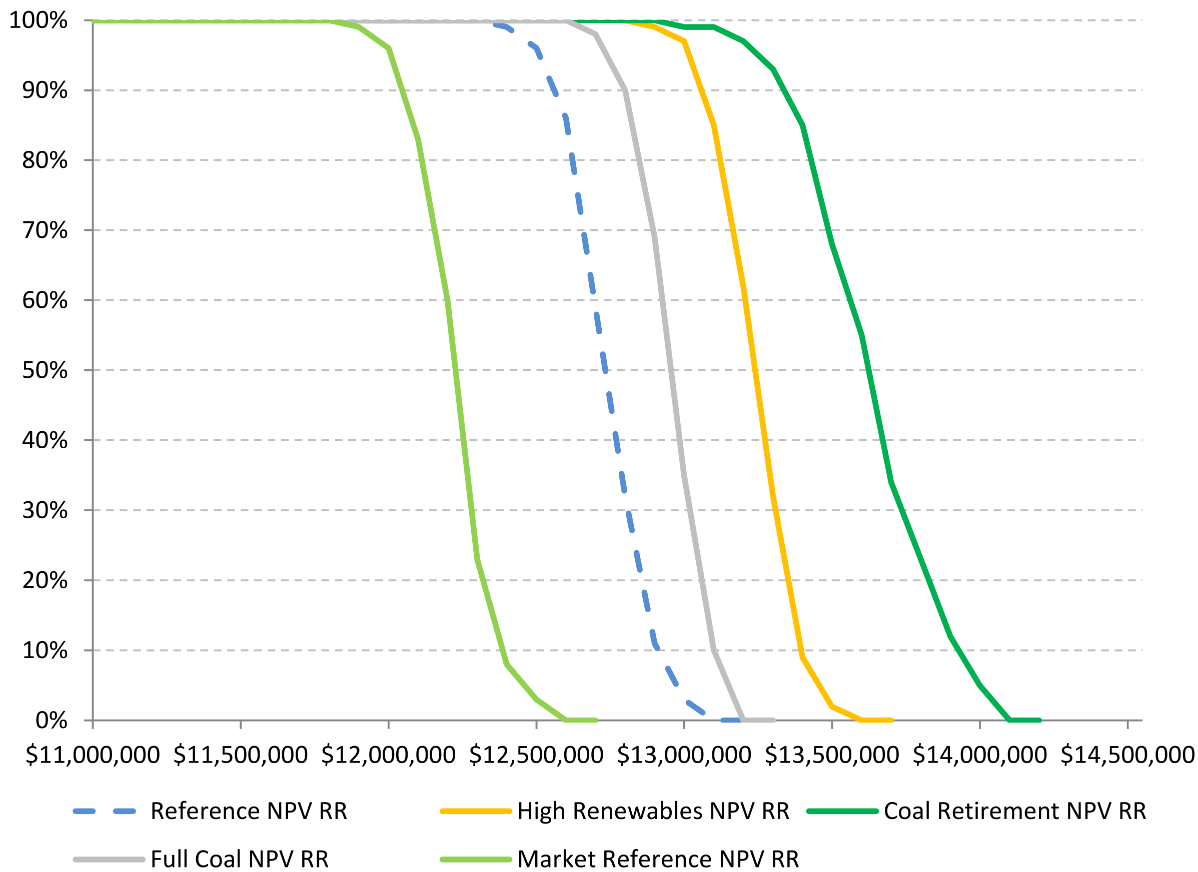
Chart 85 – NPVRR Summary of Cases by Iteration



EXCEEDENCE PROBABILITY BY CASE

Chart 86 shows a summary of exceedence probability for each portfolio. Each point on each curve represents the percentage of outcomes that had NPVRR exceeding the value on the horizontal axis. Portfolios with curves that are farther to the right represent higher cost/risk options relative to the others.

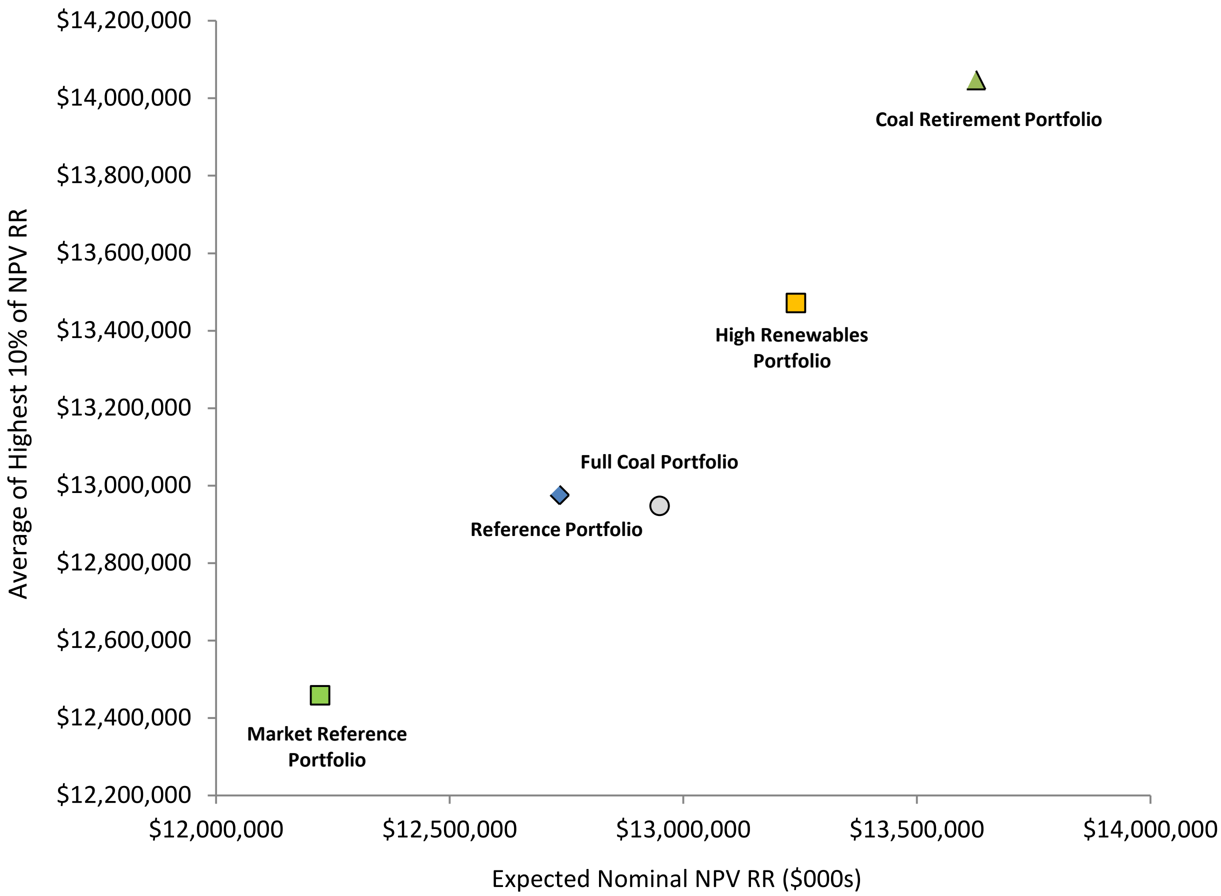
Chart 86 – Exceedence Probability by Case



NPVRR MEAN AND WORST CASE RISK

Finally, Chart 87 shows a summary of each portfolio with respect to both expected average NPVRR and the "worst case" risk associated with each portfolio as represented by the average of the highest 10% of its NPVRR outcomes. Values lower on the graph and farther to the left, represent lower risk and lower cost options respectively.

Chart 87 – Summary of NPVRR Mean and Risk



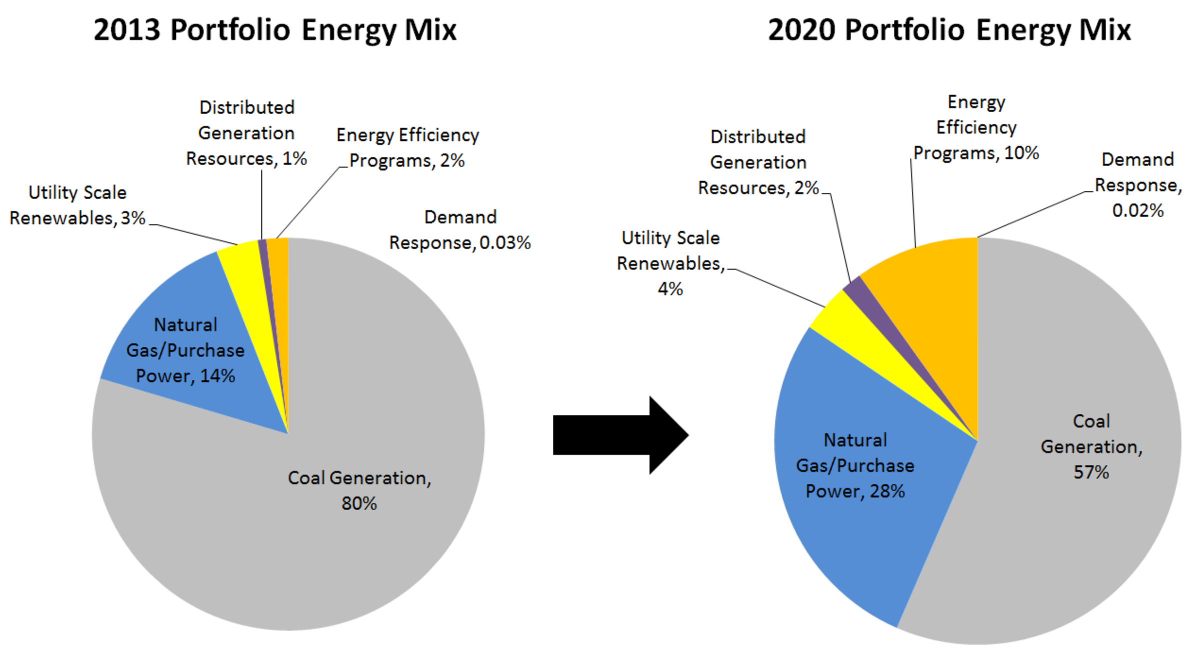
RISK ANALYSIS CONCLUSIONS

As illustrated in all of the charts shown above, the Reference Case plan demonstrates its robustness to market price and load shocks relative to the High Renewable, Full Coal Retirement, and Coal Retrofit portfolios. Relative to future market and load uncertainty, the Reference Case plan represents both a lower cost and lower risk option than the other portfolios. With respect to the market and load variables, the theoretical Full Coal portfolio had similar risk characteristics to the Reference Case plan, with higher expected cost. The Market Reference case plan, which assumes that market resources are available after 2019, had the best performance with respect to cost and risk. This indicates that if market resources are available, there is significant value to TEP in their utilization relative to building sufficient assets to serve 100% of the peak load in 2019 and beyond.

CONCLUSIONS

The 2014 Reference Case plan results in significant reductions in both air emissions and cost impacts on TEP's customers. Over the last five years, TEP, along with other regional utilities have worked with the EPA to develop a number of cost saving "Better than BART" proposals for Regional Haze at it existing coal-fired generating stations. In addition, TEP's planned acquisition of a low cost gas-fired combined cycle power plant at Gila River Power Station will enable TEP to save approximately $140 M in capital expenditures related to coal retrofits and replacement generation capacity. In addition to this cost savings, TEP's portfolio diversification strategy results in significant reductions in air emission as TEP reduces approximately 32% (492 MW) of its existing coal capacity over the next five years. On an energy basis it is expected that TEP will reduce its coal exposure from 80% today to 57% by 2020 as a result of transitioning to more environmental friendly resources such as natural gas, renewables and energy efficiency.

Chart 88 – Portfolio Comparisons



List of Acronyms

ACRONYMS

ACC – Arizona Corporation Commission
ANPR – Advanced Notice of Proposed Rulemaking
APS – Arizona Public Service Company
BART – Best Available Retrofit Technology
BTA – Biennial Transmission Assessment
Btu – British Thermal Unit
CAES – Compressed Air Energy Storage
CBM – Coal Bed Methane
CC – Combined Cycle Plant Technology
CCCT – Combined Cycle Combustion Turbine
CCR – Coal Combustion Residuals
CCS – Carbon Capture and Sequestration; Carbon Capture and Storage
CFL – Compact Fluorescent Light Bulb
CT – Combined Turbine
CO2 – Carbon Dioxide
CSP – Concentrating Solar Power
DG - Distributed Generation
DOE – U.S. Department of Energy (Federal)
DLC – Direct Load Control
DR – Demand Response
DSM – Demand Side Management
EAF – Equivalent Availability Factor
EE – Energy Efficiency
EES – Electric Energy Storage
EIA - Energy Information Administration
EPA - Environmental Protection Agency
EPRI – Electric Power Research Institute
EPS – Emission Performance Standard
FERC – Federal Energy Regulatory Commission
FIP – Federal Implementation Plan
GHG – Greenhouse Gas
GW – Gigawatt,
GWh – Gigawatt-Hour
HAPS – Hazardous Air Pollutants
HRSG – Heat Recovery Steam Generator
IGCC – Integrated Gasification Combined Cycle
IRP – Integrated Resource Plan
ISCC – Integrated Solar Combined Cycle
ITC – Investment Tax Credit
kW – Kilowatt
kWh – Kilowatt-Hour

kWyr – Kilowatt-Year
LNG – Liquefied Natural Gas
MACT – Maximum Available Control Technology
MMBtu – Million British Thermal Units, also shown as MBtu
MBtu – Million British Thermal Units, also shown as MMBtu
MW – Megawatt
MWh – Megawatt-Hour
NAAQ – National Ambient Air Quality Standards
NaS – Sodium Sulphur
NASNRC – National Academies of Science National research Council
NERC - North American Electric Reliability Council
NMED – New Mexico Environmental Department
NO_X – Nitrogen Oxide(s)
NPV – Net Present Value
NREL – National Renewable Energy Laboratory
NSPS – New Source Performance Standards
NTUA – Navajo Tribal Utility Authority
O&M – Operations and Maintenance
PSD – Prevention of Significant Deterioration
PM - Particulate matter
PNM – Public Service Company of New Mexico
PPA - Purchased Power Agreement
R&D – Research and Development
RCRA – Resource Conservation and Recovery Act
REC – Renewable Energy Credit
RES – Renewable Energy Standard
RFP – Request for Proposal
ROB – Replace on Burnout
ROW – Right of Way
RTP – Renewable Transmission Project
SCE – Southern California Edison
SCR – Selective Catalytic Reduction
SCT – Societal Cost Test
SCCT – Simple Cycle Combustion Turbine
SGS – Springerville Generating Station (aka Springerville)
SIP – State Implementation Plan
SJCC – San Juan Coal Company
SJGS – San Juan Generating Station
SNCR – Selective Non-Catalytic Reduction
SRP – Salt River Project
SRSG – Southwest Reserve Sharing Group
SO2 – Sulfur Dioxide
STG – Steam Turbine Generator
SWEEP – Southwest Energy Efficiency Project
TEP – Tucson Electric Power Company
TOUA - Tohono O'odham Utility Authority
WECC - Western Electricity Coordinating Council

Glossary

GLOSSARY

Base Load Resource
A generating resource that runs continuously except for maintenance and forced outages. A base load resource is typically run at a capacity factor of 65% or greater on an annual basis.

Biomass
Plant material used as a fuel or energy source; e.g. logging or mill residues, urban wood-waste and construction debris, dedicated wood or agricultural crops, and agricultural waste.

Biogas
Methane and other combustible gases released from the decomposition of organic materials.

Capacity Factor
Actual energy generated over a certain time period divided by maximum generation output over that same time period.

Combined Cycle Combustion Turbine (CCCT)
A simple cycle combustion turbine with a heat recovery unit added. The heat recovery system recovers waste heat from the combustion turbine and uses it to create steam for additional electricity generation.

Compressed Air Energy Storage (CAES)
A generating system by which air is pumped into a storage container during off-peak usage periods of low demand. Later, during on-peak periods the air is released to power a generator when energy is in high demand.

Conservation
The reduction of energy consumption resulting from increases in the efficiency of production, distribution and customer end use.

Carbon Dioxide (CO2)
Carbon dioxide is classified as a GHG because it is linked to global warming.

Centralized Solar
A thermal solar facility that concentrates sunlight in order to collect heat and use that heat to create steam which then drives a steam turbine creating electric generation (also referred to as concentrating solar thermal).

Demand
The rate at which electric energy is delivered to or by a system at a given instant, usually expressed in megawatts.

Demand Response (DR)
Programs or policies to control customer demand. Typically, DR programs involve agreements whereby consumers curtail their energy usage at the request of the utility. Includes load control, pricing strategies and interruptible tariffs.

Demand Side Management (DSM)
Programs or policies designed to reduce the amount of energy consumed by end users. Includes Energy Efficiency, Conservation and DLC.

Dispatchable Resource
A resource whose electrical output can be controlled or regulated to match the energy requirements of the electric system.

Distributed Generation (DG)
Electric generation that is sited at a customer's premises, providing energy to the customer load at that site and/or providing electric energy for use by multiple customers in contiguous distribution substation areas

Distribution System
The utility facilities that distribute electric energy from convenient points on the transmission system to customers.

Duty Cycle
Generating facility design that determines how a facility is operated. Duty Cycle classifications are base load, intermediate or peaking.

Economic Dispatch
In electrical system operations modeling, the selection of the least-cost resource under a prescribed set of conditions.

Energy
Usage over a period of time, measured in GWh, MWh, or kWh

Energy Efficiency (EE)
Measures, including energy conservation measures, or programs that target consumer behavior, equipment or devices that result in a decrease in consumption of electricity.

Federal Energy Regulatory Commission (FERC)
An agency of the United States government that is responsible for regulating power generation and licensing generation and interstate transmission systems.

Generation Capacity
The maximum amount of power that a generator can physically produce.

Geothermal Energy
Energy derived from heat deep beneath the earth's surface generated from hot rock, hot water or steam.

Gigawatt (GW) and Gigawatt-Hour (GWh)
A gigawatt is a unit of power equal to 1 billion watts, 1 million kilowatts, or 1,000 megawatts. A gigawatt-hour (GWh) is a measure of electric energy equal to one gigawatt of power supplied to or taken from an electric circuit for one hour.

Heat Rate
The ratio of energy inputs used by a generating facility expressed in Btus (British Thermal Units), to the energy output of that facility expressed in kilowatt-hours. (Btu/kWh)

Insolation
The amount of solar radiation that is striking a surface at any given time.

Integrated Gasification Combined Cycle (IGCC)
A plant configuration based on combined cycle technologies that substitutes natural gas for a process that extracts synthetic gas from petroleum coke or other carbon based fuel sources, then uses the synthetic gas (Syngas) as a fuel source.

Integrated Resource Planning
A planning approach that projects the amount of new electricity generation and conservation needed to meet future loads by considering a range of power resource alternatives and future conditions, and using evaluative criteria including but not limited to minimizing cost.

Intermediate Resource
A generating resource that is most economically run at capacity factors between 20% and 65% of the time on an annual basis.

Landfill Gas
Gas generated by the natural degrading and decomposition of municipal solid waste by anaerobic microorganisms in sanitary landfills. The gases produced, primarily methane, can be collected by a series of low-level pressure wells and can be processed into a medium Btu gas that can be burned to generate electricity.

Levelized Cost
The present value of a resource's cost (including capital, interest and operating costs) converted into a stream of equal annual payments and divided by annual kilowatt-hours saved or produced.

Load
The amount of electric power delivered or required at any specified point or points on a system. Load originates primarily at the power-consuming equipment of the customer.

Load Forecasting
The procedures used to estimate future consumption of electricity. Load forecasts are developed either to provide the most likely estimate of future load or to determine what load would be under a set of specific conditions; e.g., extremely cold weather, high rates of inflation or changes in electricity prices.

Load Duration Curve
A load duration curve provides a graphical illustration of the relationship between generating capacity requirements and capacity utilization. The load duration curve helps determine which type of resource best matches system load requirements.

Load Factor
Peak demand divided by average demand.

Load Profile or Shape
A curve on a chart showing power supplied plotted against time of occurrence to illustrate the variance in load in a specified time period.

Megawatt (MW) and Megawatt-Hour (MWh)
One thousand kilowatts, or 1 million watts; the standard measure of electric power plant generating capacity. A megawatt-hour (MWh) is a measure of electric energy equal to one megawatt of power supplied to or taken from an electric circuit for one hour.

Net Maximum Capacity (NMC)
The capacity a unit can sustain over a specified period when not restricted by ambient conditions or equipment deratings, minus the losses associated with station service or auxiliary loads.

Nitrous Oxide (NOx)
Nitrous Oxide is one of several non-CO2 gases that may contribute to global climate change and acid rain.

Peak Capacity
The maximum output of generating plant or plants during a specified peak-load period.

Peak Demand
The maximum demand imposed on a power system or system component during a specified time period.

Peaking Resource
A generating resource that is dispatched to meet a utilities peak load obligations. Typically, these resources are dispatched on limited basis for short durations. Peaking resources typically average an annual capacity factor of less than 20%.

Peak Power
Power generated by a utility system component that operates at a very low capacity factor, generally used to meet short-lived and variable high-demand periods.

Peak Shaving
A strategy used to reduce electricity use during times of peak demand, typically employed through demand-response programs.

Photovoltaic Solar
Solar generation that uses photovoltaic panels to convert sunlight directly to energy.

Planning Period
The future time frame for which a utility bases its IRP. For purposes of this report, the planning period is 20 years, from 2010-2030.

Plug-in Hybrids Electric Vehicles (PHEV)
Hybrid electric automobiles are vehicles powered by batteries that are recharged with a charging station which draws its supply from an electric utility distribution system.

Portfolio
A set of power supply resources currently or potentially available to a utility. This is used in the IRP to mean alternative sets of resources that could be added to existing resources to meet expected future needs.

Resource Adequacy
A measure defining when a utility has sufficient resources to meet customer needs under a range of conditions that affect supply and demand for electricity.

Resource Mix
The different types of resources that contribute to a utility's ability to generate power to meet its load obligations.

Renewable Resource
A resource whose energy source is not permanently used up in generating electricity. A resource that uses solar, wind, hydro, geothermal, biomass, or similar sources of energy to either generate electric power or reduce the customer electric power requirements.

Reserve Requirement
The requirement that a utility maintains firm capacity at its disposal that exceeds its expected peak demand by a certain percentage.

Shaping
Configuring a resource portfolio so power generation capability and delivery of purchased power closely matches changes in demand over time.

Simple Cycle Combustion Turbine (CT)
A natural gas-fired turbine used to drive an electric generator. Combustion turbines are designed for meeting short-term peak demands placed on utility power systems. They are frequently ramped up and down to follow load as needed.

Solar
Electric generation fueled directly by sunlight.

Solar Hybrid
A thermal solar facility with the ability to supplement heat from the sun with heat derived by burning natural gas.

Sulfur Dioxide (SO2)
A common byproduct of the burning of coal that has been linked to acid rain in the atmosphere.

Sun Splash
Sun Splash occurs in a photo voltaic array when clouds gather around the sun to form a reflective frame, thus temporarily increasing the amount of light energy striking the array and therefore causing a momentary increase in the array's output.

Surplus Energy
Energy that is not needed to meet a utility or marketing agency's commitments to supply firm or non-firm power.

Total Transfer Capacity (TTC)
Total Transfer Capacity refers to the capacity of a transmission line.

Transmission System
An interconnected network of electric transmission lines and associated equipment for the movement or transfer of high-voltage electricity between points of supply and points at which it is transferred for delivery to consumers or to other utilities.

Wheeling
The use of a utility's transmission facilities to transmit power to and/or from another utility system.

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