UniSource Energy

2014 Integrated Resource Plan

April 1, 2014

UNS Electric, Inc.

Acknowledgements

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CHAPTER 1

2014 INTEGRATED RESOURCE PLAN

Introduction

UNS Electric, Inc.'s (UNSE) 2014 Integrated Resource Plan (IRP) describes how UNSE plans to meet future demand requirements, while maintaining system reliability, meeting future regulatory requirements and reducing environmental impacts in a cost-effective manner that leads to just and reasonable rates. In addition to providing a snapshot of UNSE's current loads and resources, the IRP highlights the near term acquisition goals through the 2014 Reference Case plan. The Reference Case portfolio is made up of renewable resources, energy efficiency, market purchases and new gas-fired generation.

The 2014 Reference Case plan highlights the following goals:

- The 2014 Reference Case highlights a portfolio strategy that firms up its long-term capacity requirements with the acquisition of a 25% ownership share in Unit 3 of the Gila River Power Station. The 2014 Reference Case assumes that UNSE will complete the Gila River purchase transaction by end of December 2014. UNSE's planned capacity share of this resource will be 138 MW and will firm up a majority of UNSE's long-term baseload and intermediate capacity needs while reducing its current dependency on market based capacity purchases.

- The 2014 Reference Case details how the Gila River acquisition along with the expansion of future natural gas resources and grid supported storage technologies will be a critical piece of UNSE's long-term portfolio strategy by supporting the integration of renewable resources.

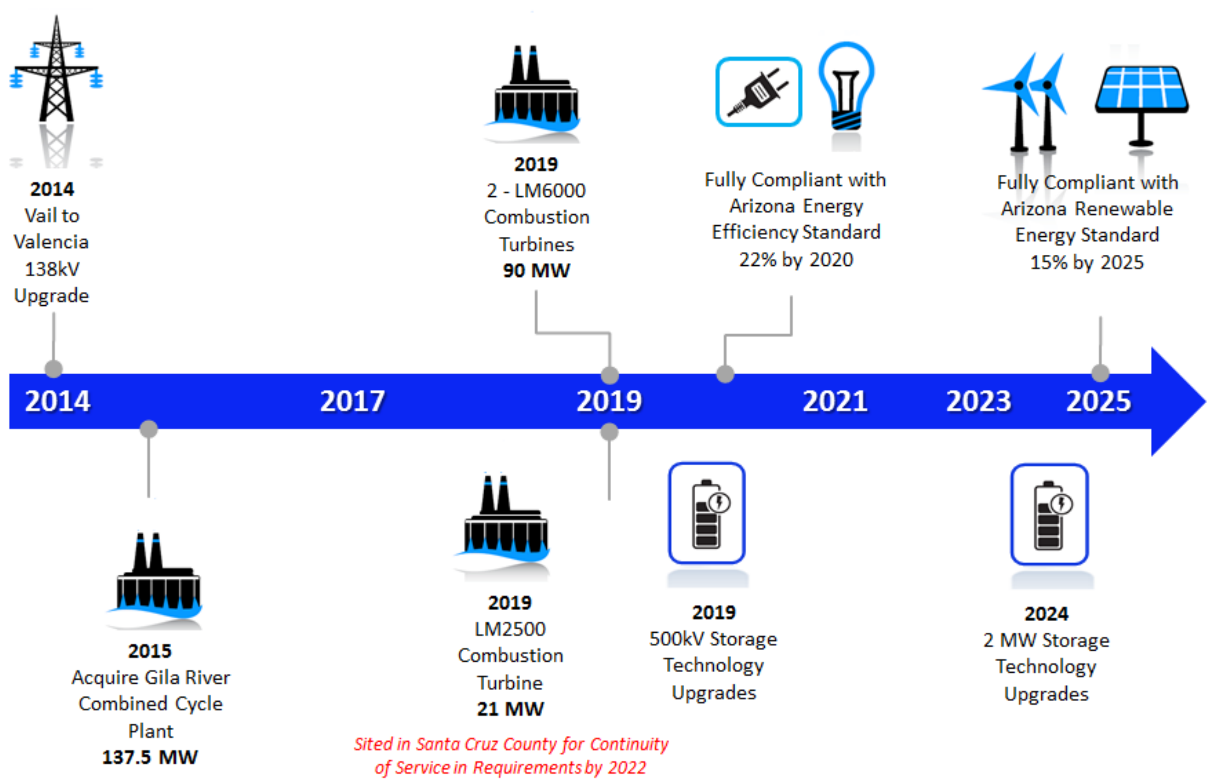
- The Reference Case plan will implement an energy efficiency portfolio that includes a range of cost effective energy conservation programs. The 2014 Reference Case plan assumes an energy efficiency portfolio that is consistent with the Arizona Energy Efficiency Standard.

- The 2014 Reference Case highlights UNSE's successful efforts to develop a well-diversified renewable resource portfolio that meets Arizona's Renewable Energy Standard (RES) requirements. UNSE plans to continue development of low cost renewable projects that minimize water usage and negative impacts to the environment as well as providing long-term value to UNSE's retail customers in Mohave and Santa Cruz counties.

Overview of the 2014 UNSE Reference Case Plan

This section presents an overview of the 2014 Reference Case plan and provides the associated timelines for future resource additions. Figure 1 below details the significant resource planning decisions assumed for the 2014 Reference Case. As part of its resource planning strategy, UNSE plans to acquire approximately 138 MW from Power Block 3 at the Gila River Power Station in December 2014. This natural gas combined cycle resource will cover a majority of UNSE's baseload and intermediate capacity requirements for the next several years. For UNSE's longer term peaking needs, the UNSE 2014 Reference Case plan assumes the need for 111 MW of additional gas fired generation by 2019. 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 2014 Reference Case also highlights the recently completed Vail to Valencia 115 kV to 138 kV transmission upgrade that went into service at the end of 2013. This new 138 kV transmission line will strengthen the southern portion of UNSE's distribution system resulting in improved system reliability in Santa Cruz County. Finally, the 2014 Reference Case recognizes the need for future storage technologies to support the integration of intermittent resources. For purposes of this filing, UNSE assumes that approximately 1.85 MW of battery storage technology will be required by 2028 to support future ancillary service requirements for the grid.

Figure 1 – 2014 UNSE Reference Case Plan

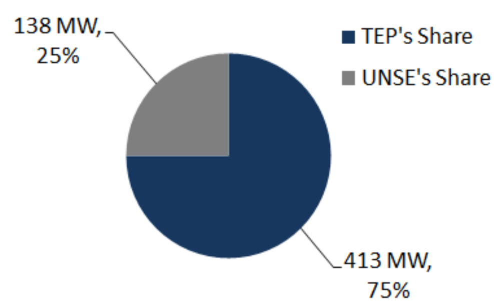


UNSE's Planned Acquisition of the Gila River Power Station

In the 2012 Resource Plan, UNSE made a commitment to actively monitor the wholesale merchant market for potential resource alternatives as part of its on-going resource procurement process. In May 2013, UNSE's sister company Tucson Electric Power Company (TEP) conducted a Request for Proposal (RFP) to evaluate the wholesale merchant market for potential capacity alternatives. As a result, TEP received fourteen different proposals from nine different bidders. Based on the bid analysis, Gila River Unit 3 was chosen as the final bidder due to the economic and operational advantages of their proposal. Due to the substantial size of the unit, and UNSE's need for baseload generating capacity, a decision was made to take advantage of this unanticipated and unique opportunity that would benefit both UNSE and its customers, by including UNSE as a potential buyer. In December 2013, both TEP and UNSE 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 nominal 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. TEP and UNSE expect the transaction to close in December 2014.

Figure 2 – Gila River Power Station Overview

Gila River Power Station Overview



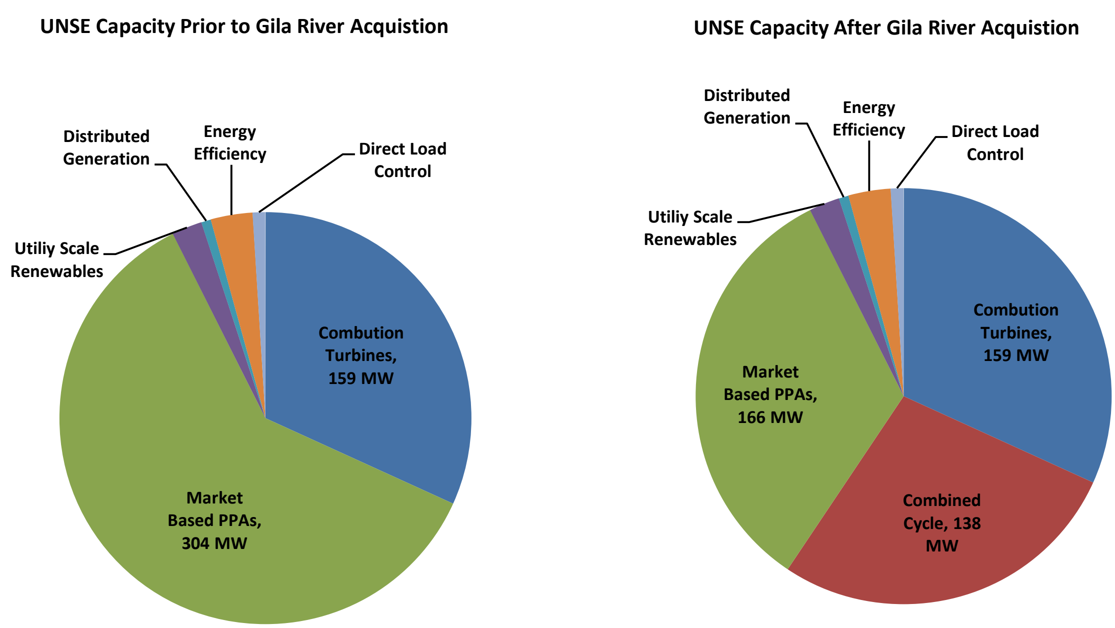
- Location: Gila Bend Arizona
- Size of Site: 1,100 Acres
- Nominal Station Capacity: 2200 MW
- Nominal PB 3 Capacity: 550 MW
- Fuel Type: Natural Gas / Combined-Cycle
- Technology: GE 7FA 2x1 Units
- Heat Rate: 7200 Btu/kWh
- Interconnection: APS 500kV (Jojoba)

- Station Operator: Wood Group
- Gas Transportation: El Paso and Transwestern
- Owners of Power Blocks 1 & 2 – Sundevil LLC
- Owners of Power Block 3 – TEP and UNSE (Proposed)
- Owners of Power Block 4 – Entegra LLC

UNSE's Plan to Reduce Reliance on Market Based Capacity

Today, UNSE relies on the wholesale market for approximately 300 MW of its annual resource capacity needs. With UNSE's planned acquisition from the Gila River Power Station, UNSE will reduce its market based capacity exposure by about 45% from approximately 304 MW to 166 MW in 2015. Chart 5 shows the expected change in UNSE's resource capacity mix with the inclusion of a 25% ownership share of Power Block 3 at the Gila River Power Station.

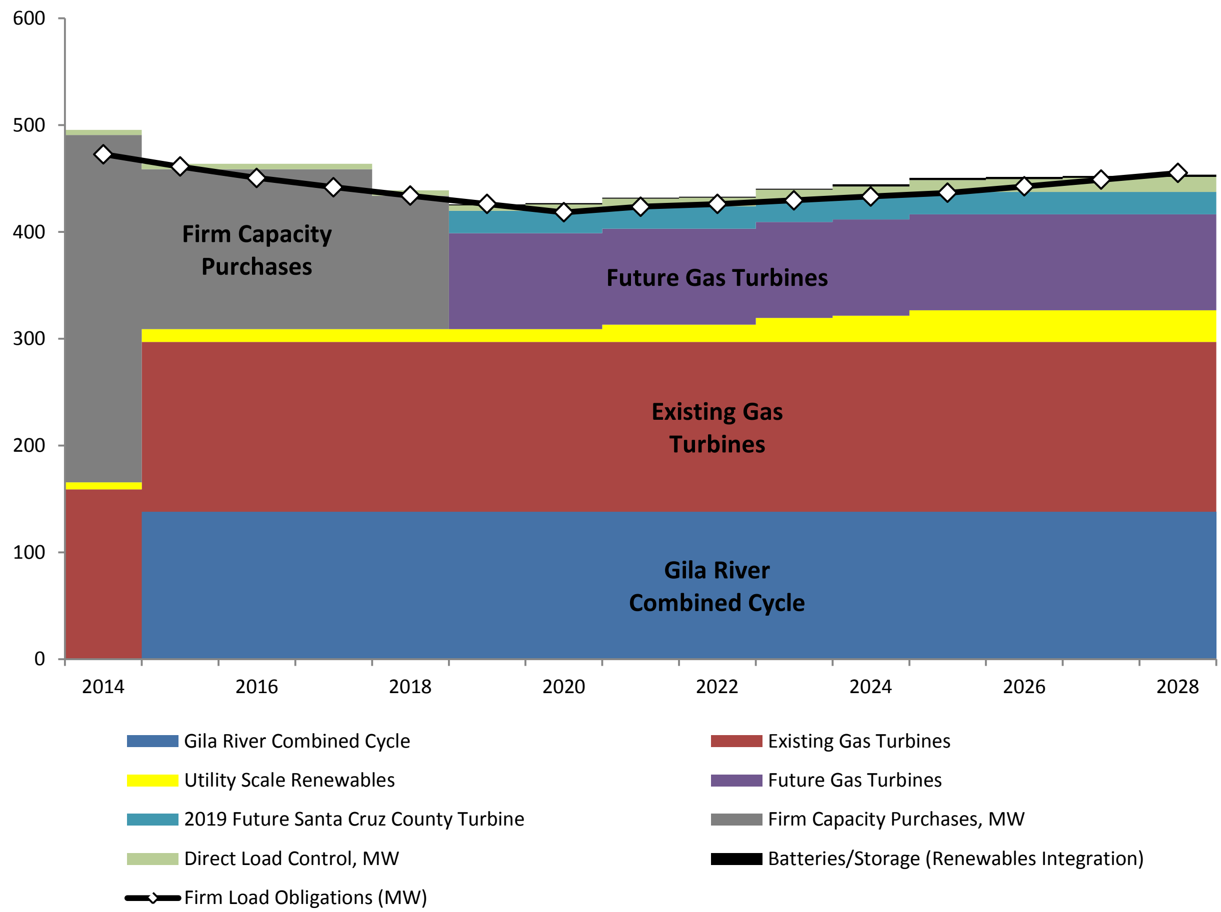
Chart 1 – UNSE's Market Based Resource Capacity Prior to and After the Gila River Acquisition



UNSE Reference Case Load and Resources

The loads and resources chart shown below details how UNSE's firm load obligations are met under the 2014 UNSE Reference Case. The firm load obligations represent UNSE's retail demand less energy efficiency and distributed generation plus a 15% planning reserve margin.

Chart 2 – UNSE 2014 Reference Case Loads and Resources



Note: Future Gas Turbine resources may be a combination of firm long-term purchase power agreements, plant acquisitions, or construction of new local area generating facilities.

Energy Efficiency and Demand Response

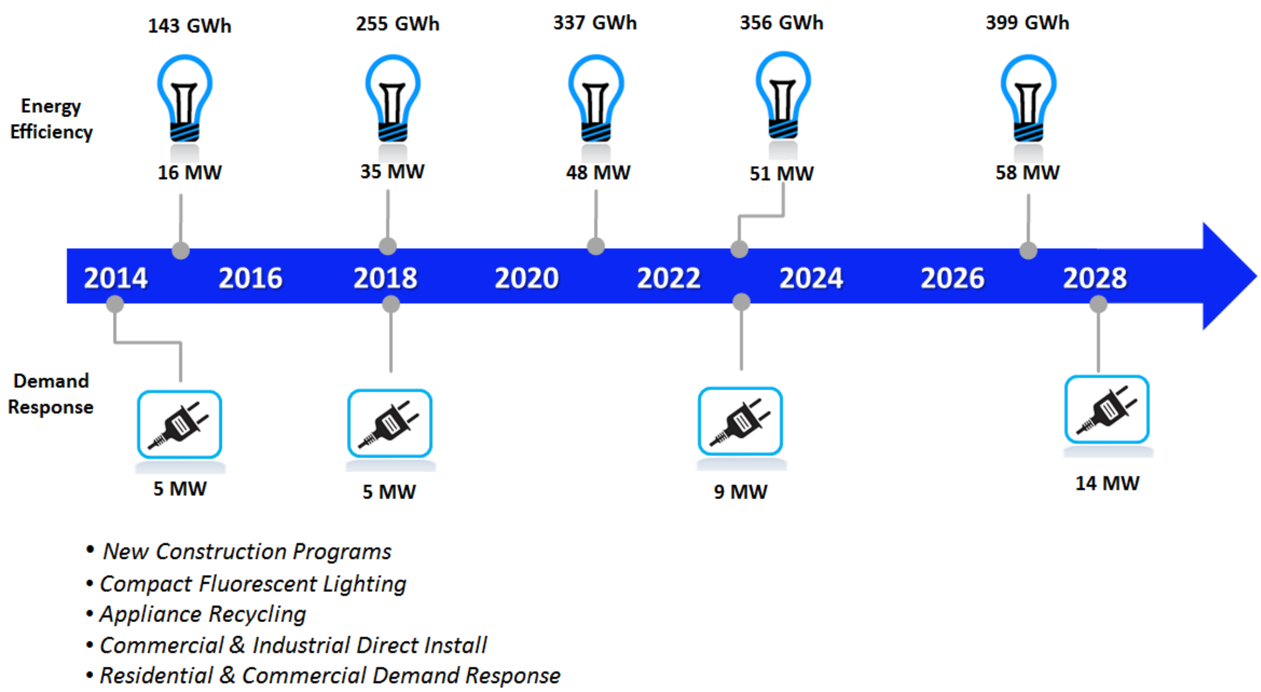
Energy Efficiency

UNSE proposes to pursue a range of cost-effective and industry-proven programs to meet future energy efficiency targets. UNSE's proposed energy efficiency portfolio is intended to meet compliance with the Arizona Energy Efficiency Standard which 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 UNSE's annual energy requirements by approximately 407 GWh and reduce UNSE's system peak demand by 59 MW.

Demand Response

The 2014 Reference Case plan targets dispatchable demand response programs that reduce UNSE's summer peak loads. UNSE's future demand response programs are expected to reduce UNSE's system peak demand by 14 MW by 2028. Figure 3 shows the equivalent capacity reductions installed under future energy efficiency and demand response programs for the 2014 Reference Case plan from 2014 through 2028.

Figure 3 - Energy Efficiency and Demand Response (Equivalent Capacity Reductions)



Utility Scale Renewables and Distributed Generation

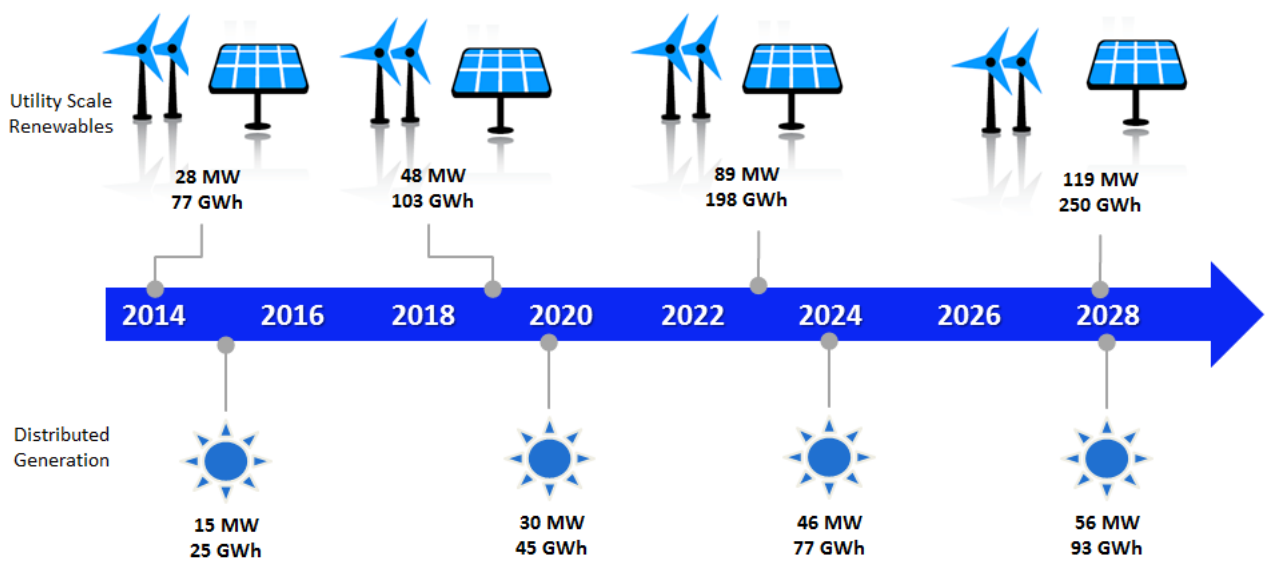
Utility Scale Renewables

The 2014 Reference Case plan also includes a diverse portfolio of renewable resources that complies with the Arizona Renewable Energy Standard (RES). The 2014 Reference Case plan meets the renewable energy standard goals, which requires UNSE to obtain renewable energy which is equivalent to 3.5% of its 2014 retail load requirement, growing to 15% by 2025. By 2028, the Reference Case plan will include over 119 MW of renewable nameplate capacity. These utility scale renewable resources are expected to supply over 250 GWh of energy on an annual basis in 2028.

Distributed Generation

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 RES requirement. By 2028, the Reference Case plan will include 53 MW of distributed generation nameplate capacity. Distributed generation resources are expected to supply at least 93 GWh of energy on an annual basis in 2028. Figure 4 below shows the expected cumulative nameplate capacity to be installed under future utility-scale renewable and distributed generation programs from 2014 through 2028.

Figure 4 - Utility Scale Renewables and Distributed Generation Resource Capacity



EXISTING RENEWABLE RESOURCES

Overview

Over the last several years, UNSE has worked with third-party contractors to develop three new renewable resource projects within UNSE's service territory. In addition, the Company is currently working with Torch Renewables to develop a new solar fixed PV project located in Willcox, Arizona. The table below provides an overview on UNSE renewable projects. Chapter 9 provides additional details on each individual project.

Table 1 – UNSE's Renewable Resources (Existing and Planned)

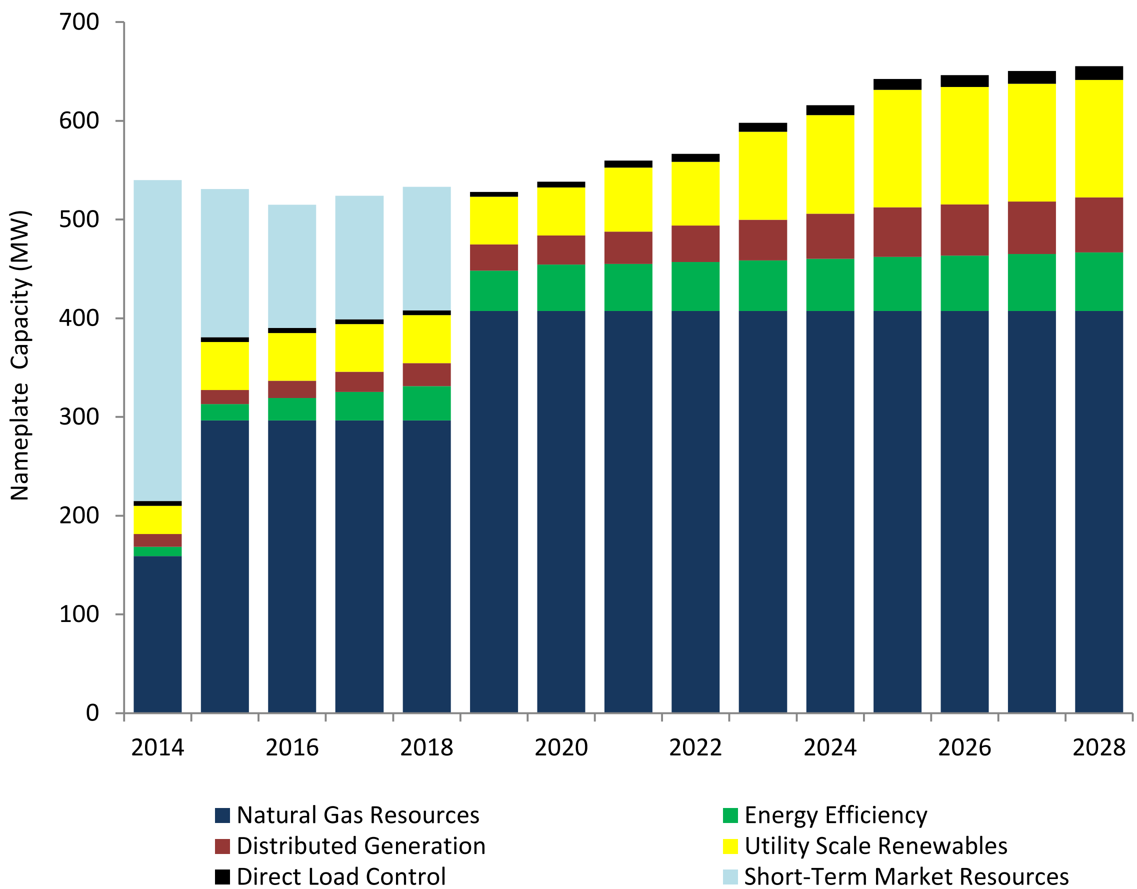
Resource- Counterparty	Owned/PPA	Technology	Location	Operator-Manufacturer	Completion Date	Capacity MW
Western Wind	PPA	Wind	Kingman, AZ	Western Wind	Sept 11	10.5
La Senita School	PPA	SAT PV	Kingman, AZ	Solon	Nov 11	1.22
Black Mountain	PPA	SAT PV	Kingman, AZ	Solon	Jun 12	10
Red Horse Solar (Future)	PPA	PV	Willcox, AZ	Torch Renewables	Q4 2014	TBD

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

Reference Case Plan - Future Capacity Additions

The Reference Case plan identifies the need for approximately 655 MW of nameplate capacity through 2028. Chart 3 below shows the incremental nameplate capacities installed by year and resource type.

Chart 3 – Reference Case Plan Capacity Additions, Future Nameplate Capacity (MW)



Reference Case Plan - Future Capacity Additions

Table 2 shows the future resource nameplate capacities by year and resource type. This table summarizes the cumulative capacity additions that are expected under the Reference Case plan.

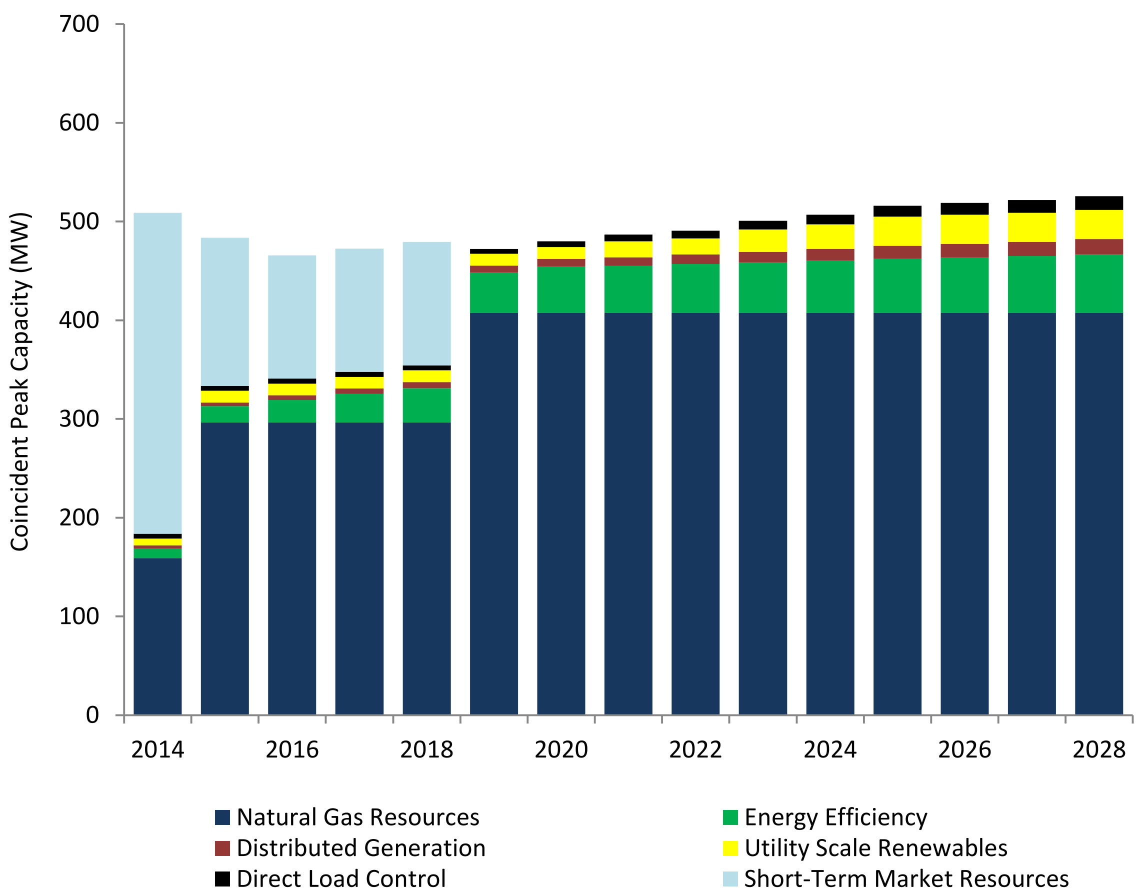
Table 2 – Reference Case Plan Capacity Additions 2014 - 2028, Future Nameplate Capacity (MW)

Resources Capacity (Nameplate Capacity MW)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Natural Gas Resources	159	297	297	297	297	408	408	408	408	408	408	408	408	408	408
Utility Scale Renewables	28	48	48	48	48	48	48	65	65	89	100	119	119	119	119
Distributed Generation	13	14	17	20	23	26	29	32	36	41	45	50	51	52	55
Energy Efficiency	10	16	23	29	35	41	47	48	49	51	53	55	56	58	59
Direct Load Control	5	5	5	5	5	5	6	7	8	9	10	11	12	13	14
Total Nameplate Capacity	215	381	390	399	408	528	538	560	567	598	616	642	646	650	655
Short-Term Market Resources	325	150	125	125	125	-	-	-	-	-	-	-	-	-	-
Total Resources	540	531	515	524	533	528	538	560	567	598	616	642	646	650	655

Reference Case Plan - Capacity Contribution to System Peak

Chart 4 on page 17 and Table 2 on page 18 referred to installed nameplate capacities for future resource additions. However, for resource planning purposes, it is important to value resource capacity on its coincidence to system peak. Chart 4 displays the capacity contribution coincident to system peak by resource type. For the 2014 IRP, the resource planning team determined the expected capacity contribution values for the evaluated utility-scale and distributed renewable resources. The expected capacity values were derived from hourly data sources and the capacity contribution for each renewable resource is documented in Chapter 9 of this report. The 655 MW of nameplate capacity shown in Chart 3 is adjusted accordingly and under the Reference Case plan, new resource capacity results in an expected capacity contribution of 455 MW by 2028. Table 4 summarizes the data below.

Chart 4 – Reference Case Resource Plan, New Resource Capacity (Coincident to System Peak MW)



Future Load Obligations

The tables on the next two pages provide a data summary on UNSE's loads and resources. Table 3 details UNSE's projected firm load obligations which include retail demand, less energy efficiency and distributed generation plus planning reserves.

Table 3 - Firm Load Obligations, System Coincident Peak Demand (MW)

Firm Load Obligations	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Residential	219	218	217	217	216	216	217	220	222	225	228	231	235	239	243
Commercial	97	97	96	96	96	96	96	98	99	100	101	103	104	106	108
Industrial	74	73	73	73	73	73	73	74	75	76	77	78	79	80	82
Mining	25	25	25	25	25	25	25	25	26	26	26	27	27	28	28
Other	8	8	8	8	8	8	8	8	8	8	9	9	9	9	9
Retail Peak Demand	424	421	419	418	418	418	419	425	430	435	441	447	454	462	469
Less Energy Efficiency	-10	-16	-23	-29	-35	-41	-47	-48	-49	-51	-53	-55	-56	-58	-59
Less Distributed Generation	-3	-4	-5	-5	-6	-7	-8	-9	-10	-11	-12	-13	-13	-14	-14
Net Retail Demand	411	401	392	384	377	371	364	368	371	374	377	380	385	390	396
Reserve Requirements	85	87	72	79	86	56	63	64	63	67	70	72	68	64	59
Reserve Requirements %	21%	22%	18%	21%	23%	15%	17%	17%	17%	18%	18%	19%	18%	16%	15%

Reference Case Plan – Resource Capacity

Table 4 details UNSE's Reference Case resource plan based on a resource's capacity contribution to system peak.

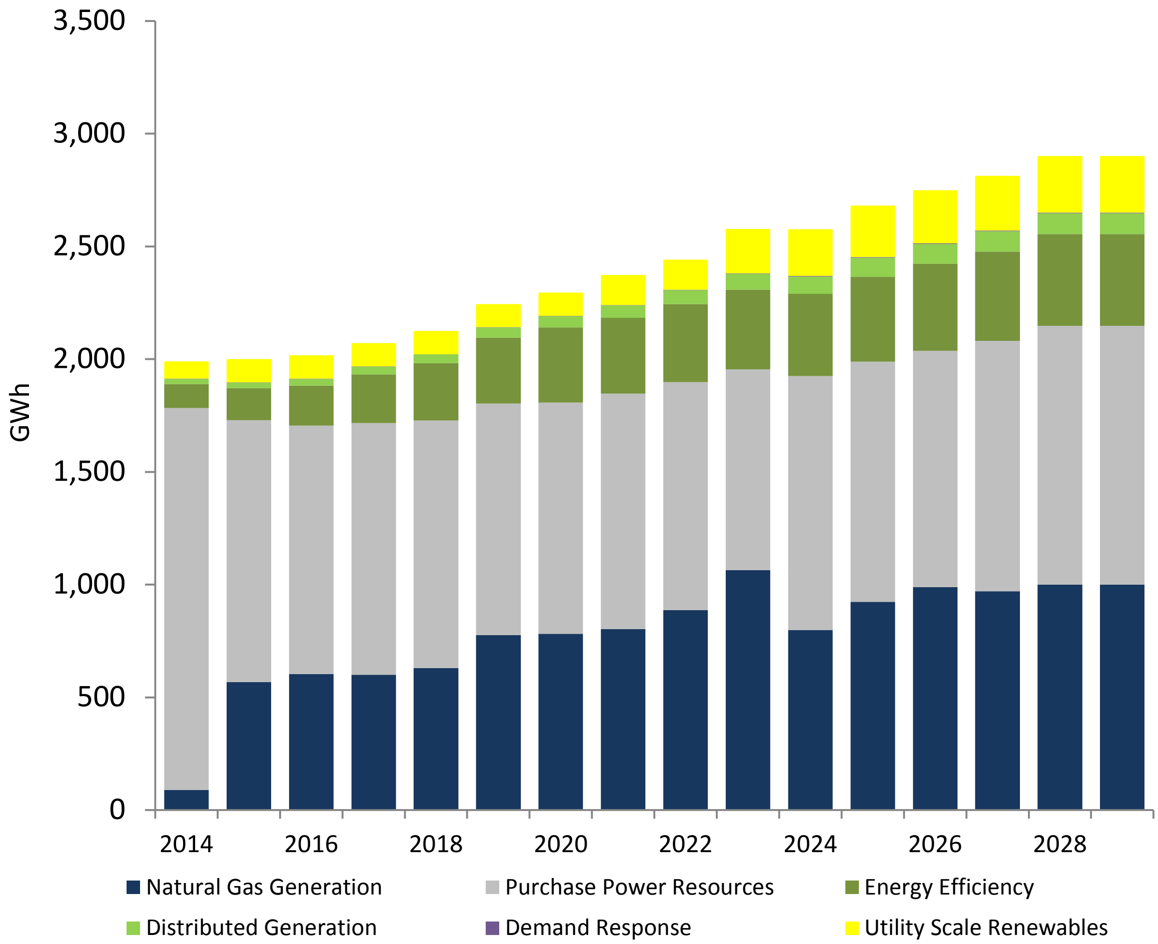
Table 4 – Reference Case Plan- Capacity Resources, System Coincident Peak Demand (MW)

Firm Resource Capacity (MW)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Black Mountain	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
Valencia	69	69	69	69	69	69	69	69	69	69	69	69	69	69	69
Gila River Combined Cycle	0	138	138	138	138	138	138	138	138	138	138	138	138	138	138
Future Natural Gas Resources	0	0	0	0	0	111	111	111	111	111	111	111	111	111	111
Natural Gas Resources	159	297	297	297	297	408	408	408	408	408	408	408	408	408	408
Utility Scale Renewables	7	12	12	12	12	12	12	16	16	23	25	30	30	30	30
Demand Response	5	5	5	5	5	5	6	7	8	9	10	11	12	13	14
Total Coincident Peak Capacity	171	313	313	313	313	425	426	432	433	440	444	450	451	452	453
Firm Purchases	325	175	150	150	150	0	0	0	0	0	0	0	0	0	0
Future Storage Resources	0	0	0	0	0	1	1	1	1	1	2	2	2	2	2
Total Resources	496	488	463	463	463	426	427	433	434	441	446	452	453	454	455

Reference Case Plan – Expected Annual Energy

Chart 5 shows the expected energy contribution required to meet UNSE's firm load obligations by year and resource type. In 2014, UNSE's energy portfolio is comprised of 90% purchase power and natural gas resources. By 2028, it is projected that UNSE's energy portfolio will be comprised of 74% natural gas and purchase power resources with 14% made up of energy efficiency and 12% renewable resources.

Chart 5 – Reference Case Resource Plan, Expected Annual Generation Output (GWh)



Action Plan

Overview

The 2014 Reference Case Plan was chosen as the portfolio that balances the competing interests for UNSE's customers based on the current view of the future. As a result, UNSE has developed a short-term action plan required to implement the resource decisions during the early phases of this strategy. Under the 2014 Reference Case as discussed in more detail herein UNSE's action includes the following:

- UNSE plans In order to meet its baseload capacity needs and reduce its dependence on the wholesale power market, UNSE plans to purchase a 25% share of Unit 3 of the Gila River Power Station in Gila Bend, Arizona in December 2014.

- UNSE plans to continue with its utility scale build out of its current RES implementation plans. UNSE anticipates that an additional 30 MW of new renewable capacity will be in-service by the end of 2015 raising the total distributed generation and utility scale capacity on UNSE's system to approximately 65 MW. By 2016, renewable resources will make up close to 15% of UNSE's total nameplate generation capacity. As a result, UNSE is currently investing resources into a number of research and development activities that will determine the need for future storage and smart grid technologies to support the grid.

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

  - As part of its near-term portfolio strategy, UNSE will continue to utilize the wholesale merchant market to acquire short-term market based capacity products. In addition, UNSE will continue to monitor the wholesale market for other low cost resource alternatives such long-term purchase power agreements and low cost plant acquisitions.

Requests for Acknowledgement

UNSE requests that the commission acknowledge it 2014 Integrated Resource plan as provided in A.A.C. R14-2-704B

CHAPTER 2

INTEGRATED RESOURCE PLANNING METHODOLOGY

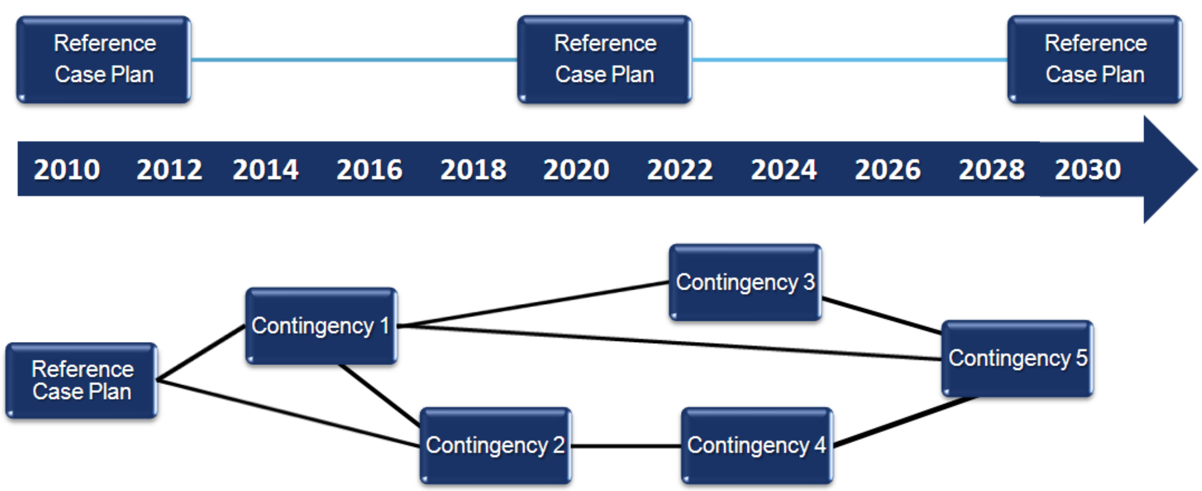
Overview

The purpose of the 2014 Integrated Resource Plan (IRP) is to develop a strategic roadmap for UNSE 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 uncertainty 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 5 shows this from a conceptual basis.

Figure 5- Resource Planning Contingency Timelines



Methodology for Analyzing Potential Portfolios

The scope of this IRP is to identify a resource portfolio that meets UNSE'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.

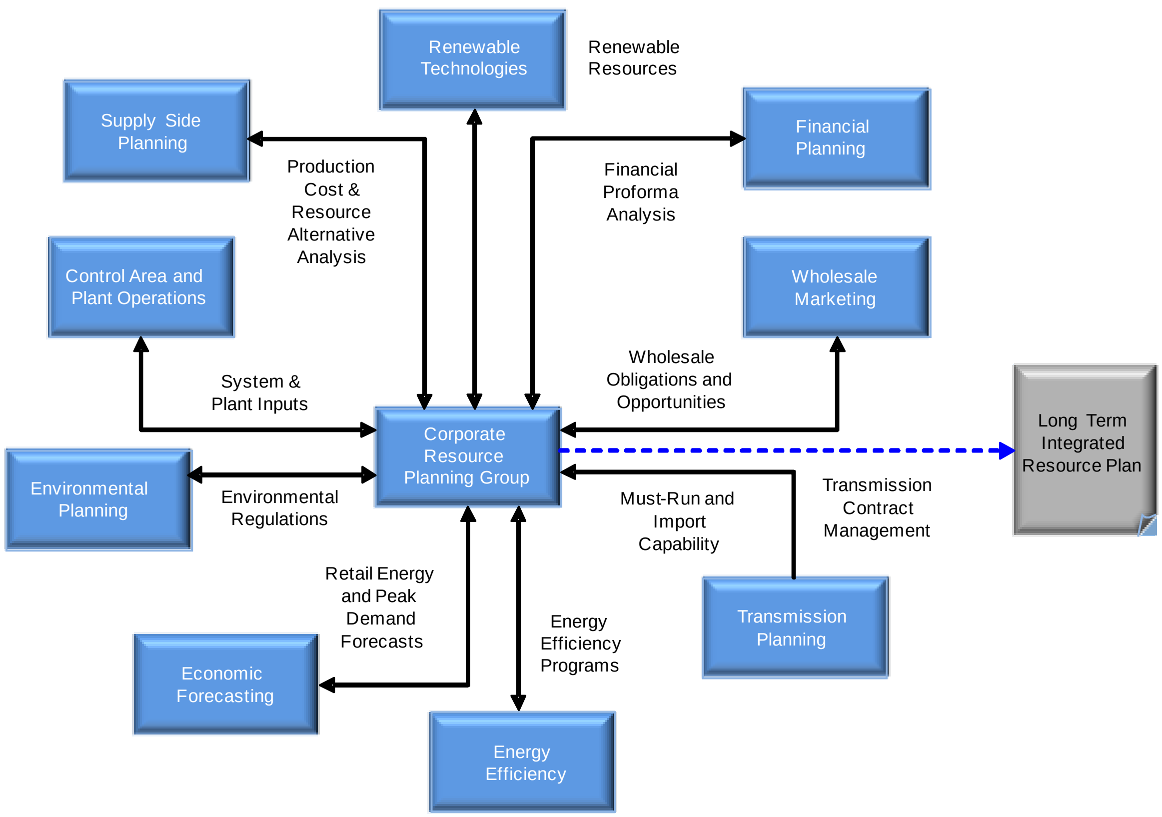
This chapter summarizes UNSE's IRP methodology and discusses the following topics related to this integrated planning process.

- 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 UNSE. This group, shown in Figure 6, 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 Energy 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 6 - Corporate Resource Planning Group



Joint Resource Planning Activities

As part of UNSE's on-going resource planning efforts, UNSE coordinates it's planning activities with its regional partners to develop potential generation and transmission resource options. Due to its organization structure UNSE works directly with TEP's Corporate Resource Planning Groups 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 UNSE and TEP retail customers. Some of these joint planning activities are listed below.

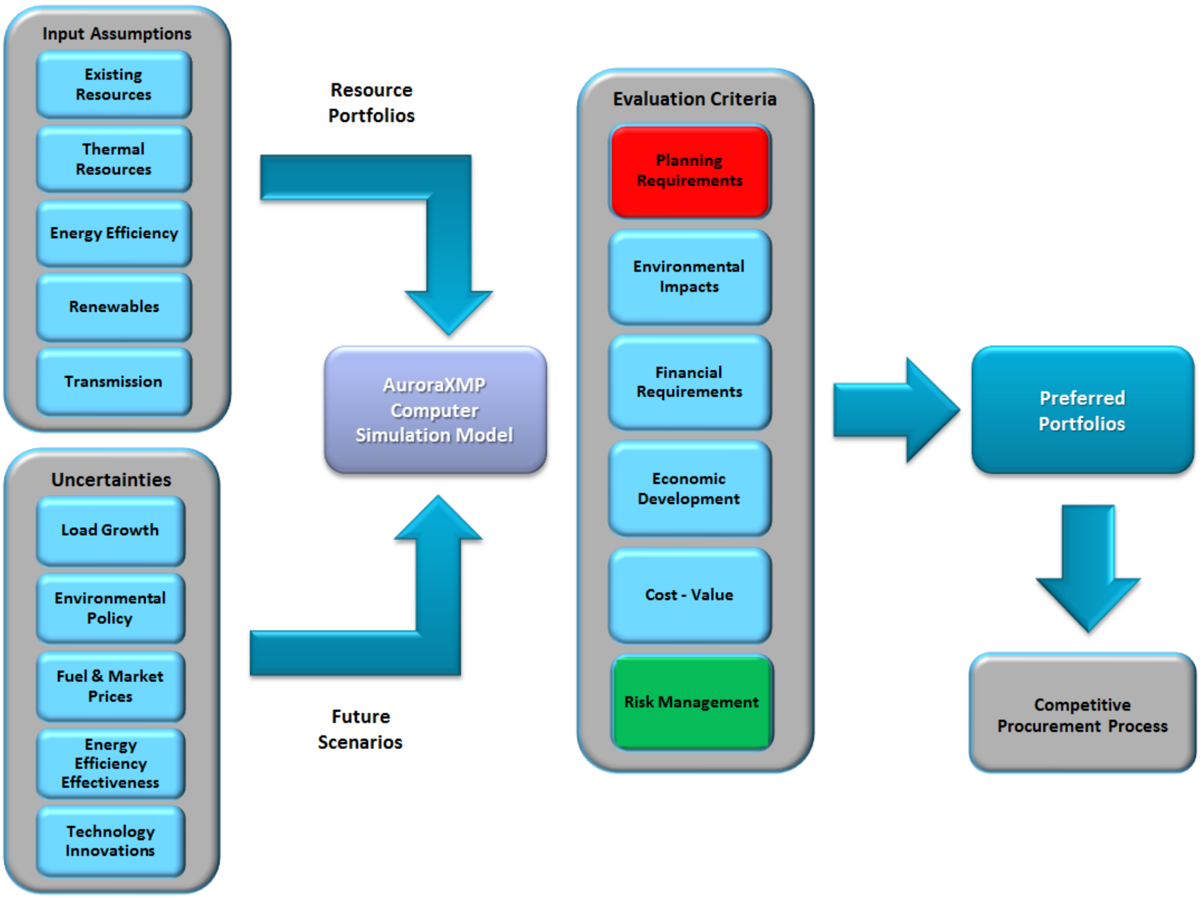
- UNSE and TEP coordinate a number operating activities such as real-time system scheduling and dispatch, portfolio hedging, capacity procurement and long-term resource planning.
- UNSE and TEP have partnered in its efforts to develop both its renewable energy and energy efficiency programs. Currently both UNSE and TEP 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.
- In 2014, UNSE and TEP 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, UNSE and TEP 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.

UNSE plans to continue to develop these types of joint partnerships with TEP 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 7 - IRP Process Overview

Figure 7 - IRP Process Overview



Computer Simulation Modeling

UNS Electric 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. 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 8 provides an overview on UNSE's energy efficiency programs and modeling assumptions.
- Chapter 9 has an in-depth write-up on UNSE'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 12.

Risk Analysis and Simulation Development

In the development of the Reference Case, 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 12. A risk profile for each candidate portfolio and a summary of simulation outcomes is provided in the discussion of IRP planning results in Chapter 14.

Minimum Resource Planning Requirements

In addition to the market input assumptions UNSE has some minimum resource planning criteria that are required under all resource portfolios. In all planning scenarios, UNSE 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, UNSE 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

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

Energy Efficiency Standard Compliance

For resource planning purposes, UNSE has assumed that it maintains compliance with Arizona Energy Efficiency Standard which targets a cumulative load reduction of 22% by 2020. UNSE's projected energy efficiency programs will achieve a cumulative reduction of 108 GWh in 2014 increasing to 410 GWh by 2028.

Renewable Energy Standard Compliance

The Renewable Energy Standard (RES) sets forth the annual renewable energy requirements for UNSE. The RES target is 4.5% of the prior year retail sales in 2014 increasing to 15% by 2025. In order to meet the RES requirements, UNSE will need to implement a renewable portfolio of utility scale and distributed generation resources to meet an annual production level of approximately 99 GWh in 2014 reaching 343 GWh by 2028.

IRP Public Workshops

In developing the 2014 Integrated Resource Plan, UNSE 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. UNSE'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
- Arizona Public Service Company
- Arizona's G&T Cooperatives
- City of Tucson
- Copper State Consulting Group
- Energy Strategies, LLC
- Freeport-McMoRan Copper & Gold, Inc.
- Pima Association of Governments
- Raytheon
- Rosemont Copper Company
- Sempra Energy
- Sierra Club Grand Canyon Chapter
- Southwest Gas Corporation
- Technicians for Sustainability
- Tucson-Pima Metro Energy Commission

These presentations are currently available on the TEP website in a PDF file format. The 2014 UNSE resource plan is at the website address 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 first 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 the current resource plan, a long term load forecast was produced. This chapter will provide an overview of the anticipated long term load obligations at UNSE, 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 currently surrounding a number of key forecast inputs.

The sections in this chapter include:

- **Company Overview:** UNSE geographical service territory, customer base, and energy consumption by rate class
- **Reference Case Forecast:** An overview of the reference case forecast of energy and peak demand used in the planning process
- **Summary:** Compilation of results from this analysis

Company Overview

Geographical Location and Customer Base

UNSE currently provides electricity to approximately 93,000 customers in two geographically distinct areas. In northwest Arizona, UNSE provides service to the majority of Mohave County. This segment of the service territory includes approximately 74,000 customers located primarily in the Kingman and Lake Havasu City areas. In addition to Mohave County, UNSE also provides service to the majority of Santa Cruz County in southern Arizona. This southern service territory includes approximately 19,000 customers located primarily in the Nogales area.

The two regions are very different both in terms of population and geography. For instance, Mohave County is estimated to have a current population of approximately 203,000 and has experienced an estimated 2% annual growth over the last decade, while Santa Cruz County is estimated to have a current population of approximately 47,000, and has grown at an estimated 1.7% annual rate over the same period. In addition to the varying population dynamics, the geography and weather of the two service areas are also distinctly different. For example, Lake Havasu City sits at an elevation of approximately 735 feet, while Nogales is located in mountainous terrain and sits at 3,823 feet. The differences in population growth rates, topography, and weather result in distinct patterns of demand, consumption, and customer growth within each region that must be taken into account during the planning process.

While the economic climate has slowed population growth significantly in recent years, UNSE's service areas are still expected to experience significant growth after the recessionary environment in Arizona subsides. This anticipated growth will likely require the acquisition of additional resources in order to provide service to an increasing customer base.

Map 1 - Service Area of UniSource Electric

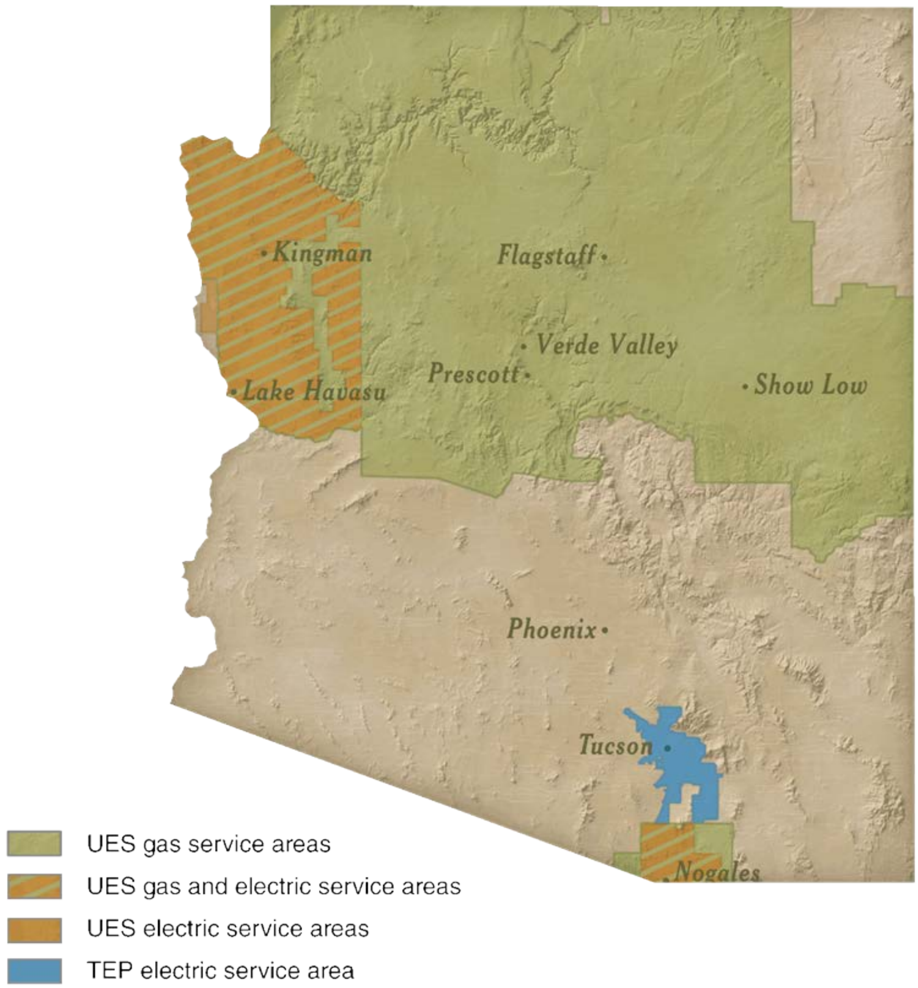
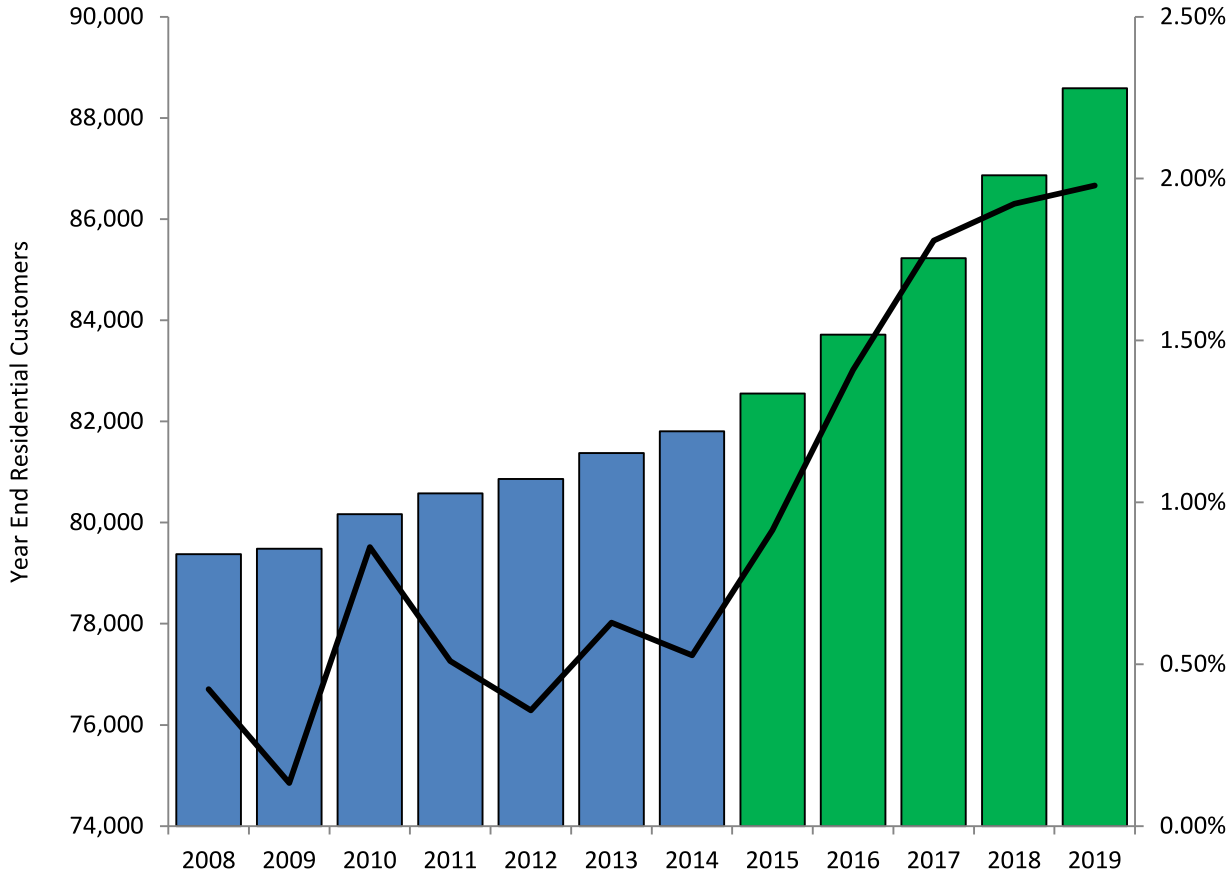


Chart 6 summarizes the historical and projected UNSE residential customer growth from 2005-2017.

Chart 6 - UNSE Customer Growth 2008-2019

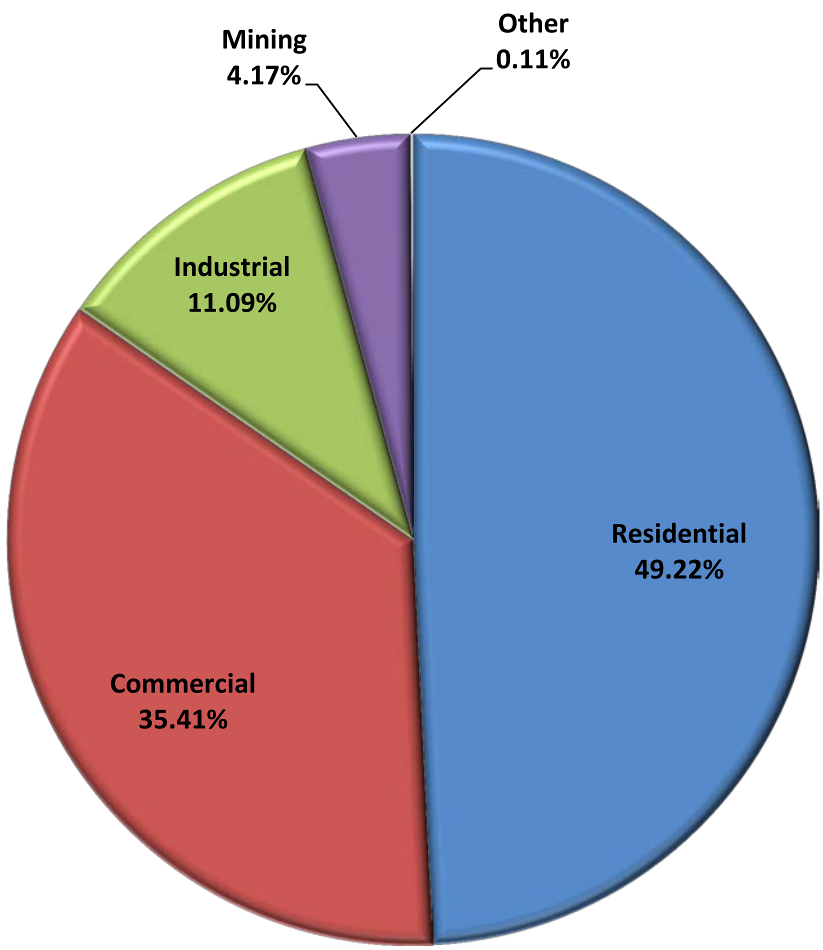


While the economic climate has slowed population growth significantly in recent years, UNSE's service area is still expected to experience significant growth after the recessionary environment in Arizona subsides. This anticipated growth will likely require the acquisition of additional resources in order to provide service to a larger number of customers.

Retail Sales by Rate Class

In 2013, UNSE experienced peak demand of approximately 430 MW while generating approximately 1,700 GWh of retail sales. Approximately 85% of 2013 retail sales were generated by the residential and commercial rate classes, with approximately 15% generated by the industrial and mining rate classes. Chapter 7 details estimated 2014 UNSE retail sales by rate class

Chart 7 – Estimated 2014 Retail Sales % by Rate Class



Reference Case Forecast

Methodology

The load forecast used in the UNSE 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). Widely varying customer usage patterns and weather in Mohave and Santa Cruz counties, as well as significant differences between customer usage and weather in the Kingman area and the Lake Havasu City area within the Mohave service territory also require that the forecasts be further segmented into three distinct geographical projections. The forecast 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. heating and cooling degree days), demographic forecasts (e.g. population growth), and economic conditions (e.g. GCP 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.

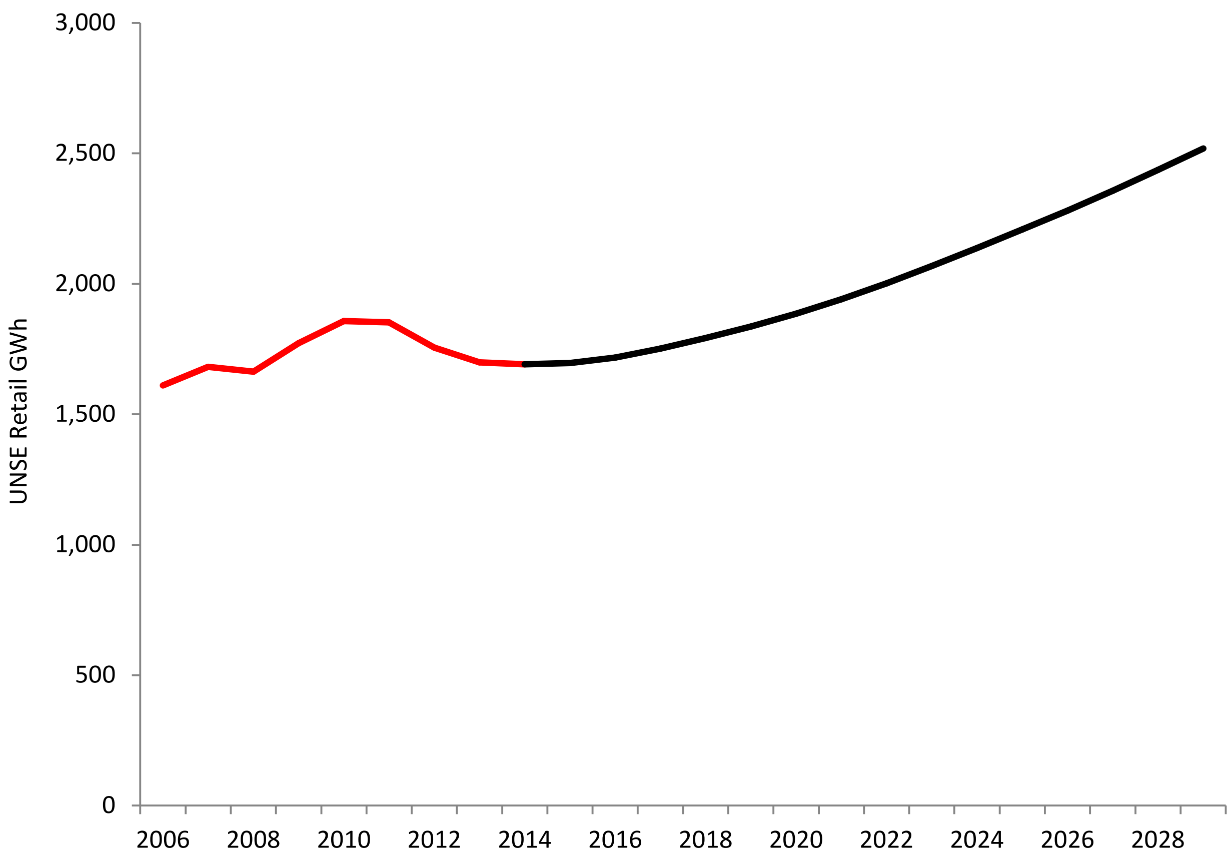
After the individual monthly forecasts are produced, they are aggregated (along with any remaining miscellaneous consumption falling outside the major categories) to produce a monthly energy forecast for the company.

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 estimates the peak demand for each month based on the historical relationship between consumption and demand in the month in question. Annual peak demand was then calculated by simply taking the maximum monthly peak demand for each year in the forecast period.

Reference Case Retail Energy Forecast

As illustrated in Chart 8, UNSE's retail sales have been, in aggregate, relatively flat since 2007. Total energy sales are expected to rebound in the near future and increase steadily throughout the forecast horizon. Chart 8 excludes the effects of distributed generation and energy efficiency.

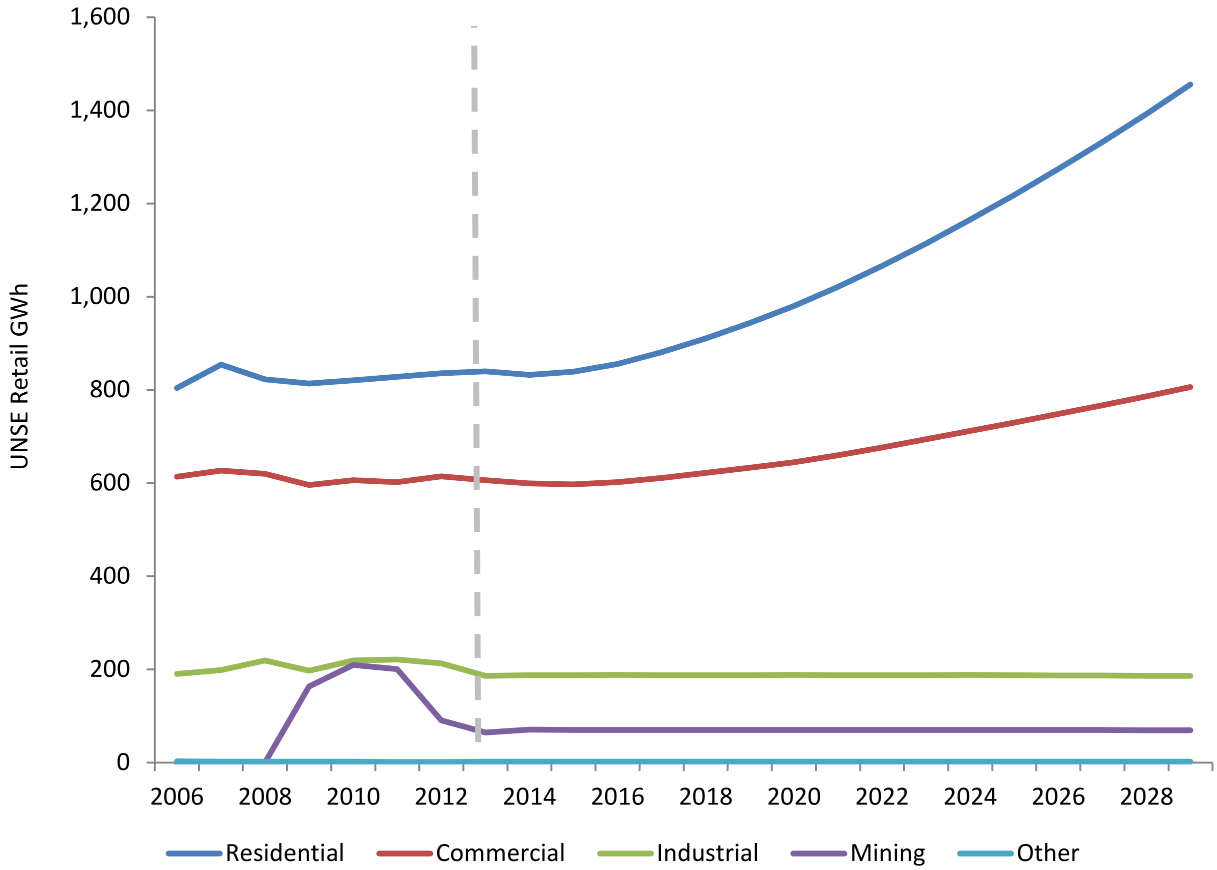
Chart 8 - Reference Case Retail Energy Sales



Reference Case Retail Energy Forecast by Rate Class

As illustrated in Chart 9, the reference case forecast assumes significant, steady energy sales growth at UNSE 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 9. Chart 9 excludes the effects of distributed generation and energy efficiency.

Chart 9 - Reference Case Retail Energy Sales by Rate Class

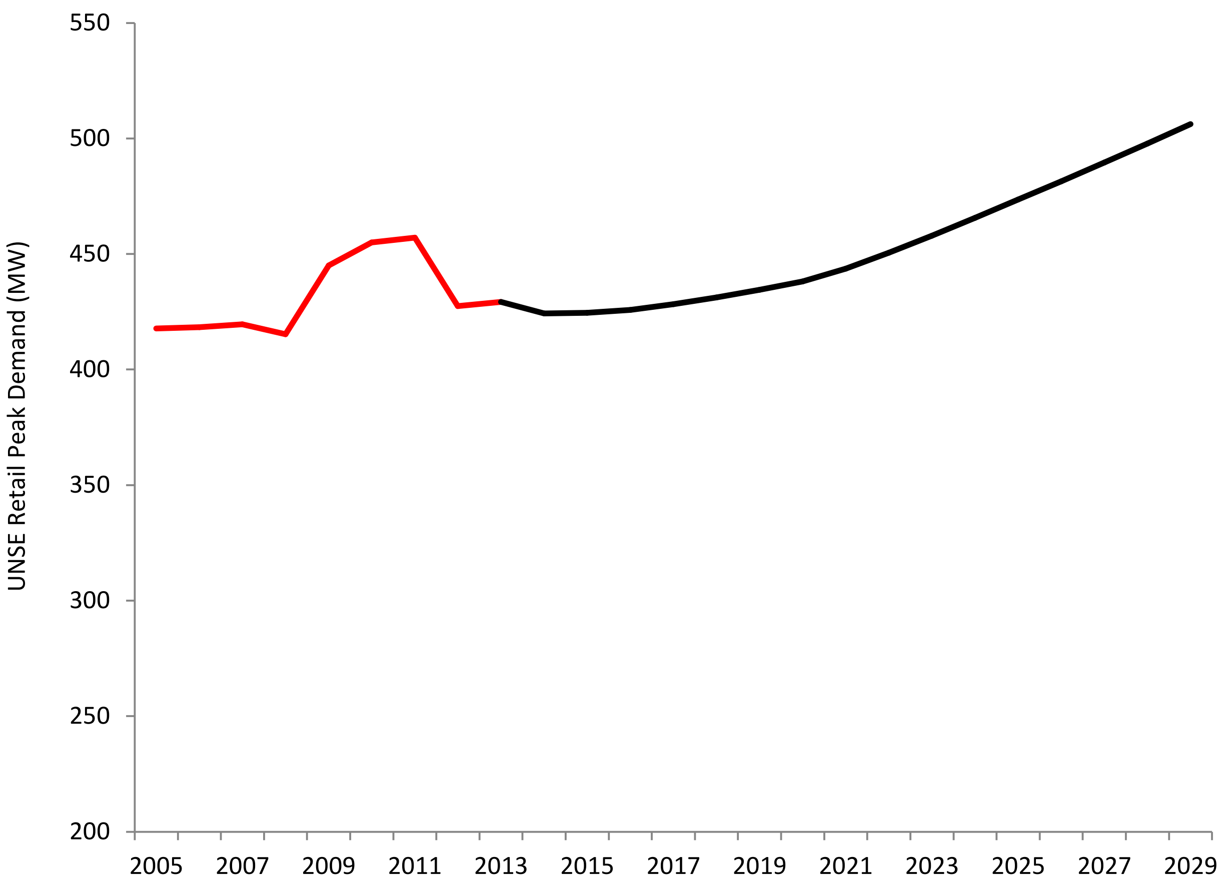


Reference Case Peak Demand Forecast

As illustrated in Chart 10, UNSE's peak demand has been, in aggregate, relatively flat since 2007. Demand is expected to increase at a significant rate throughout the forecast period.

Note that, all references to peak demand are "coincidental" peak system demand (i.e. the highest demand seen simultaneously in the Mohave and Santa Cruz service areas). Due to geography, the two service areas typically experience individual service area peaks at different times with the Santa Cruz peak typically occurring in June and the Mohave peak typically occurring in July or August. Because Mohave County generates much higher demand (and energy sales), the UNSE coincidental system peak also typically occurs in July or August.

Chart 10 - Reference Case Peak Demand



Data Sources Used in Forecasting Process

As outlined above, the reference case forecast requires a broad range of inputs (demographic, economic, weather, etc.) For internal forecasting processes, UNSE 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
- NOAA
- Weather Underground

Risks to Reference Case 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 UNSE 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 11.

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 in the next section.

Load Growth Scenarios

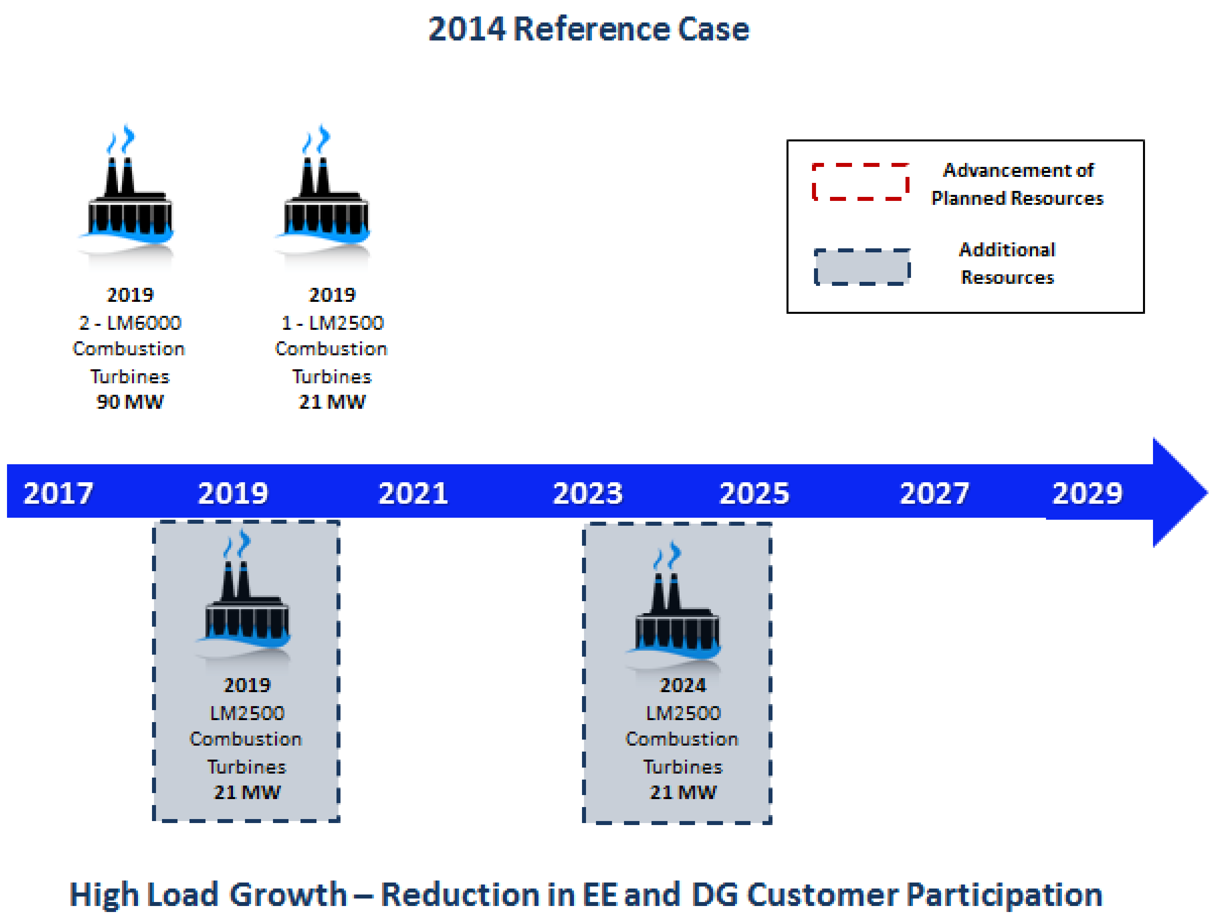
The 2014 Reference Case projects UNSE peak demand staying relatively flat due to customer participation in energy efficiency and distributed generation programs. This change in grow assumes no significant expansions in UNSE's large industrial customers and assumes that targets for energy efficiency (22% by 2020) and distributed generation (30% of 15% by 2025) are realized per Arizona state standards.

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

Reduction in Energy Efficiency or Distributed Generation

For purposes of this change in load growth scenario, it is assumed that UNSE only achieves about 50% of the energy efficiency and distributed generation targets. Under this scenario, UNSE's peak demand grows between 0.5% and 1.0% per year. This change in the forecast has only moderate impacts on UNSE's 2014 Reference Case plan. As shown in Figure 8 below, UNSE would have to install additional combustion turbines in 2019 and 2024 as the result of this increased load growth.

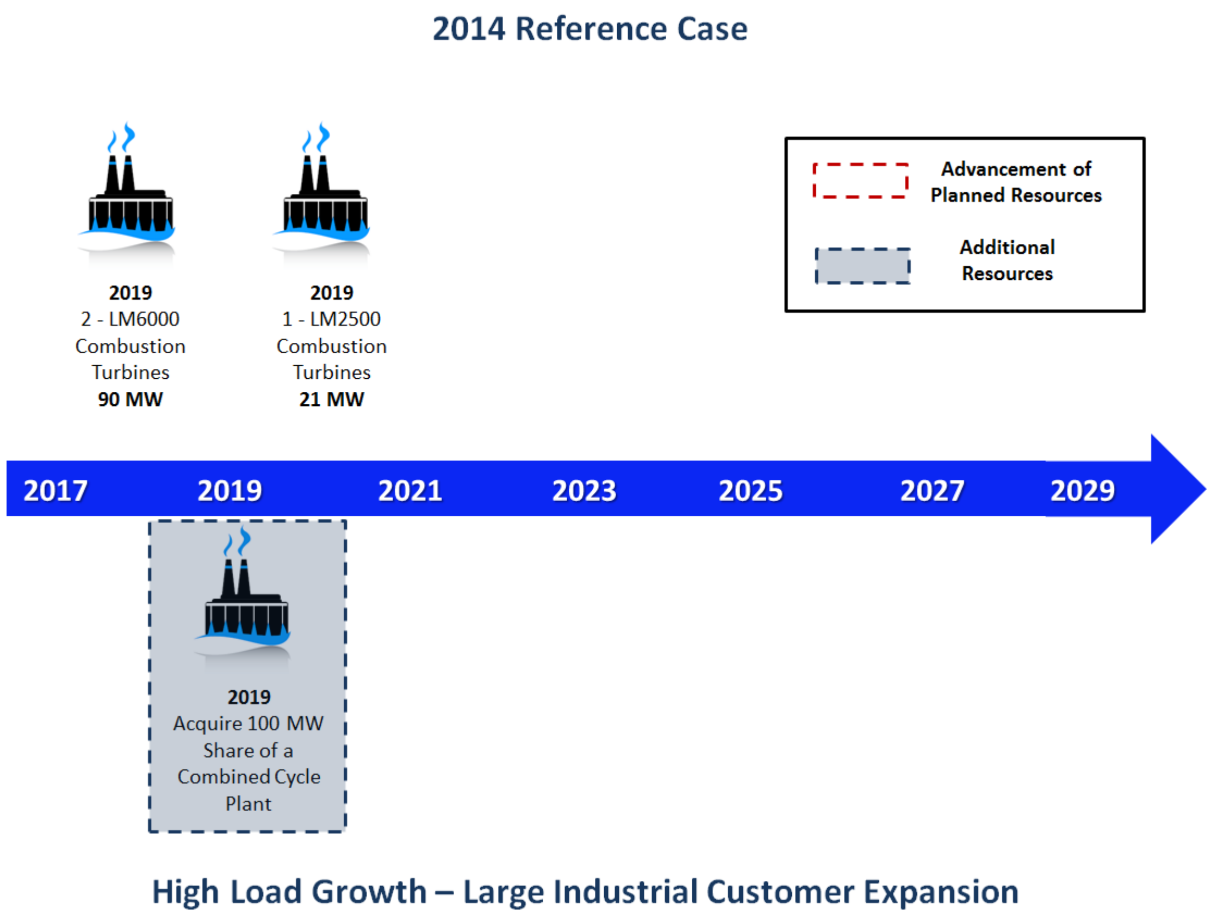
Figure 8 – Reduction in EE and DG Load Growth Scenario



Large Industrial Customer Expansion

For purposes of this load growth scenario, it is assumed that UNSE'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, UNSE's peak demand increases by 50 MW in 2017 and again in 2019 by 50 MW (for a total of 100 MW, a 10% increase in retail demand). This change in the forecast would result in the need for additional generation resources in the near term. As shown in Figure 9 below, UNSE 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 an additional 100 MW share from a combined cycle resource starting in 2019.

Figure 9 – Reduction in EE and DG Load Growth Scenario



CHAPTER 4

EXISTING RESOURCE CAPACITY

UNSE's Existing Resource Portfolio

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

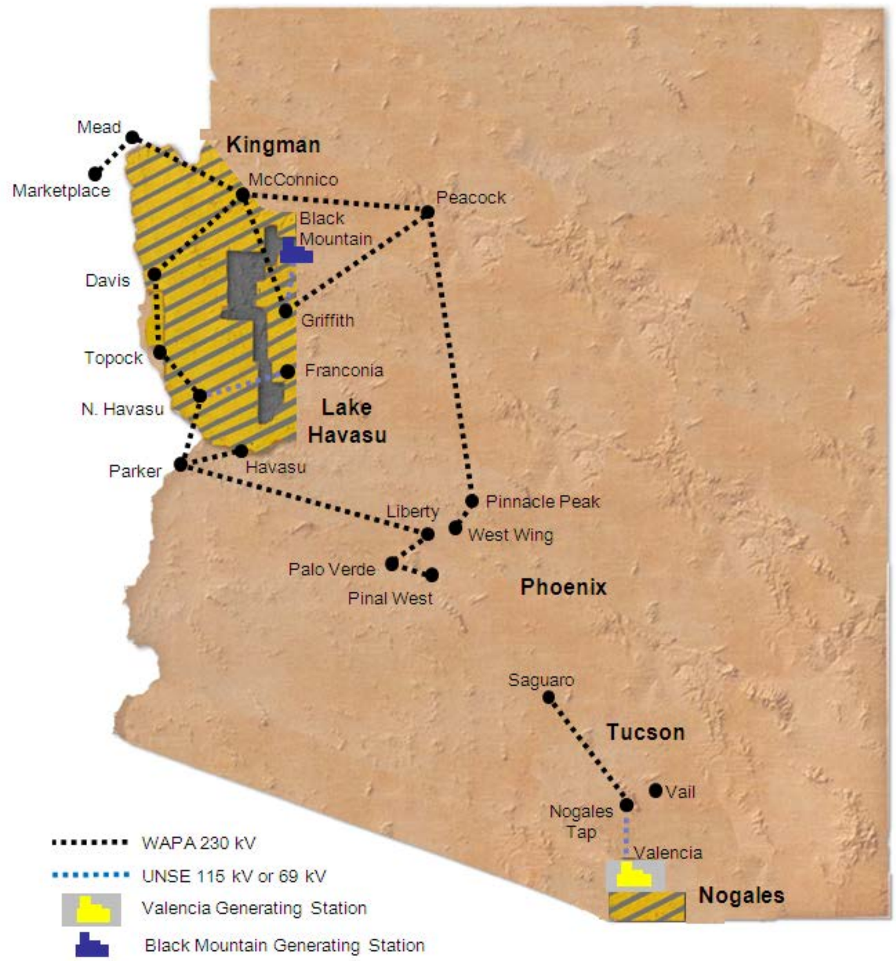
UNSE's existing resource capacity that is currently owned is 153 MW. In addition, the Company also relies on the wholesale market for the balance of its resource needs. Table 5 provides a summary of UNSE's existing resources.

Table 5 - UNSE Existing Resource Portfolio

Generating Station	Unit	Fuel Type	Technology	Commercial Year	Operating Agent	UNSE's Share %	Planning Capacity
Black Mountain	1	Gas	Turbine	2008	UNSE	100	45
Black Mountain	2	Gas	Turbine	2008	UNSE	100	45
Valencia	1	Gas	Turbine	1989	UNSE	100	14
Valencia	2	Gas	Turbine	1989	UNSE	100	14
Valencia	3	Gas	Turbine	1989	UNSE	100	14
Valencia	4	Gas	Turbine	2008	UNSE	100	21
Total Resource Capacity							**153**

Existing Resource Overview

Map 2 - UNSE Generation and Transmission Resources



Black Mountain Generating Station

Station Overview

The Black Mountain Generating Station (BMGS) is located in Kingman, Arizona and provides UNSE with 90 MW of combustion turbine capacity.

Primary Fuel Supply

The Company purchases natural gas for Black Mountain on the spot market.

Black Mountain Generating Station

Black Mountain Emission Controls

Black Mountain Generating Station is a natural gas-fired combustion turbine with dry LNB and SCR for NOx control. As a greenfield site, a Prevention of Significant Deterioration (PSD) permit was obtained prior to construction. A PSD permit requires that BACT be applied for control of SO2 and NOx, and the facility must comply with the Acid Rain program limits for SO2 and NOx.

Black Mountain (2012)	SO2	NOx	CO2	PM	Hg	Water (Acre Feet)
Air Emissions, Pounds	2,604	70,800	88,754,000	5,293.08	0.17	34.81
Air Emissions, lbs/MWh	0.03	0.94	1,173.76	0.07	0.00	150

Valencia Generating Station

Station Overview

The Valencia Generating Station (VGS) is located in Nogales, Arizona and provides UNSE with 63 MW of combustion turbine capacity.

Valencia Generating Station

Primary Fuel Supply

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

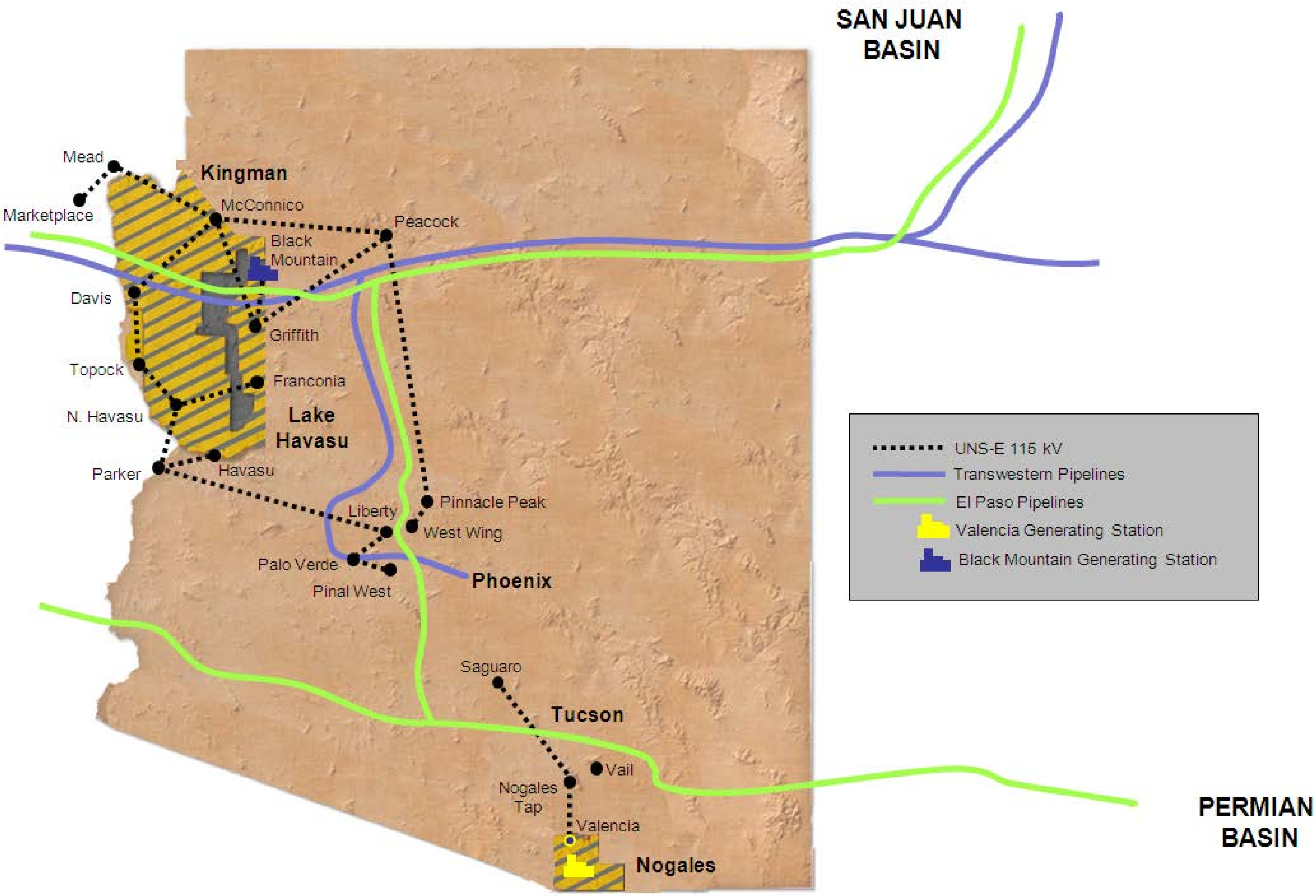
Environmental Controls

Valencia Power Plant (VPP) combustion turbine Units 1-4 burn natural gas and diesel fuel, and each unit is equipped with water spray injection for control of NOx. Plant wide voluntary emission limits of 250 tons per year for SO2 and NOx were incorporated into the Title V permit in order to maintain below "major source" thresholds. Each of the units is required to meet NSPS for NOx and SO2. However, each of these units is less than 25MW capacity; therefore, they are not subject to Acid Rain provisions.

Valencia (2012)	SO2	NOx	CO2	PM	Hg	Water (Acre Feet)
Air Emissions, Pounds	479	16,462	26,140,000	1,316	4.32E-02	8.65
Air Emissions, lbs/MWh	0.03	0.88	1,390.38	0.07	2.30E-06	150

UNSE Generation and Primary Natural Gas Sources

Map 3 - Map of UNSE Generation and Primary Natural Gas Sources



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. UniSource Energy strives to maximize the value of service to our 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 maintained. This assessment of the existing resources and market purchases, in part, predetermine the need or resource adequacy for the future. In this chapter, we will present an assessment of generation resources, culminating with a preview of the generation required in order to maintain a flexible, conscientious and adequate balance of resources.

Load and Resource Assessment

The mix of existing resources for UniSource Electric Services (UNSE) at Mohave and Santa Cruz counties consists of six gas-fired combustion turbines (159 MW) and starting in 2015 it is assumed that UNSE will acquire a 25% ownership share in Power Block 3 at the Gila River Power Station (138MW).

A critical component to the IRP is the assessment of resources and the corresponding load obligations. UNSE's peak demand occurs during the summer months of June and July. Table 6 presents a tabular assessment of UNSE's resources and loads for the single-hour peak demand for the years represented.

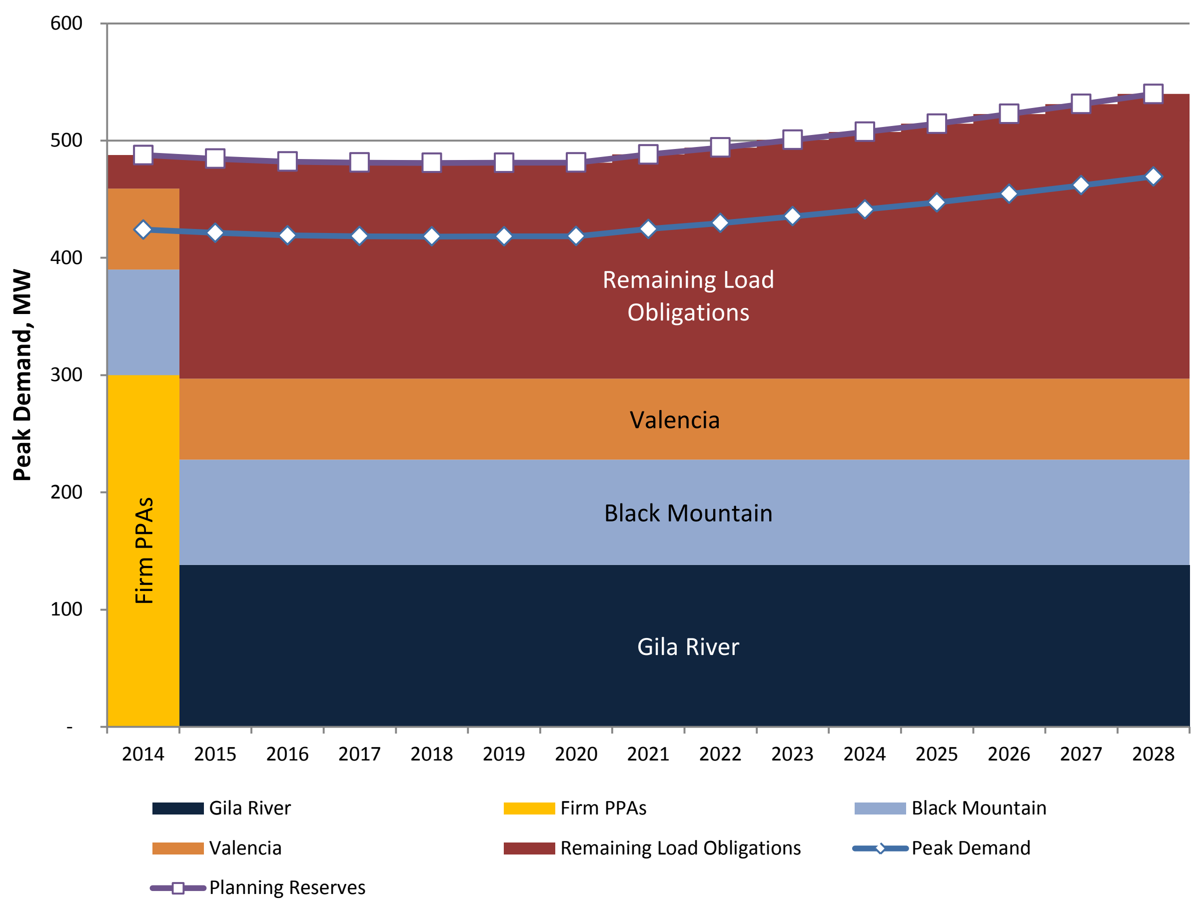
Table 6 - UNSE Existing Load and Resources (Excluding Future Resources)

Firm Load Obligations (MW)	2014	2015	2016	2017	2018	2019	2020
Retail Peak Demand	424	421	419	418	418	418	419
Reserve Requirements	64	63	63	63	63	63	63
Retail, Firm & Reserves	488	485	482	481	481	481	481
Resource Capacity	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Total Thermal Resources	159	297	297	297	297	297	297
Total Firm PPAs	300						
Total Firm Resource Capacity	459	297	297	297	297	297	297
Net Capacity Obligations	29	188	185	184	184	184	184

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 on 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 UNSE's capacity obligations.

A visual depiction of - UNSE Existing Loads and Resources is presented below, in Chart 11. The top-most area in orange represents the Net Capacity Obligation for the planning period. Included in this figure is an 'Planning Reserve' target which represents about 15% 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 11 - UNSE 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 10 – 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

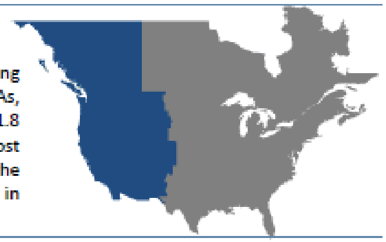
	WECC-CAMX Percent (%)	WECC-NWPP Percent (%)	WECC-RMRG Percent (%)	WECC-SRSG Percent (%)
Anticipated Reserve Margin	17.88	21.20	53.32	33.87
Prospective Reserve Margin	17.88	21.20	53.32	33.87
NERC Reference Margin Level	15.01	15.02	14.45	13.56

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 11 – NERC 2013 Long-Term Reliability Assessment (WECC)

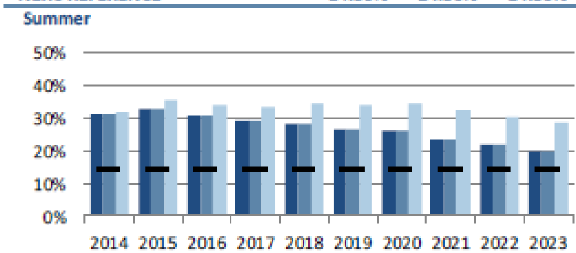
WECC

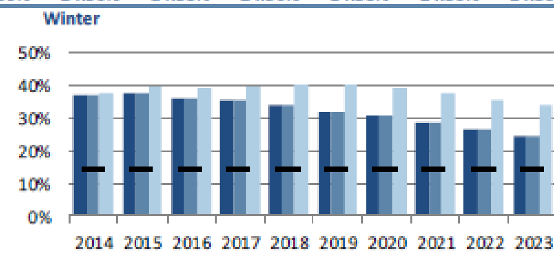


The Western Electricity Coordinating Council (WECC) is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members, which include 39 BAs, represent a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square 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.

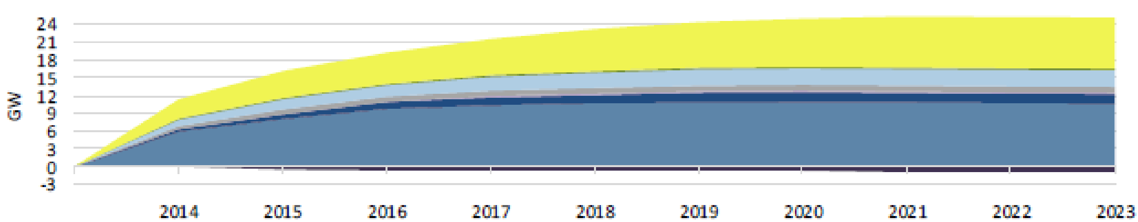
Planning Reserve Margins

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%**





Cumulative 10-Year Planned Capacity Change

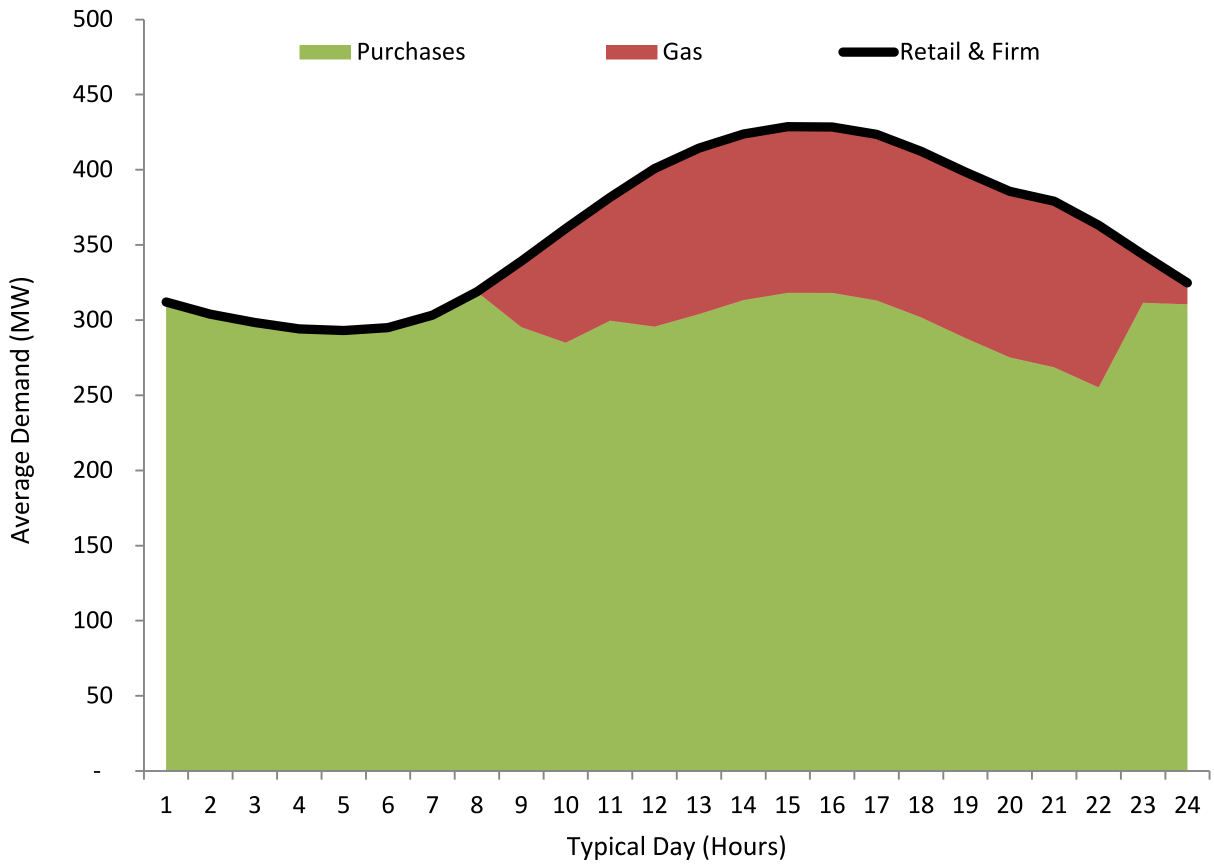


	2013 Existing		2023 Planned			2023 Planned & Conceptual		
WECC-TOTAL	Capacity (MW)	Share (%)	Capacity (MW)	Share (%)	Change (MW)	Capacity (MW)	Share (%)	Change (MW)
Coal	38,798	19.7%	37,787	17.1%	-1,011	37,787	16.0%	-1,011
Petroleum	1,047	0.5%	1,047	0.5%	0	1,047	0.4%	0
Gas	89,870	45.6%	100,534	45.4%	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 12 - 2015 Typical Summer Day Dispatch and Chart 13 - 2015 Typical Winter Day Dispatch illustrates the manner in which existing resources are expected to be dispatched to meet anticipated load requirements in 2015. The figures do not represent a peak day; instead the demand profiles demonstrated in these figures are an average typical day representative of each season for 2015. Chart 12 and Chart 13 are derived from a production costing model that dispatches resources economically to serve firm load and wholesale obligations. The area shown above the 'Retail & Firm' line represents opportunity sales made to the spot market.

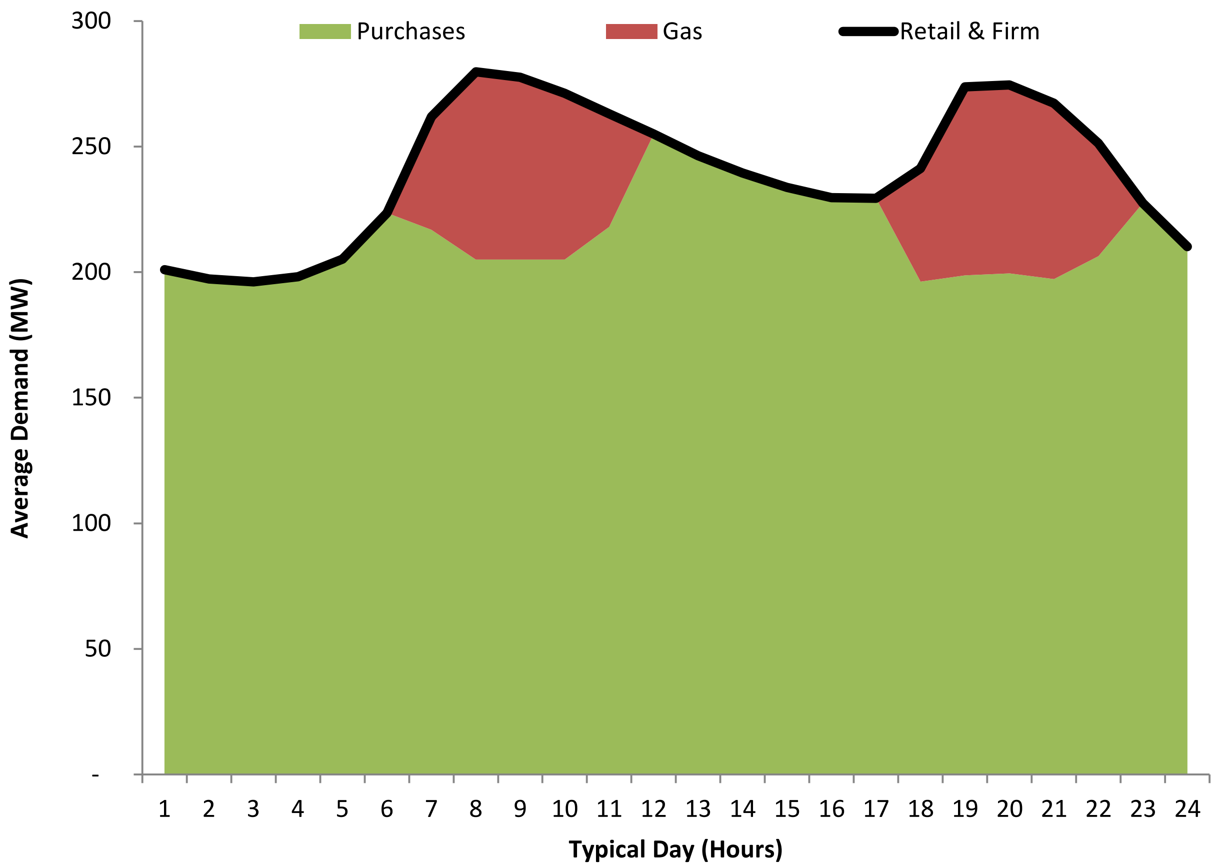
Chart 12 - 2015 Typical Summer Day Dispatch



In Chart 12 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). If indeed there is capacity available for purchase, the gas and energy market price forecasts dictate that a part of UNSE'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. As demonstrated in Chart 12, UNSE experiences its peak demand at 4 to 5 PM in either July or August.

The UNSE winter load profile, as seen in Chart 13 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 13 - 2015 Typical Winter Day Dispatch

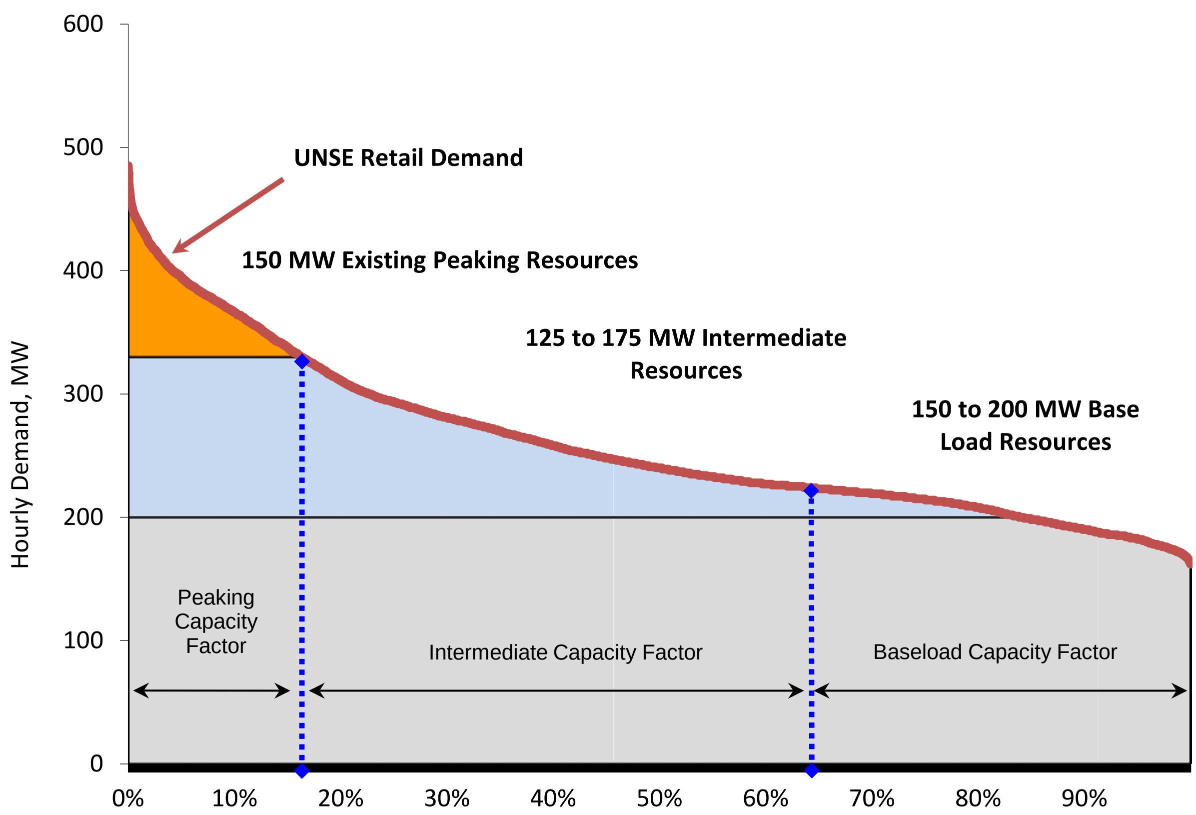


Projected Capacity Requirements

The seasonal load diversity in UNSE's service territory presents different challenges and opportunities. UNSE is strictly active as a buyer in the wholesale market during the winter and summer seasons. In the summer, the focus is shifted toward meeting the retail and firm peak demand. Gas turbines are more routinely dispatched to meet 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.

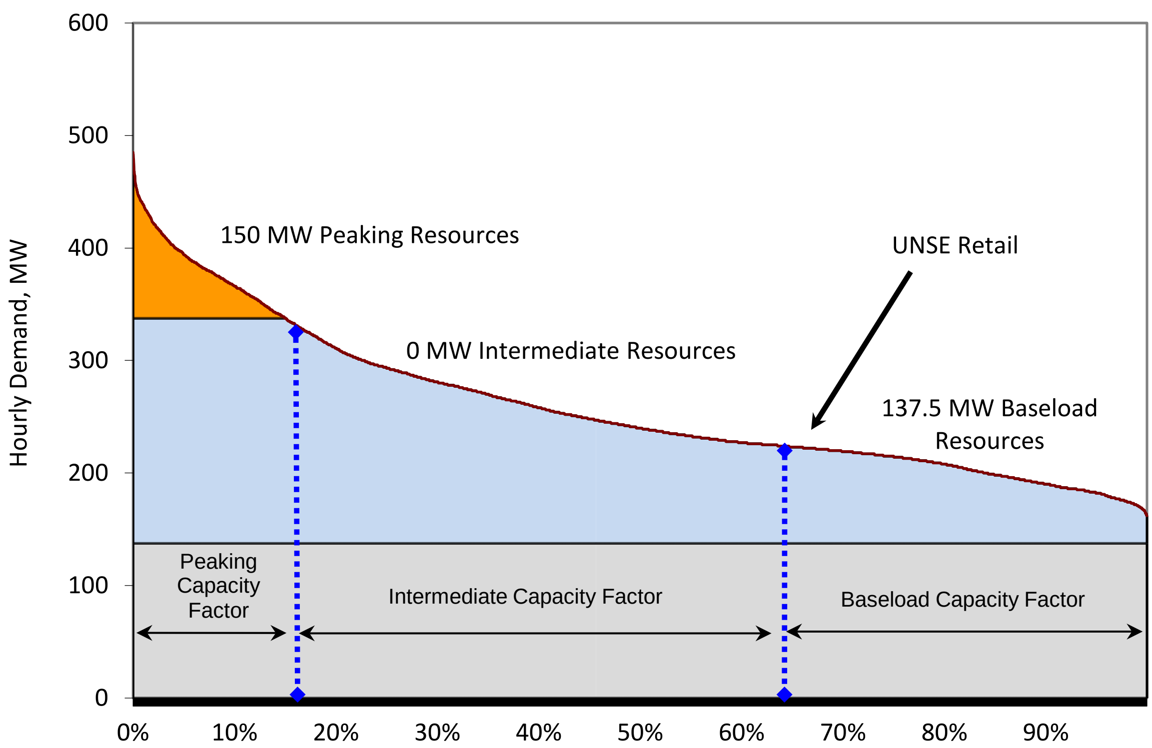
The 'base load' requirement can be defined as a minimum level of demand on an electrical system over a specified time interval. Base load generation is dependable, consistent and low cost and is dispatched to serve above the minimum requirement. This specific type of generation is most efficient and 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. UNSE has no base load units and currently relies on the market for base load capacity. In 2015, the base load requirements are approximately 150 to 200 MWs.

Chart 14 - 2015 UNSE Load Duration with Suitable Resource Mix



In Chart 15 above, presented and illustrated in the 2014 IRP, that there are approximately 150 MWs of peaking capacity required for 2015. The total peaking capacity present for UNSE is at an acceptable level. For UNSE, the focus was on obtaining intermediate and base load resources. In total, this deficiency is approximately 325 MWs without considering a margin for planning. (With a 15% planning reserve, the capacity shortage is approximately 400 MWs.) UNSE has an adequate amount of peaking resources. Based on this assessment of loads and resources, we determine that it is reasonable to expect to seek base load and intermediate resources foreseeable future. The addition of combined cycle, market purchases and solar resources (or a combination there of) seem to best complement the existing load and resource portfolio. 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. 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. UNSE seeks intermediate type capacity from the market. 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 15% of the time. UNSE has approximately 150 MW of combustion turbines to utilize during the summer peak season. In the summer of 2013, UNS Energy Corporation issued a Request for Proposal (RFP) for Tucson Electric Power. The RFP resulted in the selection of Block 3 of Gila River Power Station (Gila River) submitted by Entegra Power Group LLC. Upon final agreement and execution of the contract terms, UNSE is expected to gain ownership of 25% of Block 3 or 137.5 MW of peaking power capacity. Chart 15 below demonstrates the mix of resources (base load, intermediate and peaking) for UNSE upon the addition of Gila River. UNSE addresses the need for base load and/or intermediate resources in 2015 with the addition of Gila River.

Chart 15 - 2015 UNSE Load Duration with Gila River



MARKET RESOURCES

UNSE's Wholesale Marketing Department is charged with procuring firm capacity to meet UNSE's peak load and reserve requirements. These firm capacity purchases consist of a diversified mix of purchased power agreements, firm short-term purchases and spot-market purchases. UNSE currently utilizes its 3-year hedging policy requirements to systematically lock in future capacity needs. On an on-going basis, UNSE is actively engaged in acquiring competitive market-based generation and transmission resources to meet its future load requirements.

Wholesale Market

The Western Electricity Coordinating Council (WECC) evaluates the Power Supply Margins of sub-regions in the Western Interconnection. The annual Power Supply Assessment (PSA) identifies the potential for supply shortages within the sub-regions of the WECC. The report is based on collaborative and comprehensive feedback from the WECC member utilities. The data reported includes but is not limited to demand and resource data, and transmission constraints within and between the sub-regions. For the 2014, it is assumed that UNSE will rely on the wholesale market to fulfill a major portion of its near-term resources needs through 2019 from the wholesale market.

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 7 - 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	UNSE 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, UNSE 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, UNSE 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	$4.50	$4.50
Levelized Cost $/MWh	$180	$149

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 UNSE 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	$7.60	$7.60
Levelized Cost $/MWh	$168	$186

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 UNSE 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	$5.55	$5.55
Levelized Cost $/MWh	$208	$214

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 UNSE 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 CO2 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%
CO2 Rate, lbs/MWh	850	850
SO2 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%
CO2 Rate, lbs/ MWh	0
SO2 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 8 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.

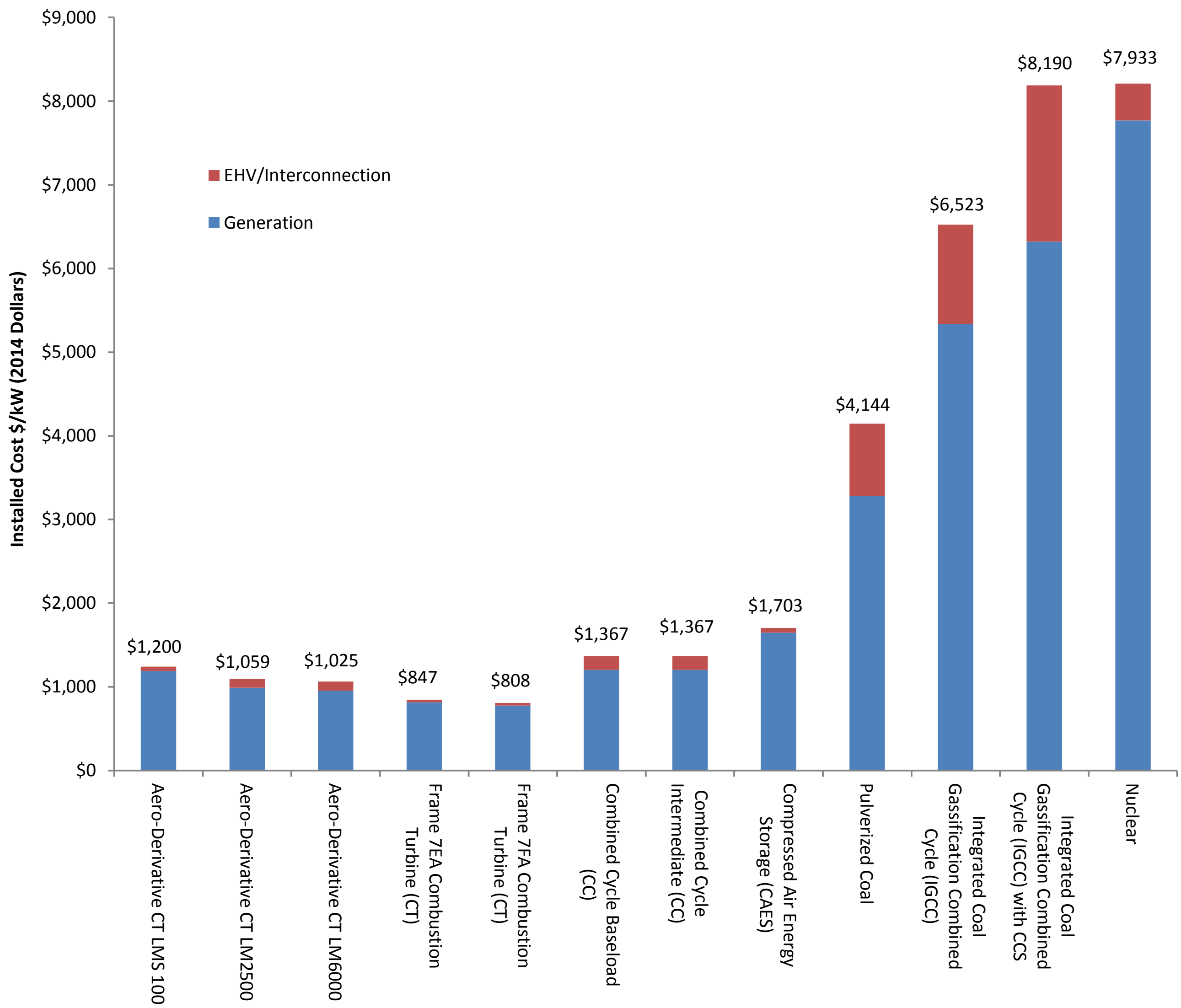
Table 8 - Resource Comparisons

		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	149	0	0
	Arizona (AZ Wind)	2,278	180	0	0
	Solar PV (Single Axis)	3,313	186	0	0
	Solar PV (Fixed)	1,993	168	0	0
	Biomass Direct	3,624	120	100	0
	Solar CSP	5,591	208	800	0
	Solar CSP (Storage)	7,144	214	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 16 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.

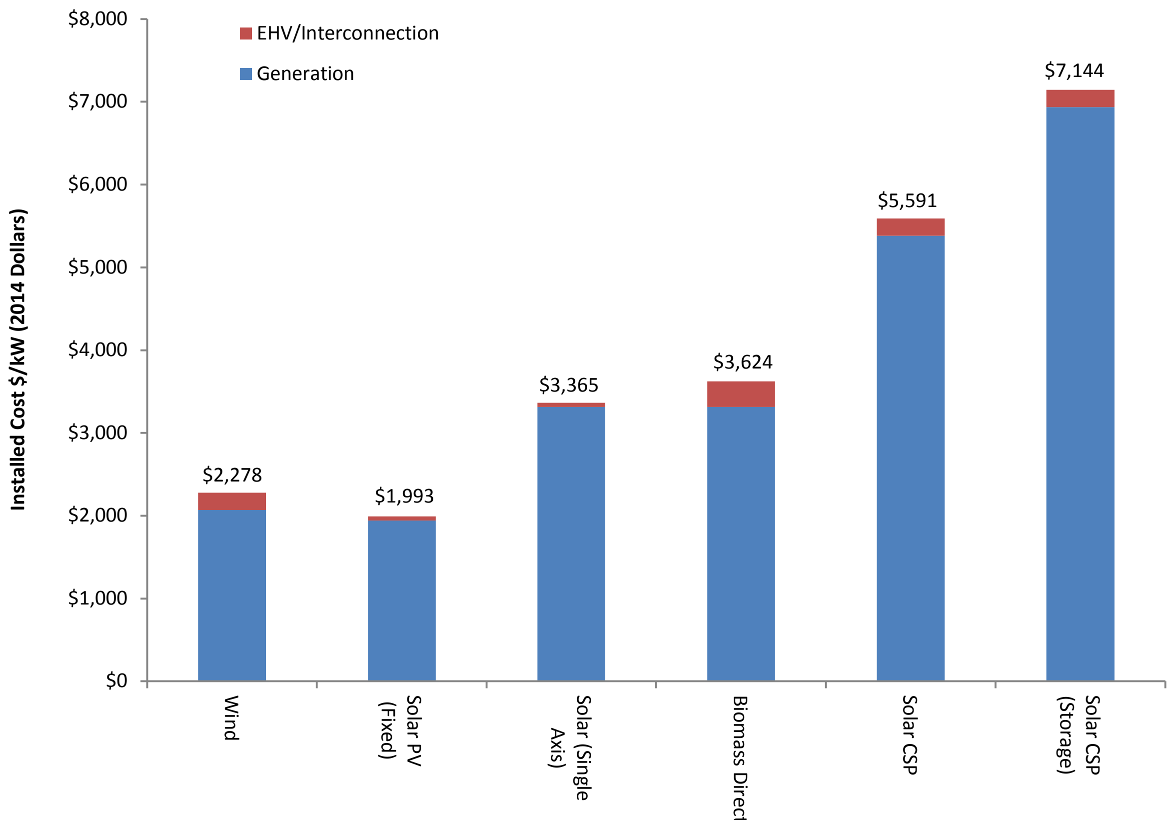
Chart 16 - Conventional Resource Capital Costs, $/kW



Capital Costs – Renewable Resources

Chart 17 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.

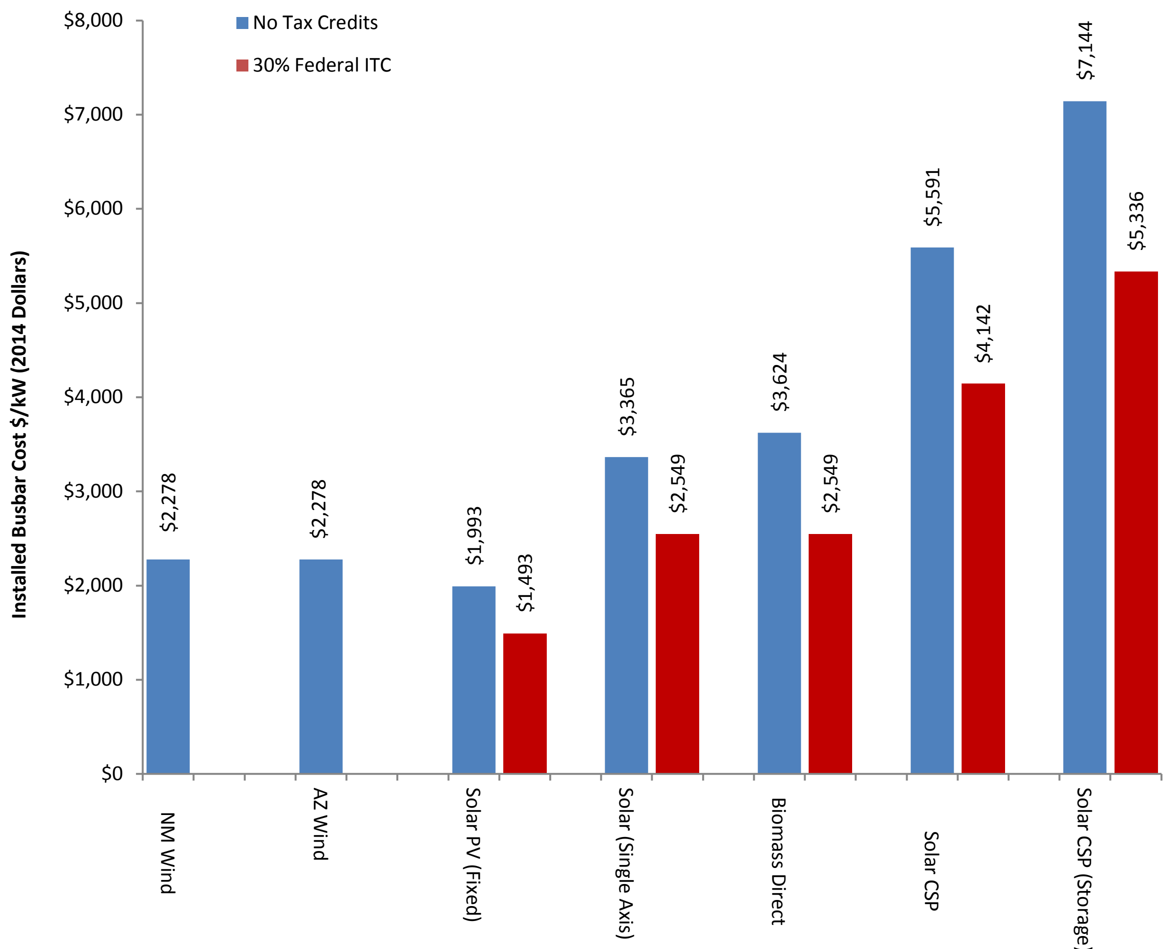
Chart 17 - Renewable Resource Capital Costs, $/kW



The Effects of Investment Tax Credits on Renewables

Chart 18 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 18 - 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.

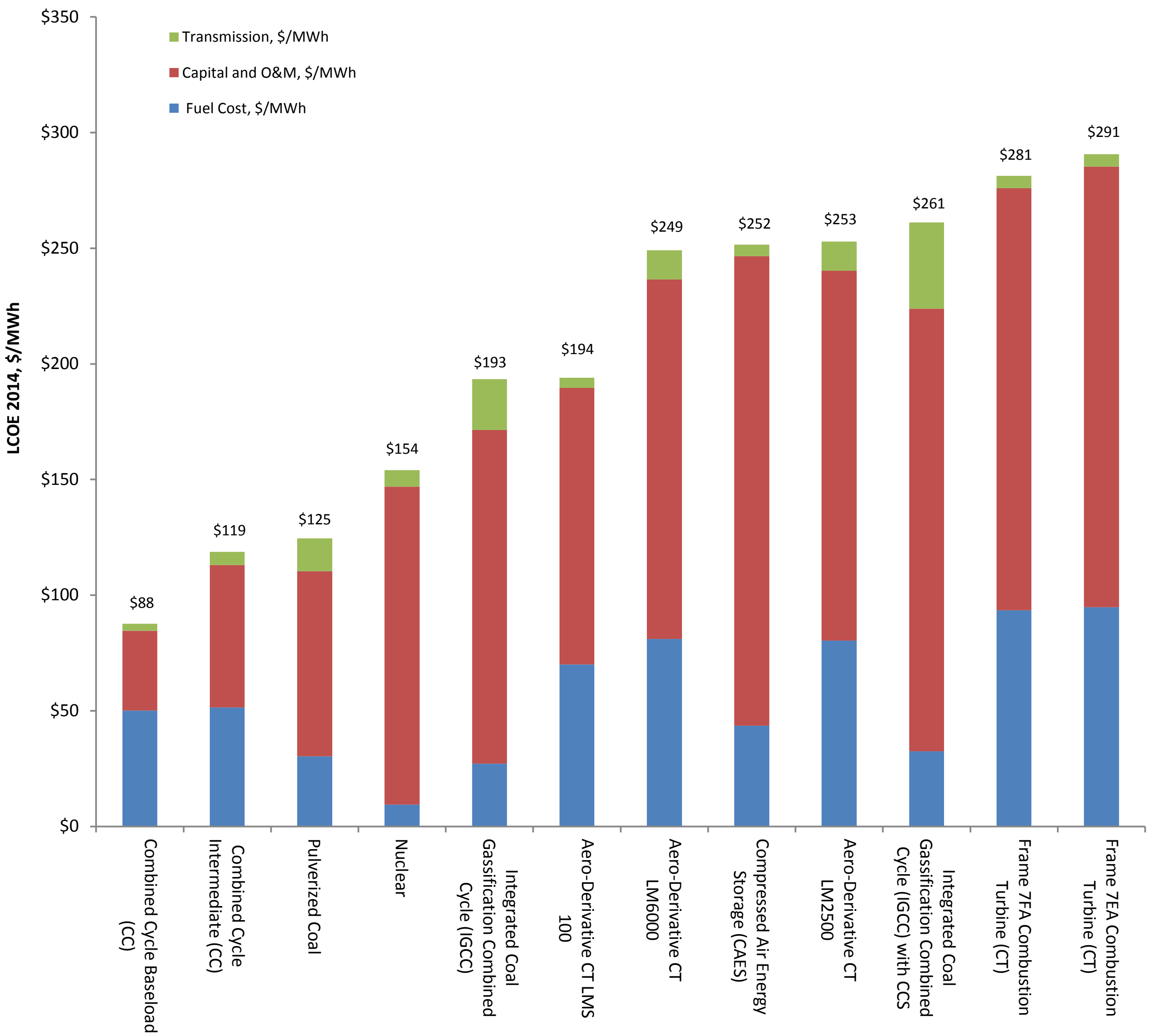
Levelized costs represent the present value of the total cost of building and operating a generating plant over its financial life, converted to equal annual payments and amortized over expected annual generation from an assumed duty cycle.

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 19 below provides a comparison on the levelized 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 $/MWh.

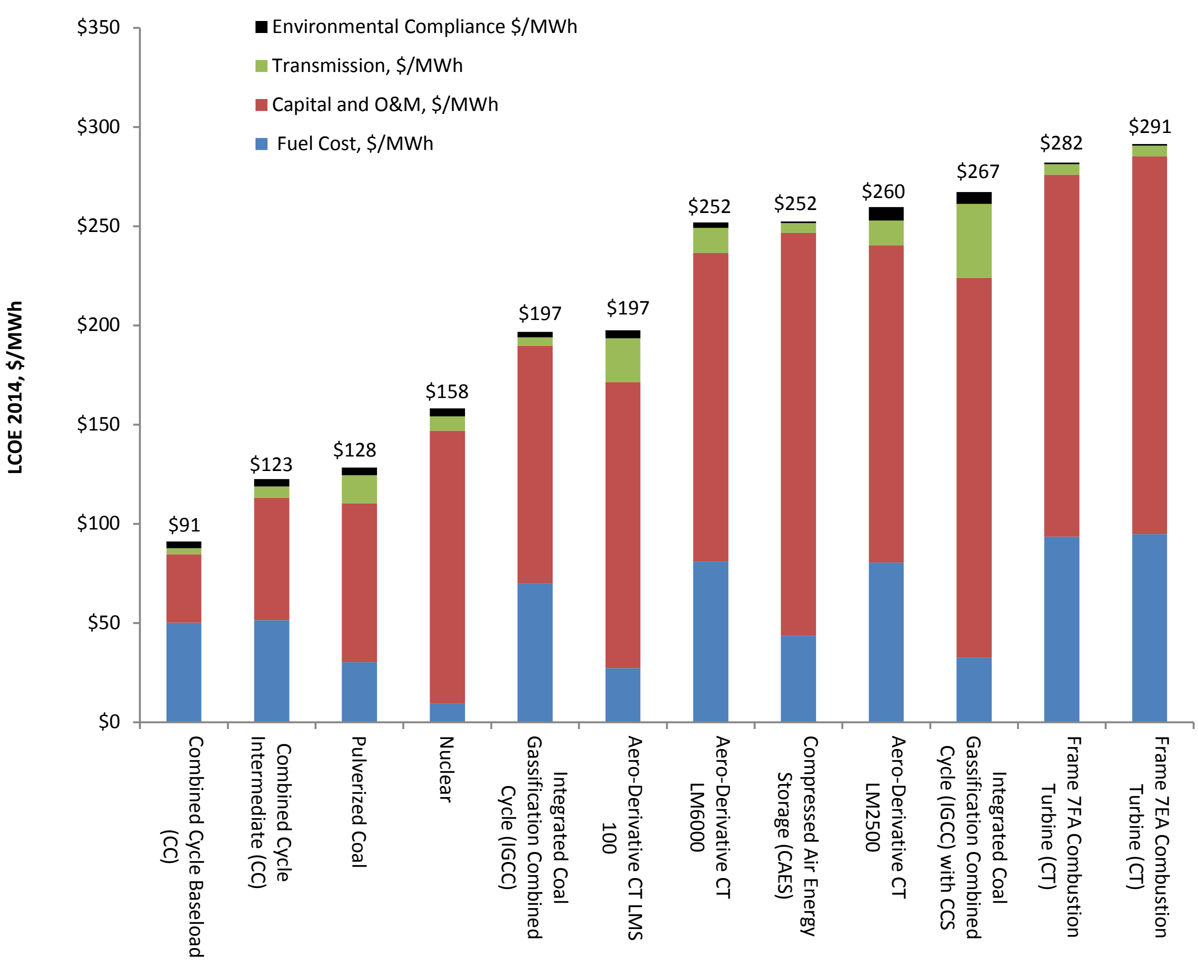
Chart 19 - Levelized Cost of Conventional Resources



LEVELIZED COST OF ENERGY – CONVENTIONAL RESOURCES WITH CO_2

Chart 20 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.

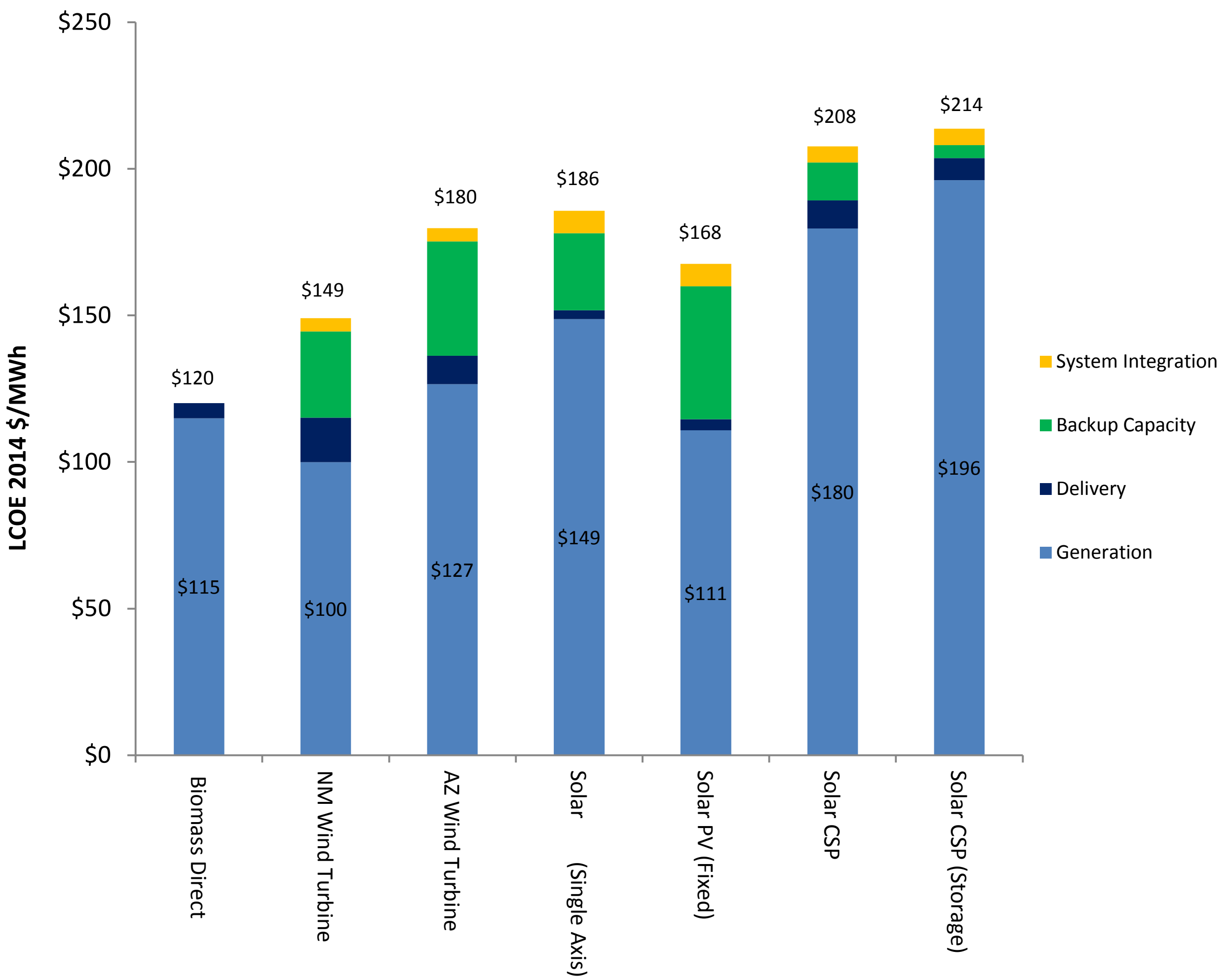
Chart 20 - Levelized Cost of Conventional Resources with CO2 Tax



LEVELIZED COST OF ENERGY – RENEWABLE RESOURCES

Chart 21 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 21 - Levelized Cost of Renewable Resources, $/MWh



All solar technologies assume 30% federal investment tax credit (ITC).

RENEWABLE TECHNOLOGIES – COST DETAILS

Table 9 includes the renewable technology cost assumptions used in the 2014 Integrated Resource Plan.

Table 9 - 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	$4.50	$4.50	$7.60	$7.60	$5.55	$5.55	
Levelized Cost of Energy	$/MWh	$149	$180	$168	$186	$208	$214	$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 10 includes the conventional resource cost assumptions used in the 2014 Integrated Resource Plan.

Table 10 - 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 11 includes the conventional resource environmental assumptions used in the 2014 Integrated Resource Plan.

Table 11 - 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

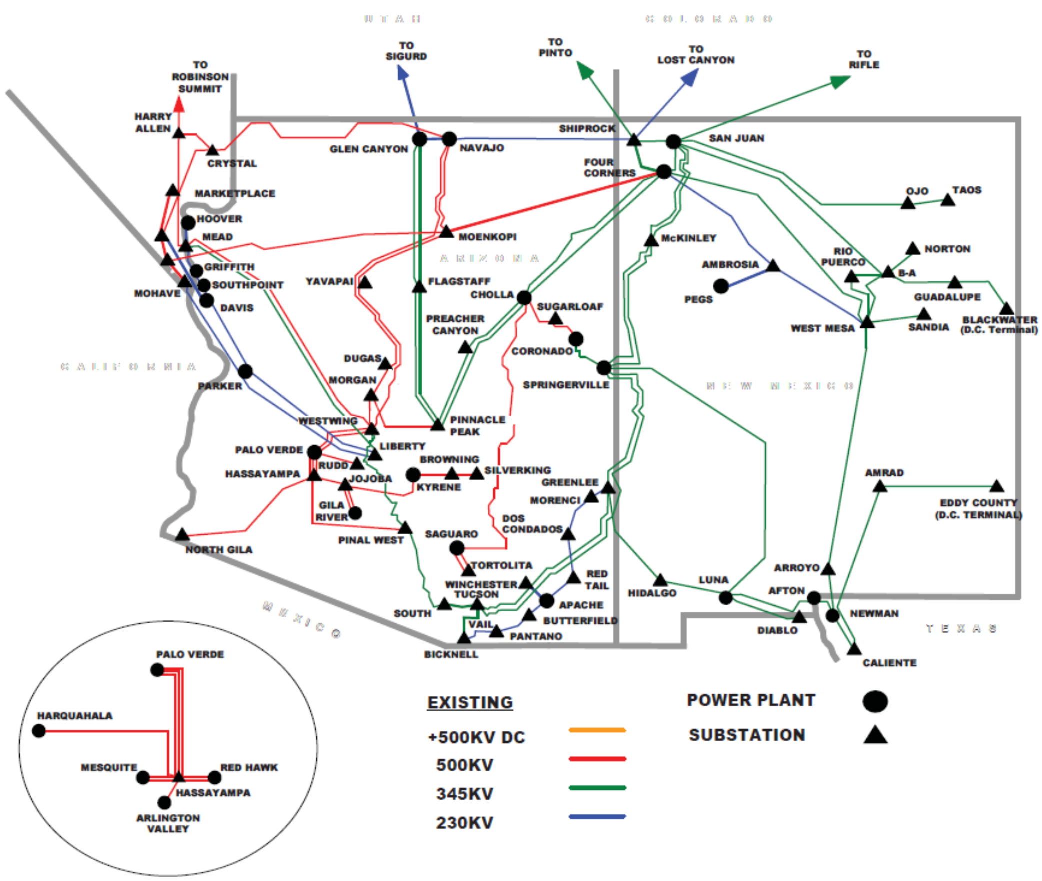
CHAPTER 7

TRANSMISSION RESOURCES

Overview

Transmission resources are a key element in UNSE's resource portfolio. Adequate transmission capacity must exist to meet UNSE's existing and future load obligations. UNSE'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, UNSE 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 4 – Arizona and New Mexico Generation and Transmission



UNSE's Transmission Resources

UNSE's transmission resources include approximately 292 miles of transmission lines owned by UNSE, long-term transmission rights (Point to Point and Network service) purchased from Western Area Power Administration (WAPA), and Point to Point transmission purchased from other transmission providers on an ad hoc basis. Given UNSE's dependence on third-party transmission providers UNSE works closely with WAPA's transmission planning group to ensure adequate long-term transmission capacity is available to serve the Mohave service territories. WAPA has conducting an updated System Impact Study (SIS) for UNSE to address current and future load growth options.

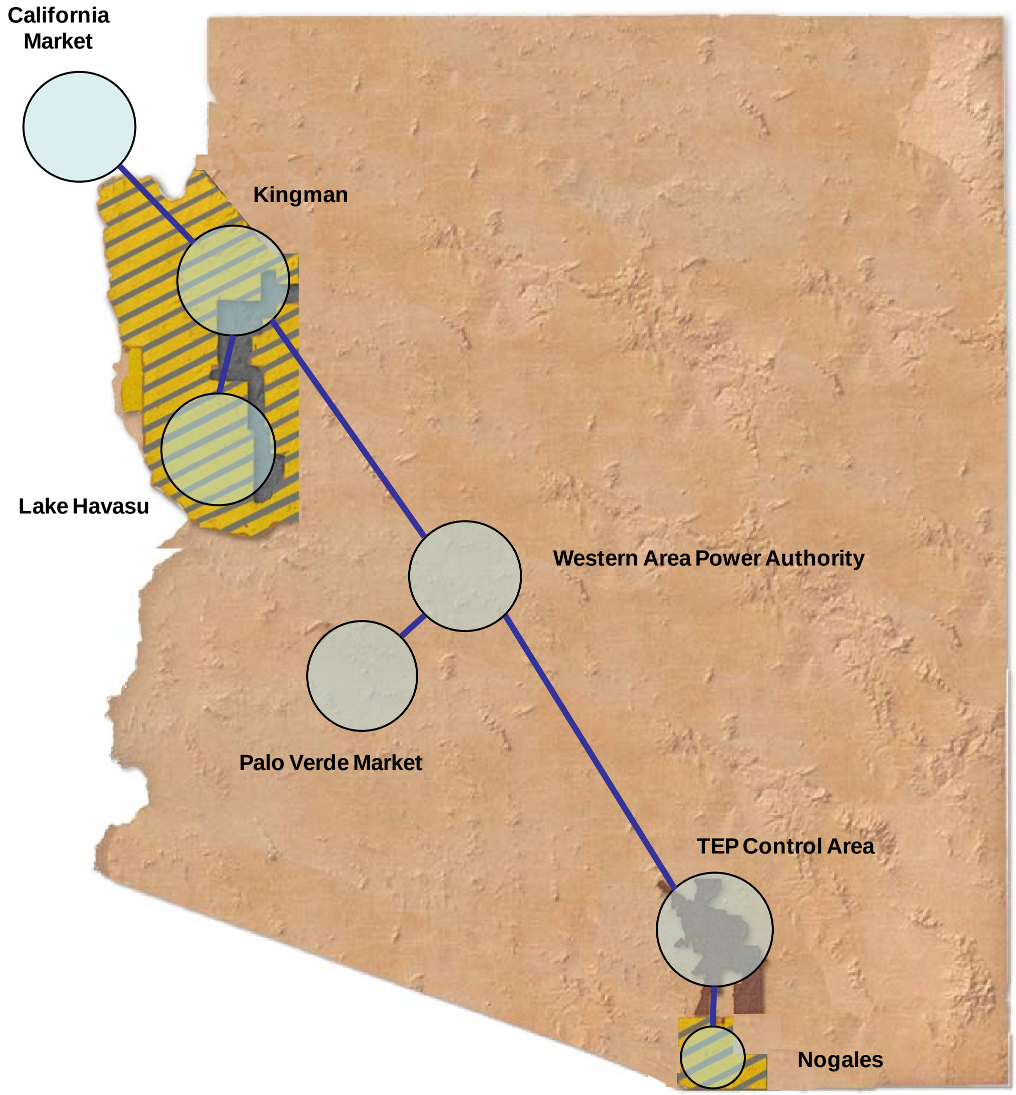
Control Area Services Agreement

Beginning in June 2008, UNSE entered into a long-term Control Area Services Agreement with UNS Electric under which UNSE will manage, for a fee, the UNSE Transmission assets and needs of UNSE. Ancillary Services include: Administration, Reactive Supply & Voltage Control, Regulation& Frequency Response, Spinning Reserve and Energy Imbalance. Services and charges under this Control Area Services Agreement are provided under UNSE's FERC approved Open Access Transmission Tariff (OATT).

UNSE's Projected Load Serving Capability

For the 2014 IRP, UNSE applied an integrated generation and transmission approach to maximize UNSE's future retail load serving capability. UNSE's load serving capability is defined as the sum of local area generation capacity plus UNSE's transmission import capacity at system peak. As a result of this work, UNSE developed future generation and transmission portfolios which optimized both the supply-side requirements with future transmission investments. Based on WAPA's available transmission capacity, the load serving capability for Mohave County is sufficiently above the load projections within the study period of this IRP. In Santa Cruz County, UNSE has completed the new Vail to Valencia 115 kV to 138 kV transmission upgrade in December 2014 fulfilling Phase 1 of its Continuity of Service Plan. Phase 2 of the Continuity of Service Plan will require UNSE to build out additional local area generation in the City of Nogales. Based on current load projections, these additional generation resources will not be needed until 2022. Under Phase 1 and Phase 2 of UNSE's Continuity of Service Plan, UNSE is expected to meet the load serving capacity requirements of Santa Cruz County through 2030.

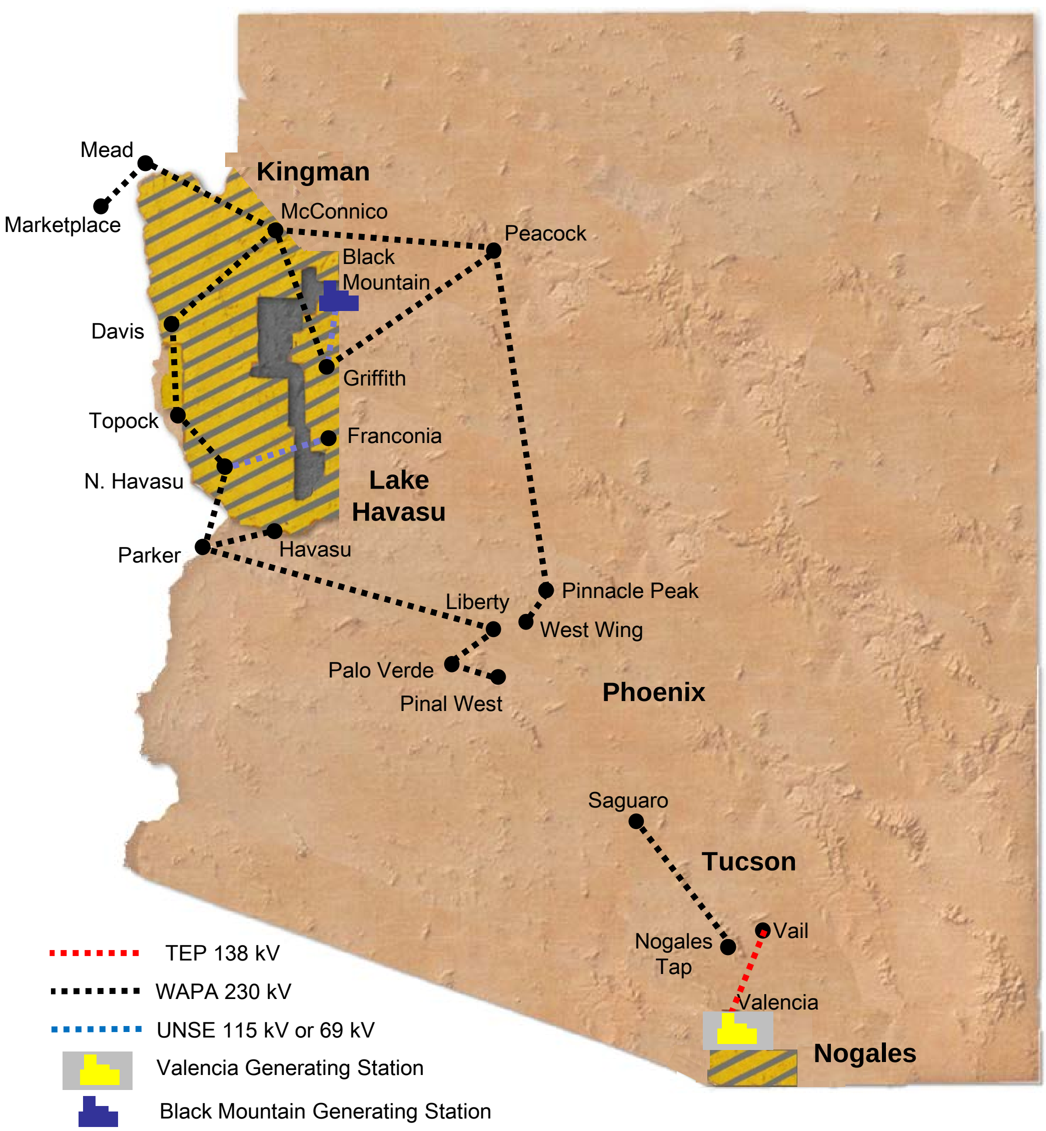
Map 5 - UNSE Load and Market Delivery Points



Existing Transmission Resources

UNSE existing transmission system as constructed is contained within 2 service areas in Arizona; Mohave and Santa Cruz counties. As shown on Map 6, the UNSE-Mohave service territory area supplied by Western's 230 kV network which is interconnected to the EHV transmission system via three 345 kV substations: Mead, Liberty and Peacock. Firm system purchases designated as Network Resources are delivered to Pinnacle Peak. UNSE-Mohave receives NITS from Western at several 230 kV points of delivery including: Hilltop, McConnico, Black Mesa, North Havasu, and Griffith. These stations interconnect and supply energy to the local system. UNSE owns approximately 236 miles of 69kV transmission lines in Mohave County and 56 miles of 138kV transmission lines in Santa Cruz County.

Map 6 - UNSE Transmission Delivery Points

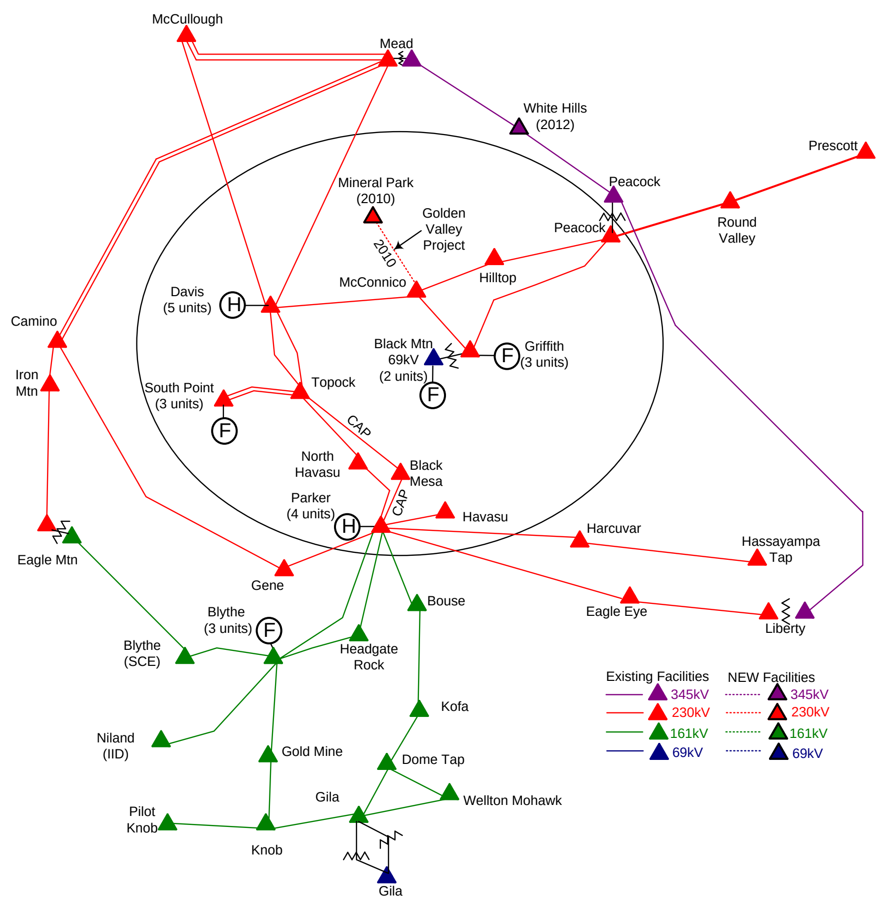


Mohave County Transmission

UNSE has three long term transmission contracts with WAPA. One contract provides approximately 225 MW of network service on WAPA's system. The Networked Agreement which currently has Pinnacle Peak as a receipt point and Hilltop, Duval-Warm Springs, Planet Ranch, McConnico and North Havasu as delivery points in Mohave County, and delivery to Saguaro for Santa Cruz County. The networked service agreement is projected to allow 12-15 years of unimpeded load growth in Mohave County.

The second contract provides approximately 100 MWs of point to point service on both WAPA's Parker Davis System and its Central Arizona Power System. A third contract provides 110 MW point to point service on WAPA's Intertie Power System and on its Central Arizona Power System again. UNSE also buys point to point transmission over WAPA's Open Access Same-Time Information System (OASIS), on an ad hoc basis. UNSE is able to purchase access on transmission systems of other providers in the region as needed.

Map 7 – Mohave County Transmission Delivery Points



Future Transmission Resources

Several of the projects that were included in UNSE's ten year transmission plan were considered in the development of this integrated resource plan. The final list of transmission projects included in the IRP process was chosen in conjunction with UNSE's future generation resource requirements. The result was a short list of transmission projects that improved the overall reliability, import capacity and flexibility for future market resources.

Alternative	Mohave County Transmission Options
Project 1	Griffith-North Havasu Transmission

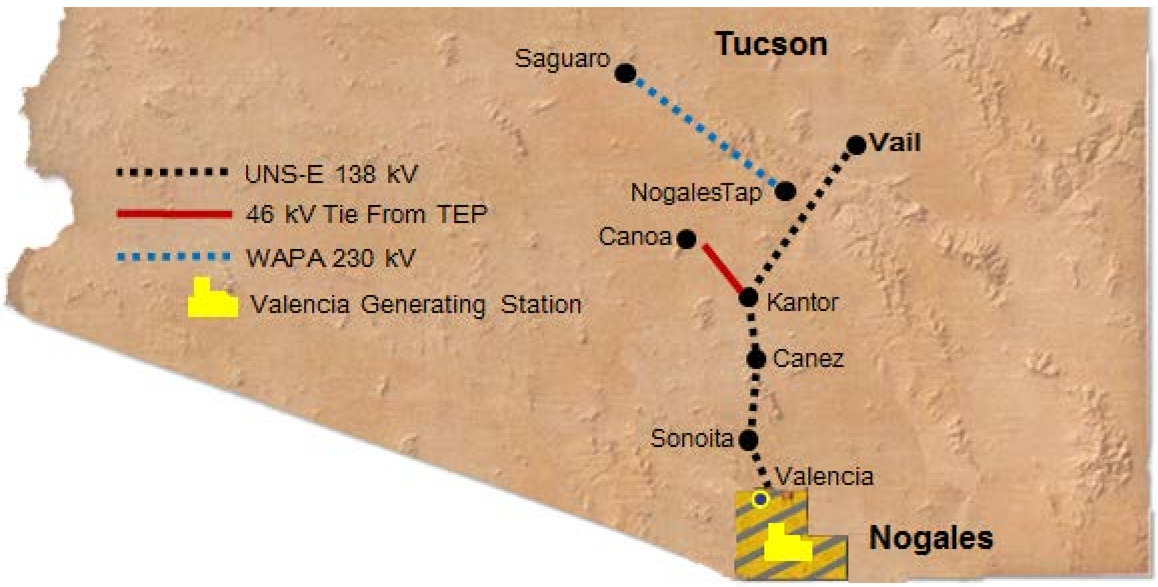
Mohave County

UNSE considers the Griffith – North Havasu 230kV line as a viable upgrade, and currently has an approved Certificate of Environmental Compatibility (CEC) for this line addition. UNSE has received an extension to the expiration date of this CEC to 2012. UNSE is considering a request for further extension to 2016 or beyond, pending further review of the results of the Mohave County RMR study. The timing for construction of this project is predicated on results of load growth in conjunction with limitations on the ability of the Western transmission system to support this load growth. A portion of this project (North Havasu to Franconia) was completed in 2007 and is currently energized at 69kV for distribution needs at Franconia.

Santa Cruz County Transmission Overview

Santa Cruz County relies on a single 138 kV transmission line feeds the local distribution grid located in the City of Nogales. In 2013, UniSource Energy Services (UES) upgraded an existing 115 kV transmission line with a 138 kV transmission line between the Vail Substation, located southeast of Tucson, and the Valencia Substation in Nogales, Arizona. The existing transmission line is the primary source of electrical service for customers in Nogales, Arizona and surrounding communities.

Map 8 – Santa Cruz County Transmission Delivery Points



Vail to Valencia 138kV Upgrade

The new Vail to Valencia line spans approximately 55 miles from an area south of Tucson to Nogales, Arizona, over private and state-owned land. Although much of the new line will follow the route of the existing 115 kV line, portions of the project will follow a new alignment.

Self-weathering steel monopoles will be installed along the project route. Steel poles are more reliable and require less maintenance. In areas with rugged terrain, helicopters may be used to assist with line construction. Use of helicopters in these areas will help to limit construction time and ground disturbance.

UNSE journeymen Nic Lyons and George Molina and helicopter pilot Jeffery Wojtowictz prepare to pull the new 138kV transmission line on the Vail Valencia Project

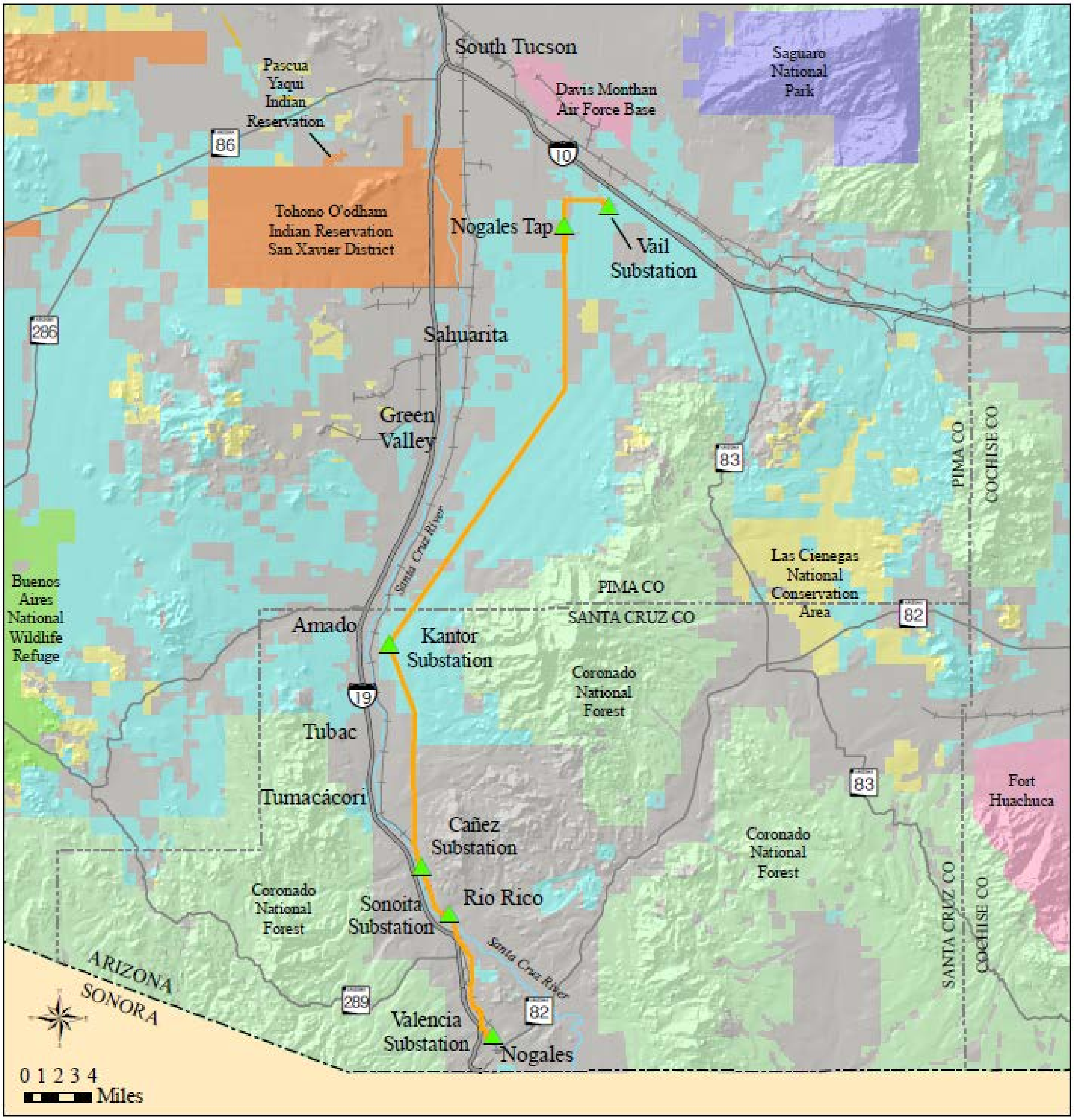
Primary elements of the project included:

- Changing the interconnection point from the current location at Western Area Power Administration's "Nogales Tap" to Tucson Electric Power's Vail Substation
- Replacing the existing 115kV line with a new 138 kV line
- Replacing transformers at three of the four UES substations
- Replacing aging wooden H-frame structures with steel monopoles

This project will help to improve reliability and meet the increasing demand for power in Nogales and the Santa Cruz River Valley. The new line will strengthen UES' current electrical distribution system, which will allow UES to adequately and reliably serve the area now and in the future.

Comparison of the recently installed steel monopole structures alongside old wooden "H-frame" structures along the Vail to Valencia Transmission route. The H-frame structures will be removed after construction of the new facilities in 2014.

Vail to Valencia Project Map

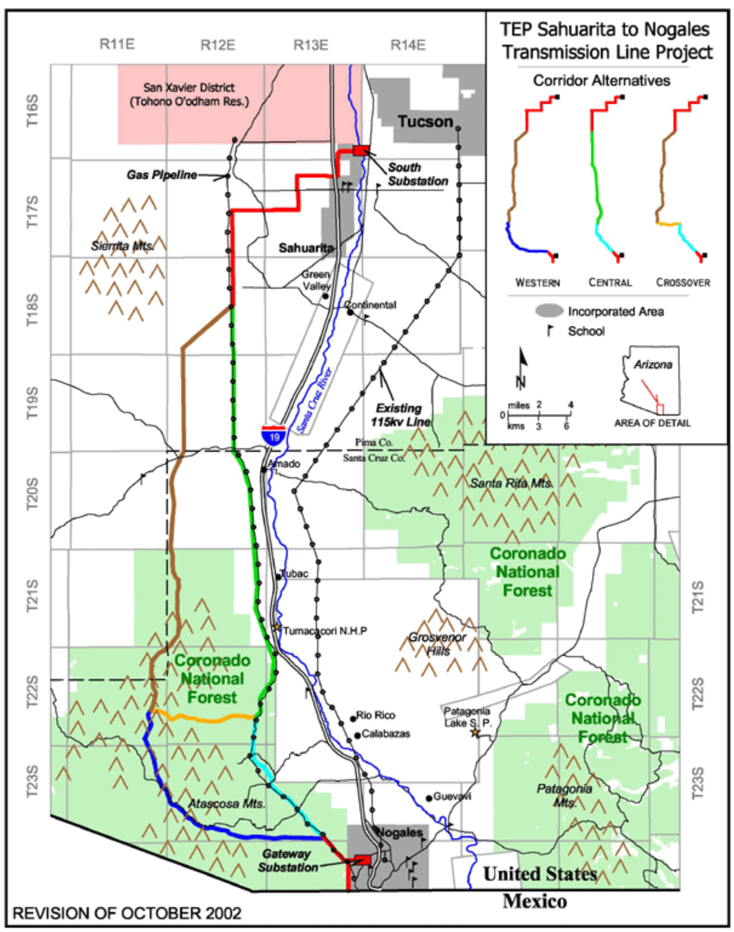


History on the Nogales Transmission Line

In 1998, Citizens Utilities (later to become UNSE) and the Western Area Power Administration experienced unprecedented failures of the power delivery system that resulted in an unusual number of power outages for customers in the Nogales, Arizona area. The City of Nogales filed a complaint regarding the quality of service, and the ACC conducted an investigation. As a result, the ACC ordered Citizens to make improvements to its electric system. Those improvements included building a second transmission line that could be tied to the existing 115 kV line and operated as a "closed loop". This "closed loop" configuration would ensure that Santa Cruz County would continue to have reliable service under a single contingency line outage.

In 2001, both TEP and Citizens entered into a joint project agreement to develop a new 345-kV transmission line from TEP's South Substation in Sahuarita to a proposed Citizens substation near Nogales, Arizona. The original project proposal planned to extend the new line into Mexico, enabling international energy exchanges while improving electric reliability on both sides of the border. In January 2002, the ACC authorized constructing a transmission line along the so-called Western Route. Due to a number of factors such as disagreements over the final line siting and the potential cost impact on UNSE's retail customers, the Arizona Corporation agreed to let UNSE put the Nogales Transmission Project on hold indefinitely.

Map 9 – Santa Cruz County Transmission Corridor Alternatives

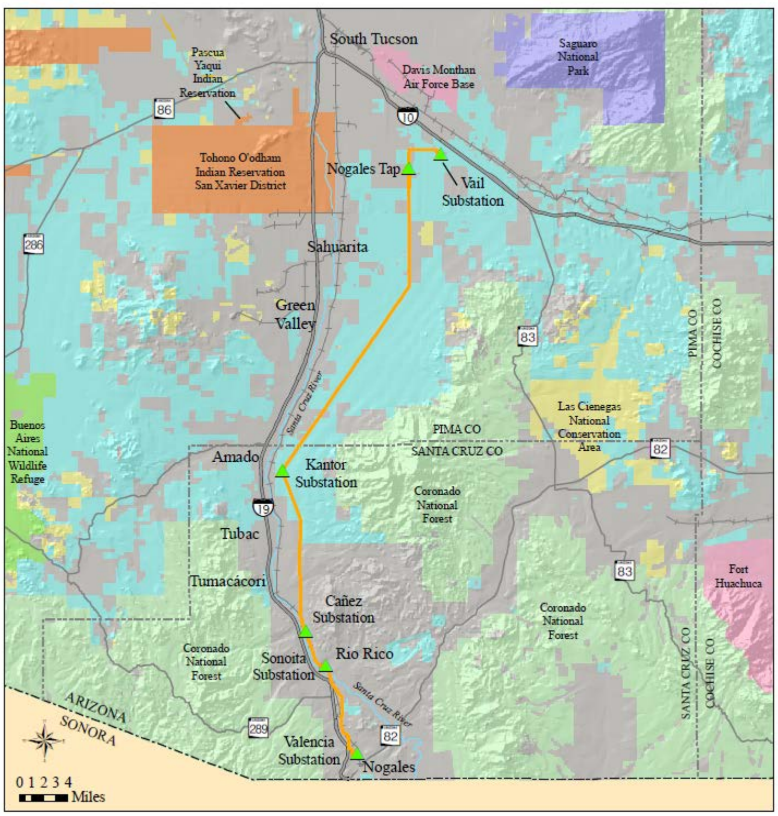


Continuity of Service Plan

Phase 1 - Vail to Valencia 115kV to 138kV Upgrade Project

UNSE's Continuity of Service Plan is broken up into two phases. Phase 1 was based on the completion of the Vail to Valencia 138kV Transmission Project that went into service in December 2014. Phase 2 is the construction of additional local area generation in the City of Nogales. The Vail to Valencia 138kV Transmission Line will establish a 138kV link between UNS Electric's Vail Substation and UNSE' Valencia Substation in Nogales. A map of the final approved route, which has been approved by the ACC, is shown below. Although much of the new line will follow the same route of the 115kV line it is replacing, portions of the project will follow a new alignment. New steel monopoles structures were installed in the boundaries of 100-foot-wide right-of-way that will be required to build and maintain the transmission line. The final phase of this project included transferring the point of interconnection of UNSE from Western's Nogales Tap switchyard to an interconnection in UNSE's Vail Substation.

Map 10 – Phase 1 - Vail to Valencia 115kV to 138kV Upgrade Project

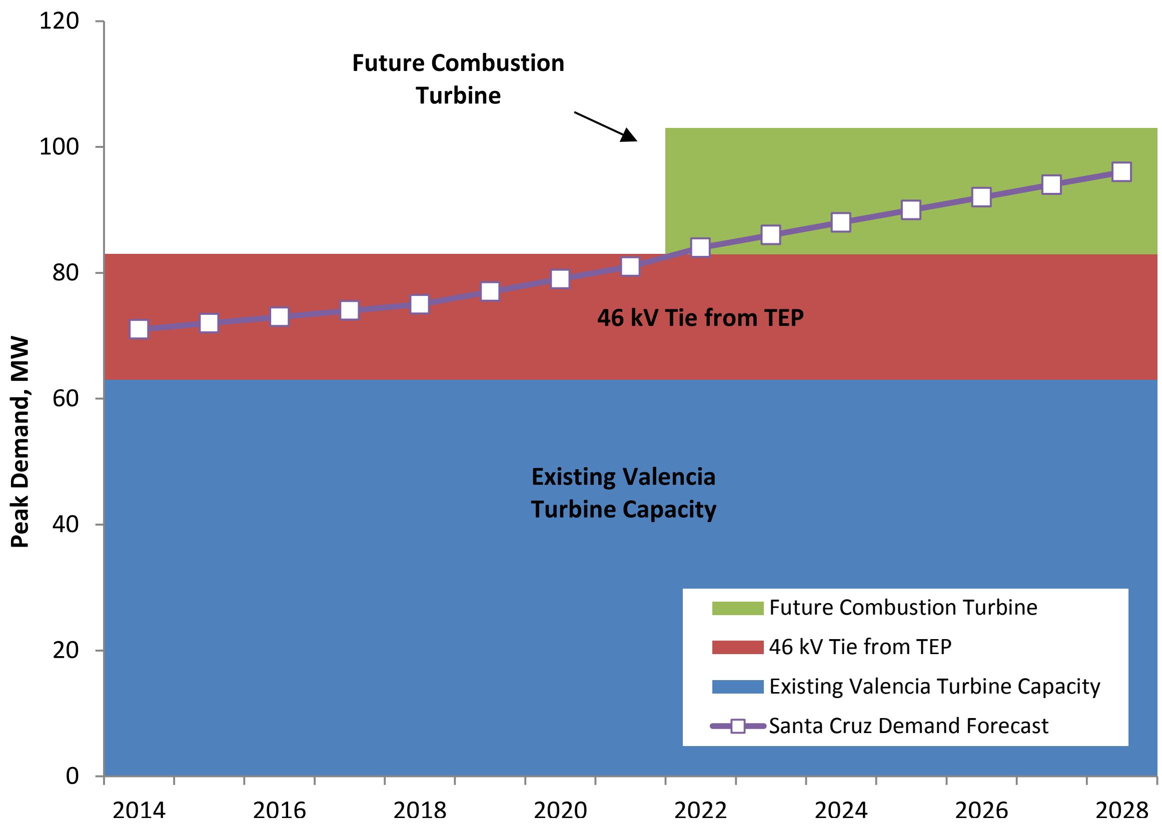


Continuity of Service Plan

Phase 2 – Local Area Combustion Turbine

Phase 2 of the Continuity of Service Plan, will require UNSE to build out additional local area generation in order to maintain reliable service to the City of Nogales during transmission outages. Based on future load growth expectations for Santa Cruz County, a new local area generation resource is not needed until 2022. However, for purposes of the 2014 IRP, UNSE modeled a new 21 MW gas fired combustion turbine sited at the Valencia Generation Station in 2019. This early in-service date is related to UNSE's need for additional peaking capacity starting in 2019 for purposes of meeting summer load requirements. The exact timing of this new local area resource is dependent on a number of factors, including future load growth, customer participation in energy efficiency programs, and the availability of other supply-side resource options such as wholesale purchase power agreements or low cost plant acquisitions. UNSE will monitor Santa Cruz county load growth and will adjust its plans to install an additional turbine at the Valencia Generation Station as necessary.

Chart 22 - Santa Cruz Continuity of Service Forecast



Transmission Resources Needed for New Generating Resources

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 UNS 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 Kingman, Havasu or Nogales local areas 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 12 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 12 - 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 UNSE'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. UNSE is currently an active participant in this project. If this project moves ahead within the next three years, UNSE 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

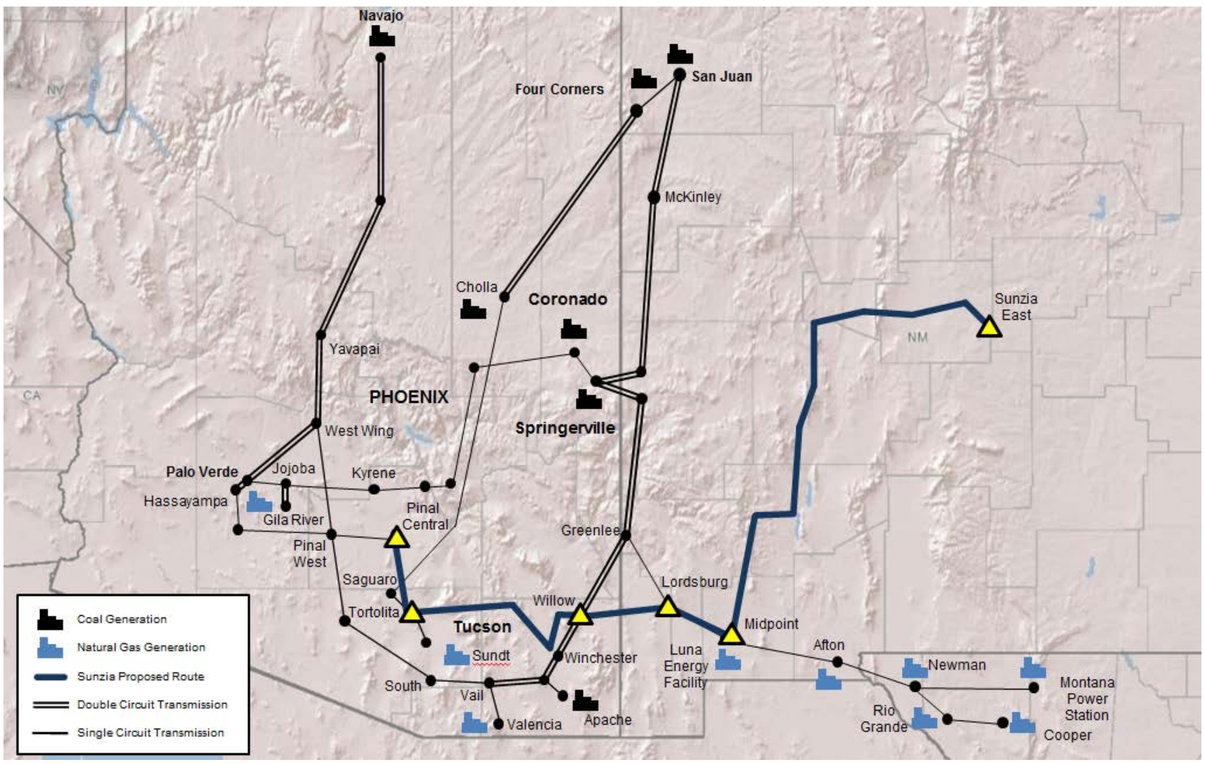
- SunZia currently proposes to interconnect with up to five substations:
- Pinal Central (near Coolidge in Pinal County, AZ)
- Willow 500 kV (East of US 191 in Graham County, AZ)
- Lordsburg (located in Hidalgo County, NM)
- SunZia South, also referred to as Midpoint (near Deming in Luna County, NM)
- 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 11 - Sunzia Proposed Project Route



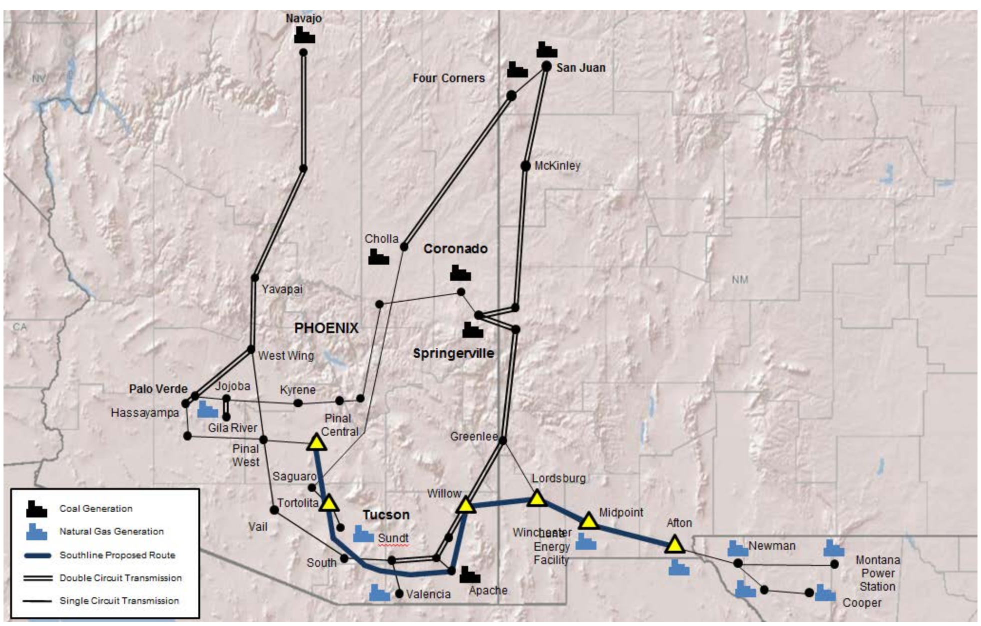
The Southline Transmission Project

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 UNS Electric 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 12 - Southline Proposed Project Route



CHAPTER 8

Energy Efficiency

UNS Electric – Overview

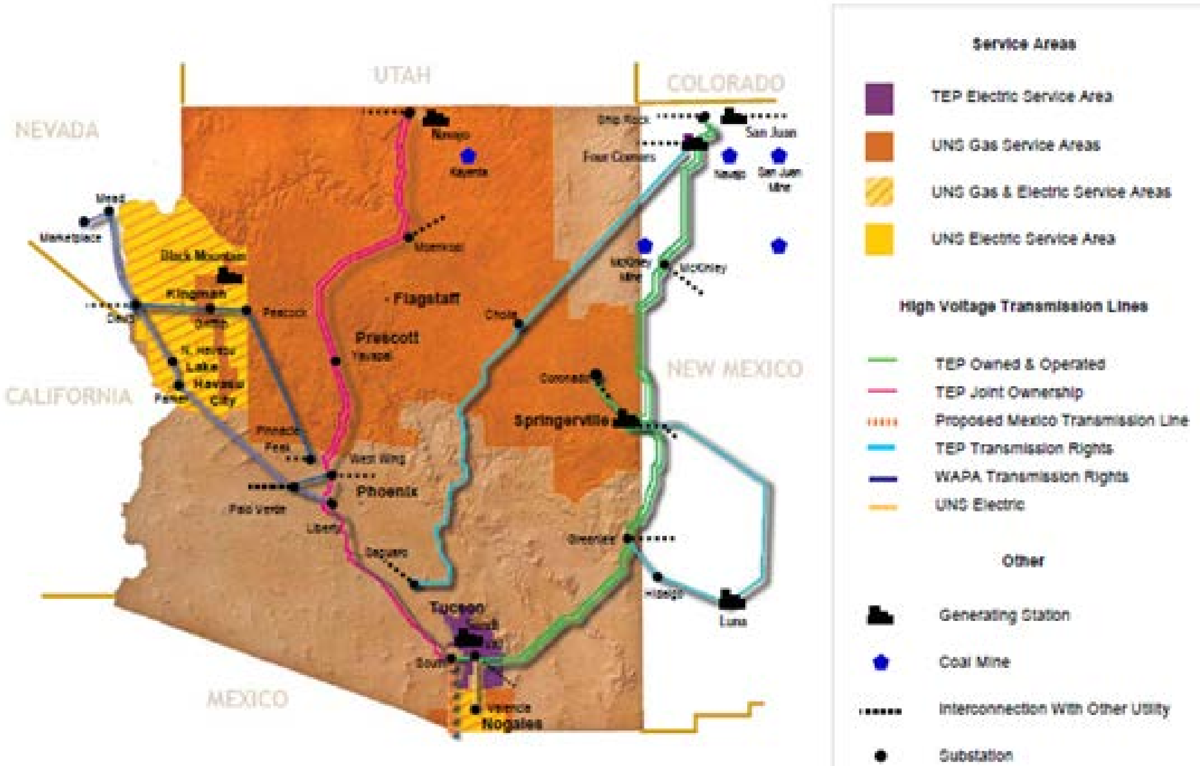
UNS Electric, Inc. (UNSE) recognizes that energy efficiency can be a cost-effective way to reduce our reliance on fossil fuels. UNS Electric offers a variety of energy saving options for customers, from simple consultation to incentives that encourage both homeowners and businesses to invest in efficient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

UNSE is striving to achieve 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.

UNSE, 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. Many of the programs were designed to take advantage of the economies of scale with Tucson Electric Power. 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, UNS Electric's service territory is shown in Map 13 on the next page.

Map 13 – UNSE Service Territories



2014 Implementation Plan, Goals, and Objectives

UNSE'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.
- When feasible, maximize opportunities for program coordination with other efficiency programs (e.g., Tucson Electric Power Co., Southwest Gas Corporation, Arizona Public Service Company) to yield maximum benefits.
- Maximize program savings at a minimum cost by striving to achieve comprehensive cost-effective savings opportunities.
- Provide UNS Electric customers and contractors with web access to detailed information on all efficiency programs (residential and business) for electricity savings opportunities at www.uesaz.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

UNSE'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 UNS Electric customers in particular. A substantial amount of information including evaluations, program plans and potential studies were used to develop specific programs for UNS Electric. With input from Navigant and SWEEP, UNSE 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, UNSE'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. UNSE 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, UNSE will attempt to capitalize on those sectors of the market willing to invest in energy efficiency regardless of the challenging economic landscape.

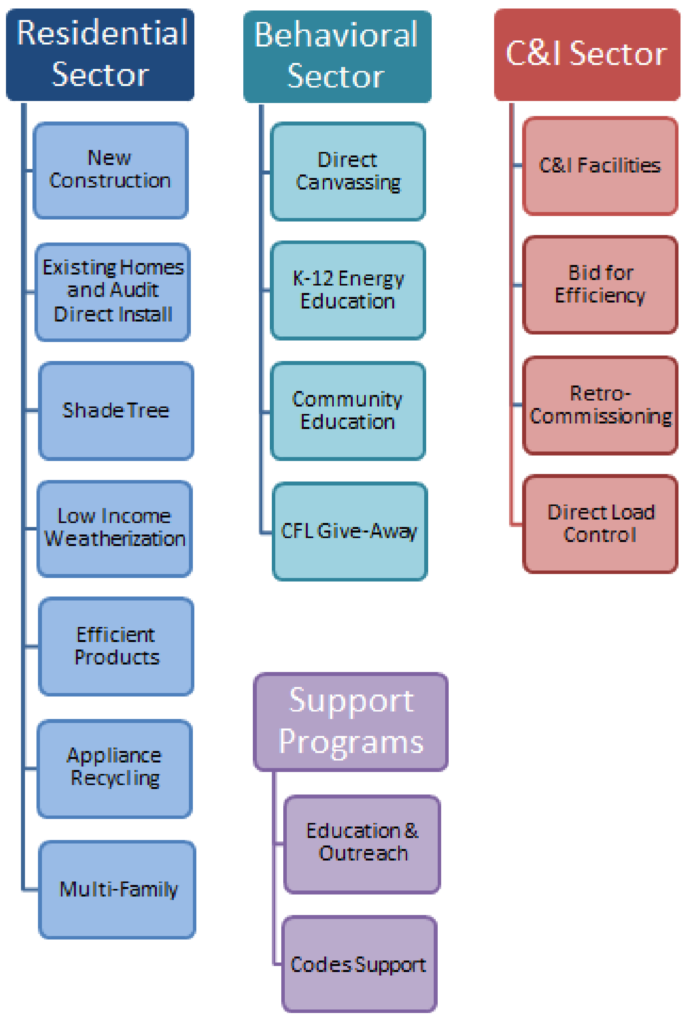
UNSE used the following strategies to minimize the risks and produce the lowest cost portfolio of energy efficiency programs:

- 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 UNSE staff. UNSE designs programs on the most cost-effective basis utilizing implementation contractors where they provide the lowest cost per kWh and likewise utilizing UNSE staff when appropriate.

Program Portfolio Overview

As demonstrated in Figure 12, UNSE's portfolio of programs can be divided into residential, commercial, behavioral, and support sectors with administrative functions providing support across all program areas.

Figure 12 - UNS Electric Portfolio of Programs



Savings, Budgets, and Benefit-Cost Results Overview

In January 2011, UNSE submitted a two-year Implementation Plan (2011-2012) to meet the requirements of the Energy Efficiency Standard. The UNSE Plan submitted was dependent upon the same or similar programs or measures receiving approval in TEP's 2011-2012 EE Plan. In January of 2012 the UNSE (2011-2012) Implementation Plan was approved with no new measures or programs. The TEP plan was not approved and in June of 2013 the Commission closed Docket No. E01933A-11-0055 (the docket for the TEP 2011-2012 EE Plan) and did not approve any new programs for TEP. As a result, UNSE cannot take advantage of economies of scale in implementing certain EE programs. UNSE's ability to meet the standard was hindered for 2013. Without the ability to take advantage of the economies of scale and no new programs or measures, UNSE will continue to be hindered from meeting the standard in subsequent years. An Implementation Plan for 2015 will be filed in June of 2014.

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 13, UNSE has developed this plan with the intent of meeting cost effective electric savings goals as a percentage of prior year retail sales in accordance with Energy Efficiency Standard Section R14-2-2418 in the Commission Rules. For 2013, UNSE's budget forecast was $3.8 million increasing to $5.4 million in 2014.

Table 13 – 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 Cost Ratio
2011	$2,113	15,005	133,905	$6,052	2.86
2012	$4,507	35,032	283,593	$15,042	3.34
2013	$3,874	34,764	294,066	$9,373	2.42

As noted in Table 14, 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%. UNSE's portfolio of will meet the 2014 program goals, but not the Energy Efficiency Standard.

Table 14 - Energy Efficiency Standard Target Savings based on Implementation Plan

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)	0.81%	2.70%	4.83%
Incremental Annual MWh Savings (required by EE Standard)	15,005	50,037	84,801
EE Standard Target Annual MWh Savings	27,857	55,587	87,777
% of Planned Savings Goal Achieved (Incremental Year)	54%	90%	97%

Note: MWh Savings include line loss reductions created from energy reductions which are not included in the Authorized Revenue Requirement True-up.

The Actual Annual MWh Savings stated in both Table 13 and Table 14 is a summation of annual savings obtained by each program in UNSE's portfolio with the exception of UNSE'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 15 - 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 15 - 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 UNSE 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 UNSE has provided a SCT that accounts for the societal discount rate. UNSE is however, unable to provide a true societal test given the uncertain values of environmental externalities. As required by the Commission, UNSE 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), UNSE filed the societal costs as the results of the stakeholder meetings.

Residential Energy Efficiency Programs

Residential New Construction

The Residential New Construction Program for UNS Electric is marketed as the Energy Smart Homes ("ESH") Program. The ESH Program emphasizes the whole-house approach to improving health, safety, comfort, durability, and energy efficiency. The Program promotes homes that meet the Environmental Protection Agency ("EPA")/Department Of Energy ("DOE") Energy Star® Home performance requirements. To encourage participation, the Program provides incentives to homebuilders for each qualifying home. On-site inspections and field testing of a random sample of homes is required to ensure that homes meet the Energy Star® Home performance requirements; these will be conducted by third-party Residential Energy Services Network ("RESNET") certified energy raters selected by each builder. Components of the ESH Program include development of branding, builder training curriculum, and marketing material.

Existing Homes and Audit Direct Install

The UNS Electric Existing Homes Retrofit Program is marketed as the Efficient Home Program. The Program is designed to encourage homeowners to increase the energy efficiency of their homes through equipment replacement and duct system repairs. The Program provides incentives for high-efficiency heating, ventilation and air conditioning ("HVAC") equipment and for the testing and sealing of leaky duct work. The Program provides direct incentives to participating contractors with the requirement that the incentives are passed on to utility customers as a line item credit toward approved Program measures.

Shade Tree

The Shade Tree program is an ongoing environmental element of the program 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 cooling load. UNSE partners with the University of Arizona Master Gardeners, that helps educate customers during community outreach events. UNSE provides various opportunities for customers to receive approved trees through the Trees for You Program. Customers can receive their tree at several onsite events held throughout the year, or they can purchase a tree directly and apply for a $15 bill credit by filling out and sending in an application form. 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 UNSE 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). UNSE partners with several agencies to provide the actual weatherization services to UNSE customers. UNSE along with these agencies coordinates with the Arizona Energy Office to follow approved state WAP rules when using funding from UNSE, 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 UNSE service area. The 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.

Efficient Products

The UNS Electric Efficient Products Program promotes the purchase of energy efficient retail products through in store buy-down promotions or other delivery methods. The Program promotes the installation of energy-efficient lighting products and other energy saving appliances by residential and commercial customers in the UNS Electric service territory.

Appliance Recycling

The Appliance Recycling Program will target the removal and recycling of operable second refrigerators and freezers. An appliance recycling contractor will provide implementation services that include verification of customer eligibility, scheduling of pick-up appointments, appliance pick-up, and recycling services. The objective of the program is to produce long-term electric energy savings in the residential sector by permanently removing operable second refrigerators and freezers from the power grid and recycling them in an environmentally safe manner.

Multi-Family

The Multi-Family Program targets multi-family buildings with 5 dwelling units or greater. The Program will recruit multi-family building owners to participate in a direct-install campaign to install CFLs and low-flow water devices in individual units. Multi-family facility managers will also be referred to the Small Business Direct Install program to encourage measure installation for the common areas.

Due to various market barriers, such as split incentives, capital constraints, and lack of awareness, energy efficiency improvements typically fall far below other types of improvements on the priority list. Although the current rebate programs offer some opportunities for energy efficiency improvements in this market, primarily through the Efficient Products Program, there is not a comprehensive offering that addresses the unique needs of this market. Through the direct installation, and renovation/rehabilitation implementation framework, this program seeks to fill this important gap in the UNSE program portfolio and provide substantial energy savings.

The objectives of the program are to reduce peak demand and overall energy consumption in the multifamily housing market segment; to promote energy efficiency retrofits of both dwelling units and common areas in this market segment; and to increase overall awareness about the importance and benefits of energy efficiency improvements to the landlord and property ownership community.

Commercial and Industrial (C&I) Programs

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

C&I Facilities

The UNSE C&I facilities program parallels the TEP Small Business Direct Install Program in many ways. It 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 small and large commercial customers. The program offers incentives for the installation of energy-efficiency measures including lighting equipment and controls, HVAC equipment, motors and motor drives, compressed air and refrigeration measures. There is currently a $10,000 incentive cap and the restriction that only two large commercial customers can participate at a limit of $50,000 incentive cap each year. These limiting components of the approved program negatively impact participation and prevent UNSE from reaching participation goals.

The C&I Facilities 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.

Bid for Efficiency

The Bid for Efficiency (BFE) Program is designed to take an innovative approach towards energy efficiency by using elements of competition and the potential for high rewards to enhance customer interest. The BFE concept creates a pool of funds that is bid on through unique customer-driven proposals which include costs, savings and incentives. UNSE selects winning applicants based on specified criteria.

The BFE concept is an innovative approach that is being successfully deployed in other utilities' energy efficiency programs, and will encourage creativity in designing system-optimized energy use reduction. BFE participants and project sponsors may include commercial customers, ESCOs or other aggregators who organize proposals that involve multiple sites.

This program addresses customer market barriers such as small savings levels at multiple sites, longer payback periods and difficulty in organizing implementation contractors. Results will be verified through MER activity. After two years of implementation, this Program was approved for continuance in Commission Decision No. 74262. The Program has proven to be cost-effective so UNS Electric will no longer consider this a "Pilot" Program and will refer to it as the Bid for Efficiency Program in future filings.

School Facilities

Commission Decision No. 74262 combined the budget and EE measures into the UNS Electric C&I Facilities Program starting January 2014 so the Schools Facilities Program ceased as a separate Program.

Retro-Commissioning

The Retro-Commissioning program uses a systematic approach to identify building equipment and processes that are not achieving optimal performance or results in existing facilities. Eligible program applicants receive free screening energy audits. Participants also receive training to ensure proper operating and maintenance practices over time.

The program seeks to generate significant savings for DSM portfolio objectives by tapping into energy savings opportunities in existing commercial and industrial facilities. The program delivers customer benefits by lowering energy bills and improving building performance and occupant comfort while reducing maintenance calls. The program also facilitates the development of an RCx contractor pool, and enables UNSE to develop relationships with commercial and industrial customers leading to other areas of participation in UNSE's portfolio of DSM programs. RCx programs in other utility service territories have been shown to deliver average facility savings in the range of 5-15% per facility, and measures implemented as a result of program activity typically pay for themselves in savings in less than two years.

Behavioral Energy Efficiency Programs

Behavioral Energy Efficiency programs are designed to educate residential customers on how changes in behavior, including purchasing decisions, can improve energy efficiency. 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 UNSE DSM program

UNSE proposes for the 2013-2014 program year, the Behavioral Comprehensive Programs, a suite of four delivery mechanisms to achieve energy efficiency objectives, as shown in Table 16.

Table 16 - Summary of Behavioral Energy Efficiency Programs

Behavioral Energy Efficiency Programs	
Direct Canvassing	Door to door awareness and direct install campaign
K-12 Education	Classroom education including take home direct install kits
Community Education	"Train the trainer" approach and give away direct install kits
CFL Giveaway	CFL bulb giveaways at outreach events

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 four programs approaches such sociological barriers using different avenues, such as schools, community organizations, and technology:

Direct Canvassing
The Direct Canvassing initiative is a grass-root, door to door approach to promote energy efficiency, and is designed to reach neighborhoods difficult to reach through traditional messaging. Six CFLs will be left with each customer, along with program materials for appropriate UNS Electric DSM programs.

K-12 Education
In addition to energy based class room curriculum, students will be instructed in energy saving approaches for their homes. Students in grades 6-8 are given a take home kit which includes CFLs, LED nightlights, and educational material on how to reduce energy use.

Community Education
The Community Education Program will engage community groups with hands-on energy efficiency seminars. These seminars will cover 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 such as Mohave County Community Services, Kingman and Lake Havasu City Libraries and other neighborhood organizations are engaged to schedule sessions led by these mentors for the community. The seminars include hands-on information with a wide sample of materials such as weather stripping, low flow showerheads, caulk or foam sealant, CFL’s, etc. provided to participants.

CFL Promotion
The CFL Promotion program will complement UNSE’s presence at community events, its overall education and outreach efforts, and efficiency messaging. CFLs will be made available at community events and to community organizations such as those involved in our Community Education Program. Flexibility to add methods and develop partnerships to aid in the distribution of these bulbs is a program design element which will enhance program effectiveness over its lifespan.

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 ads 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 UNSE 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.

Energy Codes Enhancement Program (ECEP)

The Energy Codes Enhancement Program (ECEP) will strive to maximize energy savings through adherence to local building energy codes across the local jurisdictions within UNSE service area through a variety of activities. Activities can include participation in energy code adoption committees and providing public testimony in support of codes before city councils.

The program will employ a variety of tactics aimed at: 1) improving levels of compliance with existing building energy codes; and 2) supporting and informing periodic updates to energy codes as warranted by changing market conditions. Specific program activities will depend on the market needs expressed by local code officials and are likely to include a combination of efforts to:

- Better prepare code officials and building professionals to adhere to existing standards;
- Provide data and market insight to document the specific local benefits of code enforcement, and inform energy code changes over time;
- Ensure utility incentive/rebate programs align well with local energy codes;
- Collaborate with relevant stakeholders to help build a more robust community working to advance strong and effective building energy codes across local jurisdictions; and
- Advocate for energy code updates over time.

2014 Resource Planning Integration

DSM Forecasting

Consistent with the ACC's Decision No. 71435 on Resource Planning, UNSE forecasted cumulative energy savings for UNSE's DSM portfolio. UNSE prepared a monthly energy savings distribution for a full calendar year's annual savings impacts that results from the historical implementation of the DSM programs then projected forward. 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, UNSE 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 UNSE's system load and gets factored into resource planning. Energy efficiency forecasts for UNSE were projected over the IRP planning period.

Methodology

In order to integrate the savings impact of UNSE's portfolio of DSM programs into a 15-year planning horizon, UNSE 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.

UNSE 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. UNSE found this latter option to be more prudent given the time sensitivity and expense.

UNSE 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. UNSE selected the load shapes carefully to account for seasonal or diurnal variations in operational or end-use patterns for different measures. UNSE 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 UNSE'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, UNSE had to apply adjustment factors appropriate for its particular service territory in Arizona. First for weather calibration purposes, UNSE utilized typical meteorological year (TMY3) weather data for major jurisdictions in its service territory (i.e., Kingman, Lake Havasu City, and Nogales) and compared those 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 the major jurisdictions in UNSE'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 UNSE'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 the major jurisdictions (i.e., Kingman, Lake Havasu City, and Nogales); therefore, no such weather adjustments were needed for these load shapes.

After determining the measure shapes, UNSE 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. UNSE 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, UNSE is able to apply its definition of peak periods to determine coincident and non-coincident peak demand savings.

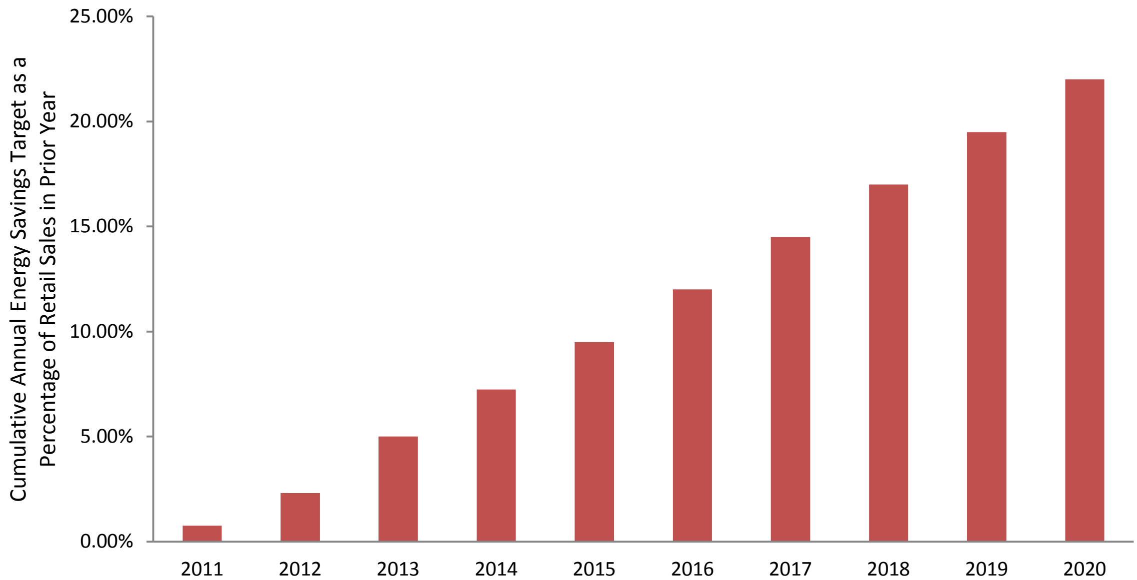
Additionally, to determine long-term cumulative energy savings forecasted on the 15-year time-frame, UNSE multiplied the effective measure life for each particular measure to the measure's annual energy savings value and aggregated these cumulative savings at the program-level and portfolio-level. The 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, UNSE also acknowledges the importance of attributing verified savings values for individual measures and programs from Measurement, Evaluation, and Research (MER) results. UNSE has retained the services of Navigant to serve as the MER contractor for UNSE'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 UNSE to forecast annual energy and peak demand savings for UNSE'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.

Figure 13 - Cumulative Annual Savings Impacts through 2020



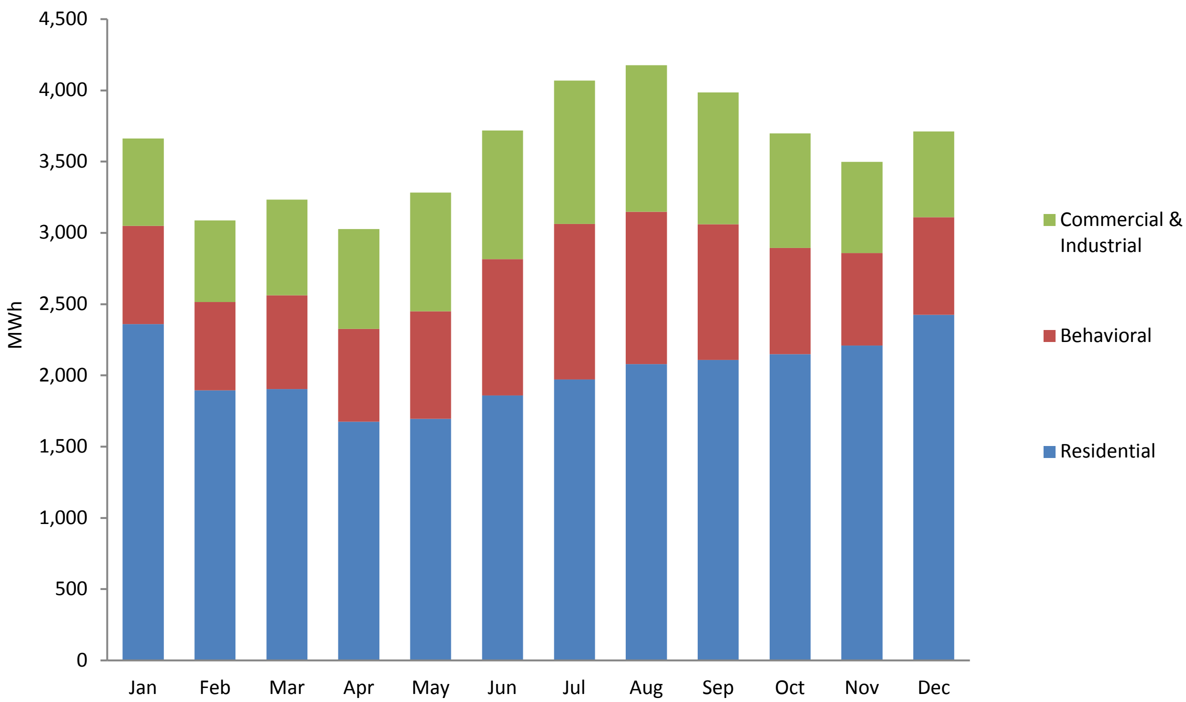
UNSE chose to include the savings impact from 2011 due to the fact that the Energy Efficiency Standard is a cumulative annual energy savings target goal that began in 2011 and carries through the end of 2020. While there is a projected shortfall of the cumulative 2011 and 2012 savings target goals, UNSE will continue to strive to achieve the cumulative targets. The Energy Efficiency Standard has significant savings target ramp ups that will require increase in DSM program investments to meet those savings targets. UNSE 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 17 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 17 – 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 UNSE's DSM portfolio, considering the full incremental year's savings impacts is beneficial to understanding how DSM program savings will affect UNSE's load on a monthly level. Utilizing the hourly savings load shape data, UNSE is able to portray the monthly energy savings that result from a full year's effect. Chart 23 shows monthly energy savings for a full year's impact that result from the implementation of the UNSE's portfolio of programs. The monthly energy savings were determined from aggregating hourly measure-level savings in the Methodology section above.

Chart 23 – Monthly Energy Savings - 2014 DSM Portfolio



Energy savings across the portfolio are greatest in the summer months due to measures that seek to reduce cooling consumption associated with 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.

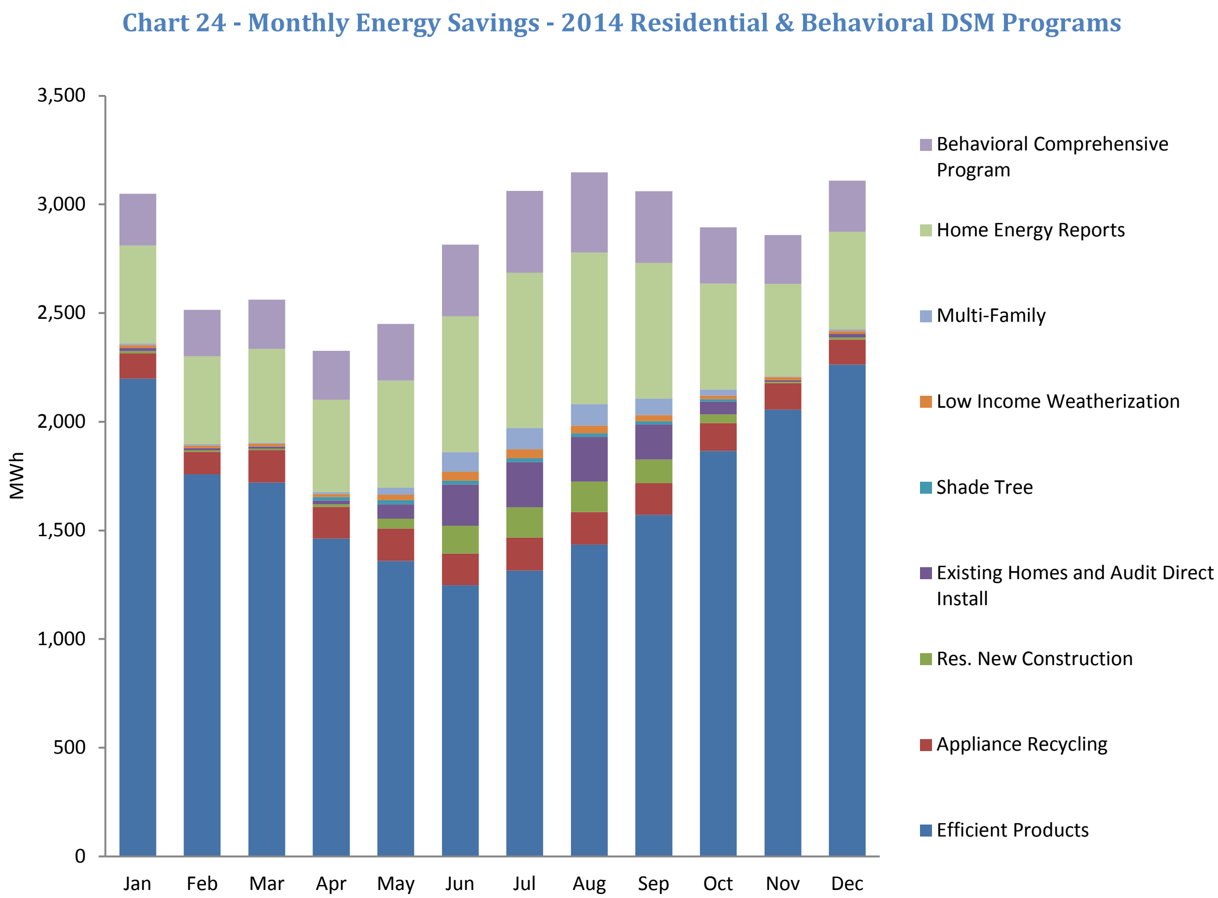


Chart 24 shows the monthly distribution of savings that result from residential and behavioral DSM programs. The Efficient Products Program, which is largely comprised of indoor lighting measures, has the greatest savings during winter months. This reflects the fact that winter months have on average 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.

Chart 25 - Monthly Energy Savings - 2014 Commercial & Industrial DSM Programs

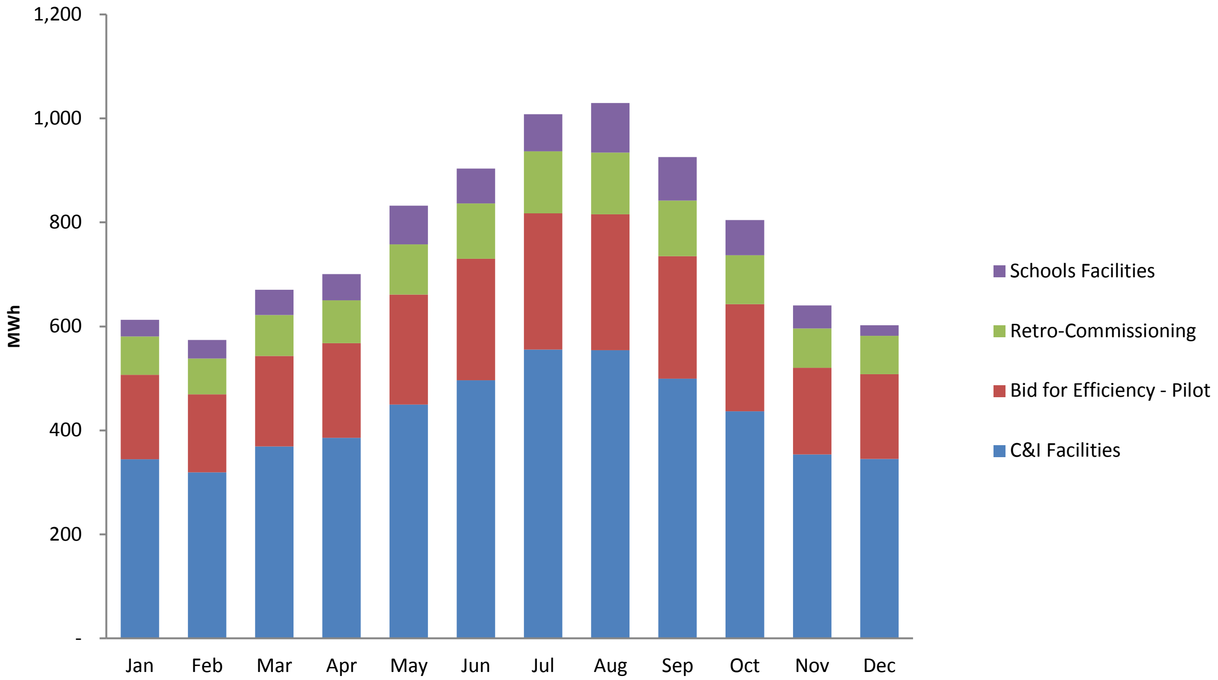
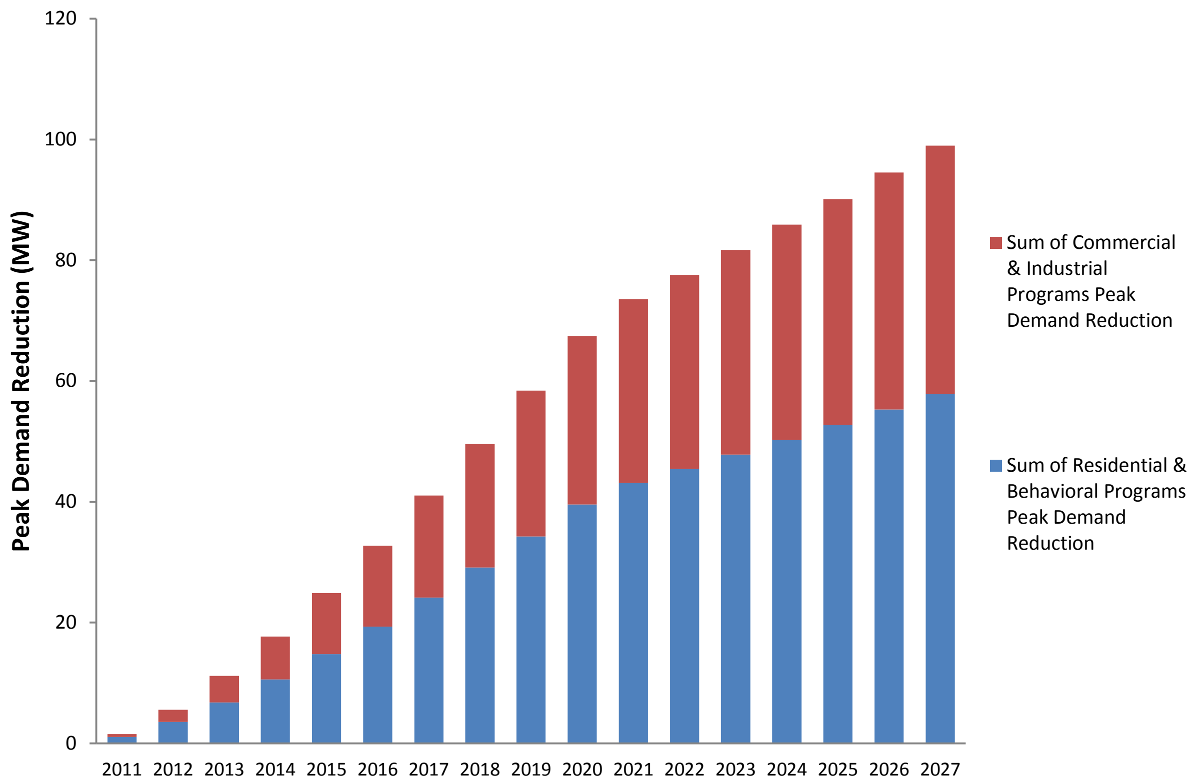


Chart 25 shows the monthly distribution of savings that result from commercial and industrial DSM programs. Many of these programs show the greatest impact in the summer months resulting from energy efficiency measures that are targeted towards reducing cooling consumption during those months. Unlike 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 UNSE's goal is to meet the Energy Efficiency Standard goal by 2020, UNSE also considered the impact that UNSE's portfolio of DSM programs will have on reducing UNSE's system peak demand. UNSE's system peak period occurs throughout the summer months; therefore, UNSE determined the cumulative long-term impact that its programs will have on reducing UNSE's system peaks throughout the peak period. Again, peak demand reduction for historical years is included because UNSE must consider the savings impact from that year towards meeting the Standard. The following figure depicts the cumulative annual peak demand savings for UNSE's portfolio beginning in 2011.

Chart 26 - Cumulative Annual Peak Demand Reduction through 2027



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

Energy Efficiency and Demand Response

Energy Efficiency

UNSE proposes to pursue a range of cost-effective and industry-proven programs to meet future energy efficiency targets. UNSE'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 2028, this offset to future retail load growth is expected to reduce UNSE's annual energy requirements by approximately 407 GWh and reduce UNSE's system peak demand by 59 MW.

Demand Response

The Reference Case plan targets dispatchable demand response programs that reduce UNSE's summer peak loads. UNSE's future demand response programs are expected to reduce UNSE's system peak demand by 14 MW by 2028. Figure 14 shows the equivalent capacity reductions installed under future energy efficiency and demand response programs for the Reference Case plan from 2014 through 2028.

Figure 14 - Energy Efficiency and Demand Response (Equivalent Capacity Reductions)

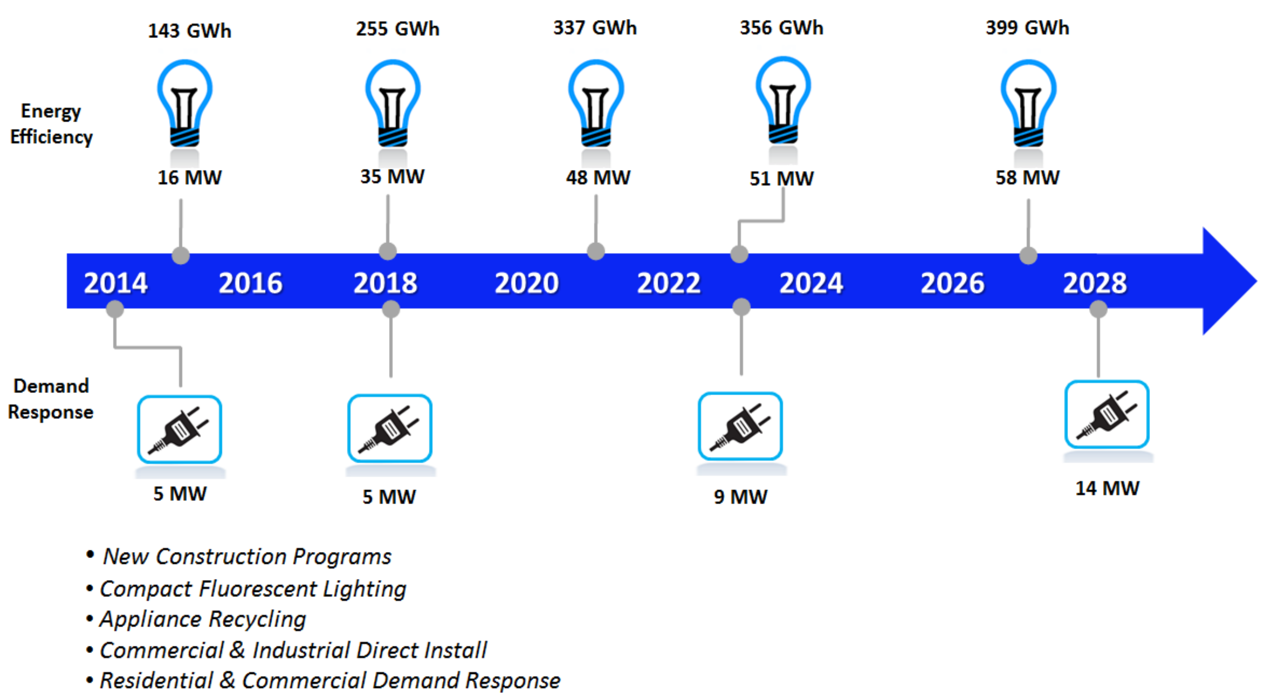


Table 18 – 2014-2021 Projected Energy Efficiency Program Schedule

Energy Efficiency Programs	2014	2015	2016	2017	2018	2019	2020	2021
Energy Efficiency, GWh	107.5	141.6	178.4	215.5	253.9	293.0	332.8	335.2
Demand Response, GWh	1.0	1.0	1.0	1.0	1.0	1.0	1.2	1.4
Total Energy Efficiency, GWh	108.5	142.6	179.4	216.5	254.9	294.0	334.0	336.6
Energy Efficiency, MW	10	16	23	29	35	41	47	48
Demand Response, MW	5	5	5	5	5	5	6	7
Total Energy Efficiency, MW	15	21	28	34	40	46	53	55

Table 19 – 2022-2028 Projected Energy Efficiency Program Schedule

Energy Efficiency Programs	2022	2023	2024	2025	2026	2027	2028
Energy Efficiency, GWh	345.3	354.4	364.5	375.1	385.8	396.4	407.2
Demand Response, GWh	1.6	1.8	2.0	2.2	2.4	2.6	2.8
Total Energy Efficiency, GWh	346.92	356.19	366.46	377.34	388.15	398.95	410.05
Energy Efficiency, MW	49	51	53	55	56	58	59
Demand Response, MW	8	9	10	11	12	13	14
Total Energy Efficiency, MW	57	60	63	66	68	71	73

Conclusion

The implementation of UNSE's 2014 DSM programs will help UNSE 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 UNSE's DSM programs with respect to seasonal and diurnal weather variations and UNSE'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 UNSE's Resource Plan. UNSE 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 UNSE's resource planning.

CHAPTER 9

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

3. 2013 Spring Reference Case, Electricity and Fuel Price Outlook, WECC Region

4. PACE Global Insights

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

EXISTING RENEWABLE RESOURCES

Overview

Over the last several years, UniSource Electric has worked with third-party contractors to develop three new renewable resource projects within UNSE's service territory. In addition, the Company is currently working with Torch Renewables to develop a new solar fixed PV project located in Willcox, Arizona. The table below provides an overview on UNSE renewable projects. Chapter 9 provides additional details on each individual project.

Table 20 – UNSE's Renewable Resources (Existing and Planned)

Resource- Counterparty	Owned/PPA	Technology	Location	Operator-Manufacturer	Completion Date	Capacity MW
Western Wind	PPA	Wind	Kingman, AZ	Western Wind	Sept 11	10.5
La Senita School	PPA	SAT PV	Kingman, AZ	Solon	Nov 11	1.22
Black Mountain	PPA	SAT PV	Kingman, AZ	Solon	Jun 12	10
Red Horse Solar (Future)	PPA	PV	Willcox, AZ	Torch Renewables	Q4 2014	TBD

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

Western Wind and Solar

Resource-Counterparty	Owned/PPA	Technology	Location	Operator-Manufacturer	Completion Date	Capacity MW
Western Wind	PPA	Wind	Kingman, AZ	Western Wind	Sept 11	10.5

The Western Wind and Solar project is a 10MW renewable energy project that began construction in December 2010 and Commercial Operations are estimated to commence in the third quarter of 2011. The project is sited on 1,100 acres located in Kingman, Arizona. UNS electric has entered into a 20-year power purchase agreement for 100% of the output from the fully integrated combined wind and solar energy project. The Kingman Project began commercial operations effective September 24, 2011. The assets include five (5) Gamesa turbines, 500 KW of Suntech Crystalline PV solar cells, a collection system, a substation, roads, interconnection facilities, a maintenance building and a fixed price PPA with UNS Electric, Inc, a subsidiary of UniSource Energy Corporation of Arizona (“UNS"), which expires on September 24, 2031.

Kingman Wind Farm (10 MW Project)

UniSource Energy Wind & Solar Project

Black Mountain Solon Solar Project

Resource-Counterparty	Owned/PPA	Technology	Location	Operator-Manufacturer	Completion Date	Capacity MW
Black Mountain	PPA	SAT PV	Kingman, AZ	Solon	Nov 12	10

Powered by SOLON's technology, including its single-axis tracking system, the 10 MW solar project will provide a faster, more cost-effective way for UNSE to integrate solar power into its renewable energy portfolio. Under the hosted PPA model, SOLON will finance, design, construct and maintain the system, with UNSE responsible only for purchasing the electricity that the system generates.

The system will be located on approximately 60 acres of land near UNSE' Black Mountain Generating Station that lies within the Mohave County Energy Overlay–Solar Photovoltaic Zone. The system was commissioned and in-service in November of 2012.

For this UNSE PPA project, SOLON provided a comprehensive level of products, development and support. In total, the system features 60 of SOLON's single-axis trackers, utilizing more than 40,000 utility solar modules. To help ensure the plant's performance and efficiency, the company is also providing its own SCADA system, which enables remote control and monitoring. In May 2012, Solon sold its ownership in the Black Mountain Solar project to Duke Energy Renewables (DER). UES is purchasing the power generated at the Black Mountain site through a 20-year purchase power agreement (PPA) with DER..

Black Mountain - SOLON Project

La Senita Elementary School Solar Project

Resource-Counterparty	Owned/PPA	Technology	Location	Operator-Manufacturer	Completion Date	Capacity MW
La Senita School	PPA	SAT PV	Kingman, AZ	Solon	Nov 11	1.22

Powered by SOLON systems and modules, the power plant will provide a faster, more cost-effective way for UES to integrate solar power into its renewable energy portfolio for Kingman residents. UNSE will own and operate the system on six acres owned by the Kingman Unified School District (KUSD) behind La Senita Elementary School. It will be the largest single physical photovoltaic (PV) system on school property in the state of Arizona. This system went into service in November, 2011

SOLON Single-Axis Tracker

Red Horse 2 Solar (Future Project, Q4 2014)

The Red Horse 2 Solar project is a 30-megawatt solar site built in proximity with the Red Horse 2 wind farm located 220 acres about 20 miles west of Willcox, AZ. The Red Horse project will be owned by Red Horse 2 LLC which was formed by Torch Renewables Energy. This project is scheduled to go on line in the fourth quarter of 2014. UNS-Electric will take power from this project under a 20-year purchase power agreement.

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

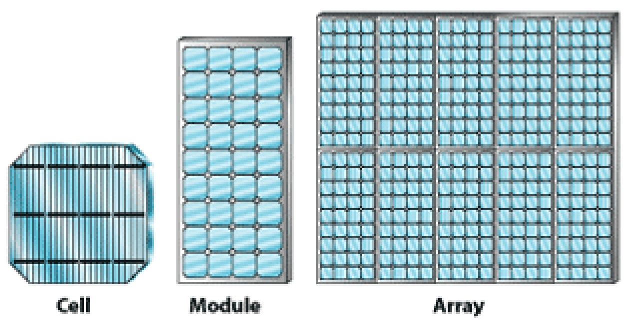
Several forms of solar power technology are available. One form is photovoltaic solar power, in which semiconductor solar cells use the photovoltaic effect to absorb sunlight and convert it into direct current power. An inverter then converts the direct current power into alternating current power. Another 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

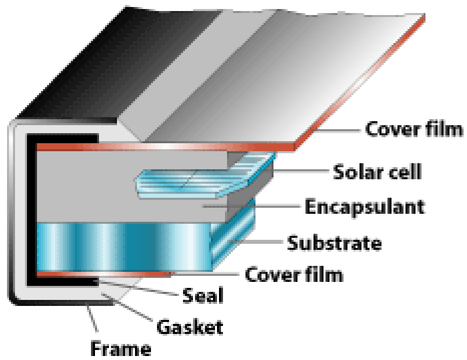


Source: NREL: National Renewable Energy Laboratory

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.

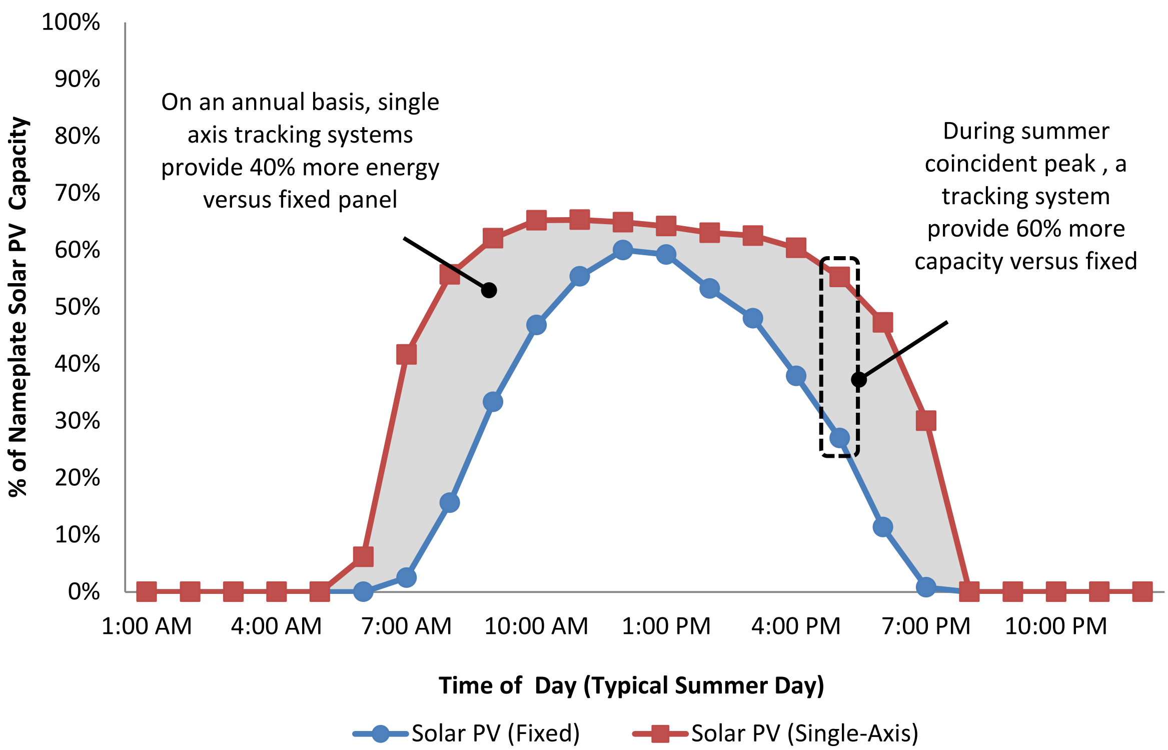
The advantages of fixed arrays are that they lack moving parts, there is virtually no need for extra equipment, and they are relatively lightweight. These features make them suitable for many locations, including most residential roofs. Because the panels are fixed in place, their orientation to the 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.

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 27 - Comparison of Solar Photovoltaic Systems

(Fixed Panel vs. Single Axis Tracking)



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

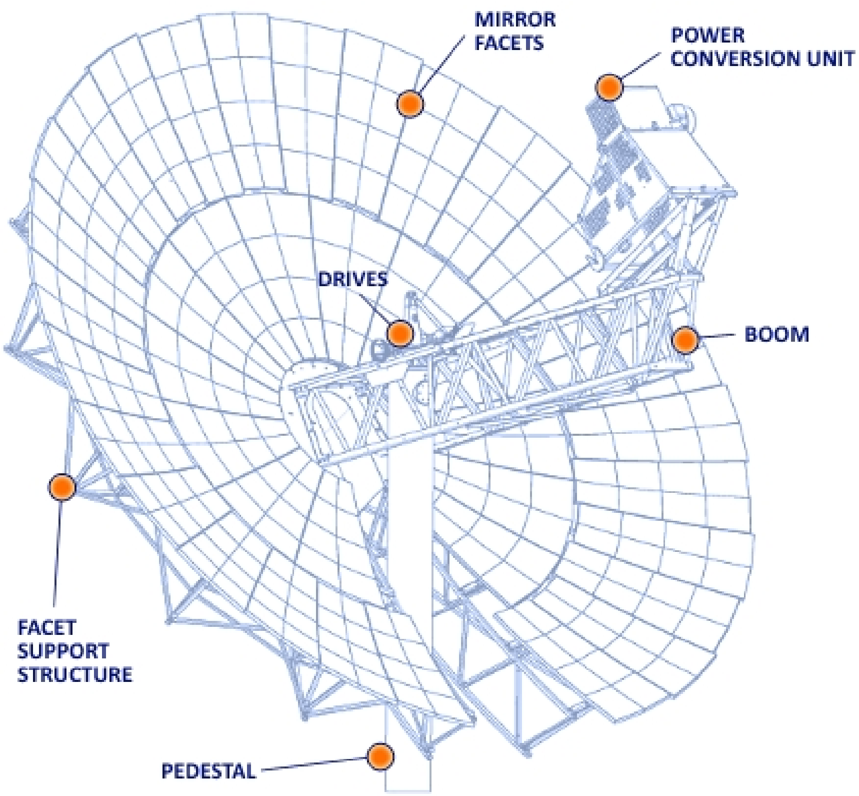
Power tower systems consist of a field of large, nearly-flat mirror assemblies (heliostats) that track the sun and focus the sunlight onto a receiver at the top of a tower. In a typical configuration, a heat-transfer fluid such as water/steam or molten nitrate salt mixture is pumped through the receiver, 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.

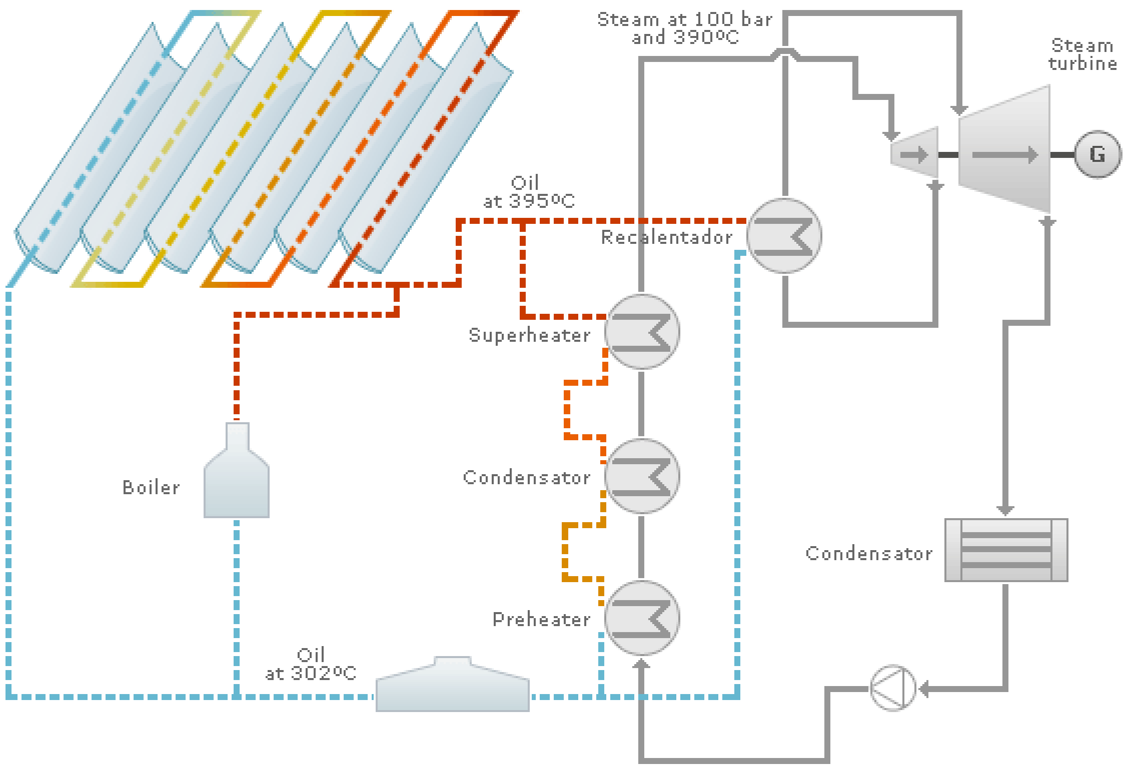
Trough Systems

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.

Co

Harper Lake Solar CSP Project (NREL)

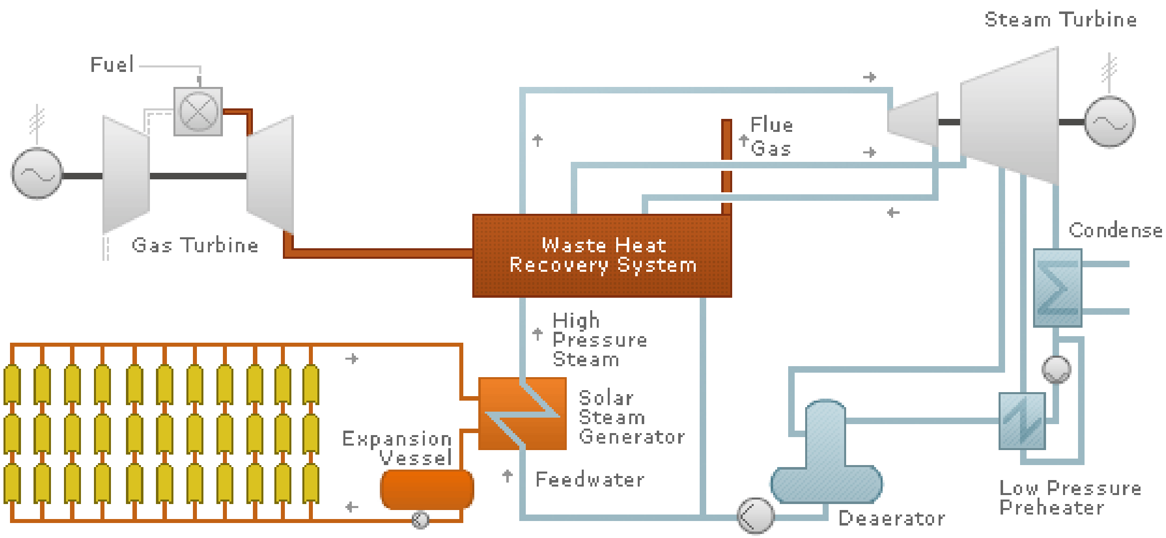
As shown below, the solar trough field heats synthetic transfer oil. Energy in the oil is used to generate superheated, high pressure steam that is delivered to a steam turbine. This turbine powers an electrical generator, creating electricity



Solar CSP (Abengoa Solar)

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

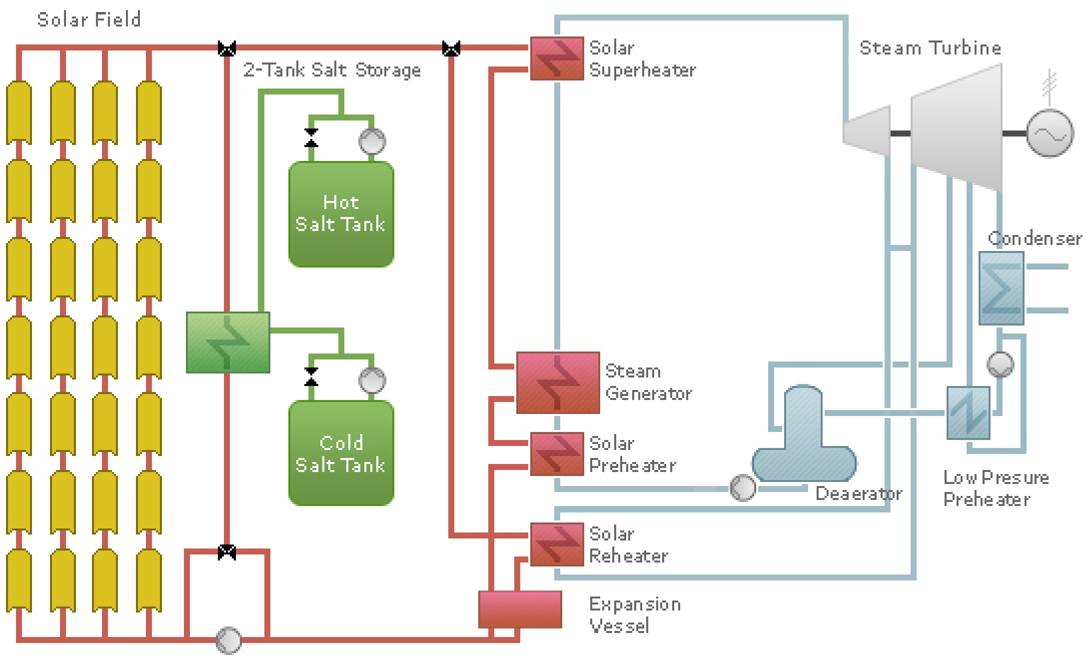
New innovative designs that incorporate hybridized configurations such as Integrated Solar Combined Cycle (ISCC) are also in the early stages of development. ISCC technology combines the benefits of solar energy with the benefits of a combined cycle. The solar resource partially substitutes the fossil 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)

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.

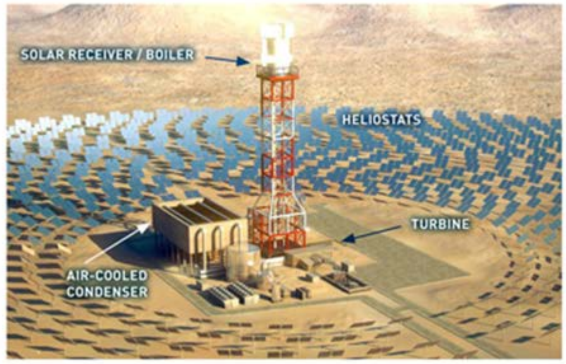
Ivanpah Computer Controlled Heliostats

Ivanpah Solar Receiver and Condensers

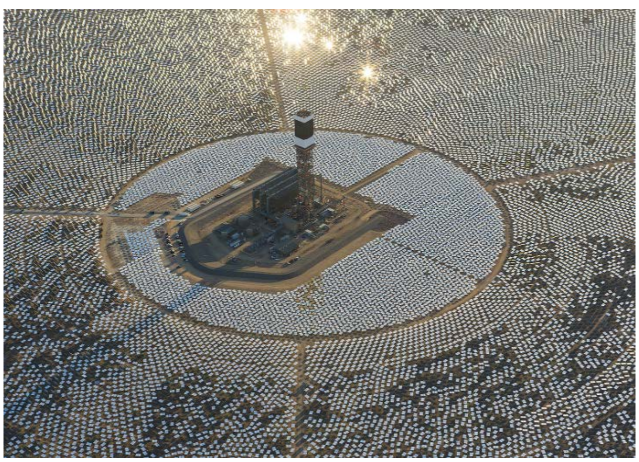
Each tower holds a 2,100-ton boiler that directs steam into a turbine generator at ground level (Figure 2). Natural gas is used to bring the boiler up from a cold start, but in normal use, it retains enough heat from the previous day to start up on sunlight alone. A 110-ton counterweight is continually 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

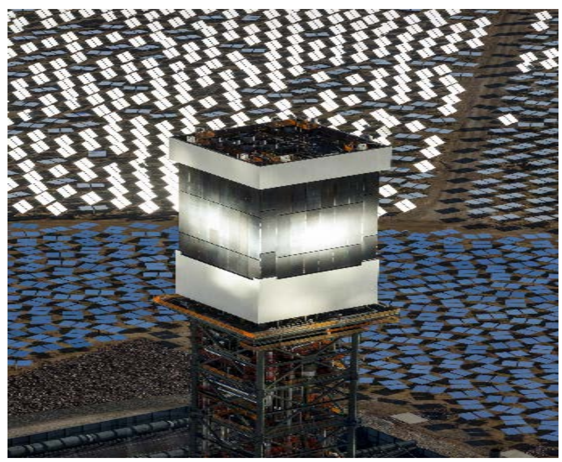
- Ivanpah will produce electricity the same way that most of the world's electricity is produced – by creating high-temperature steam to turn a conventional turbine. However, instead of burning fossil fuels to create the steam, we use the clean and infinite sun as fuel.
- At the heart of BrightSource's 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 Solar 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.

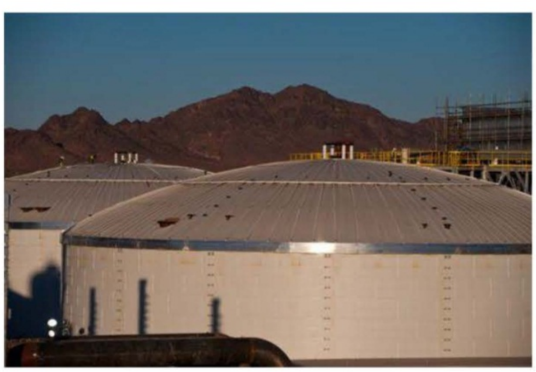
The 280-MW plant, near Gila Bend in Arizona about 70 miles southwest of Phoenix, employs molten salt to store about six hours of thermal energy at full power, allowing the facility to continue operating during periods of peak evening demand. The addition of thermal storage also allows the facility to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

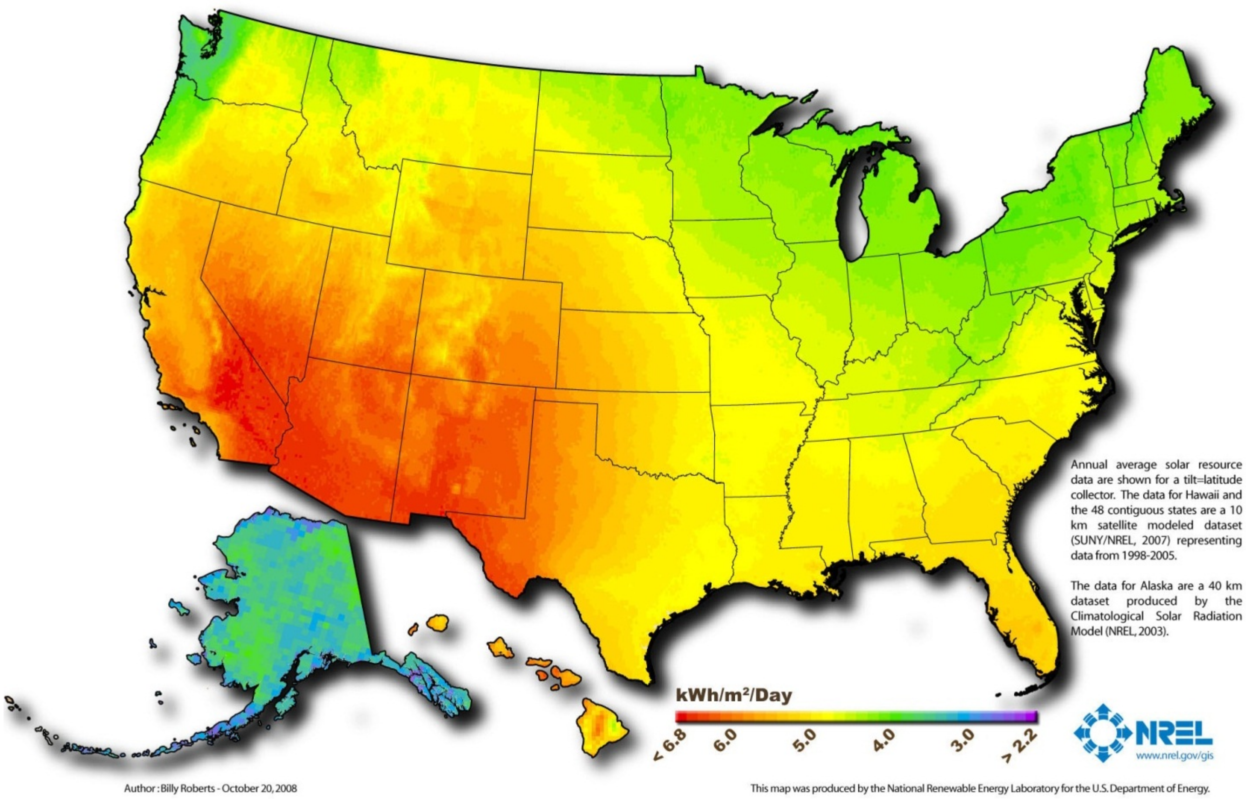
Aerial View of Mohave Solar Fields

Mohave Solar Collectors

U.S. SOLAR MAP

This map shows the national solar photovoltaics (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.

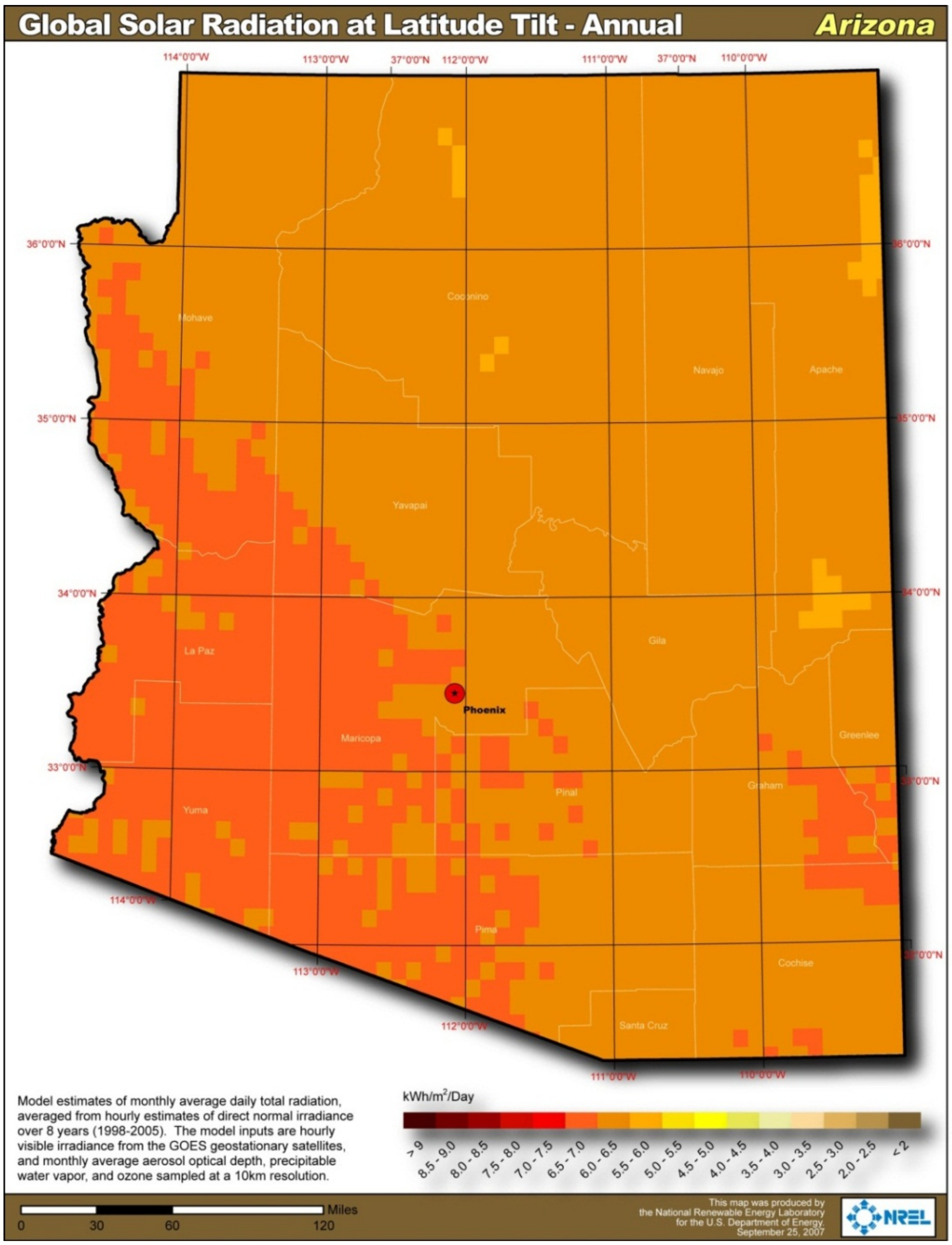
Map 14 – U.S. NREL Solar Radiation Map



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.

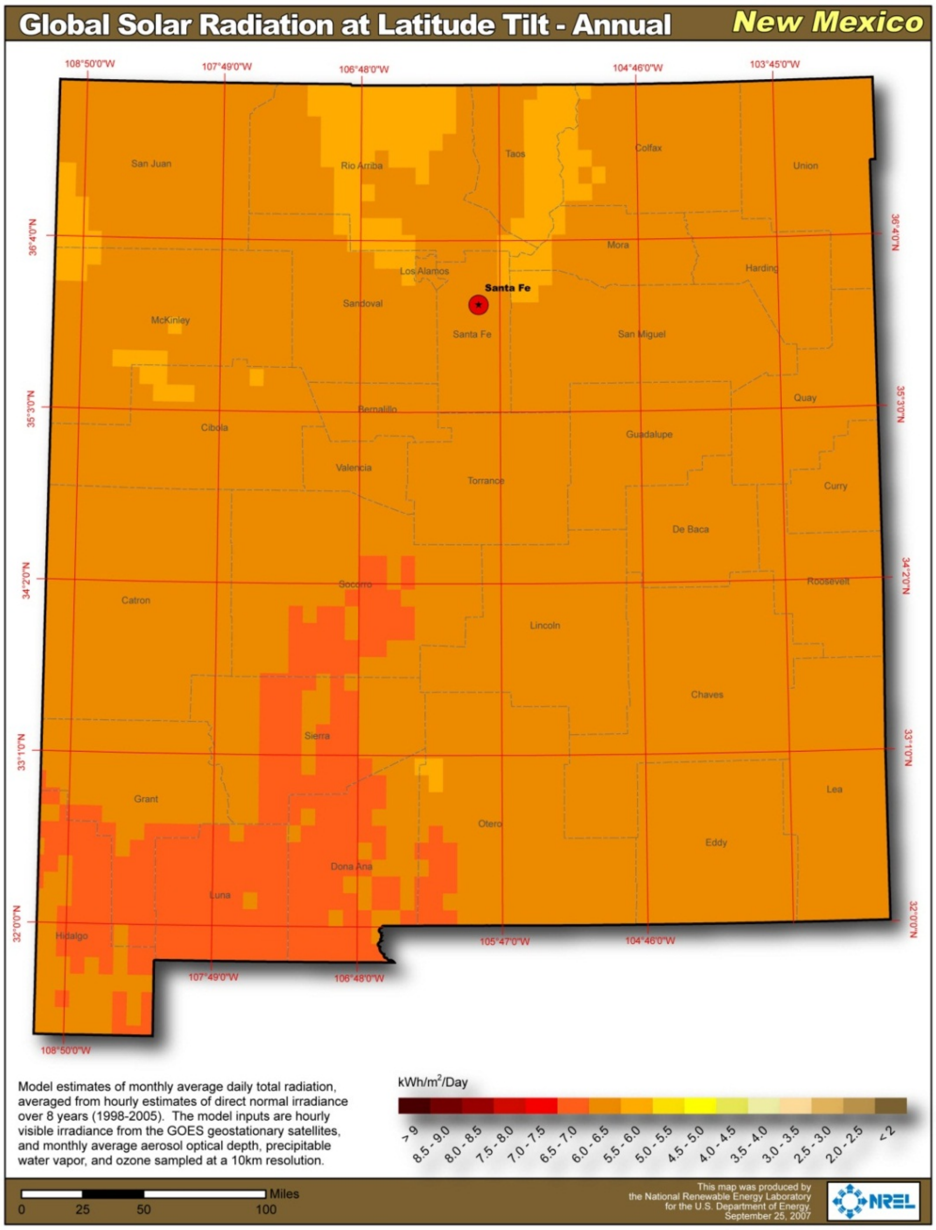
Map 15 - Arizona NREL Solar Insolation Map



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 16 – New Mexico NREL Solar Insolation Map



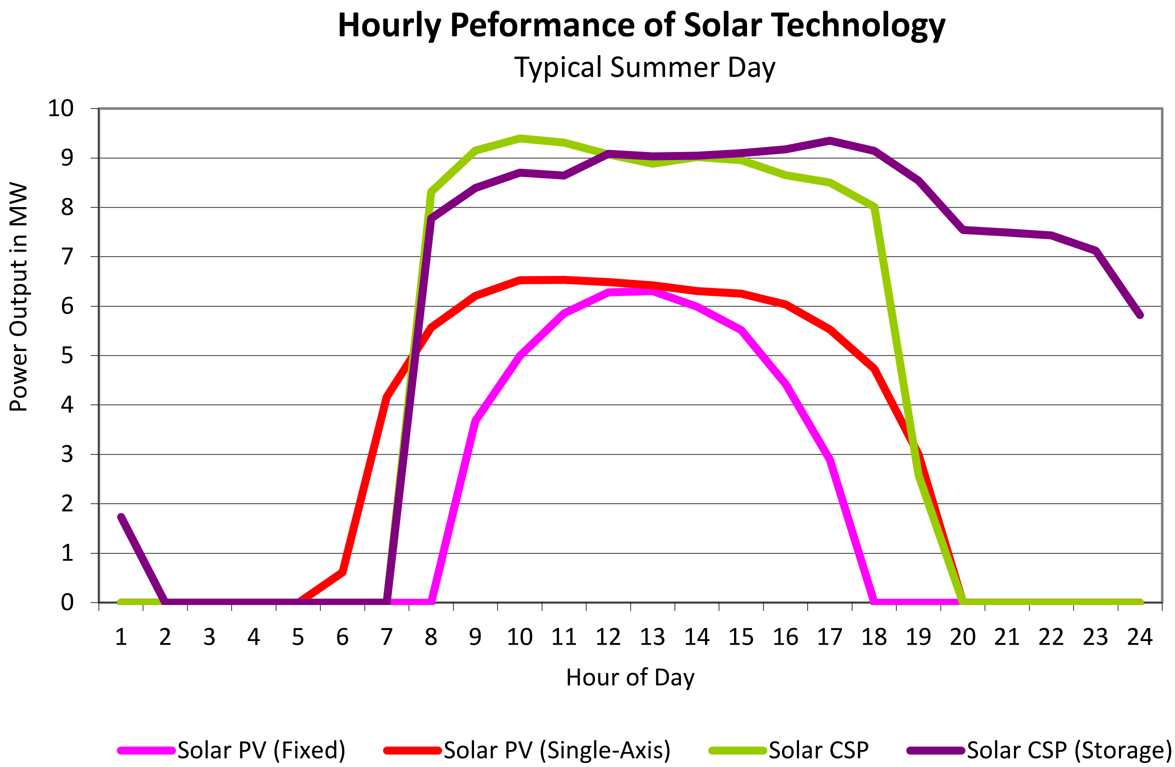
SOLAR RESOURCES MODELED

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	$7.60	$7.60	$5.55	$5.55
Levelized Cost of Energy	$/MWh	$168	$186	$208	$214
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.

Kingman Wind Farm (10 MW Project)

UniSource Energy Wind Project

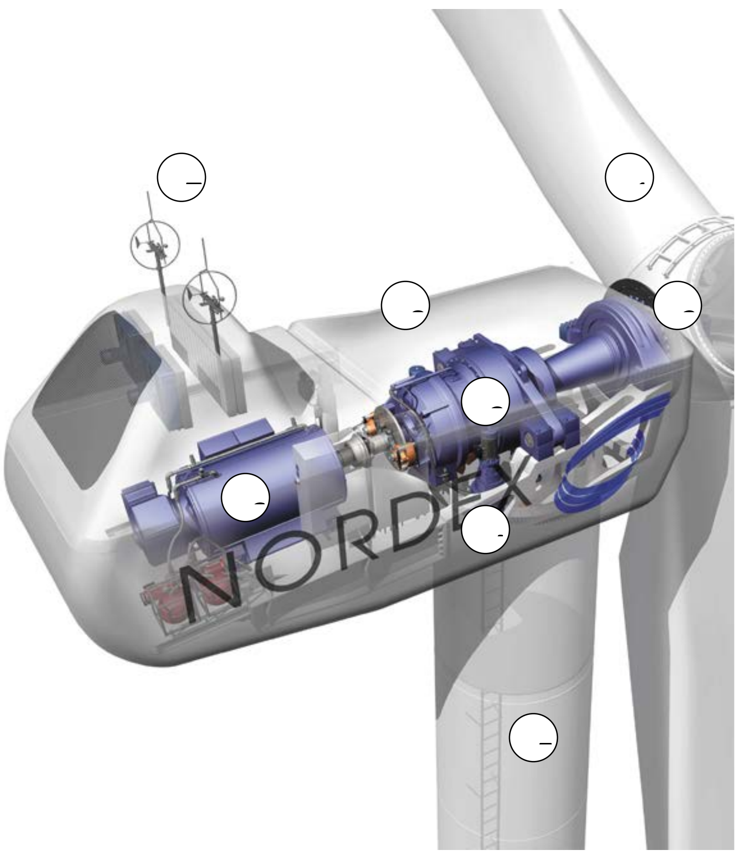
A small wind farm just outside of Kingman, Arizona developed by Western Wind Energy Corporation.

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).



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.

Figure 15 - 3D Drawing of Nordex N80/2500kW Wind Turbine

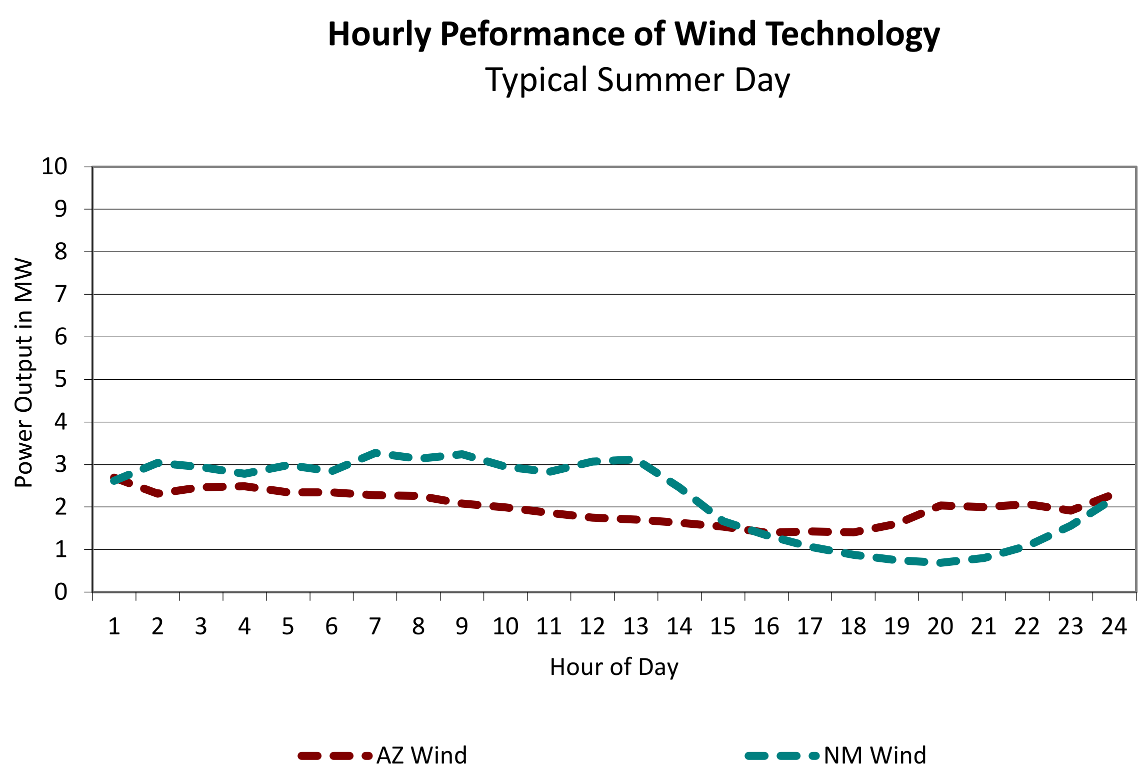
WIND RESOURCES MODELED

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	$4.50	$4.5
Levelized Cost of Energy	$/MWh	$149	$180
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

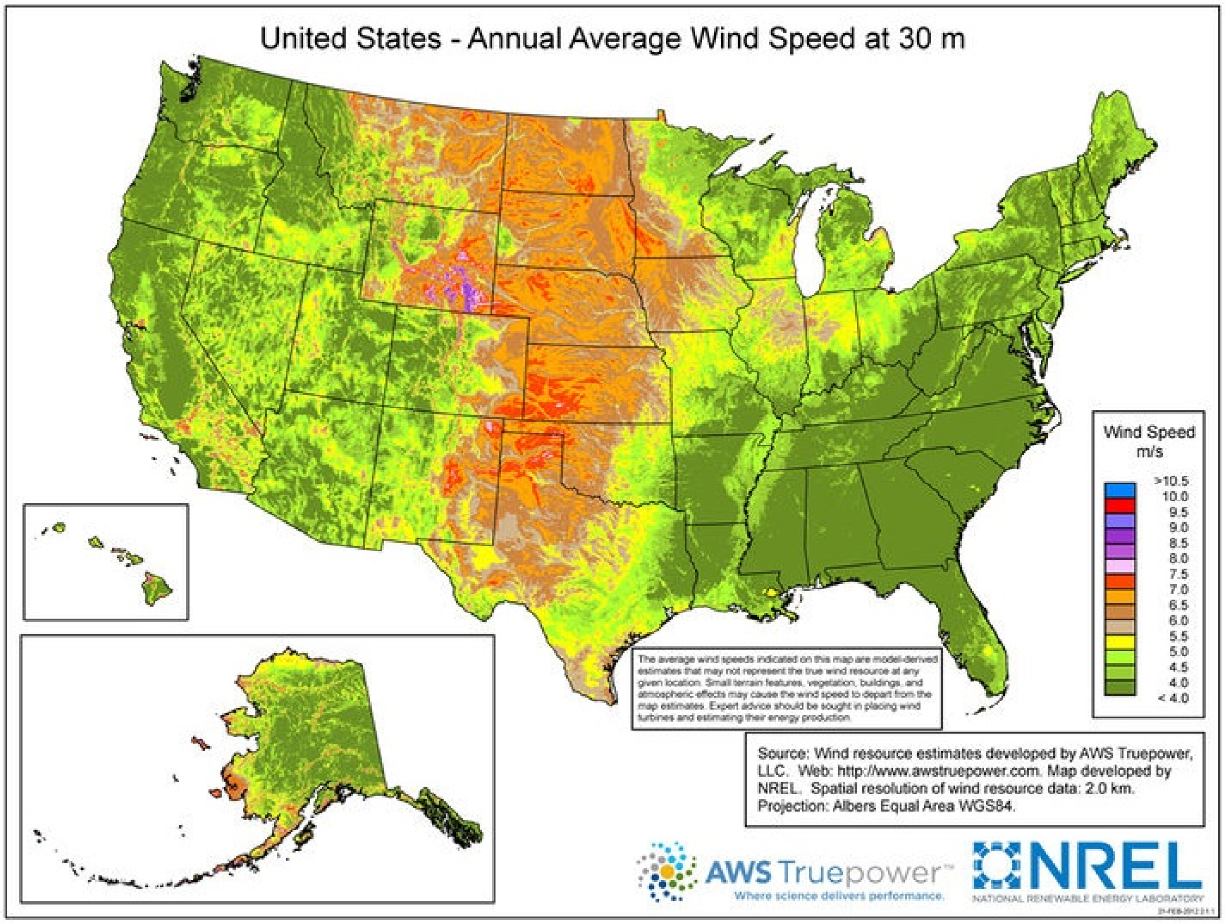
NREL's Western Wind Resource Dataset (WWRD) provided hourly wind resource data. This data was used to develop the anticipated coincident peak and expected capacity factors used in the resource planning process.



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

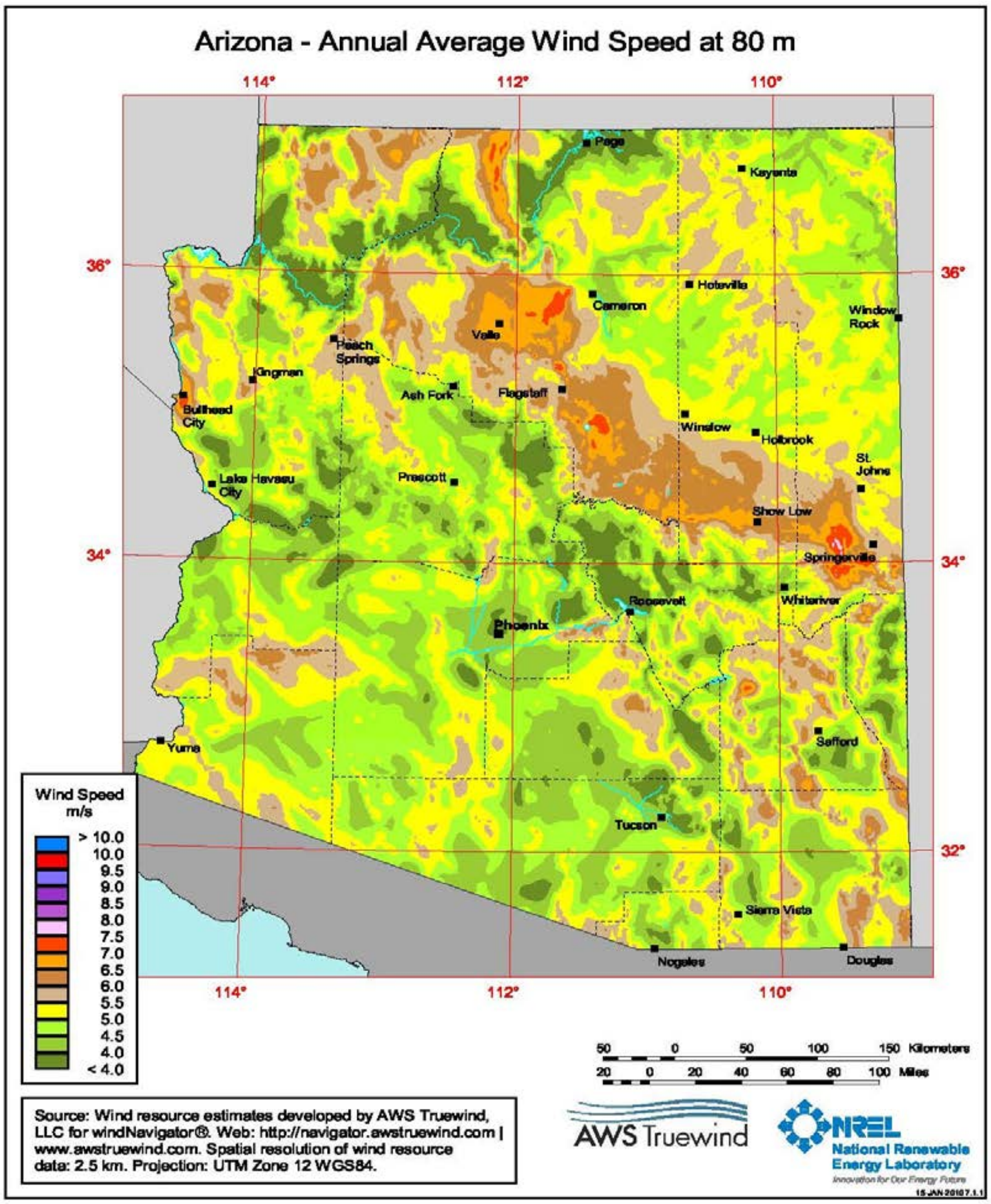
Map 17 - U.S. Wind Resource Map



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.

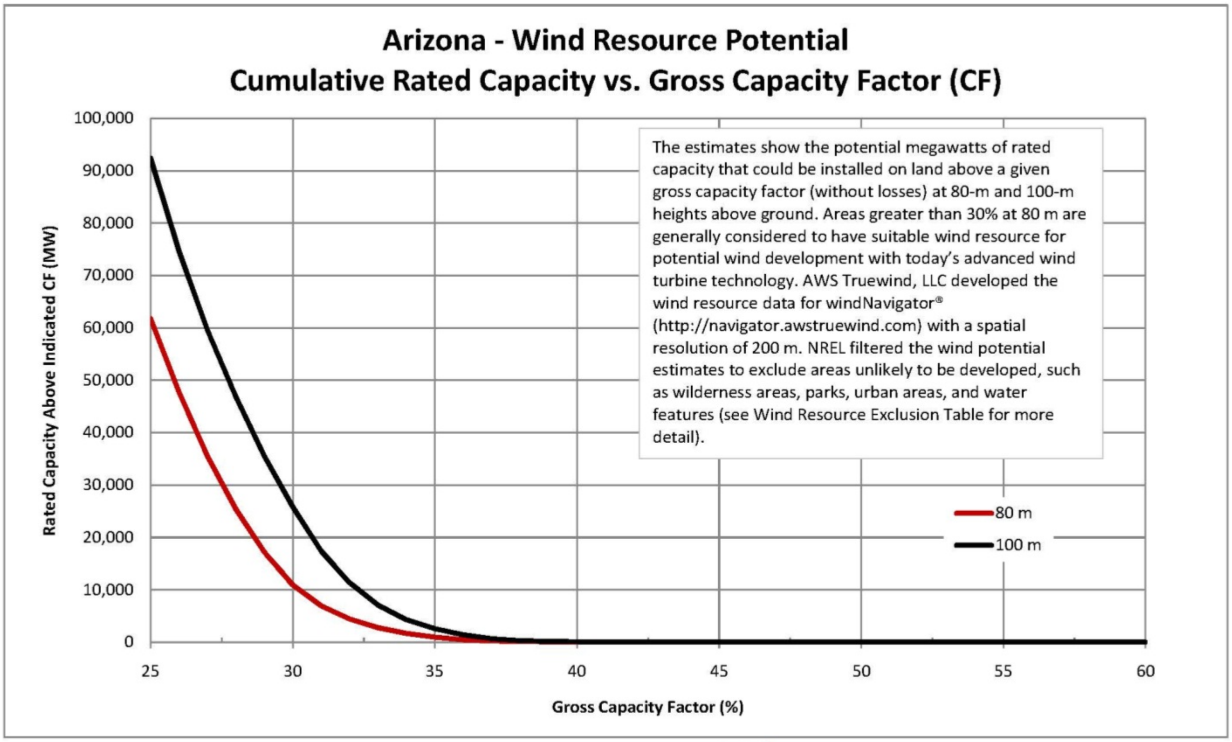
Map 18 - Arizona NREL Wind Resource Map



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.

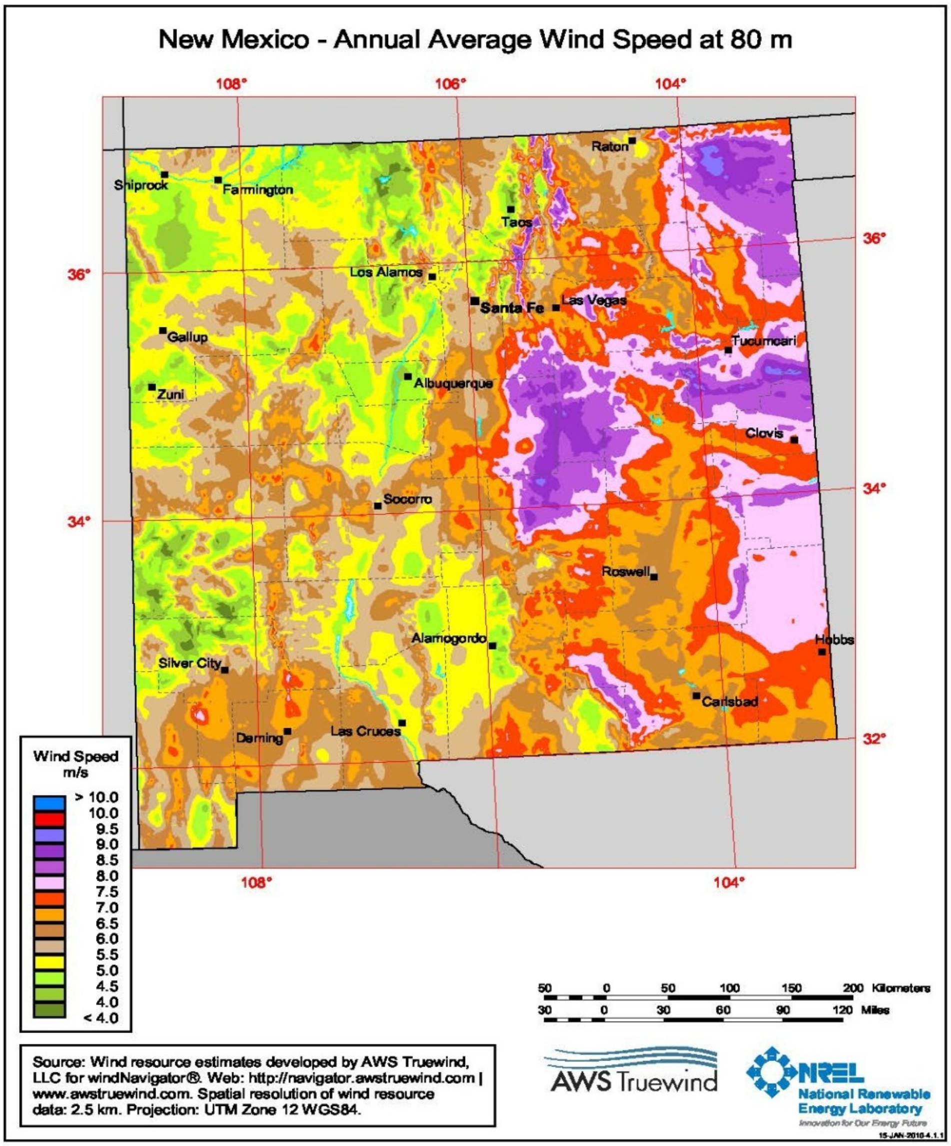
Map 19 - Arizona NREL Wind Resource Potential



NEW MEXICO WIND POWER 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.

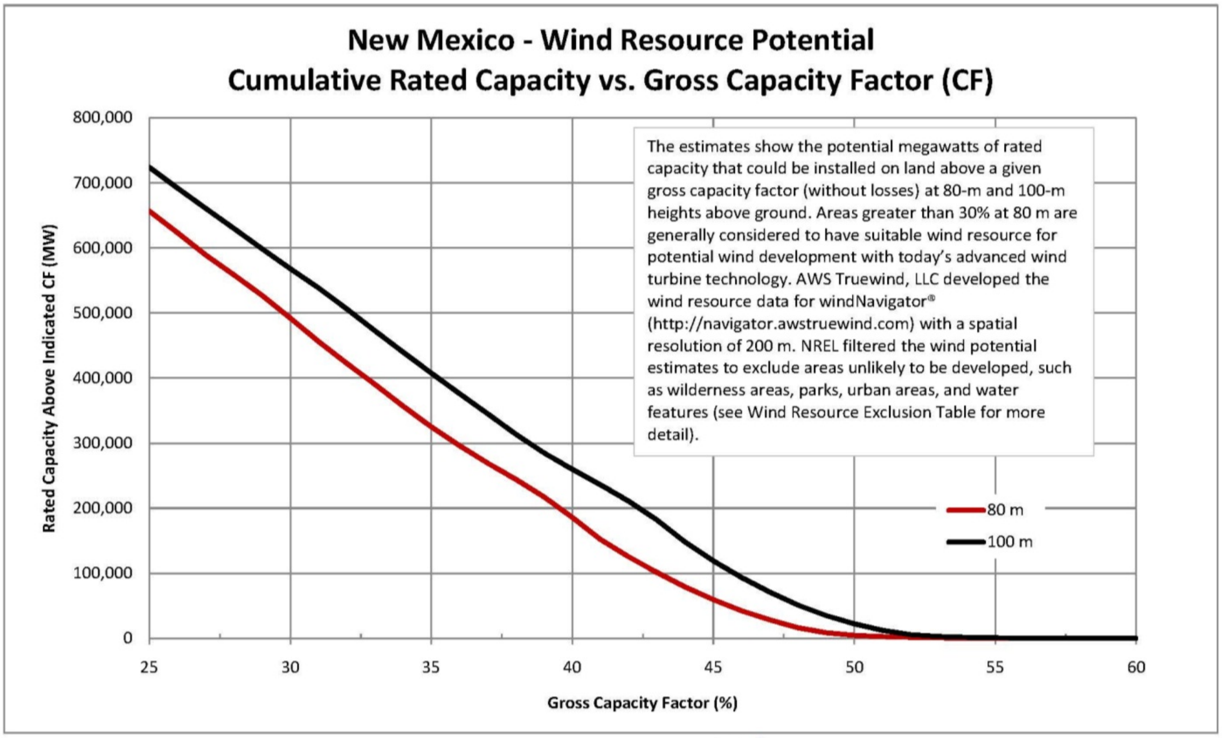
Map 20 - New Mexico NREL Wind Power Map



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 21 – New Mexico Wind Resource Potential



NREL NATIONAL RENEWABLE ENERGY LABORATORY

AWS Truepower™ Where science delivers performance.

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 UNSE'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.

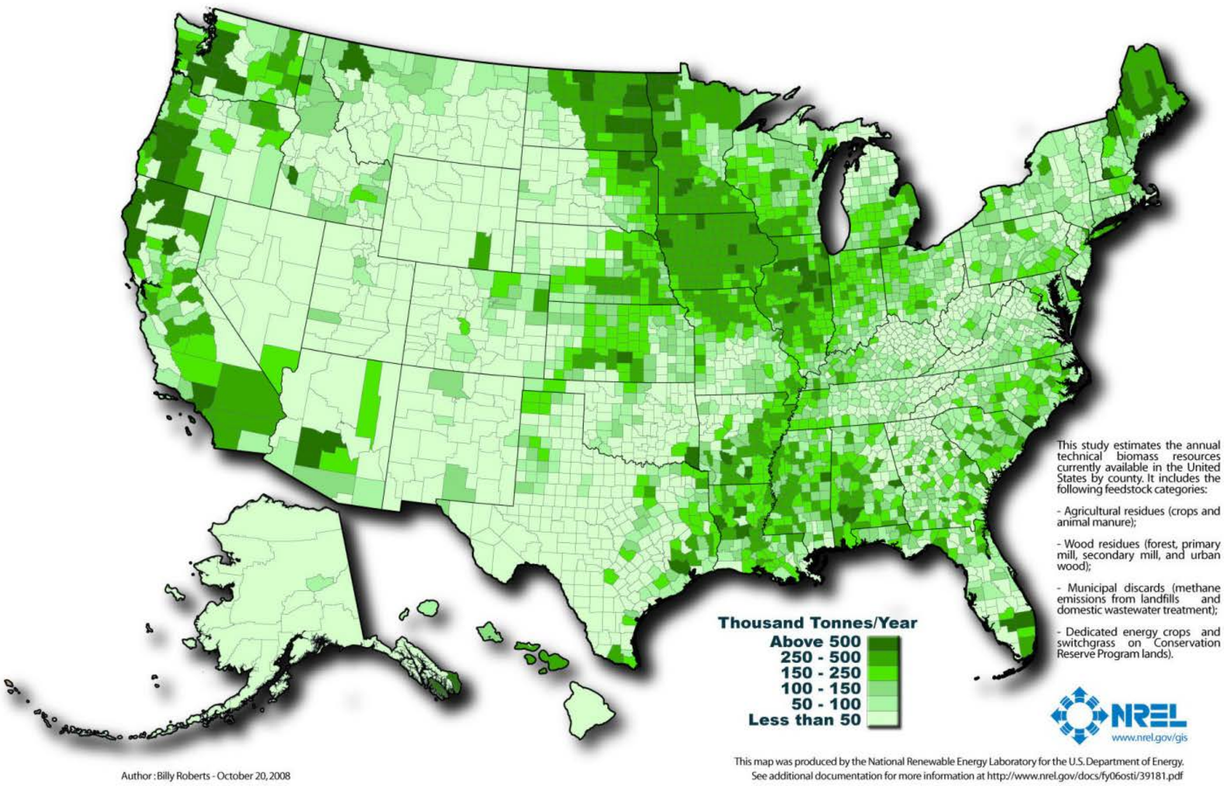
Modeling Assumptions

For the IRP process at UNSE, 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

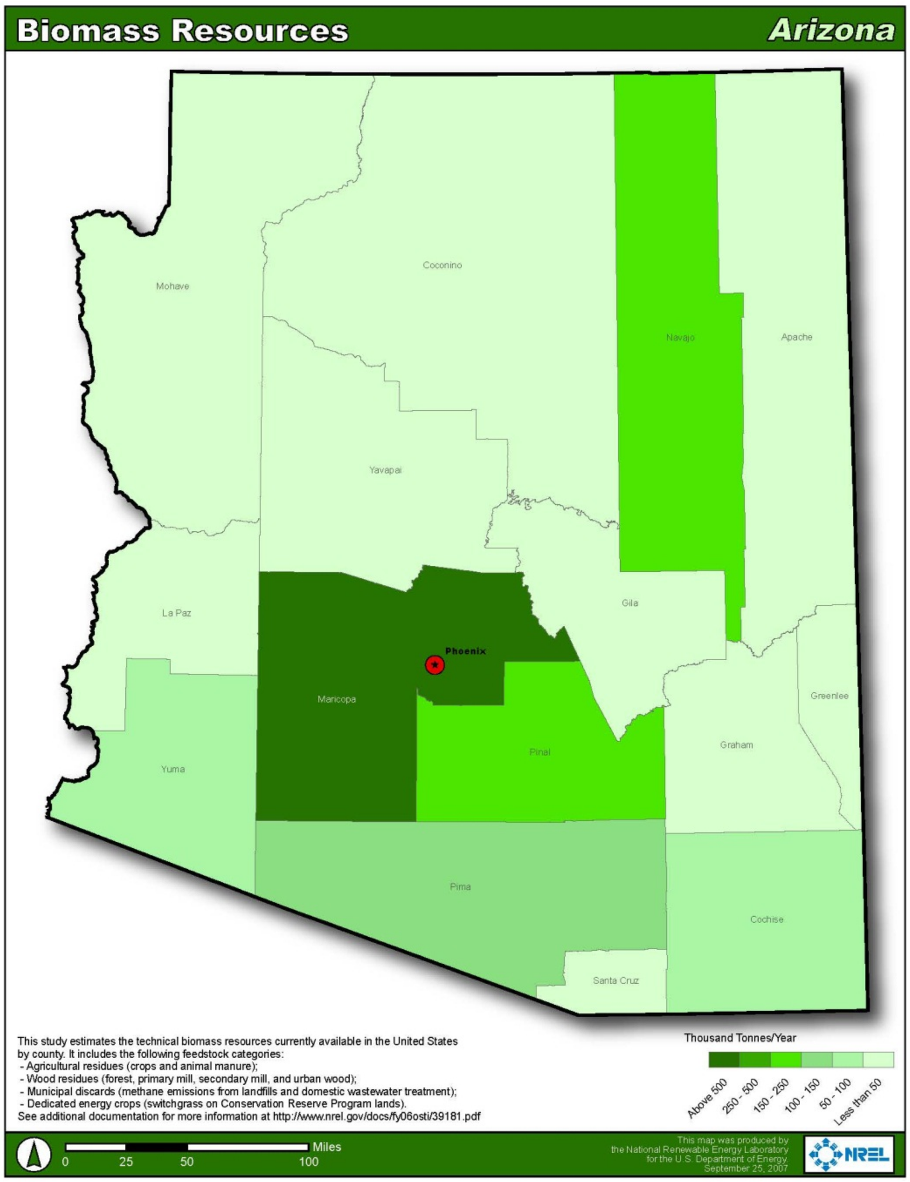
Map 22 – U.S. NREL Biomass Map



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.

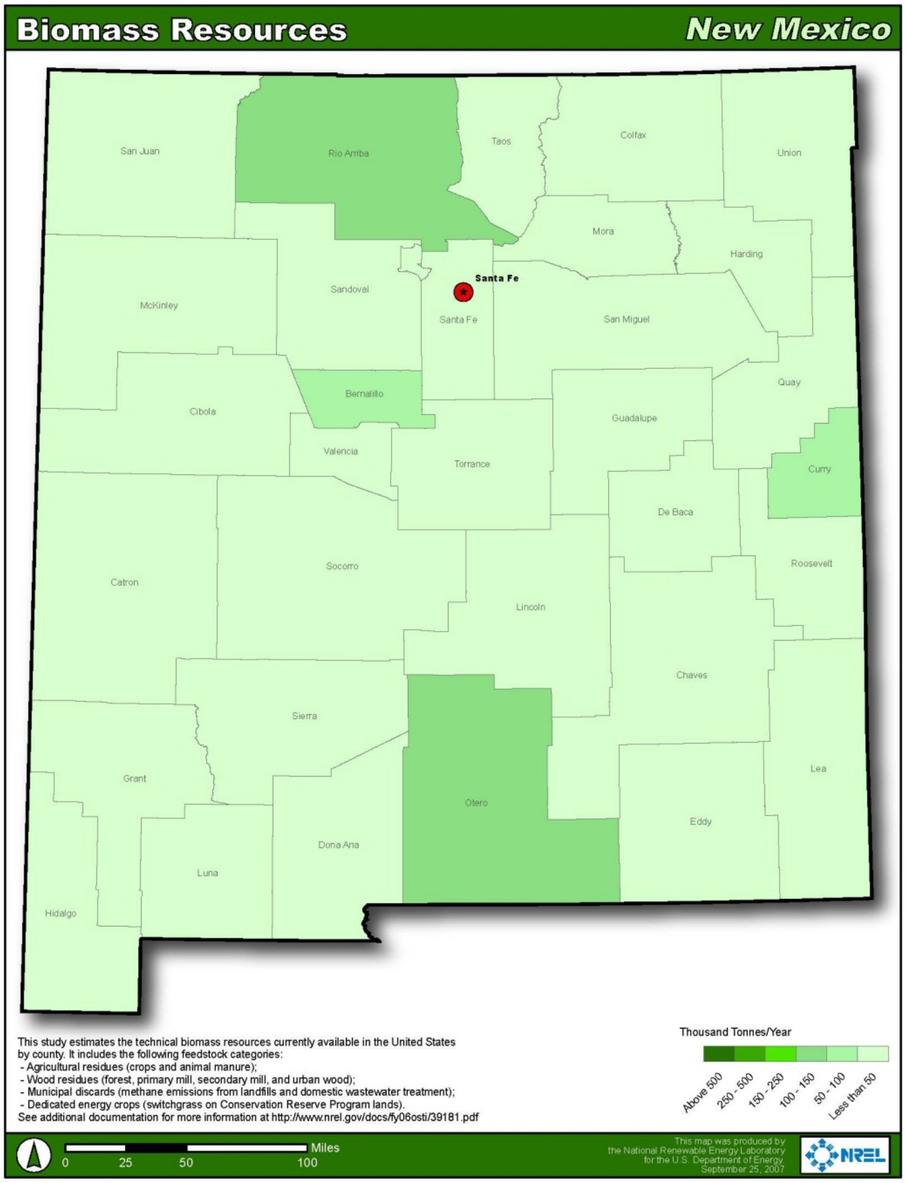
Map 23 – Arizona NREL Biomass Map



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 24 – New Mexico NREL Biomass Map



Renewable Resource Integration Costs

Table 21 below reflects the renewable integration modeling assumptions used in the 2014 IRP for Unisource Electric. 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 25 MWs of their respective technology for wind and solar as shown in the table. The 'Existing UNSE Renewables' scenario consists of 11 MWs of a mix of fixed PV and single-axis PV along with 10 MWs of wind generation at Western Wind in Kingman, Arizona. For each scenario inTable 21, 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 $4.50/MWh for Wind generation and up to $7.60/MWh for Solar PV generation. Since UNSE 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. UNSE dispatches gas and purchased power resources on the margin. This accounts for the increased costs relative to UNSE's affiliate, TEP.

Table 21 - System Integration Costs

System Integration Costs ($/MWh)			
Renewable Technology	Reference Case ($6/MMBtu Permian)	Increase per 100 MW	Increase per $1/MMBtu Permian
Wind	$4.50	$1.50	$0.90
Solar PV	$7.60	$1.00	$1.40
Solar CSP	$5.55	$1.00	$0.95
Existing TEP Renewables	$6.20		$1.35

As stated above, the PV hourly shape was comprised of UNSE's existing blend of fixed panel and wind resources. The Solar PV scenario yielded an integration cost of $7.60/MWh and $5.55/MWh for the scenario Solar CSP. The hybrid scenario is "Existing UNSE Renewables". The profile of the existing solar and wind resources for UNSE were combined and modeled in this scenario. The resulting cost of $6.20/MWh is a blend of the Wind and Solar PV scenarios. It's observed that 25 MWs of each technology contributes an additional $1.50/MWh to $3.00/MWh of costs. The variability of natural gas also has an impact on the integration costs. An increase for Permian natural gas ranges from $1.60 to $2.80 for each additional $1/MMBtu increase in gas.

This methodology captures the energy costs (fuel and purchased power) for the UNSE 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-

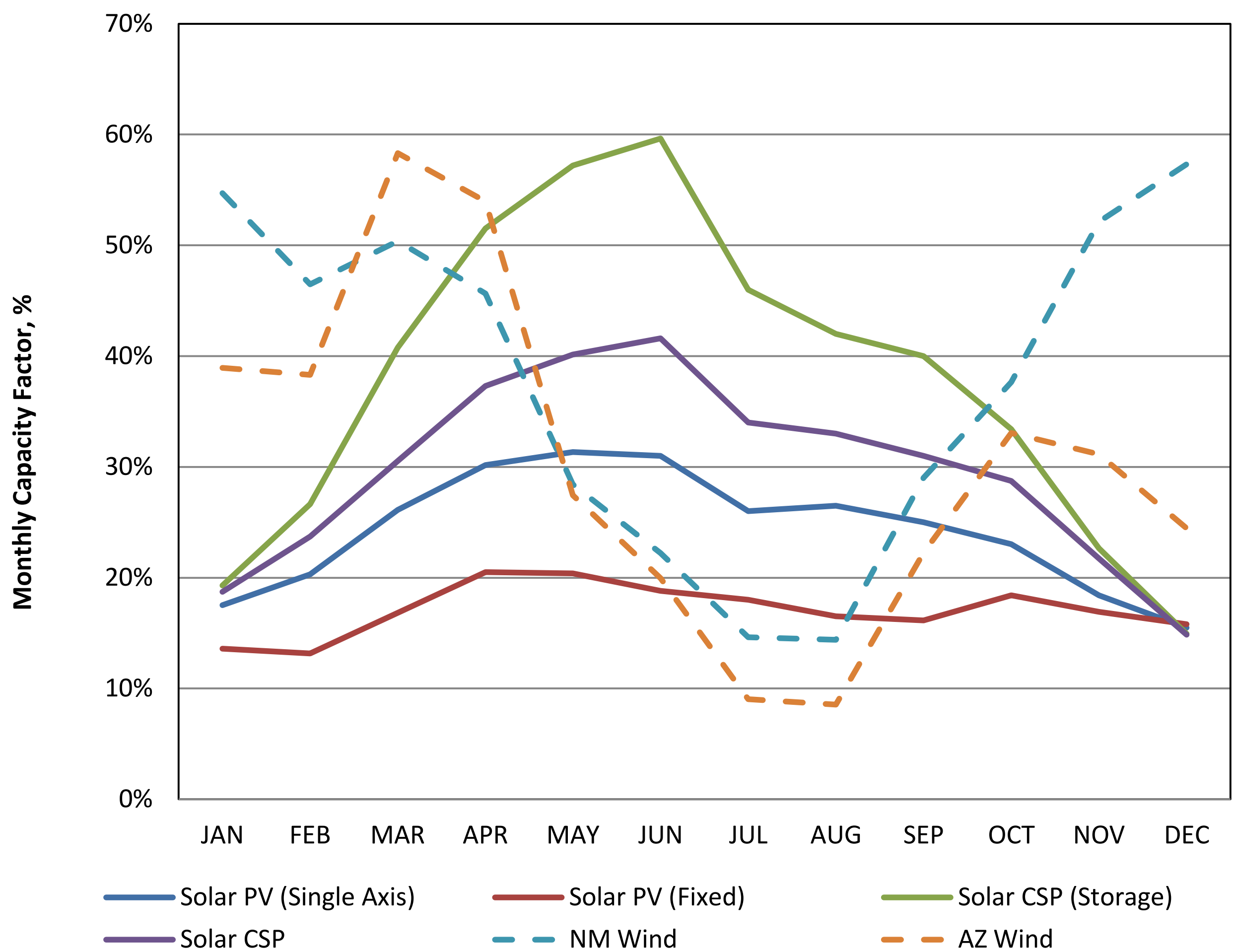
2011, titled Large-Scale PV Integration Study conducted by Navigant Energy was used to validate these integration cost calculations.

UNSE'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 UNSE'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 28 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.

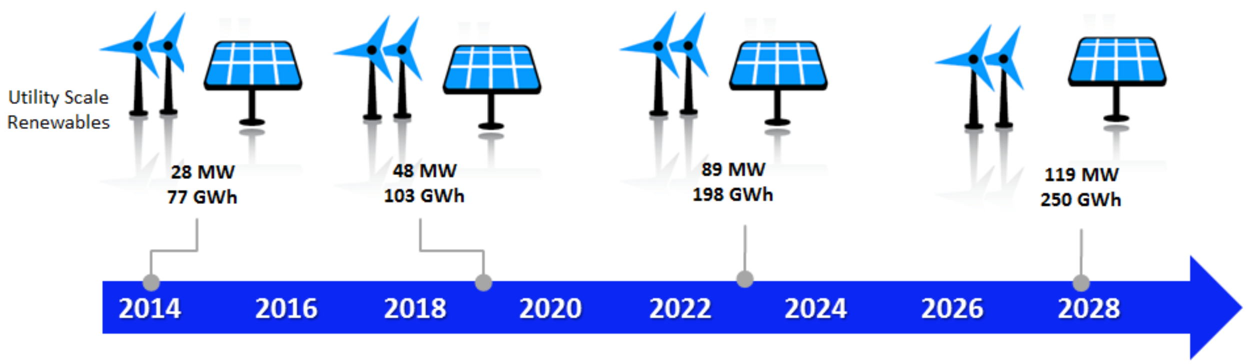
Chart 28 - Renewable Resource Seasonal Profiles



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 UNSE 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 119 MW of utility scale renewable nameplate capacity. These utility scale renewable resources are expected to supply approximately 77 GWh of energy in 2014 growing to 250 GWh by 2028.

Figure 16 – Utility Scale Renewable Capacity



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

Table 22 – 2014-2028 Projected Utility Scale Resources

REST Utility Scale Program, Energy	2014	2015	2016	2017	2018	2019	2020	2021
Utility Scale Solar, GWh	53.4	79	79.3	79	79	79	79.3	109
Utility Scale Wind, GWh	24.0	24.0	24.1	24.1	24.0	24.0	24.1	24.1
Total Utility Scale Renewables, GWh	77.4	103.1	103.4	103.2	103.1	103	103.4	133.2

REST Utility Scale Program, Energy	2022	2023	2024	2025	2026	2027	2028
Utility Scale Solar, GWh	109.0	154.0	159.8	176.6	181.8	187.0	192.4
Utility Scale Wind, GWh	24.0	43.8	47.4	53.0	54.2	56.1	57.7
Total Utility Scale Renewables, GWh	133.1	197.8	207.2	229.6	235.9	243.1	250.0

CHAPTER 10

Distributed Generation Resource

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 UNSE's proposed resource plans comply with the RES specified DG targets. For modeling purposes, UNSE 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

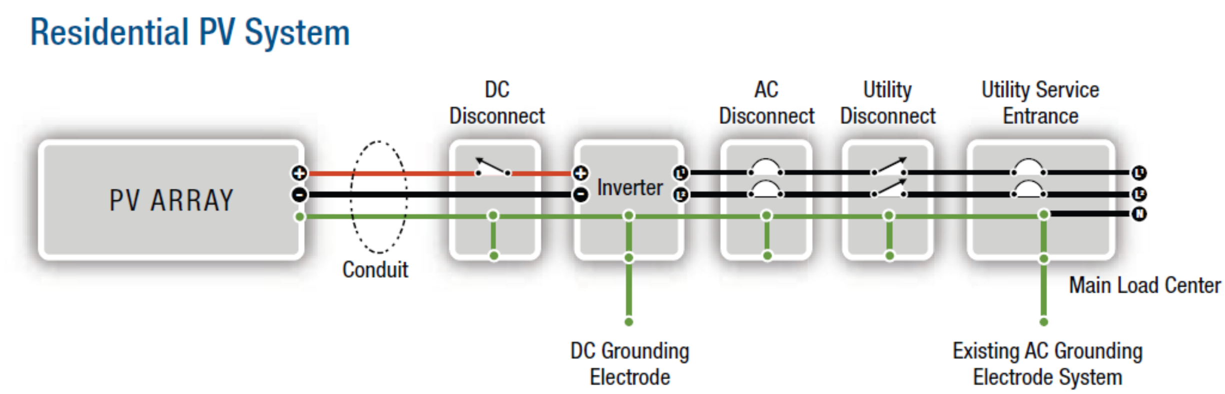
Solar Photovoltaic DG Systems Overview

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 17 – 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 18 – Typical Grid Tied PV System

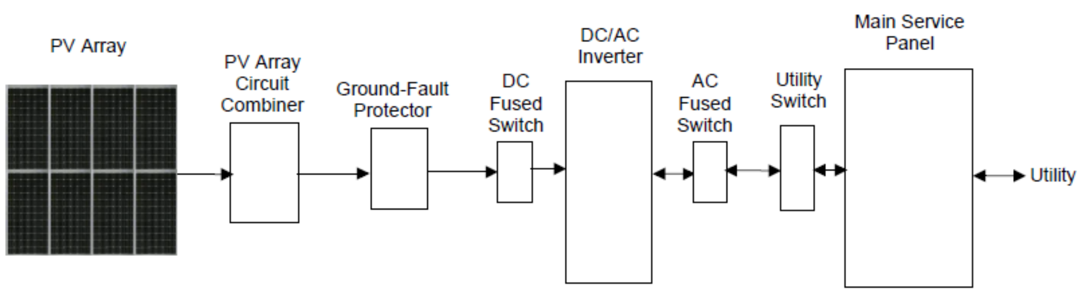
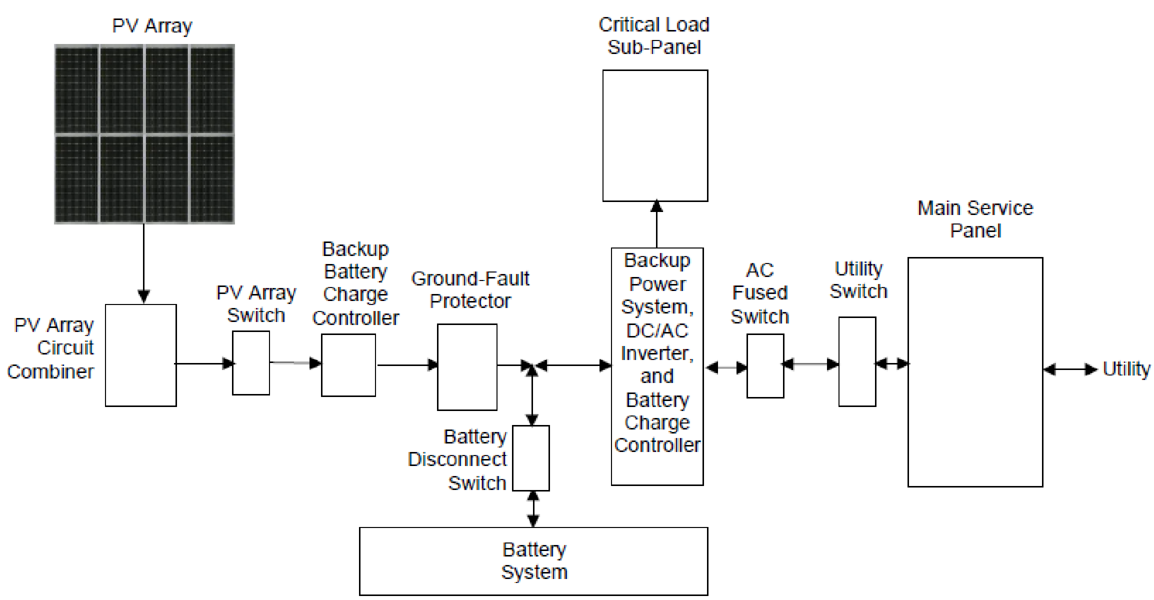


Figure 19 – Typical Grid Tied PV System with Battery Backup



Solar PV Load Profiles

Chart 29 – Typical Summer Customer Load Profile, Net Solar PV

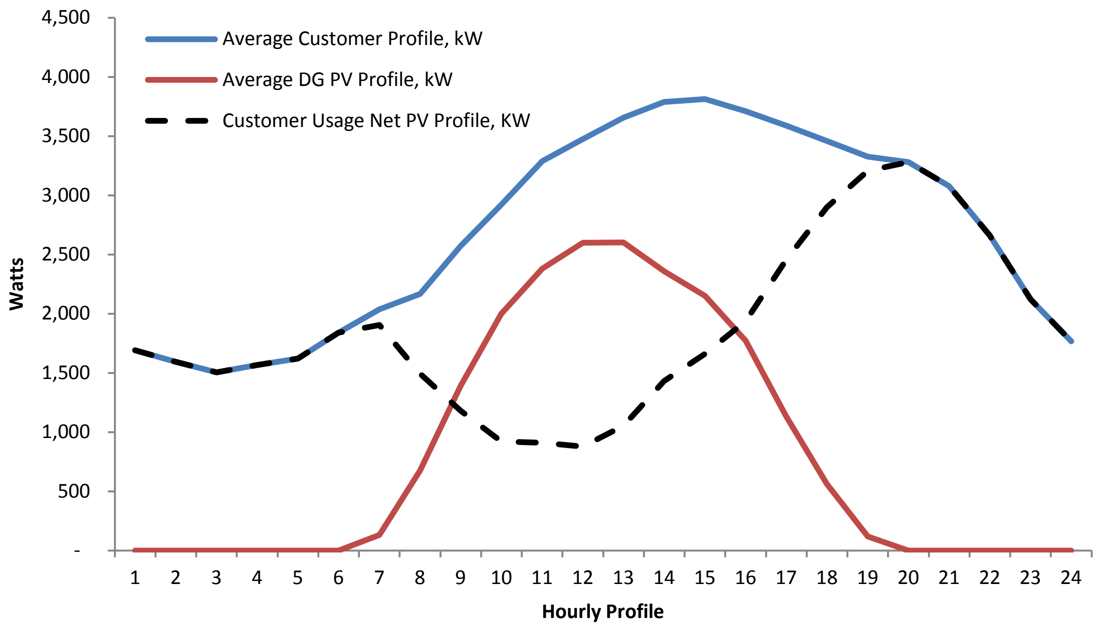
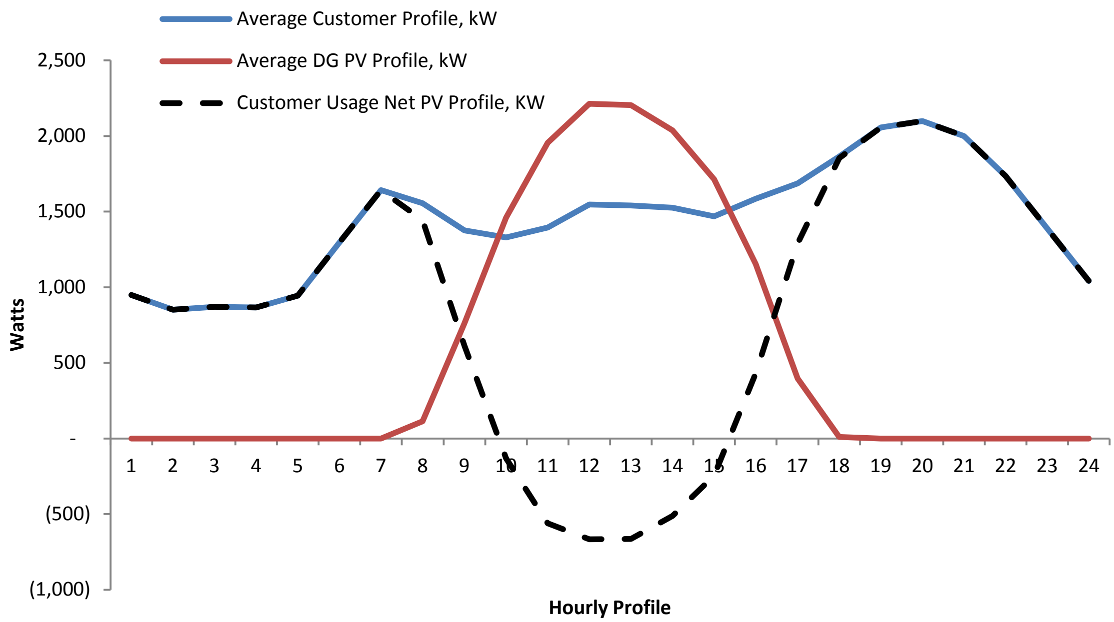


Chart 30 – Typical Winter Customer Load Profile, Net Solar PV



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:

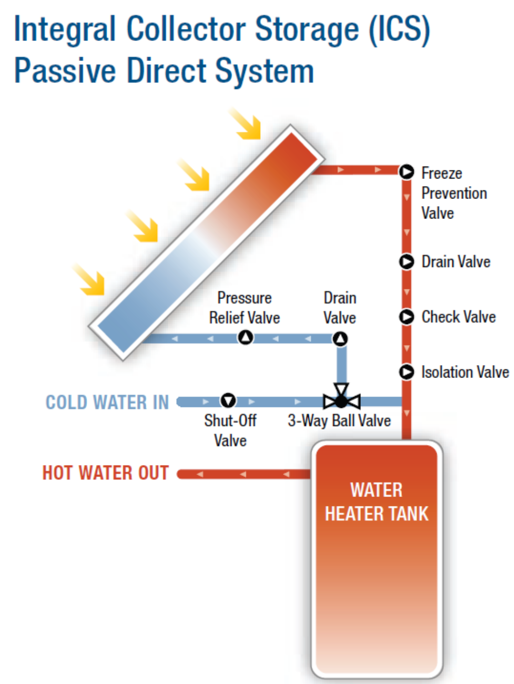
- Active systems use pumps to move fluids through the system.
- Passive systems rely on the buoyancy of warm water and gravity to move fluids through the system without any pumps.
- Direct systems heat water that feeds directly into the domestic hot water system. Direct systems always use potable water 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.

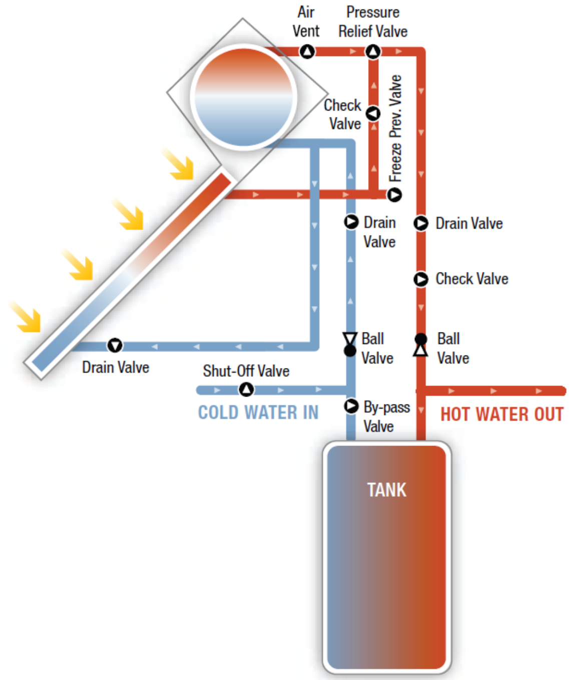
Integral Collector Storage (ICS) Passive Direct System

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

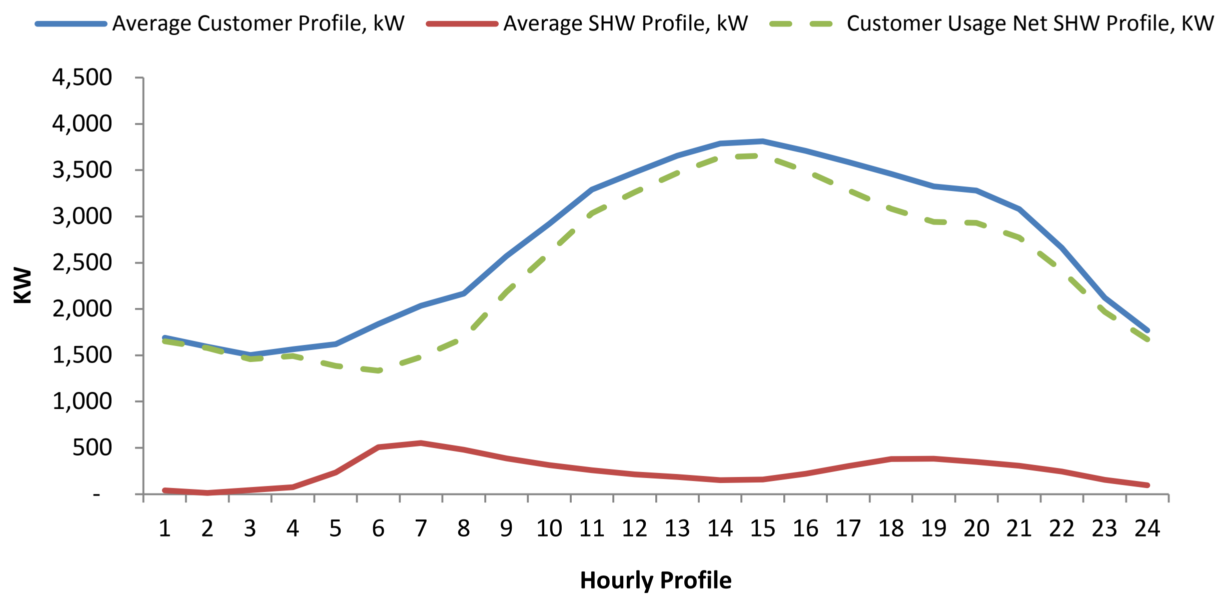
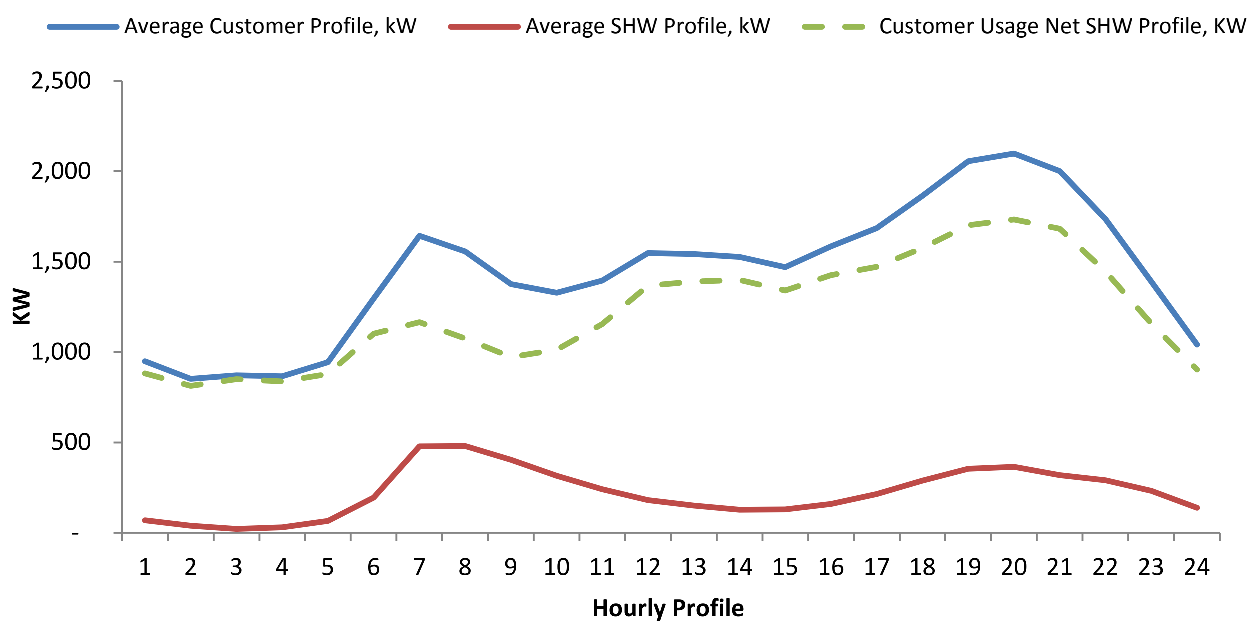


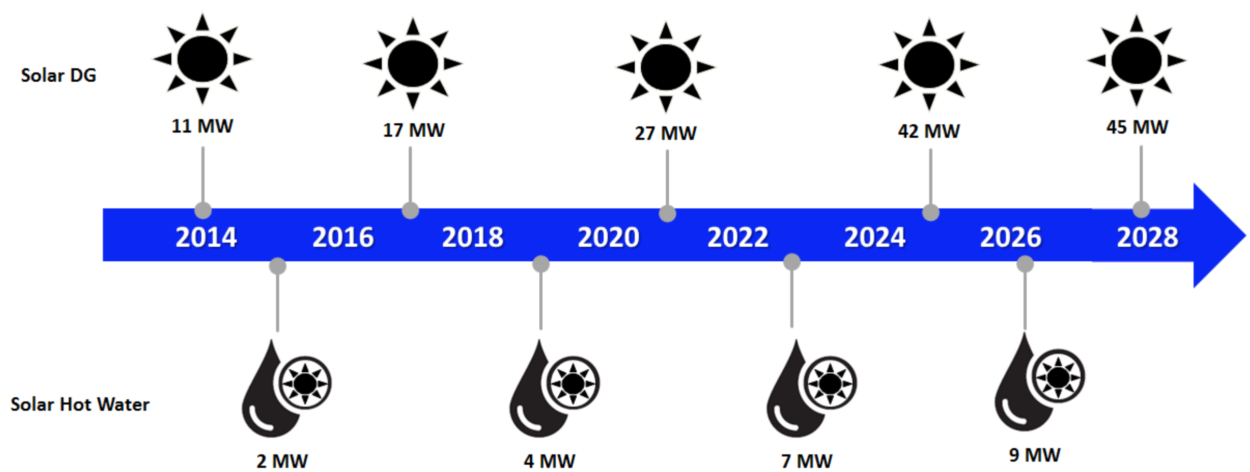
Chart 32 – Typical Winter Customer Load Profile, Net Solar Hot Water Heating



Projected Distributed Generation Requirements in the 2014 IRP

The Reference Case resource 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 13 MW of rooftop solar PV and solar hot water heating capacity. Distributed generation resources are expected to supply at least 22 GWh of energy on an annual basis in 2014 growing to approximately 93 GWh by 2028. Figure 20 below shows the expected cumulative nameplate capacity of both rooftop solar PV and solar hot water heating that will be installed in UNSE's service territory from 2014 through 2028.

Figure 20 - 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 23 – 2014-2021 Projected Distributed Generation for UNSE

Distributed Generation GWh	2014	2015	2016	2017	2018	2019	2020	2021
Solar Photovoltaic Systems	20.1	22.5	27.0	31.5	36.2	40.9	45.7	50.8
Solar Hot Water Systems	2.2	2.5	3.0	3.5	4.0	4.5	5.1	5.6
Total Portfolio Energy	22.3	25.0	30.0	35.0	40.2	45.4	50.8	56.4

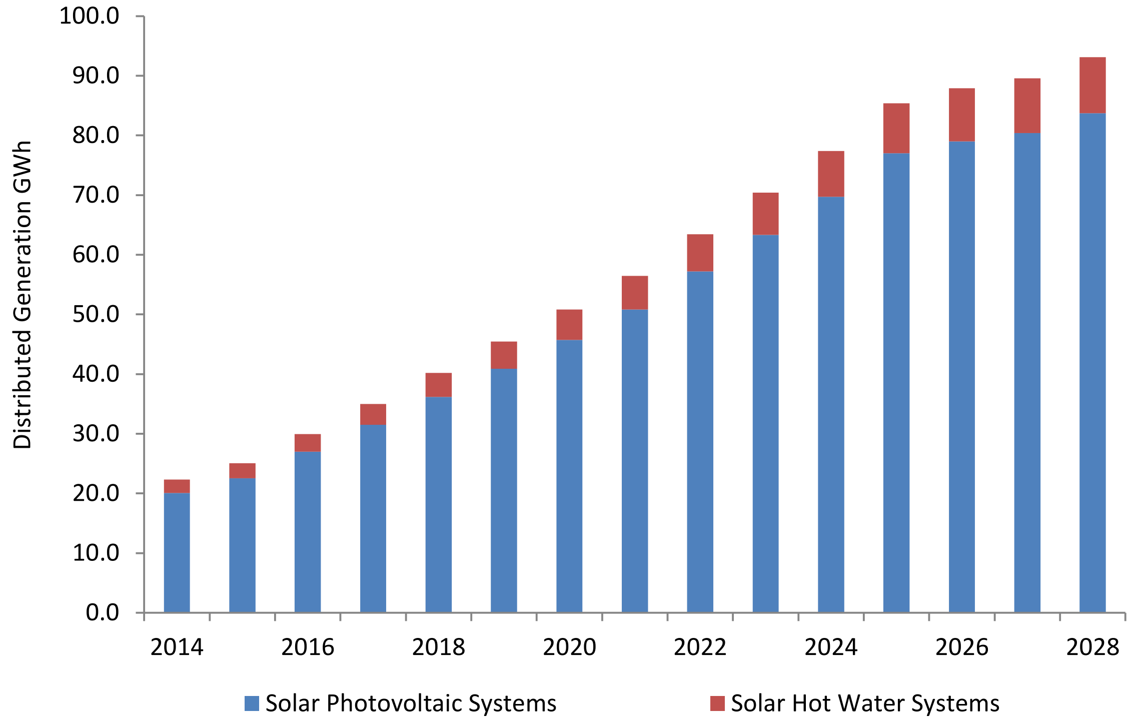
Distributed Generation MW	2014	2015	2016	2017	2018	2019	2020	2021
Nameplate Capacity, AC	13	15	17	20	23	26	29	33
System Coincident Peak	3	4	5	5	6	7	8	9

Table 24 – 2022-2028 Projected Distributed Generation for UNSE

Distributed Generation GWh		2022	2023	2024	2025	2026	2027	2028
Solar Photovoltaic Systems		57.2	63.3	69.7	77.0	79.0	80.4	83.7
Solar Hot Water Systems		6.2	7.1	7.7	8.4	8.9	9.2	9.4
Total Portfolio Energy		63.4	70.4	77.4	85.4	87.9	89.6	93.1

Distributed Generation MW		2022	2023	2024	2025	2026	2027	2028
Nameplate Capacity, AC		37	41	46	50	52	53	56
System Coincident Peak		10	11	12	13	13	14	14

Chart 33 – UNSE's Distributed Generation by Technology Type



CHAPTER 11

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 UNSE 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, UNSE 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.

Overview of Ancillary Services

For purposes of the 2014 Resource Plan, UNSE 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

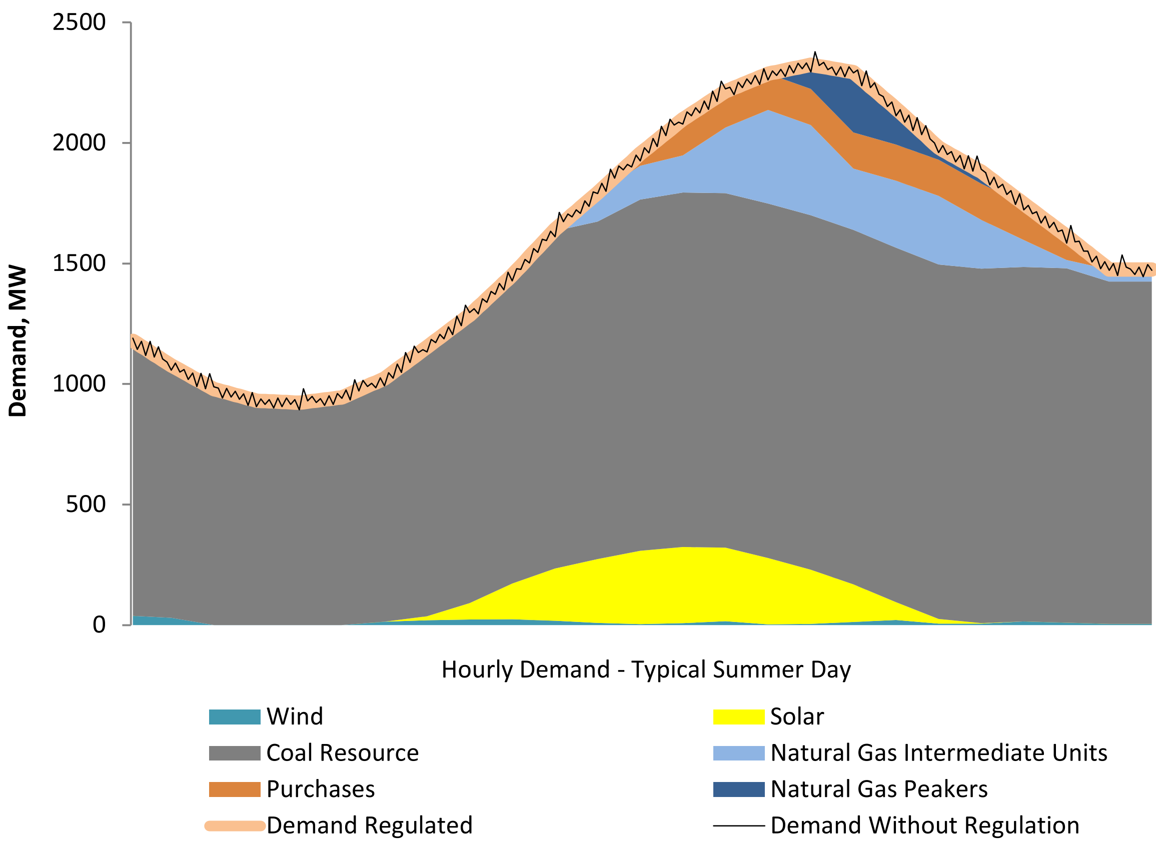
Load Following

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 34 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.

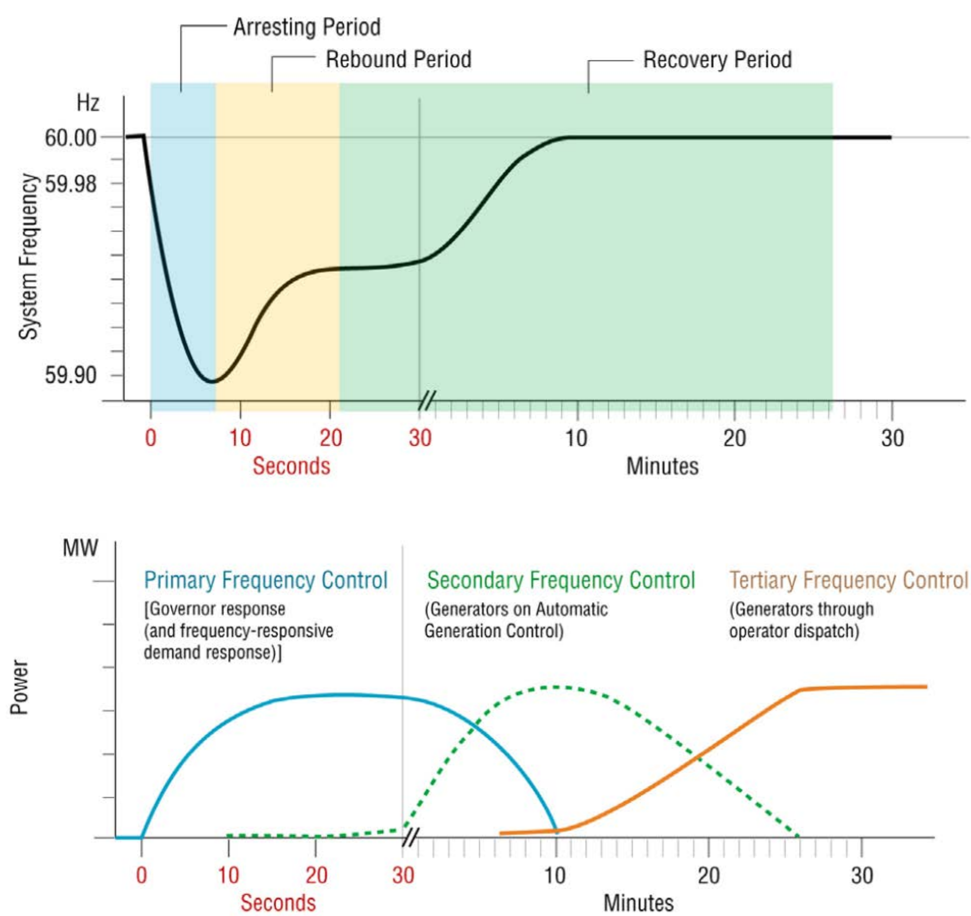
Chart 34 – Effects of Load Regulation



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 21 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 21. 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 21. 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 21 – 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 25 – Ancillary Services Technical Consideration for Storage Technologies

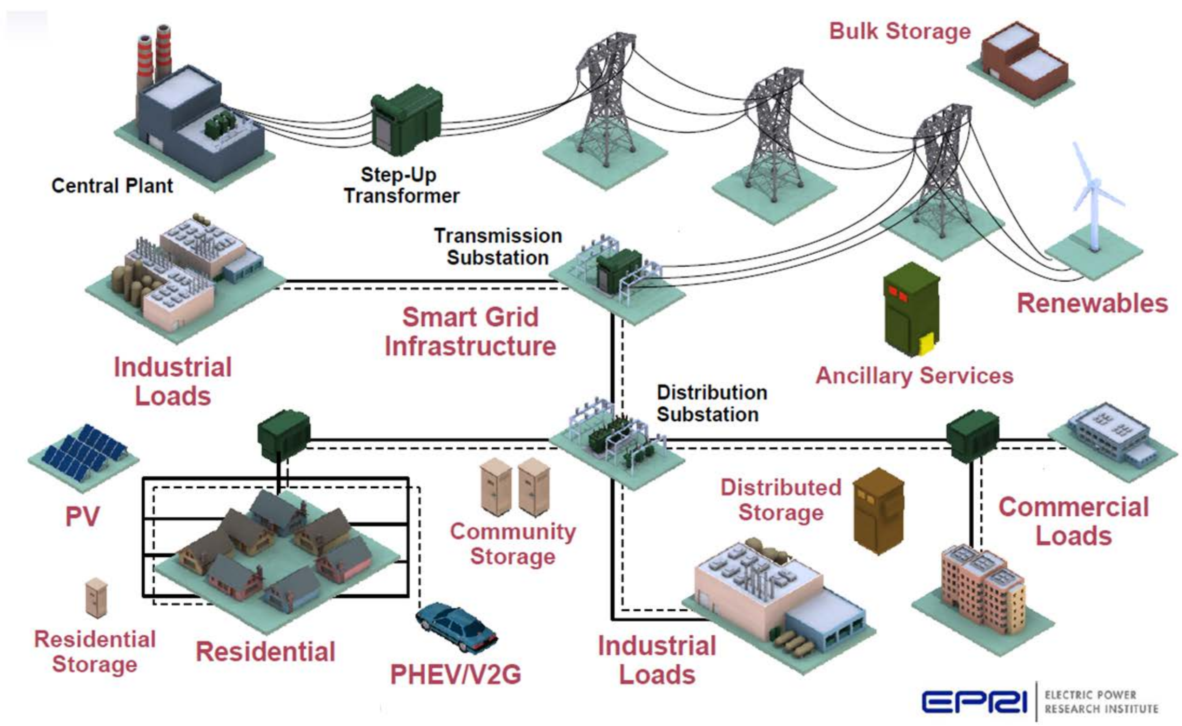
Ancillary Services	Storage System Size	Target Discharge Duration	Minimum Cycles/Year
Load Following / Ramping	1 – 100 MW	Range: 15 minutes to 60 minutes	Not Applicable
Regulation	Range: 10 – 40 MW	Range: 15 minutes to 60 minutes	250 – 10,000
Voltage Support	1 – 10 (MVAR)	Not Applicable	Not Applicable
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 22 –Role of Storage within a Distributed Grid

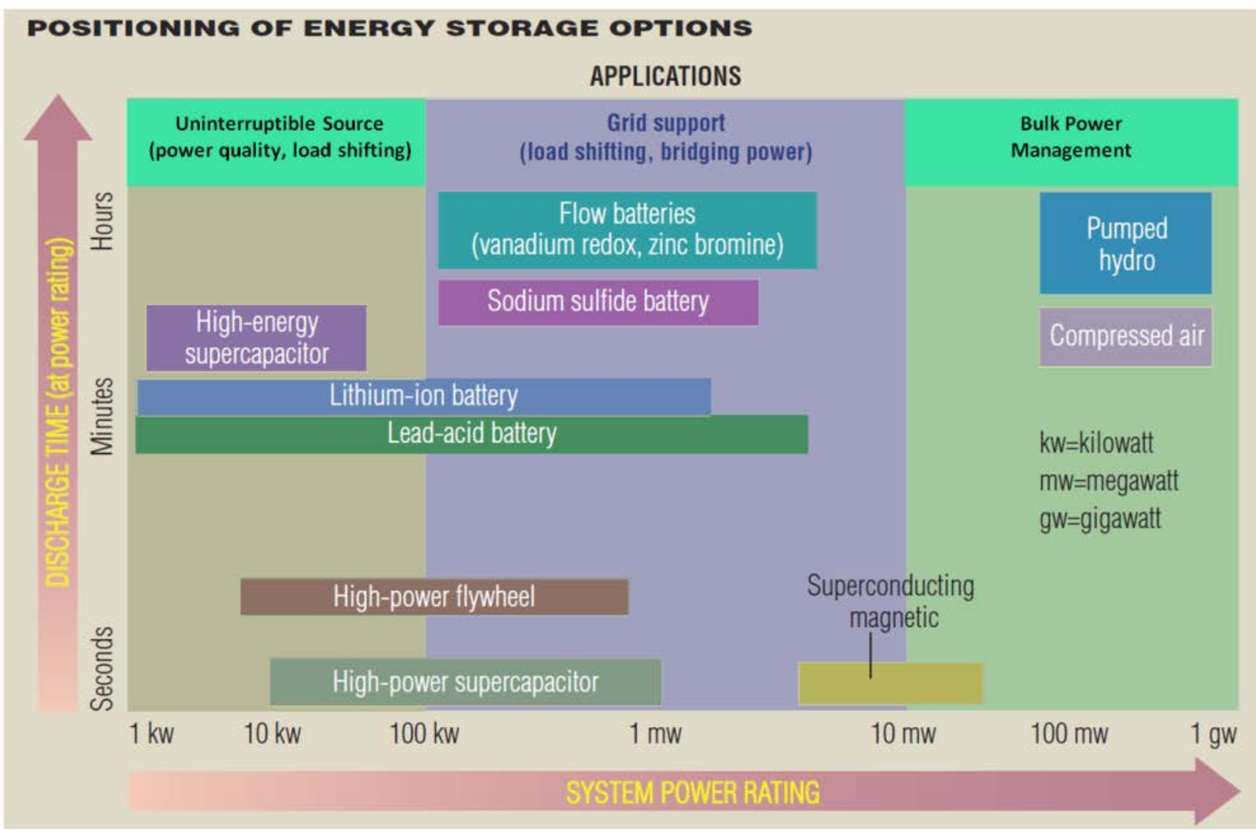


Energy Storage Options

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

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

Figure 23 – Positioning of Energy Storage Options



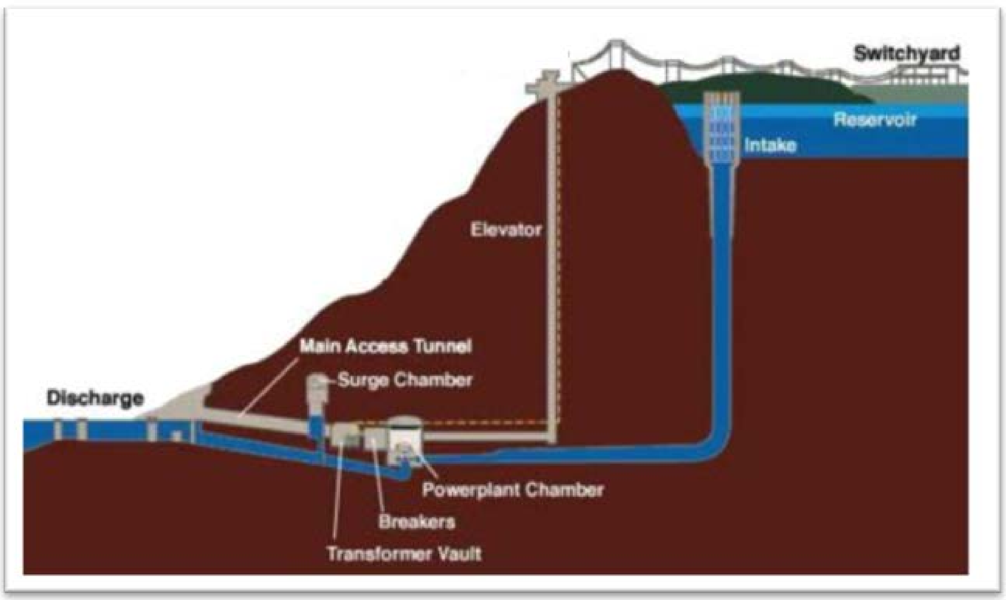
Pumped Hydro

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.

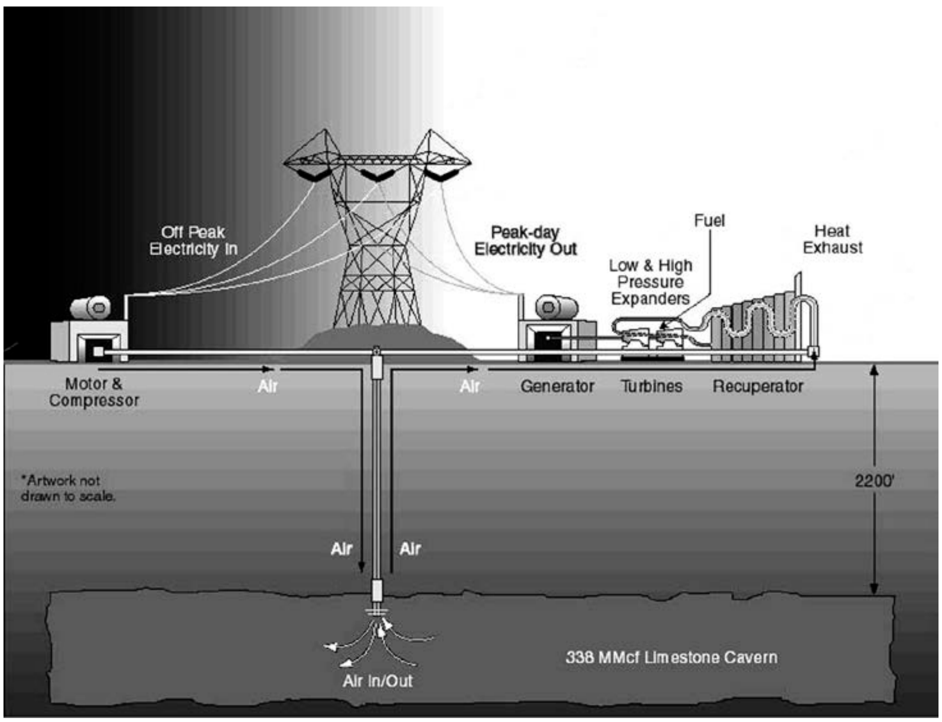
Figure 24 – Pumped Storage Project



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 25 - 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.

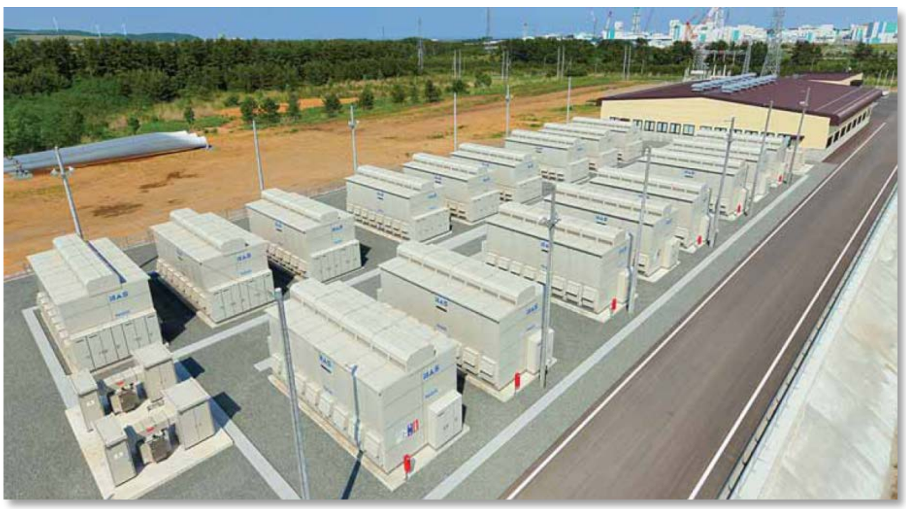
Picture 1 – PNM Prosperity Energy Storage Project

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.



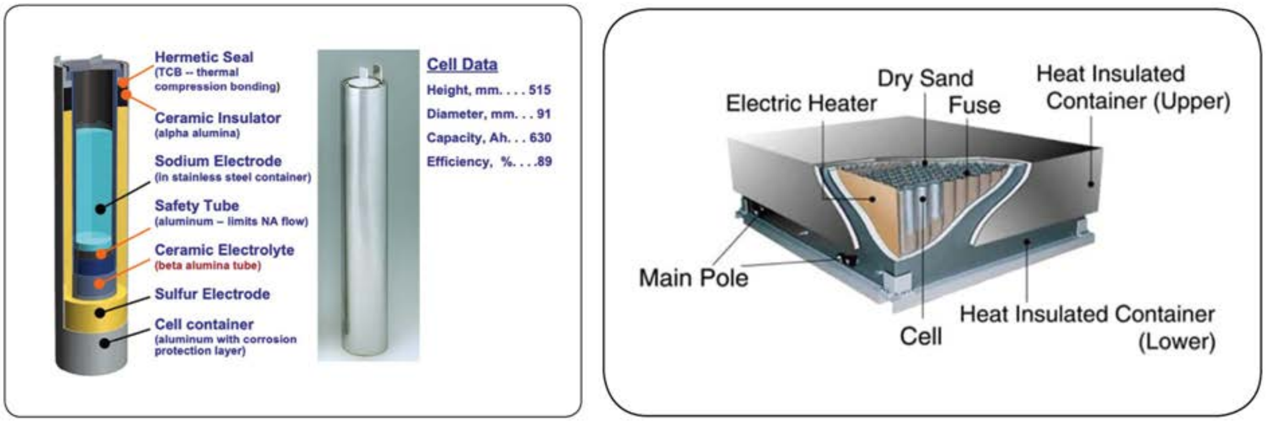
EPRI –Sodium Sulfur Battery Plant

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 26 - Xcel Energy – Wind to Battery Project



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

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.)

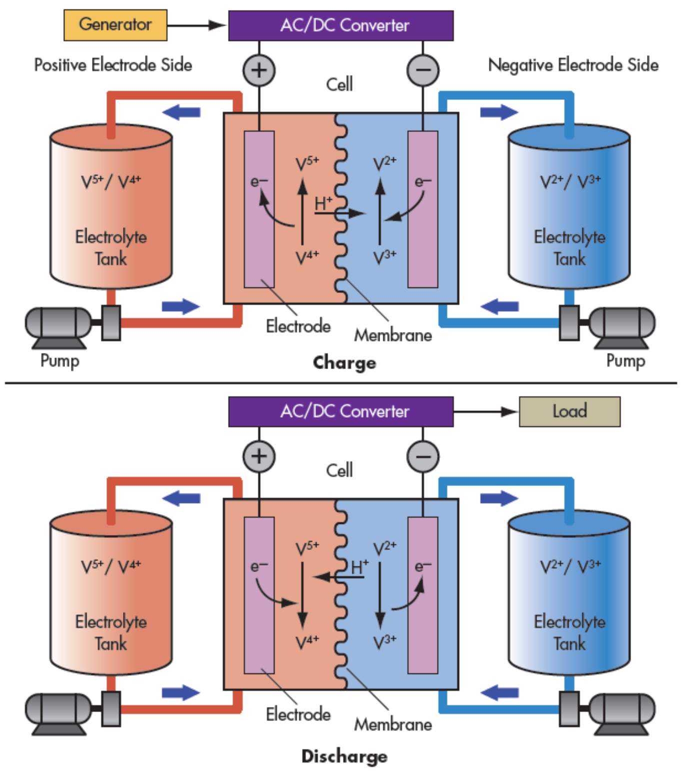
Advanced Lithium-ion (Li-ion) batteries have demonstrated energy storage capacities much higher than those of conventional lead-acid batteries of equal weight and can last through 5-10 times more deep-discharge cycles (operational life of about five years). For utility purposes characteristics of the 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.

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 27 - 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.

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.

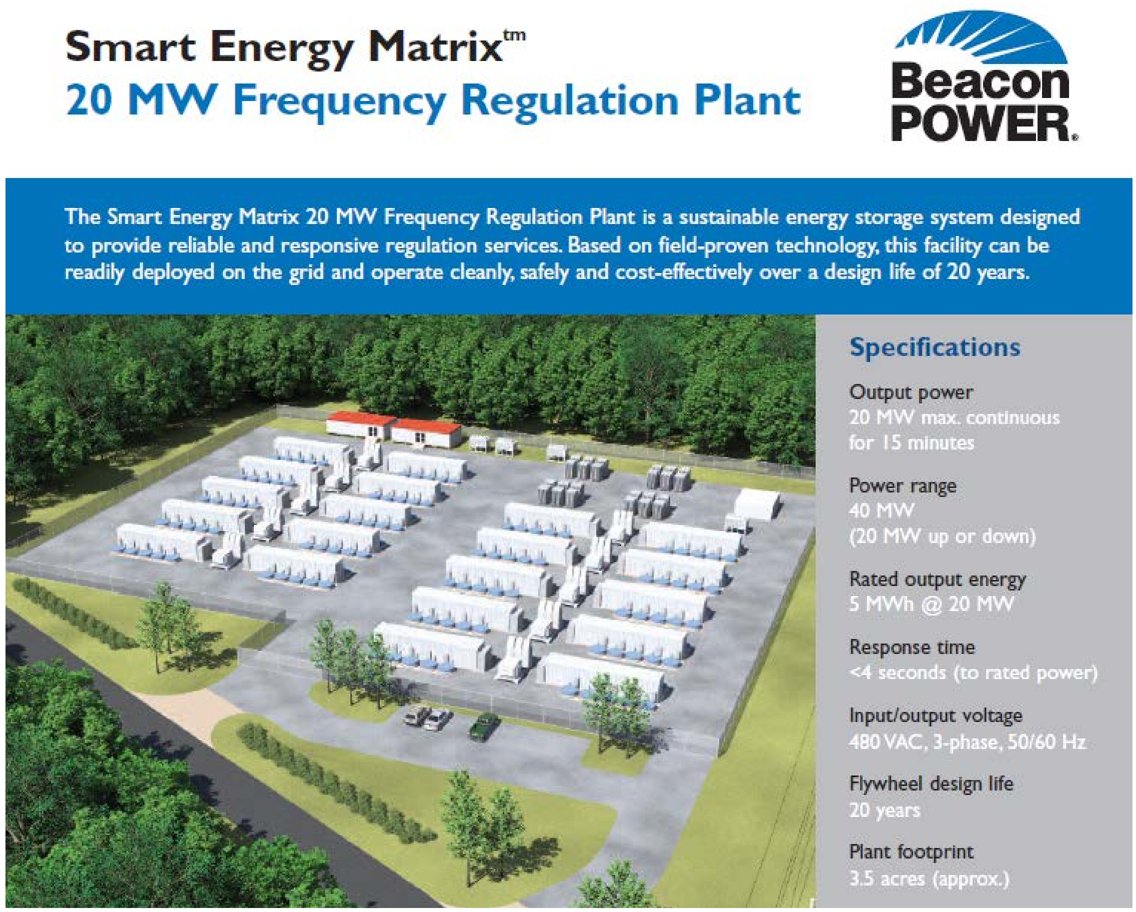
Grid Technologies

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.



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 35 – Storage Technology Installed Cost, $/kW

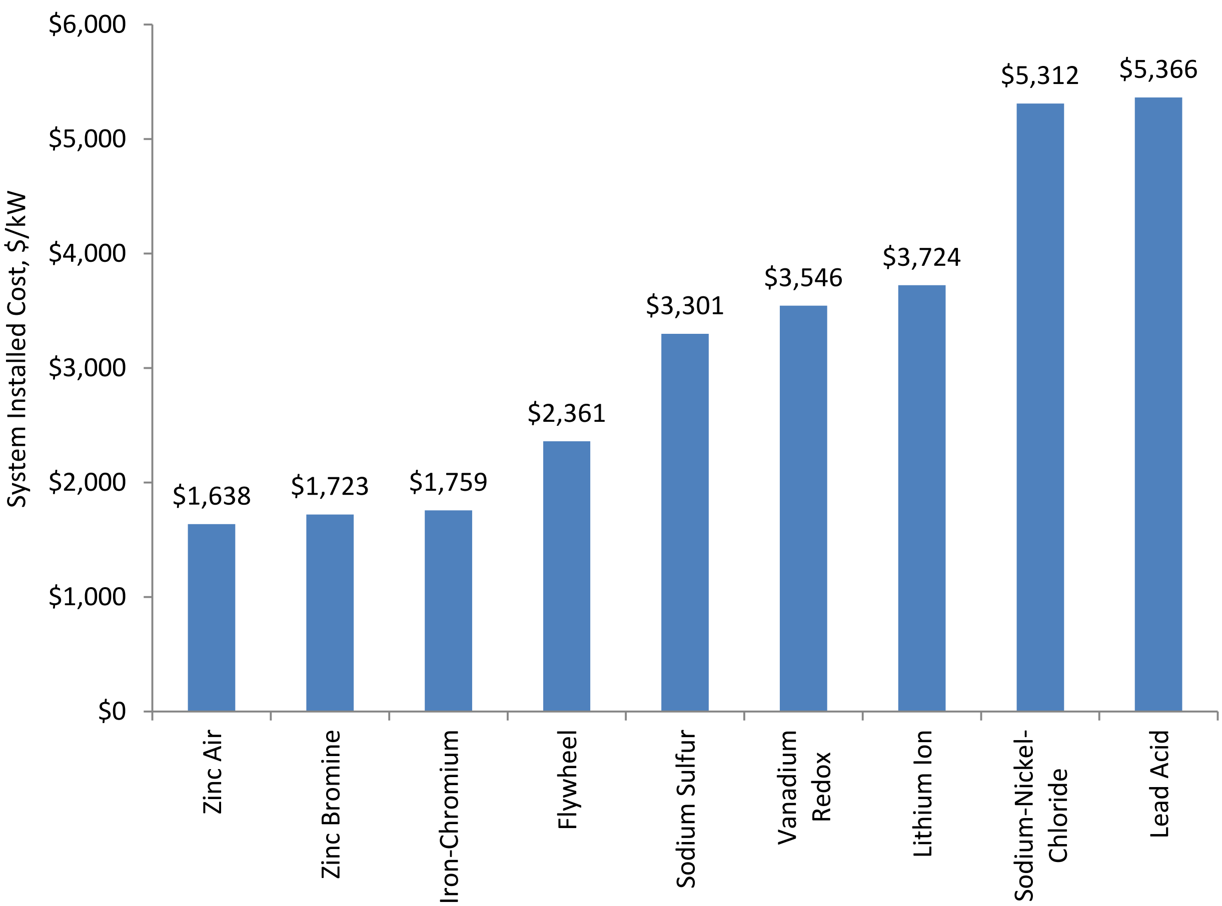


Table 26 - Summary of Energy Storage Systems (ESS)

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

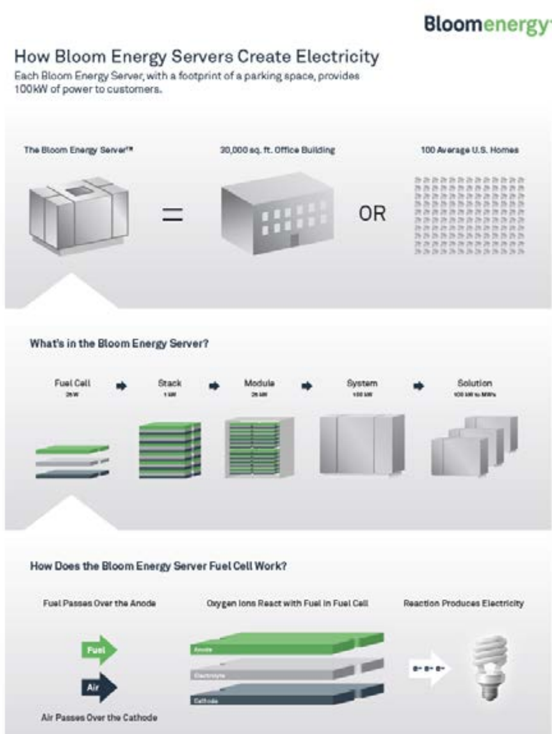
For More Information

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 12

REFERENCE CASE ASSUMPTIONS

Reference Case 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, UNSE compares its input assumptions against multiple third party sources to validate the range of potential forecast values for developing its Reference Case 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 Assumptions

This section details the reference case market assumptions for the following IRP inputs.

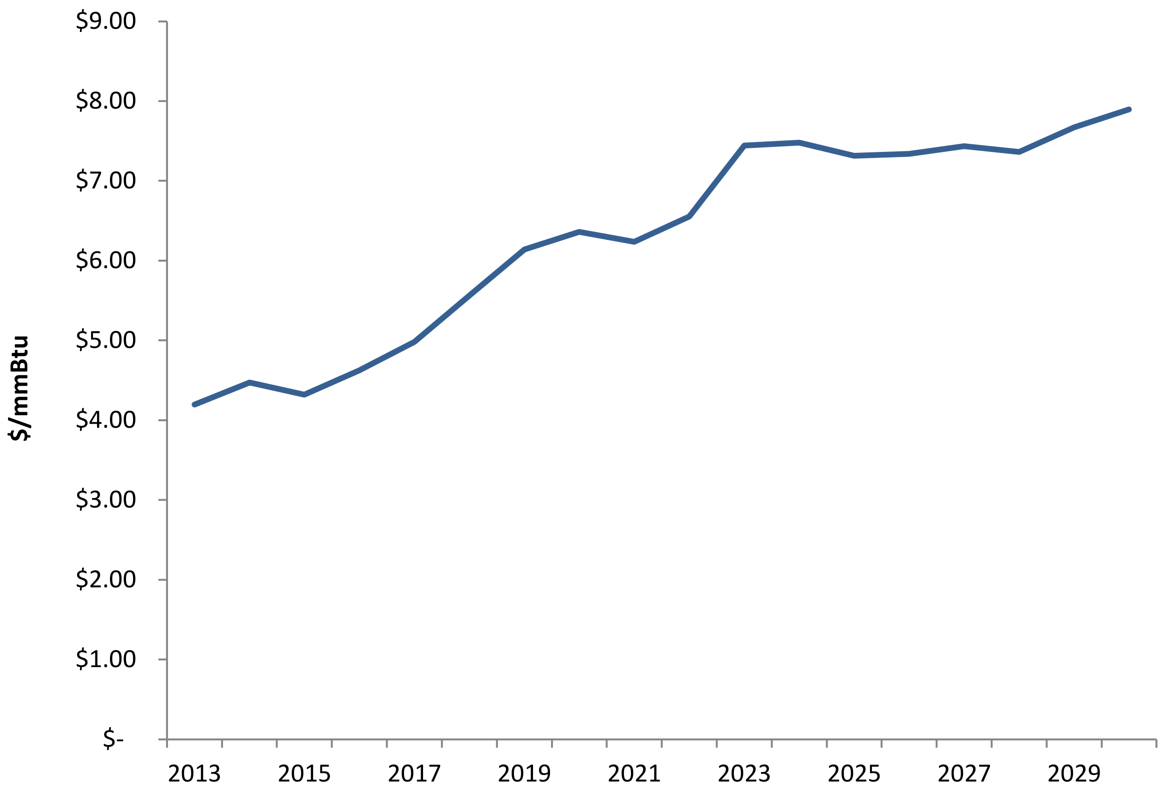
- Natural Gas Prices
- Wholesale Power Prices
- Delivered Coal Prices
- Emissions Prices

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 36 - Permian Basin Natural Gas Prices shows the 15 year natural gas price projections in nominal dollars.

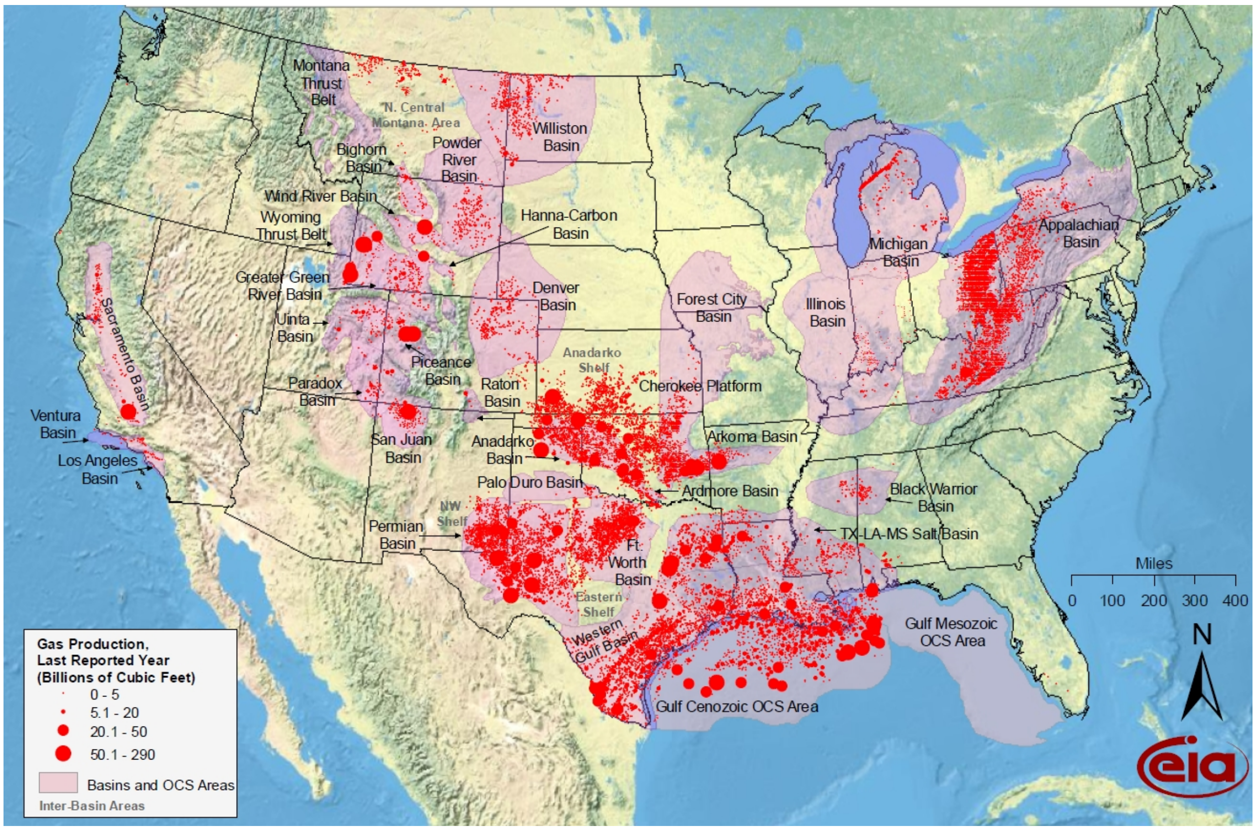
Chart 36 - Permian Basin Natural Gas Prices



Natural Gas Supply Basins

UNSE'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 25.

Map 25 - Natural Gas Production in Conventional Fields in the U.S.

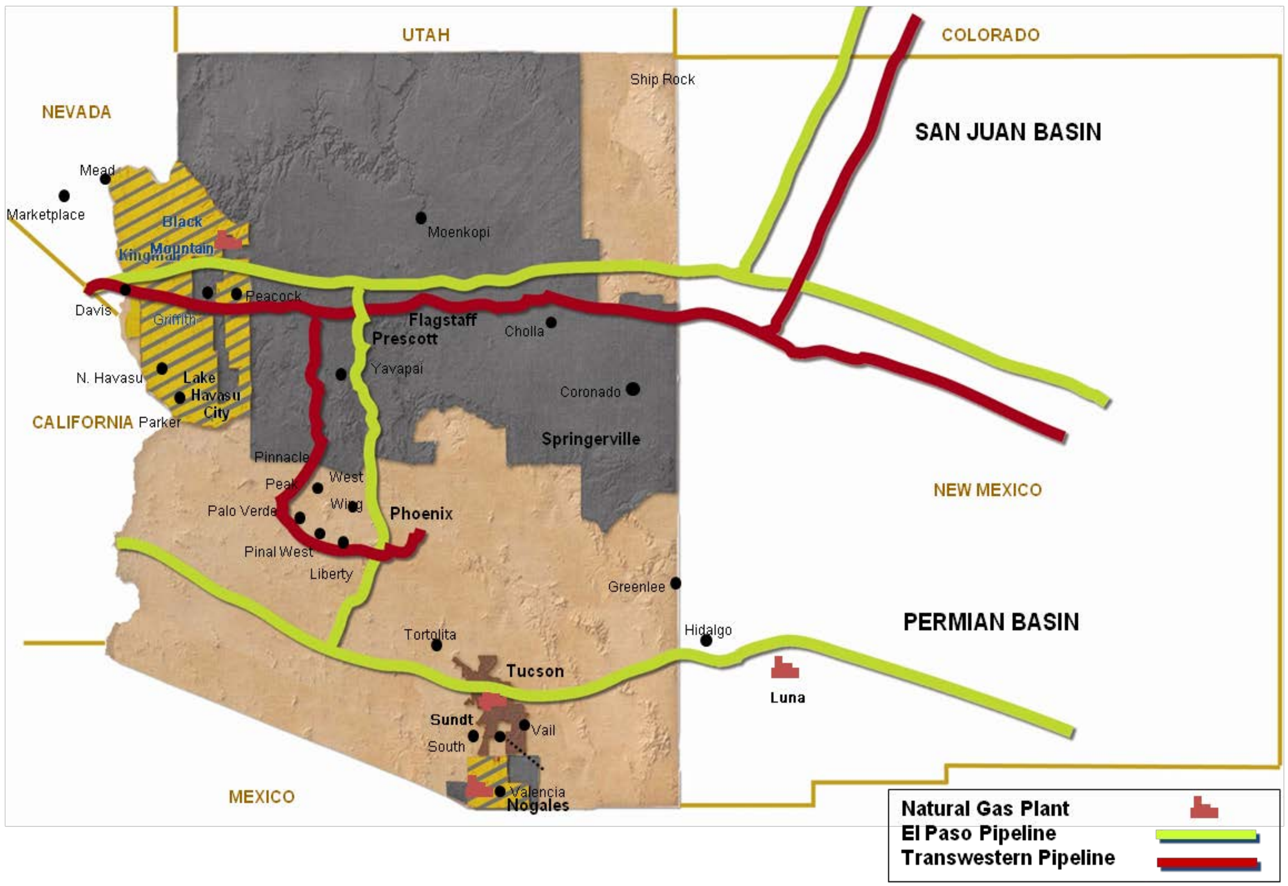


Source: Energy Information Administration (EIA) based on data from HPDI, IN Geological Survey, USGS

NATURAL GAS PIPELINE INFRASTRUCTURE

Map 26 **-** Natural Gas Pipeline Infrastructure below provides an overview of UNSE's natural gas fired generation facility in relationship to both the El Paso and Transwestern pipeline infrastructure.

Map 26 - Natural Gas Pipeline Infrastructure

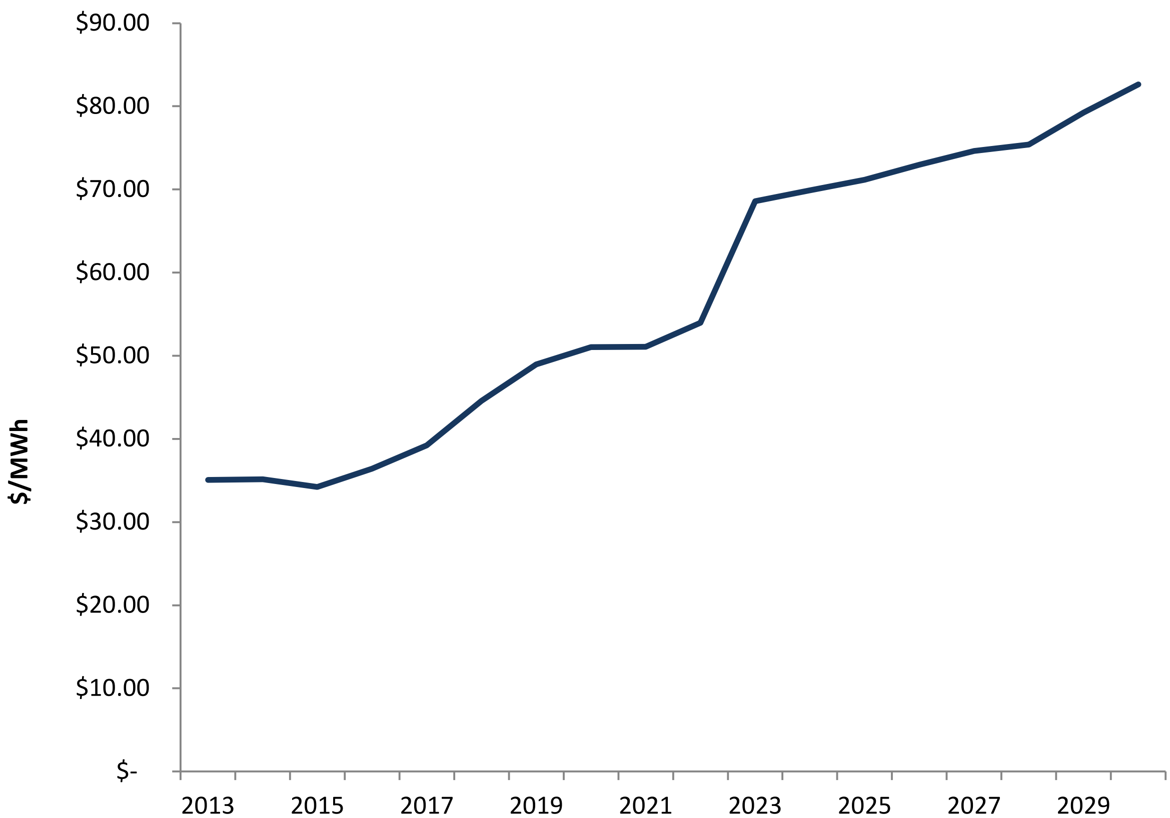


WHOLESALE MARKET PRICE FORECAST

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 37 - Palo Verde (7x24) Market Prices shows the 15 year wholesale power price projections in nominal dollars.

Chart 37 - Palo Verde (7x24) Market Prices



Wholesale Power Market Price Zones

UNSE's forward wholesale market power price projections are based on Palo Verde and Four Corner market hubs as shown below in Map 27 - Wholesale Power Market Price Zones.

Map 27 - Wholesale Power Market Price Zones

SOURCE: Ventyx.

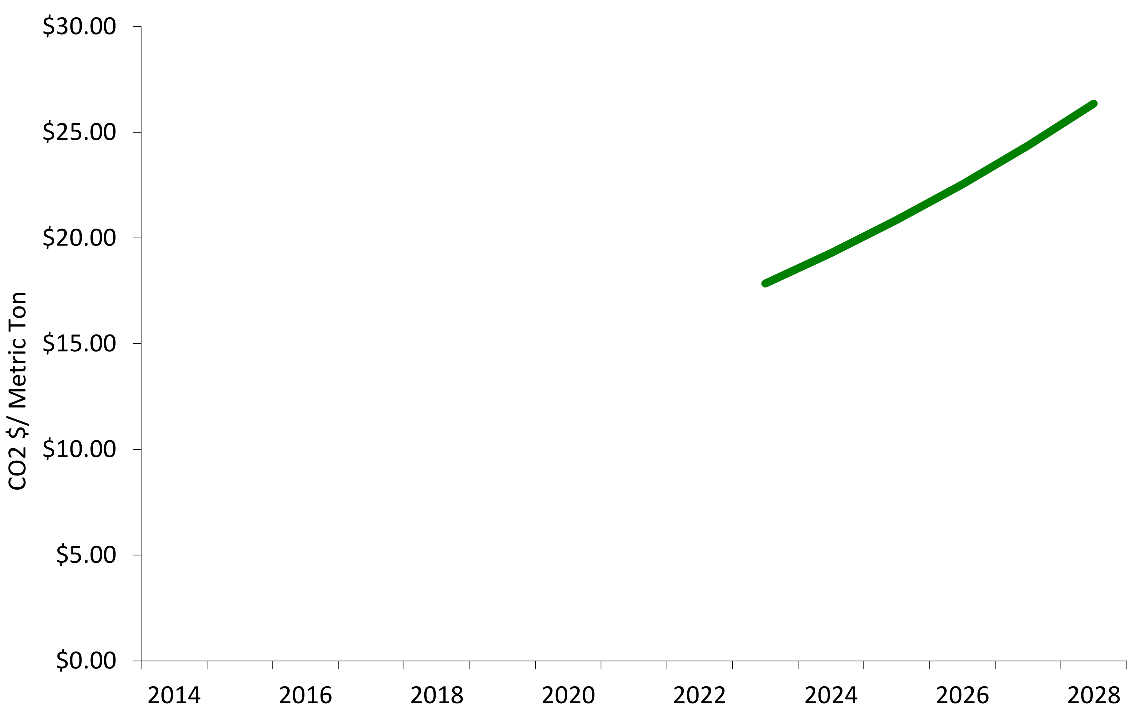
EMISSION PRICES

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 38 - CO_2 Emission Prices, $/ Metric Ton



Financial and Capital Structure Assumptions

Table 27 below details the financial and capital structure assumptions used for the 2014 IRP. The weighted average cost of capital is based on assumptions from UNSE's approved rate order in December 2013.

Table 27 - Financial and Capital Structure Assumptions

Cost Of Capital	
Debt	5.98%
Common Equity	9.5%
Composition	
Debt	52.60%
Common Equity	47.40%
Average Cost Of Capital	
Weighted Average Cost of Capital (WACC)	7.83%
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

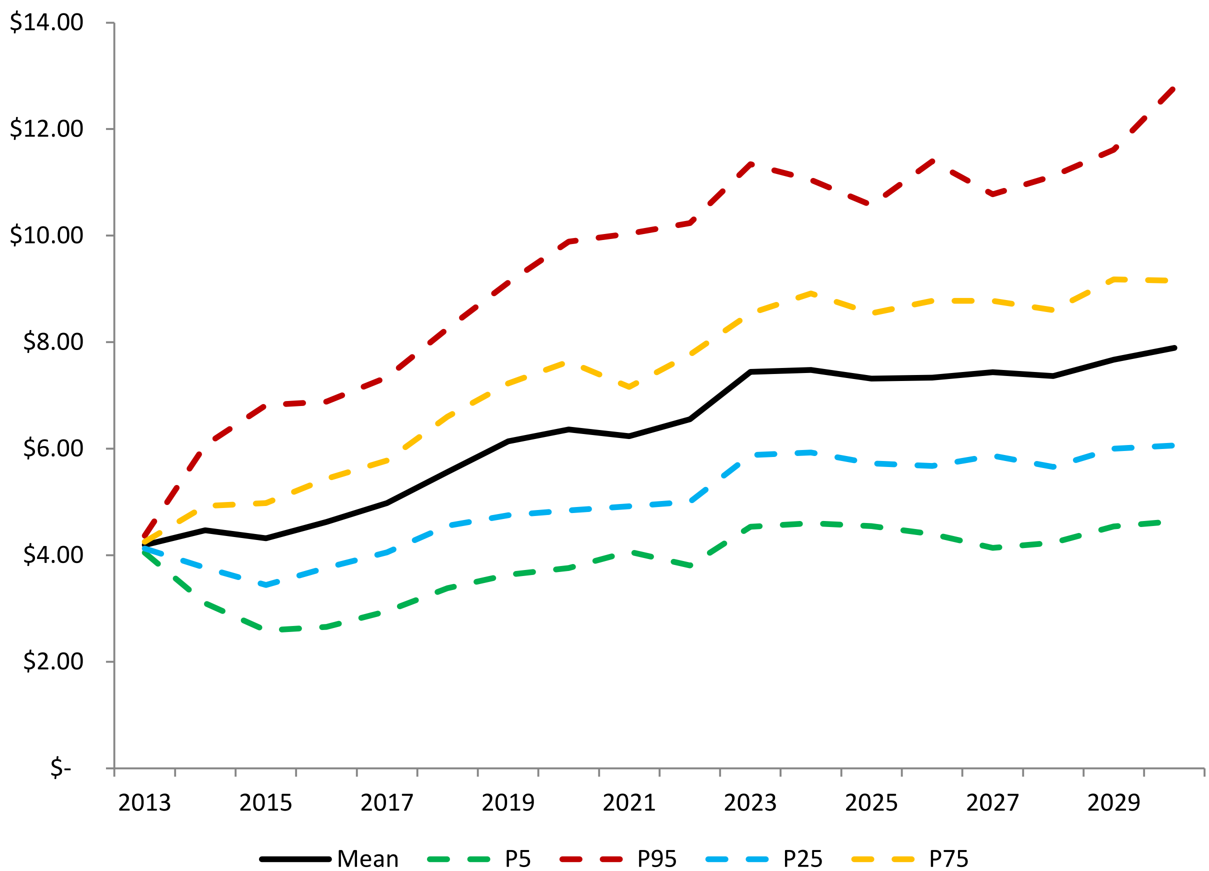
For the 2014 IRP, UNSE developed explicit market risk analytics for each candidate portfolio through computer simulation analysis. Specifically, a set of 100 iterations, each representing a possible future set of correlated, consistent inputs for natural gas prices, wholesale prices, and retail loads 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 39 - 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.

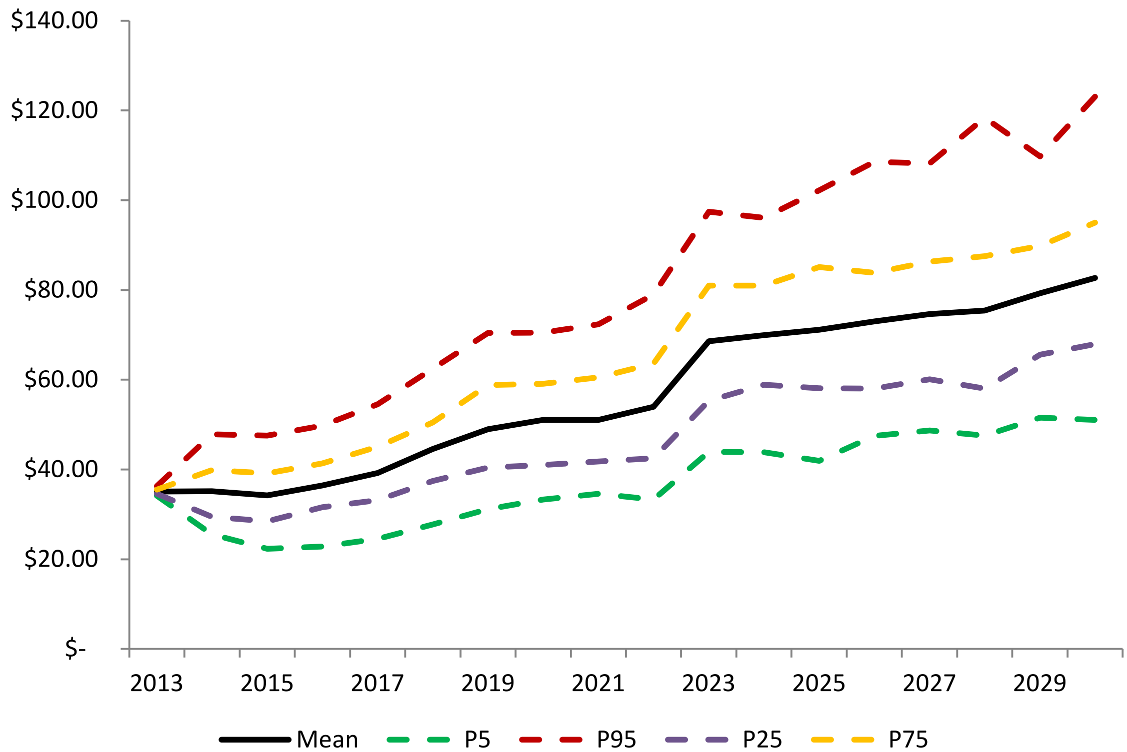
Chart 39 - Permian Basin Natural Gas Price Simulation Statistics



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 40 - 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 40 - Palo Verde (7x24) Market Price Simulation Statistics



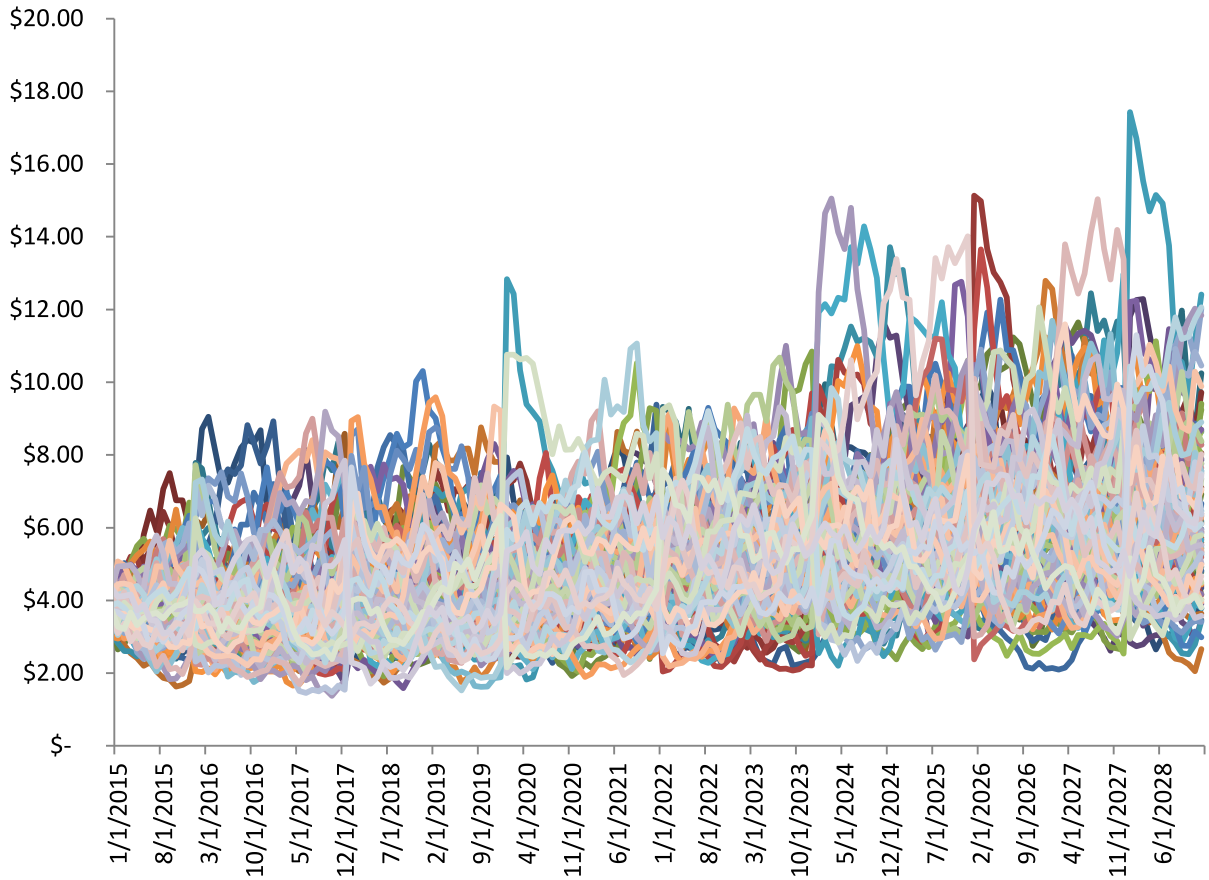
When considering Chart 39 and Chart 40 from above, it is important to note that the summary statistics are aggregations rather than individual price paths. For instance the P95 number for a given year represents the point which 95% of simulated values fall below.

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 41 on the following page shows 100 individual Permian Basin price paths.

Permian Natural Gas

Chart 41 details the 100 Permian Basin price paths against which each portfolio was evaluated.

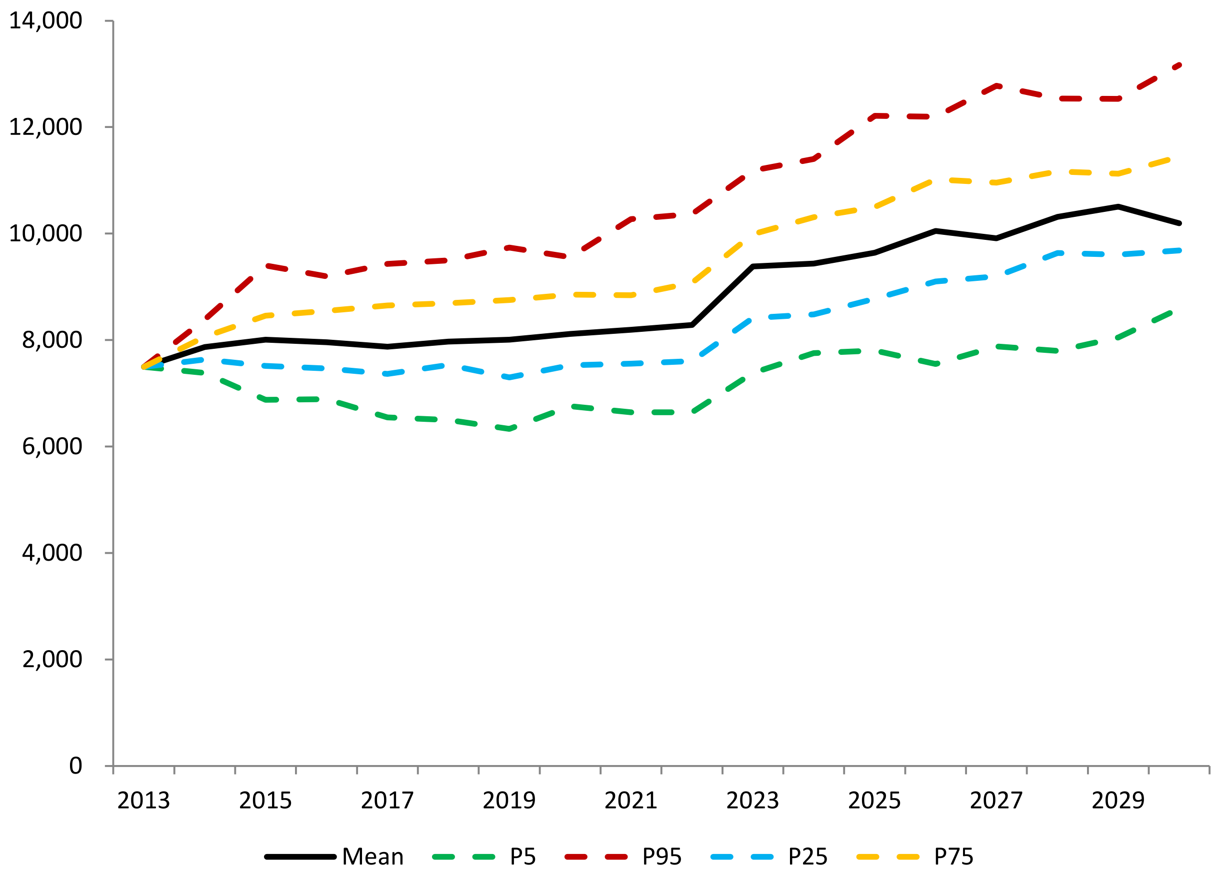
Chart 41 - Permian Basin Natural Gas Price Iterations ($/mmBtu)



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 42 provides a summary of the annual implied market heat rates in the 100 iterations used in this analysis.

Chart 42 – Simulation Implied Market Heat Rate Summary Statistics (mmBtu/kWh)



As illustrated in Chart 42, 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

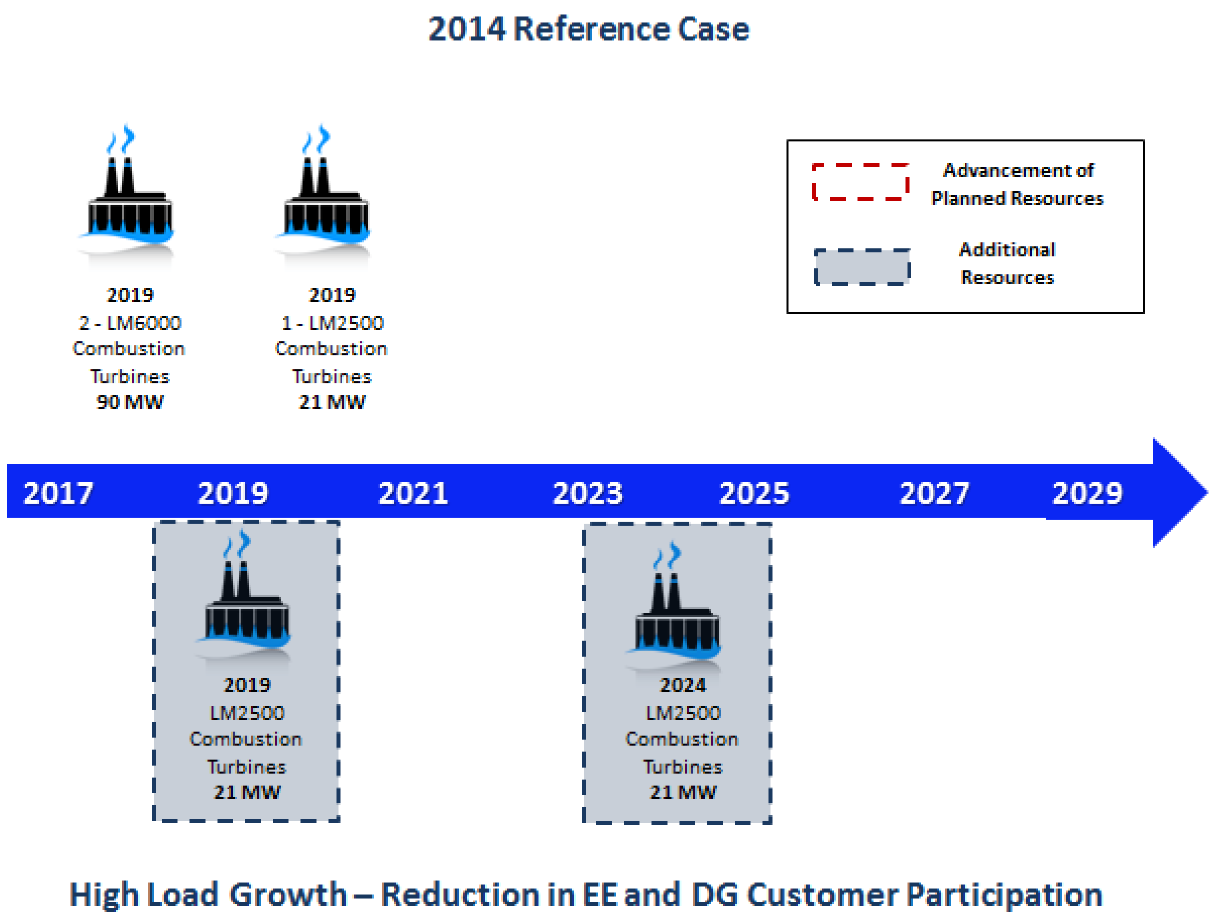
The 2014 Reference Case projects UNSE peak demand staying relatively flat for the duration of the IPR study period. This forecast assumes no significant expansions in UNSE's large industrial and mining customers and assumes that targets for energy efficiency (22% by 2020) and distributed generation (30% of 15% by 2025) are realized per Arizona state standards.

For purposes of the 2014 IRP, UNSE modeled two additional load growth scenarios that reflect two potential scenarios that may affect UNSE's long-term expansion plans. The first scenario considers the potential reductions in customer participation in UNSE'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 UNSE's service territory.

Reduction in Energy Efficiency or Distributed Generation

For purposes of this change in load growth scenario, it is assumed that UNSE only achieves about 50% of the energy efficiency and distributed generation targets. Under this scenario, UNSE's peak demand grows between 0.5% and 1.0% per year. This change in the forecast has only moderate impacts on UNSE's 2014 Reference Case plan. As shown in Figure 34 below, UNSE would have to install additional combustion turbines in 2019 and 2024 as the result of this increased load growth.

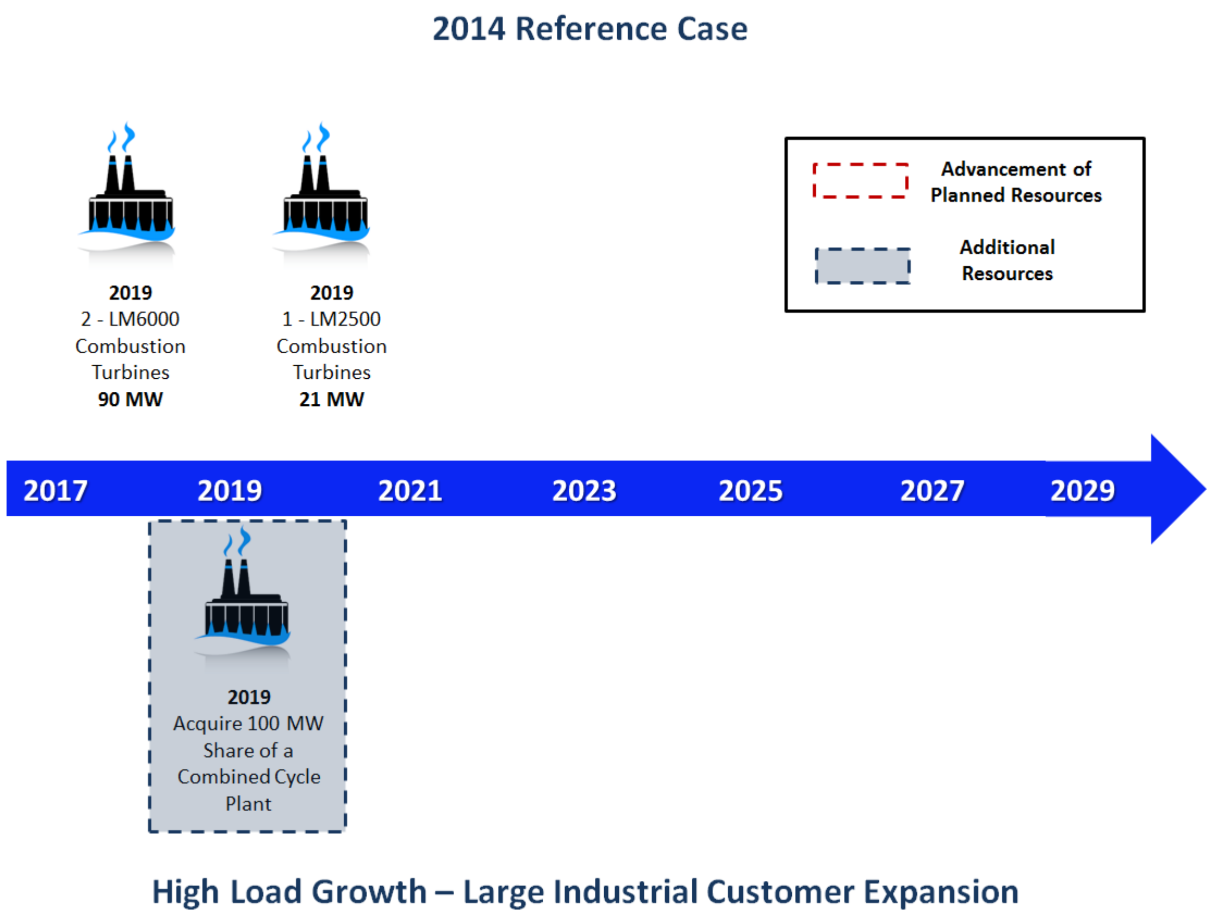
Figure 28 – Reduction in EE and DG Load Growth Scenario



Large Industrial Customer Expansion

For purposes of this load growth scenario, it is assumed that UNSE'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, UNSE's peak demand increases by 50 MW in 2017 and again in 2019 by 50 MW (for a total of 100 MW, a 10% increase in retail demand). This change in the forecast would result in the need for additional generation resources in the near term. As shown in Figure 35 below, UNSE 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 an additional 100 MW share from a combined cycle resource starting in 2019.

Figure 29 – Reduction in EE and DG Load Growth Scenario



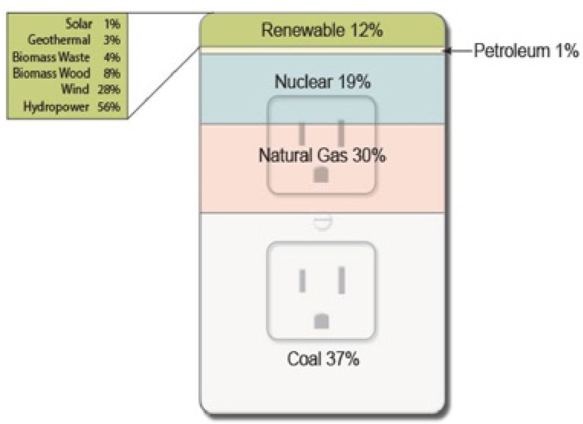
CHAPTER 13

FUEL SUPPLY

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 30- Sources of U.S. Electricity Generation, 2012

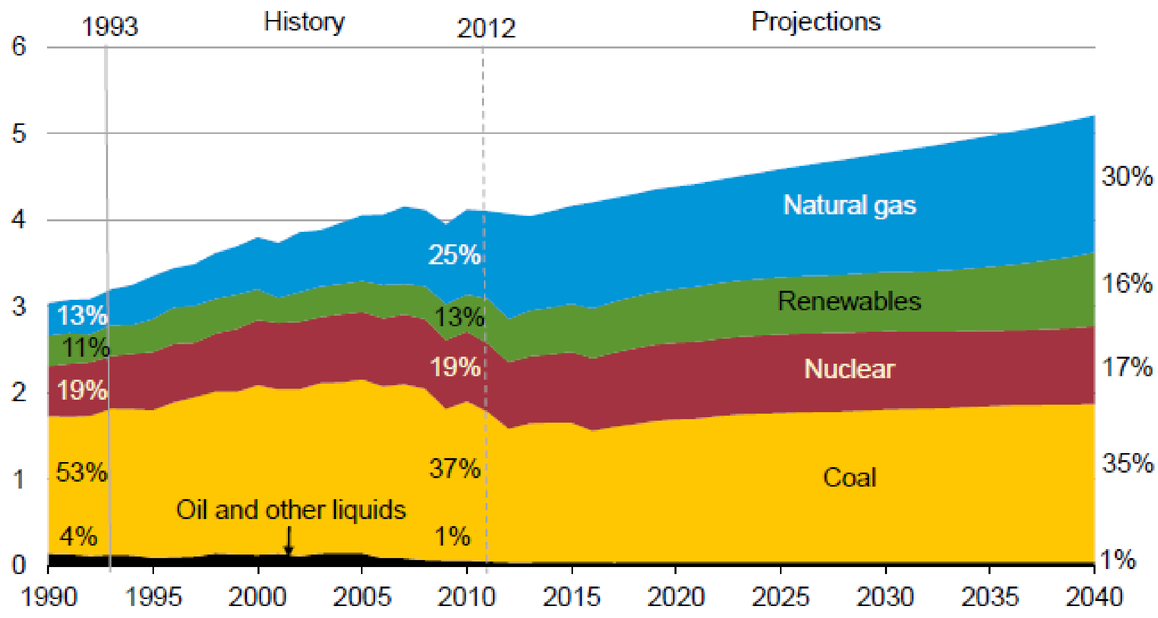


Source: U.S. Energy Information Administration, *Electric Power Monthly* (March 2013). Percentages based on Table 1.1 and 1.1a; preliminary data for 2012.

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 43 - U.S. Electricity Net Generation (trillion kilowatthours)



Source: EIA, Annual Energy Outlook 2013

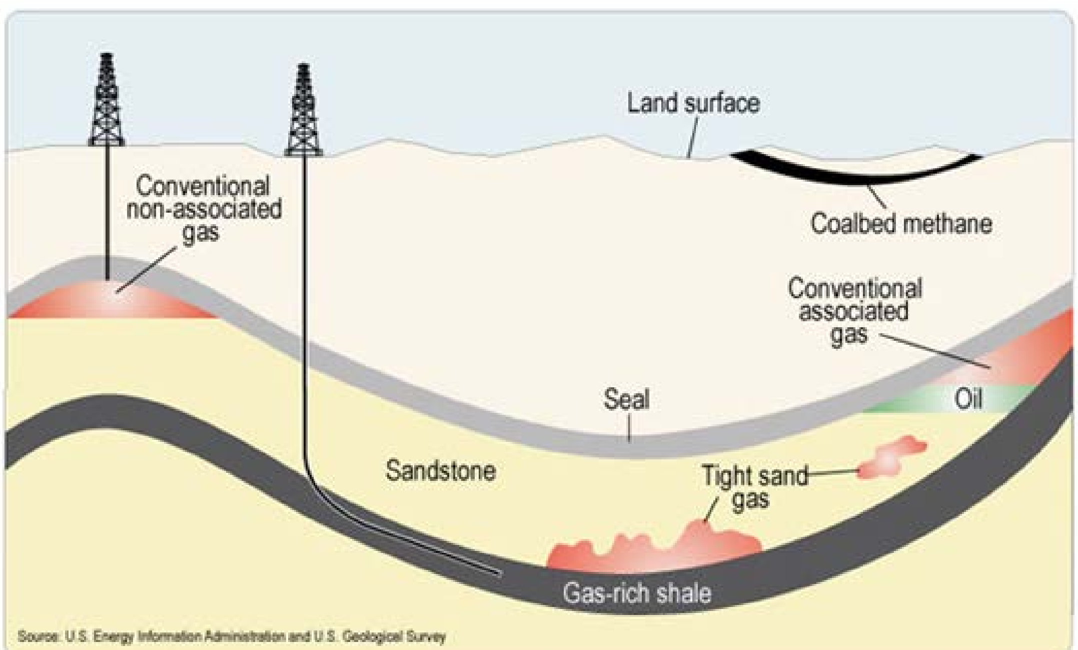
Natural Gas Supply

For the 2014 IRP, UNSE 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.

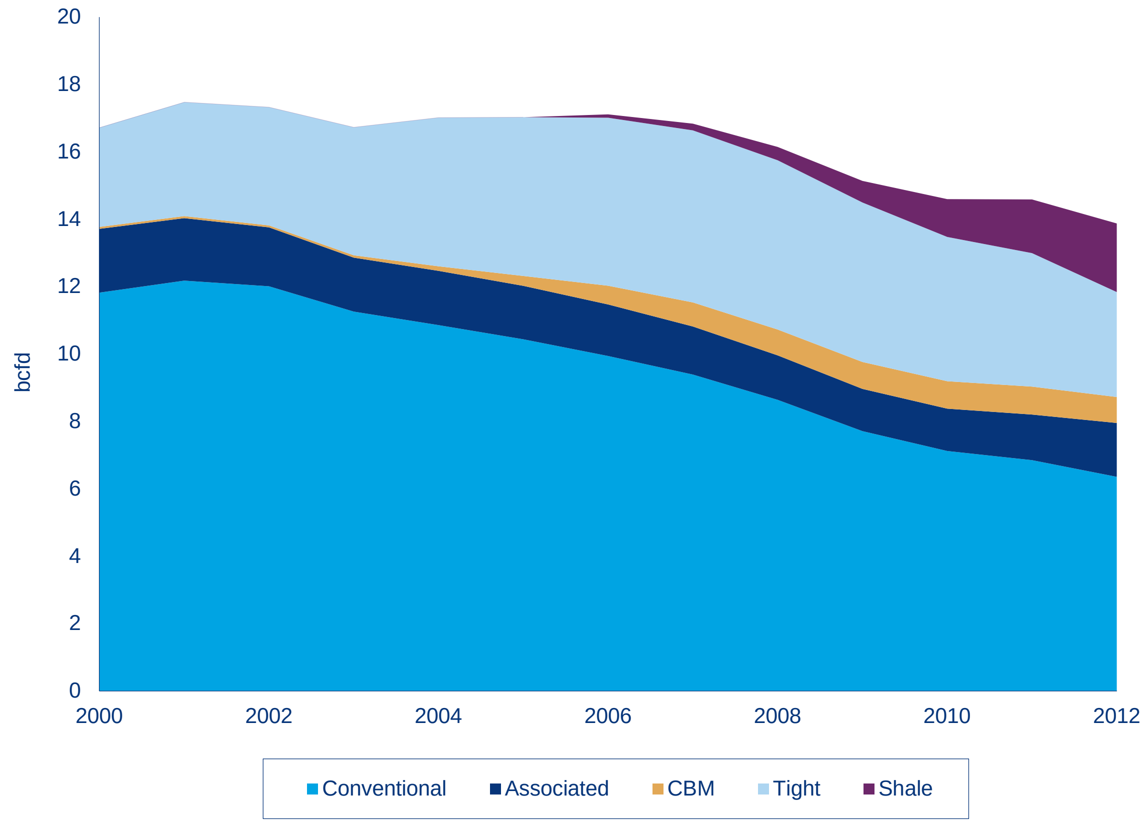
Figure 31 - Natural Gas Geological Formations



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.

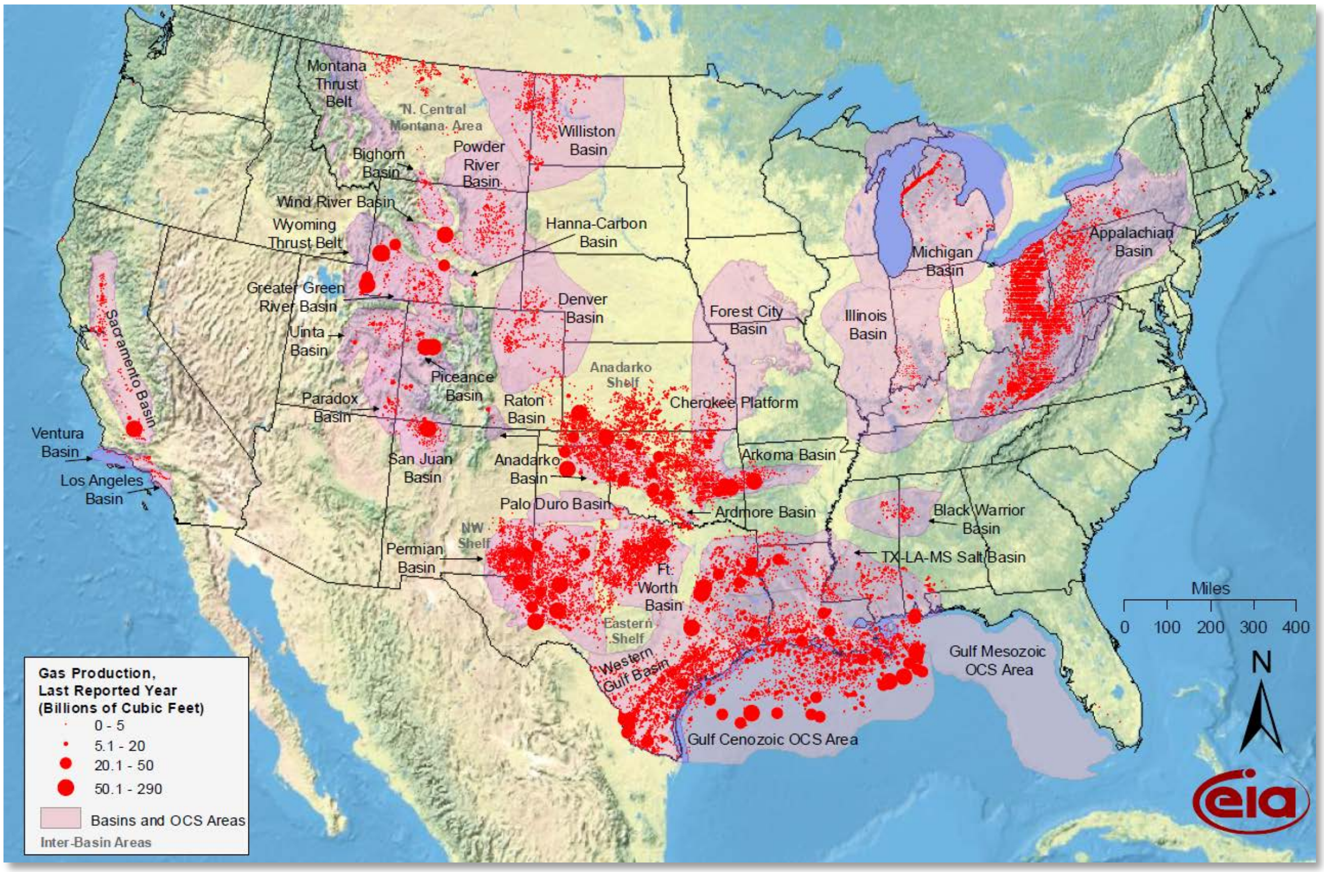
Figure 32 – Historical U.S. Gas Production, 2012 (bcfd)



Conventional Gas Locations

Map 28 below provides an overview on conventional U.S. natural gas production.

Map 28 - 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 46

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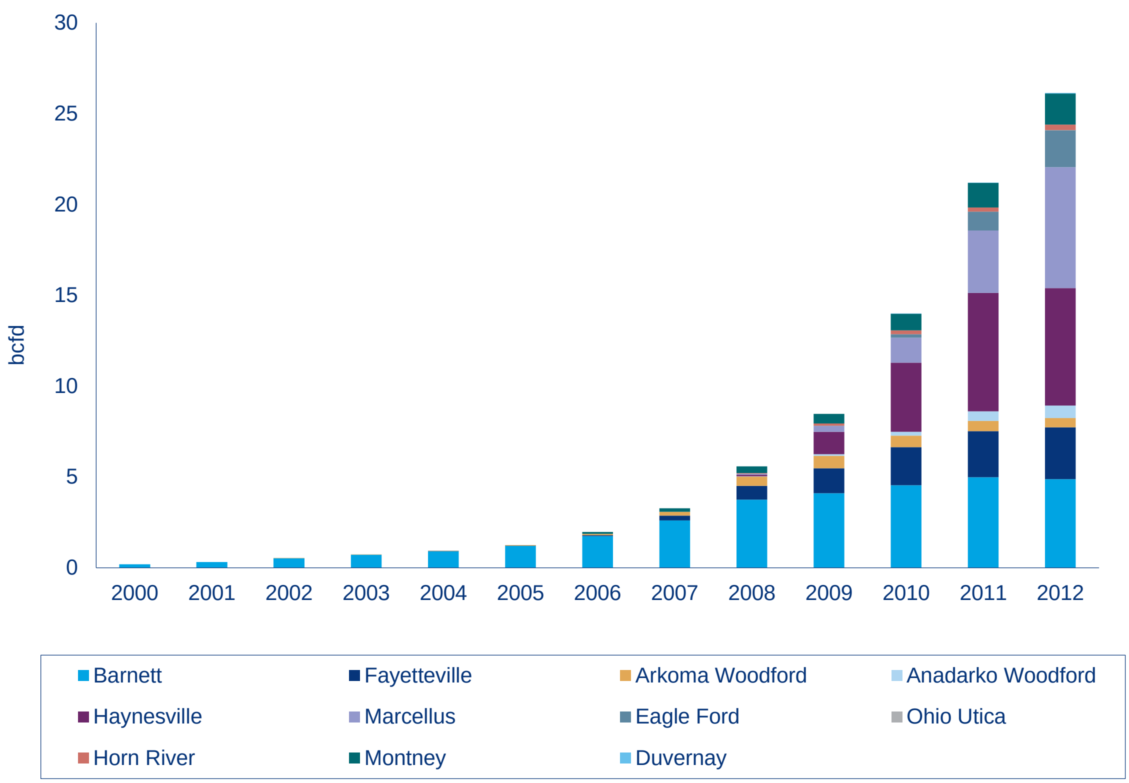
Chart 44 - U.S Shale Natural Gas Production 2000-2012, (bcfd)



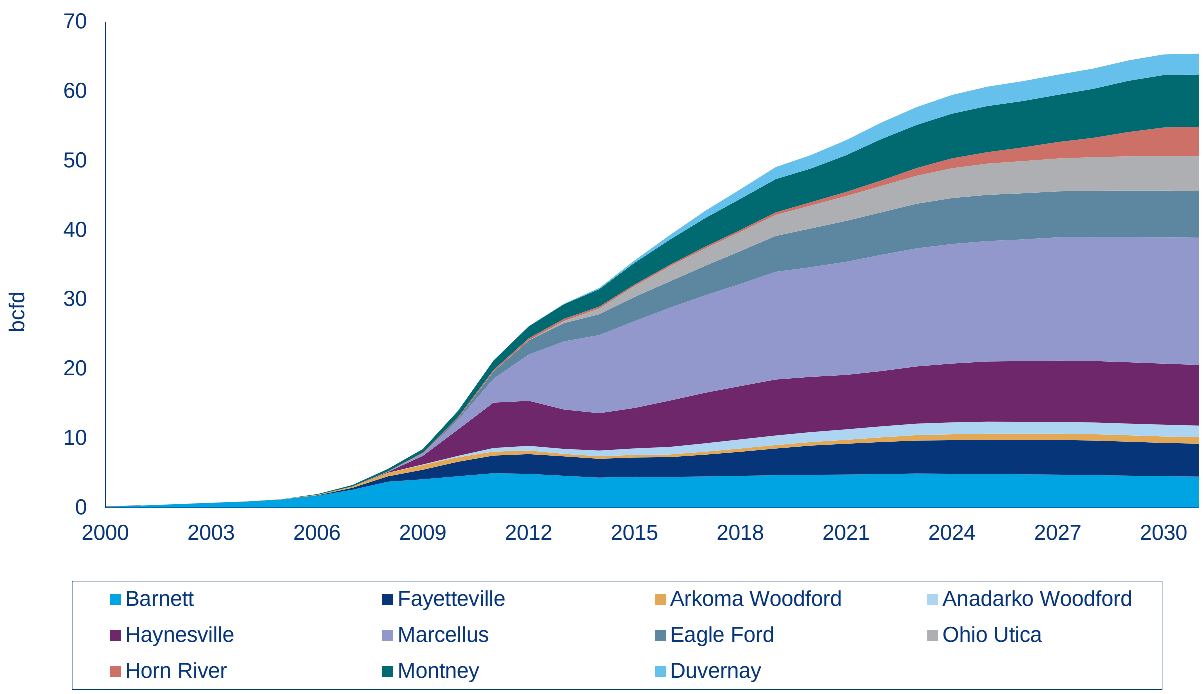
U.S. Shale Gas Plays

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.

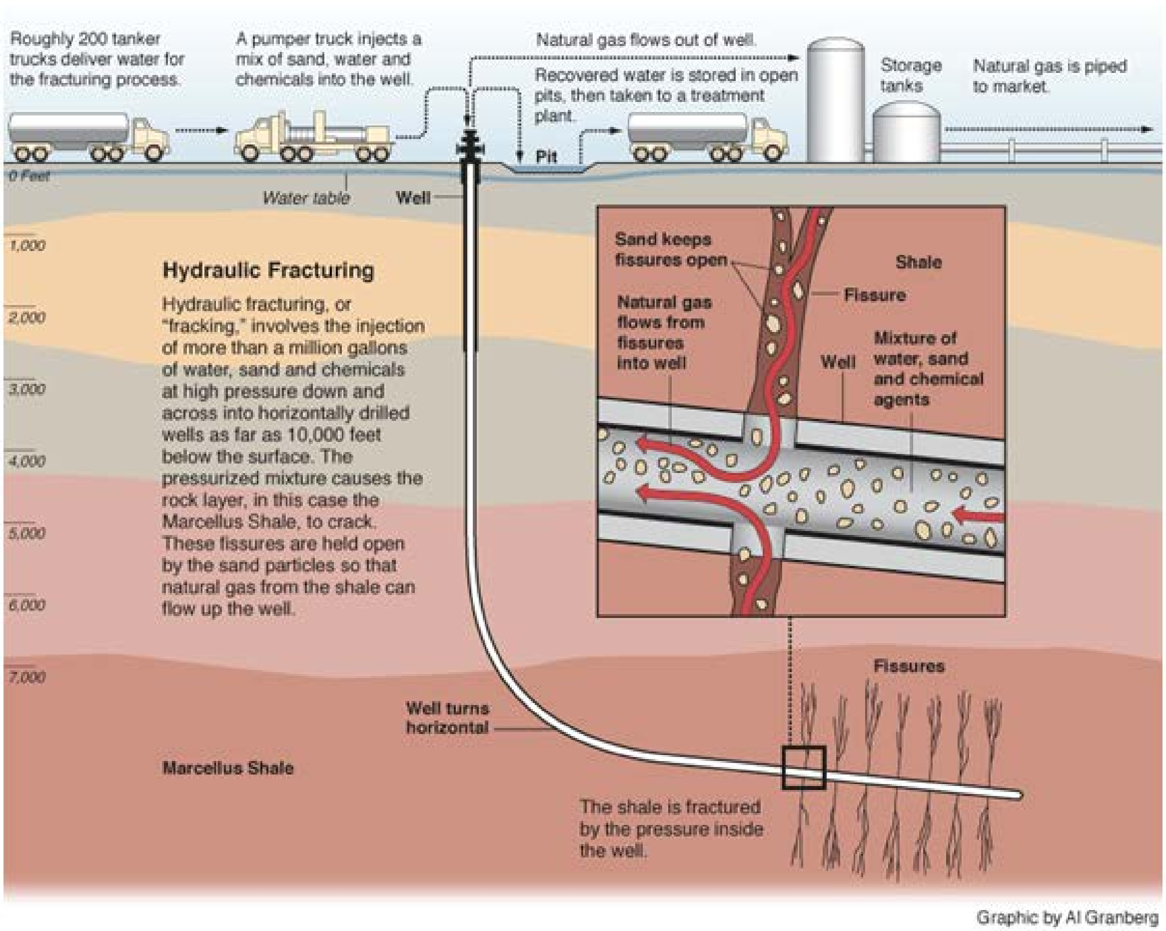
Chart 45 – Shale Plays Forecast (bcfd)



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 33 - Hydraulic Fracturing

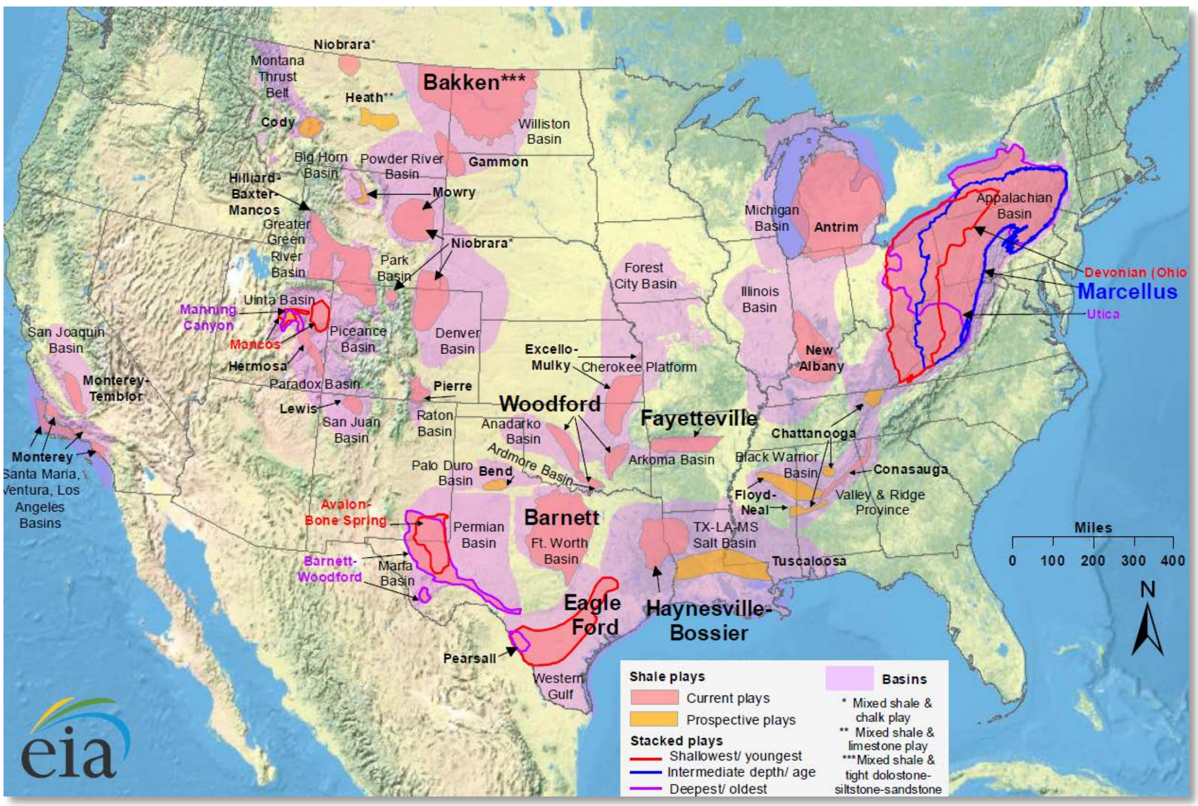


Source: EIA Energy Information Administration

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 29 below provides an overview on U.S. shale gas plays.

Map 29 - U.S. Shale Gas Plays

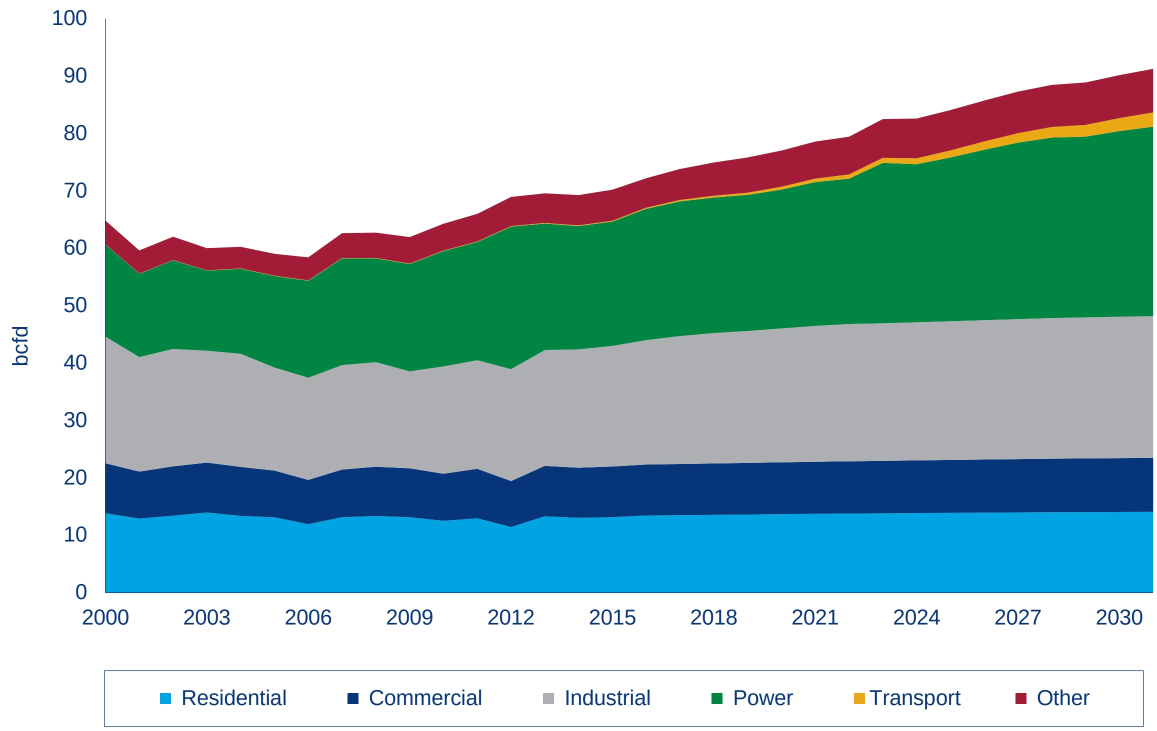


Source: EIA Energy Information Administration

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 46. 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.

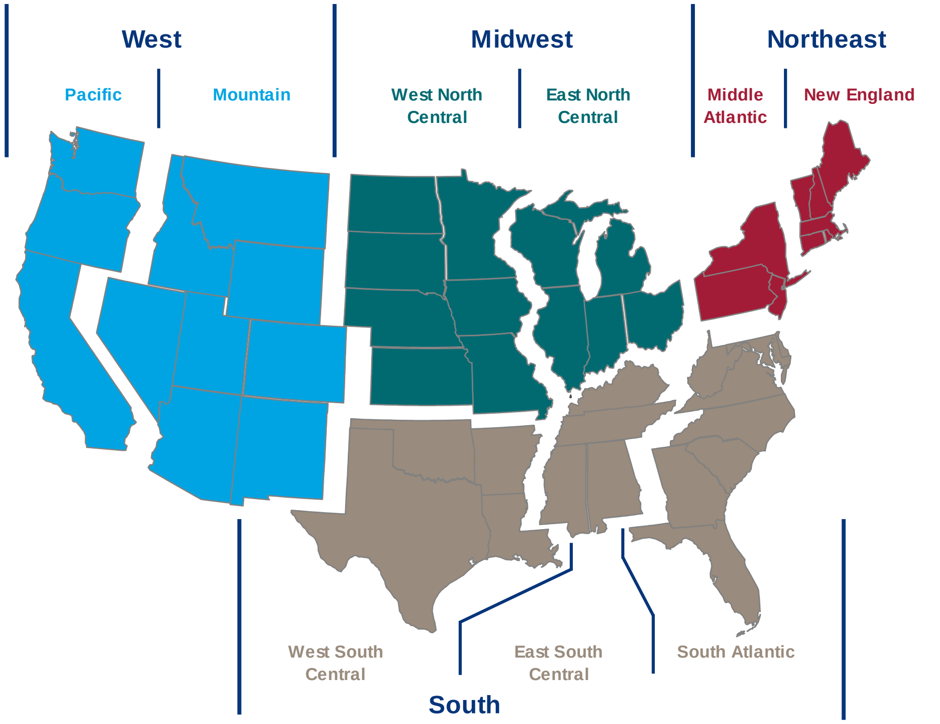
Chart 46 - U.S. Natural Gas Demand Forecast (bcfd)



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 30 - Regional State Groupings.

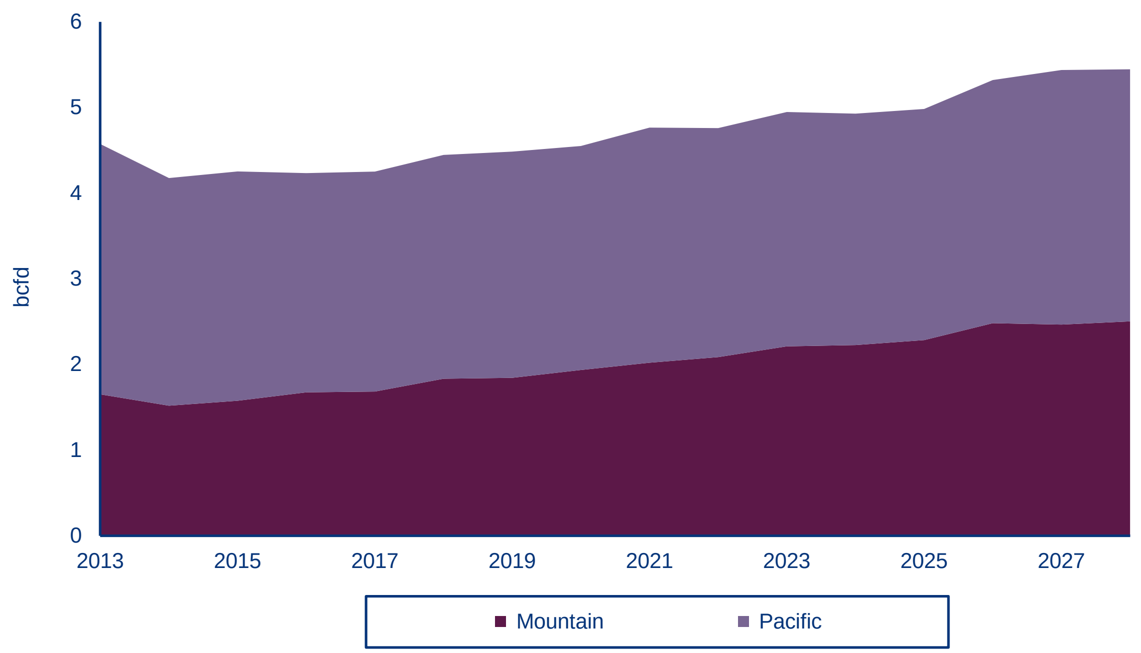
Map 30 - Regional State Groupings



Natural Gas Demand Forecast

As shown in Chart 47, 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.

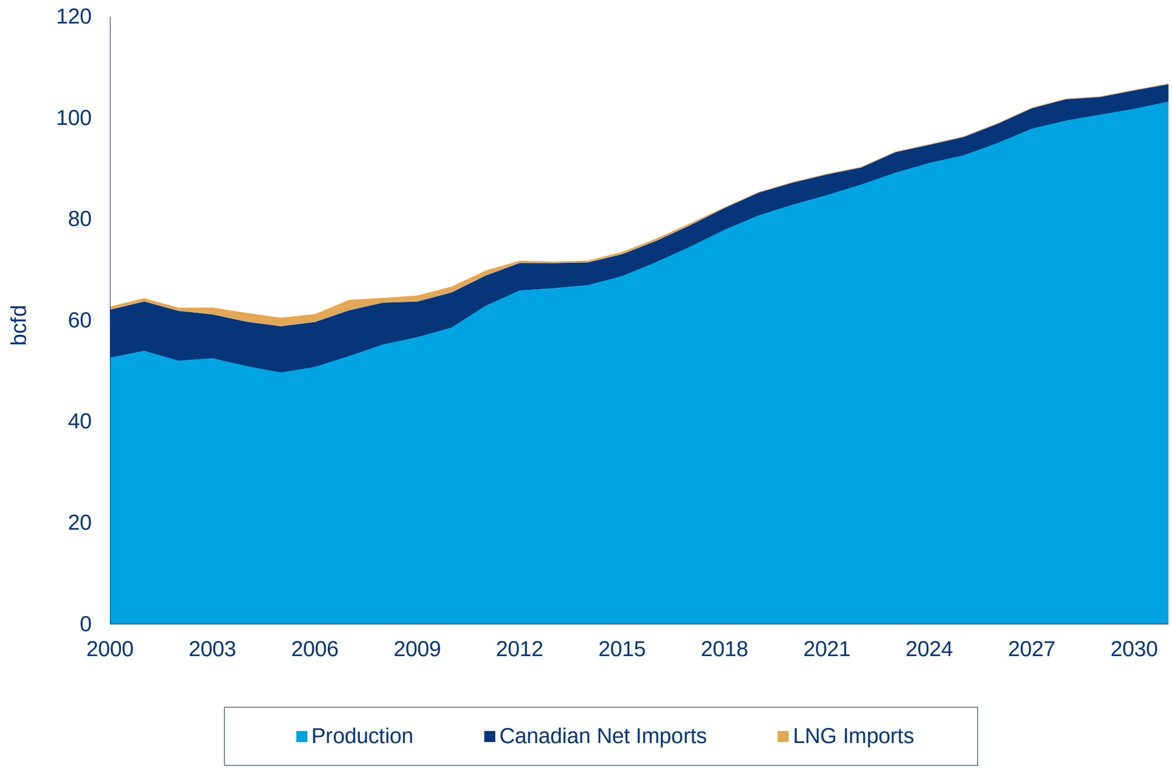
Chart 47 – WECC Regional Gas Demand Forecast (bcfd)



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.

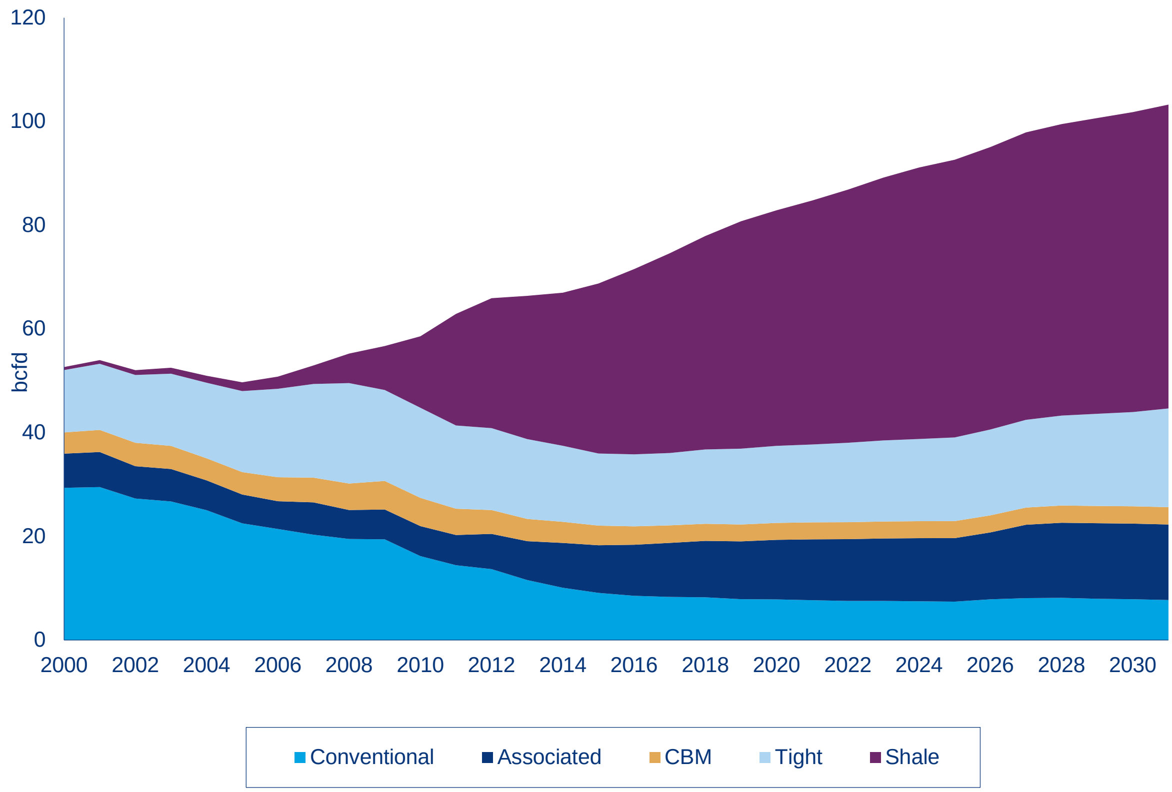
Chart 48 – U.S. Natural Gas Production Balances Net Imports (bcfd)



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.

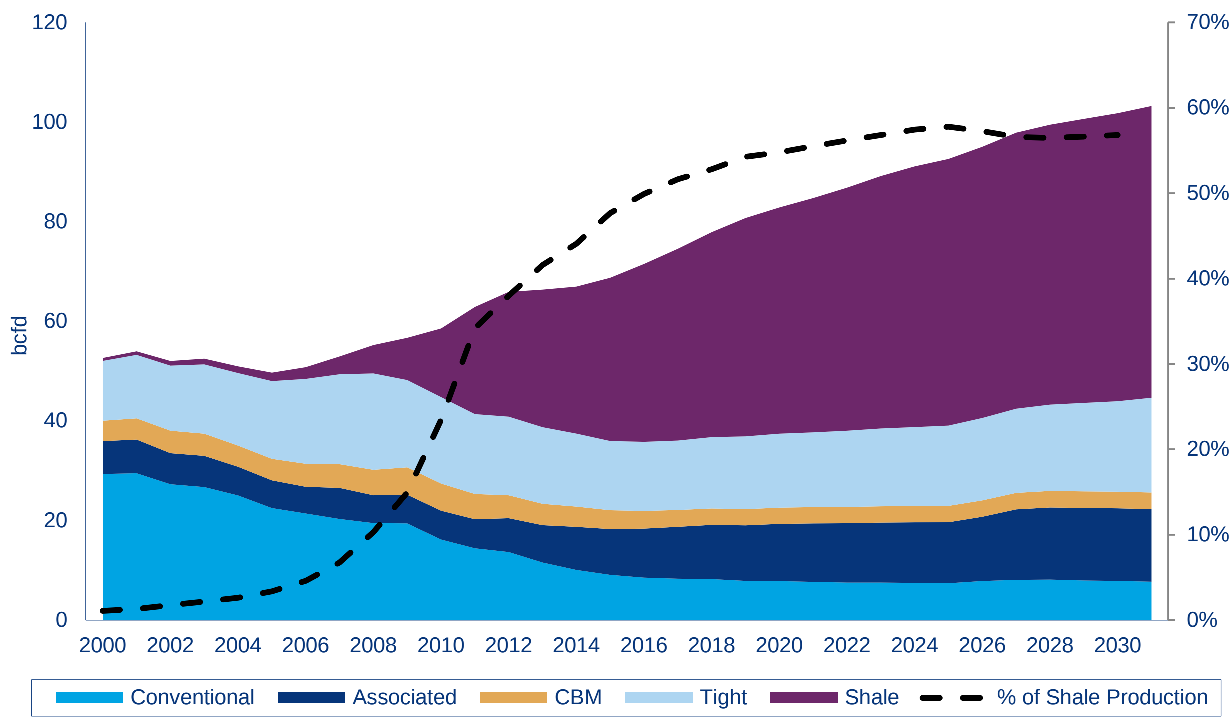
Chart 49 – U.S. Natural Gas Production by Source (bcfd)



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 50 - U.S. Natural Gas Supply Forecast (bcfd)



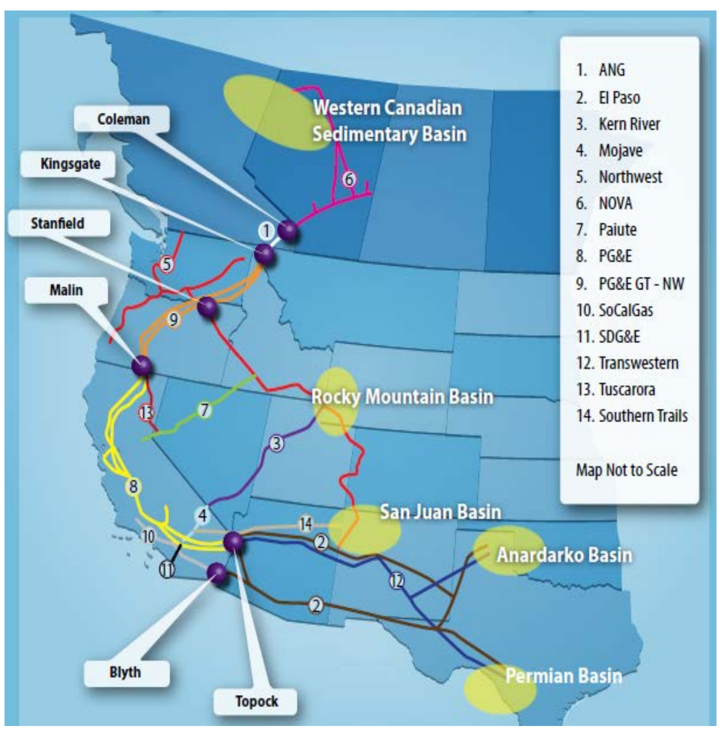
Natural Gas Transportation

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).

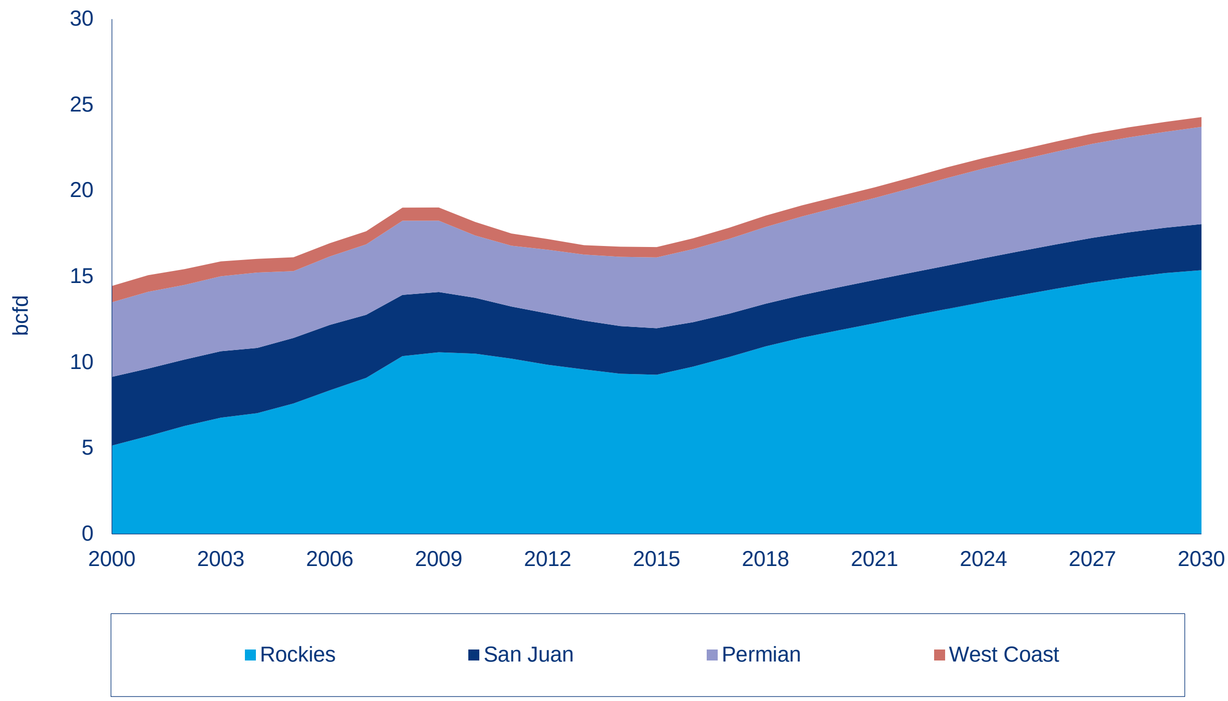
In addition, both Transwestern Pipeline Company and El Paso Natural Gas Company deliver to the Mojave Pipeline Company (0.4 Bcf per day) system, which enters the region at the northern Arizona/California border and crosses to Kern County, where it then merges with the Kern River Transmission Company 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 51, 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).

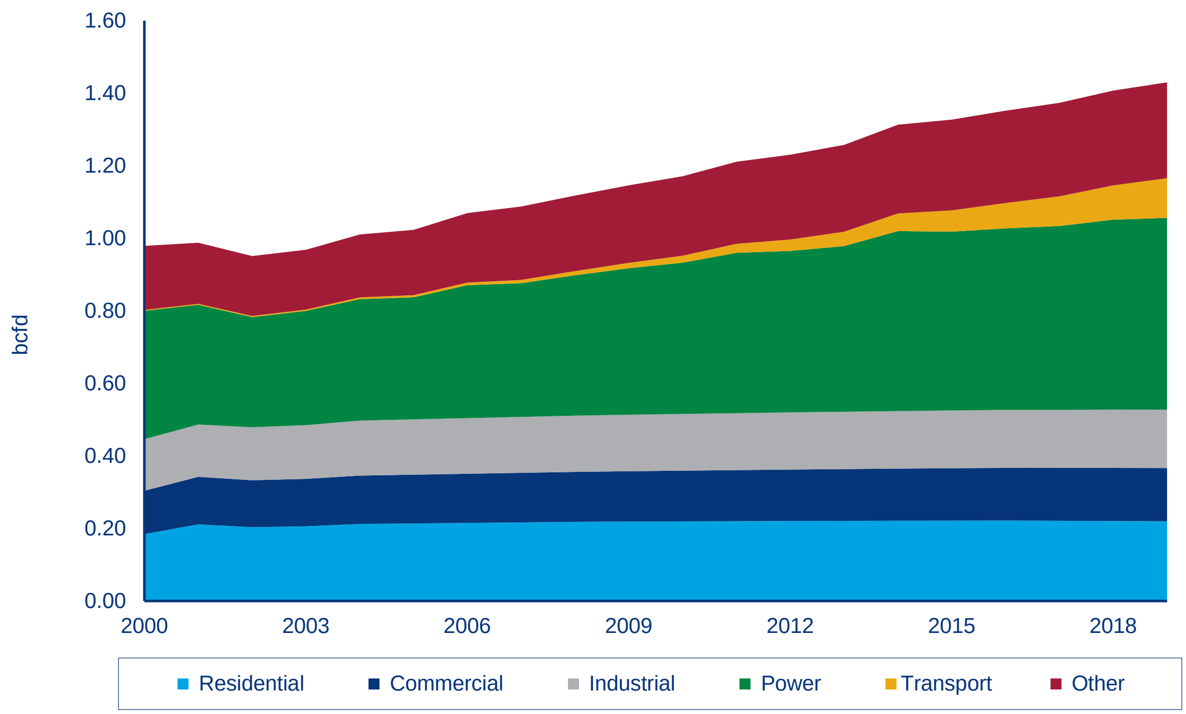
Chart 51 - Future Regional Natural Gas Production



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 52 below shows the Arizona natural gas demand by six major use sectors.

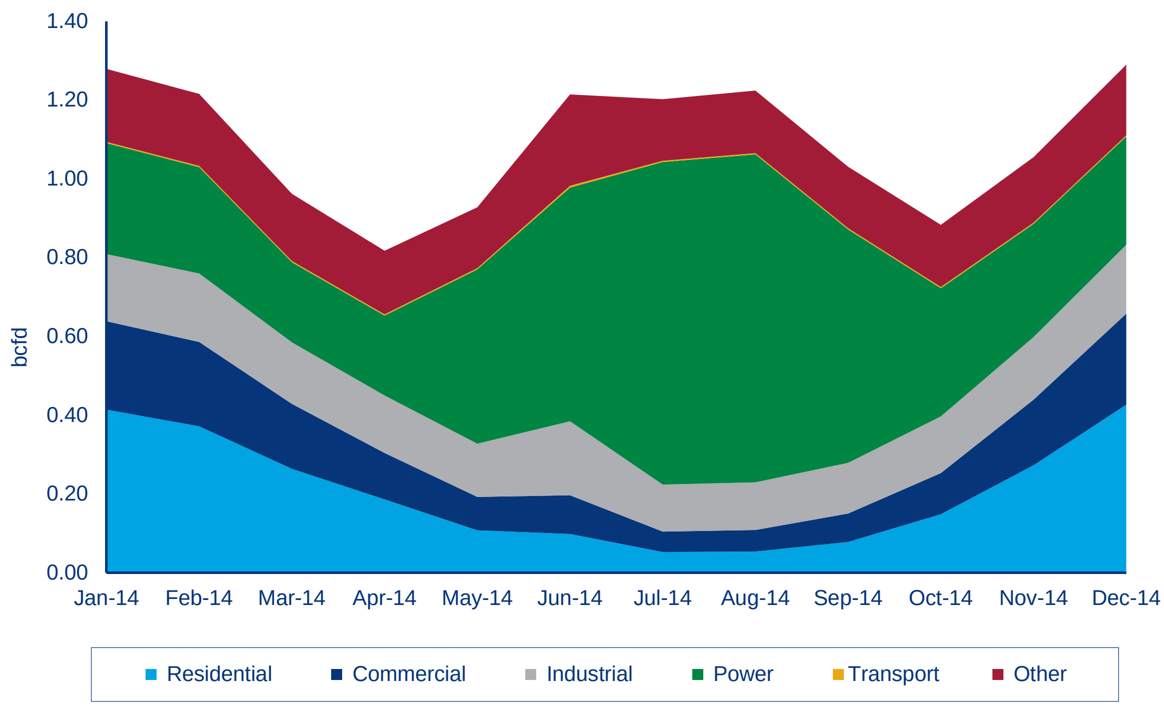
Chart 52 - Arizona Natural Gas Demand by Sector (bcfd)



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 53 below show the seasonality demand for Arizona natural gas.

Chart 53 - Arizona Seasonal Natural Gas Demand (bcfd)



CHAPTER 14

INTEGRATED RESOURCE PLANNING RESULTS

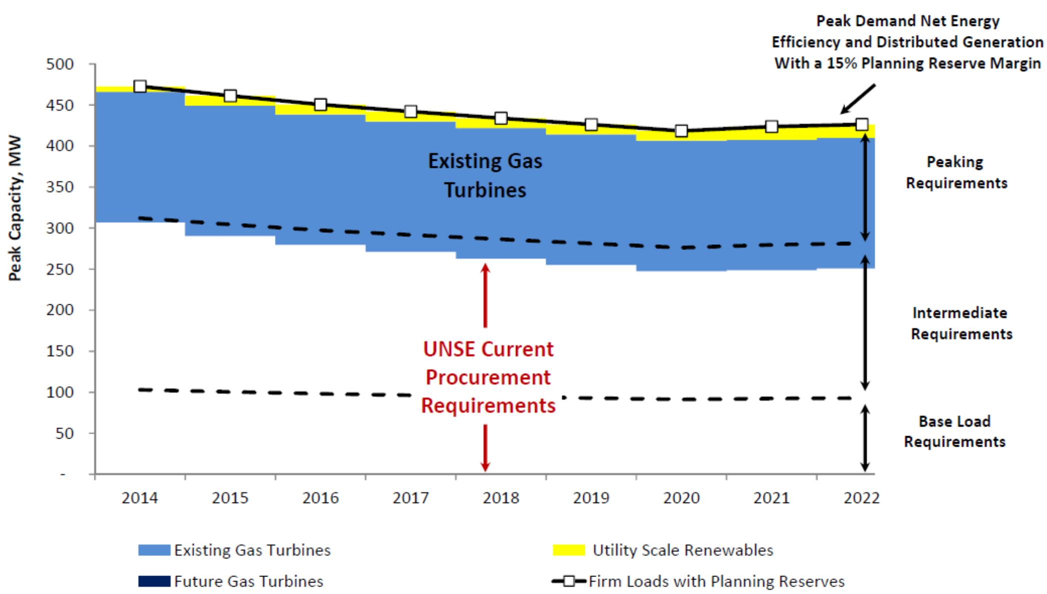
Introduction

The resource planning process starts with a set of input assumptions. These assumptions include a forecast of customer demand, costs and operating characteristics for new and existing resource options, and assumptions on future regulatory and environmental policies. These assumptions are run through detailed planning simulation models to develop an understanding of the financial requirements and risk factors 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 goal of this process is a resource planning strategy that balances competing objectives while allowing for flexibility to execute contingency plans as future uncertainties become known.

UNSE Future Resource Capacity Requirements

As shown in Chart 54 below, UNSE's 2014 load obligations, including reserve requirements, require UNSE to plan for approximately 475 MW in capacity resources. These resource requirements are divided between baseload, intermediate and peaking requirements. Since UNSE currently has approximately 150 MW of peaking capacity from its existing natural gas combustion turbines located at Black Mountain and Valencia Generating Stations, its future capacity needs are approximately 325 MW per year. For 2014, UNSE's baseload requirements are between 100 -150 MW with a need for another 150 - 200 MW of intermediate resources.

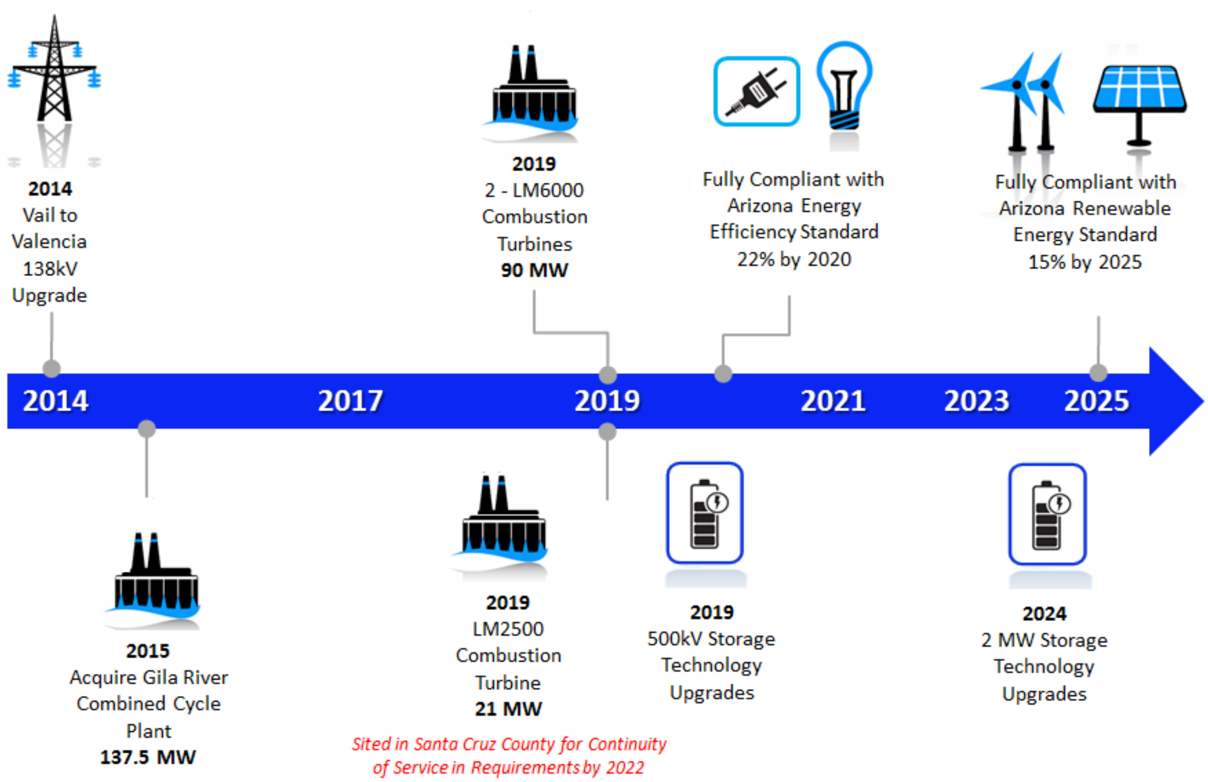
Chart 54 – UNSE's Future Capacity Needs



Overview of the 2014 Reference Case Plan

This section presents an overview of the 2014 Reference Case plan and provides the associated timelines for future resource additions. Figure 134 below details the significant resource planning decisions assumed for the 2014 IRP Reference Case. As part of its resource planning strategy, UNSE plans to acquire approximately 138 MW from Power Block 3 at the Gila River Power Station in December 2014. This natural gas combined cycle resource will cover a majority of UNSE's baseload and intermediate capacity requirements for the next several years. For UNSE's longer term peaking needs, the UNSE 2014 Reference Case plan assumes the need for 111 MW of additional gas fired generation by 2019. 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 2014 Reference Case also highlights the recently completed Vail to Valencia 115 kV to 138 kV transmission upgrade that went into service at the end of 2013. This new 138 kV transmission line will strengthen the southern portion of UNSE's distribution system resulting in improved system reliability in Santa Cruz County. Finally, the 2014 Reference Case recognizes the need for future storage technologies to support the integration of intermittent resources. For purposes of this filing, UNSE assumes that approximately 1.85 MW of battery storage technology will be required by 2028 to support future ancillary service requirements for the grid.

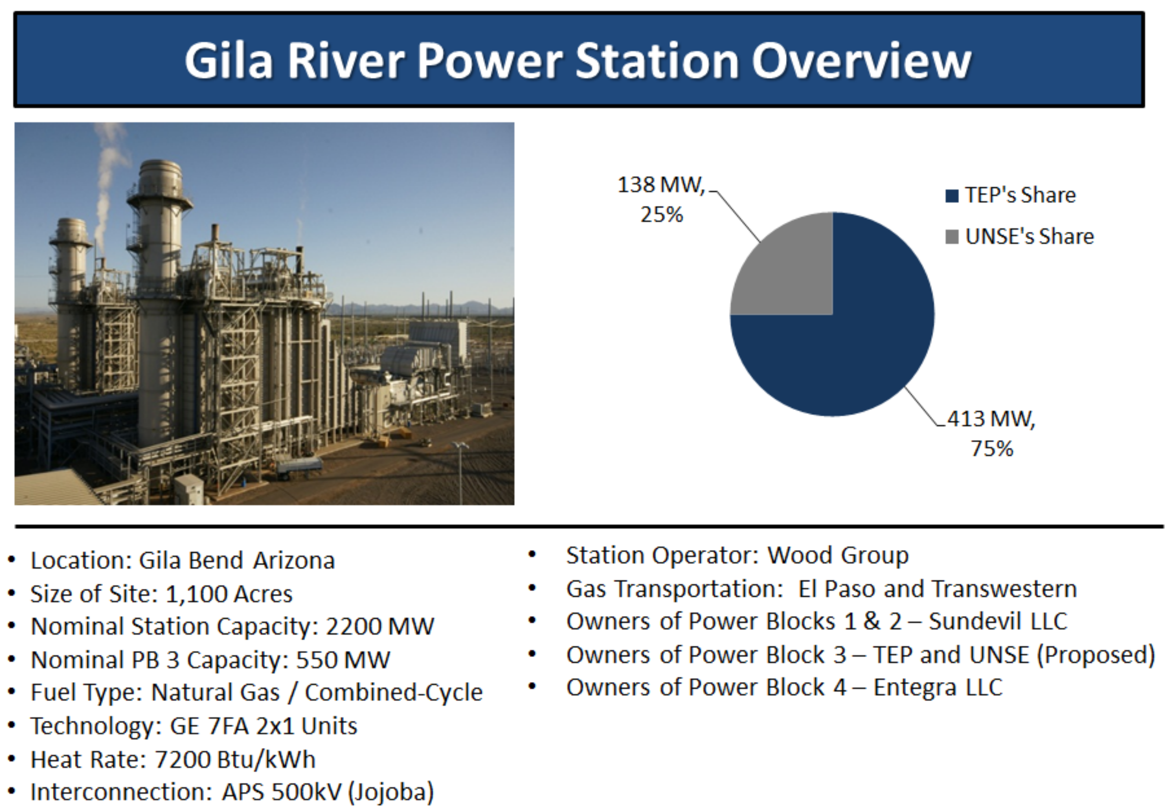
Figure 34 – 2014 UNSE Reference Case



UNSE's Planned Acquisition of the Gila River Power Station

In the 2012 Resource Plan, UNSE made a commitment to actively monitor the wholesale merchant market for potential resource alternatives as part of its on-going resource procurement process. In May 2013, TEP conducted a Request for Proposal (RFP) to evaluate the wholesale merchant market for potential capacity alternatives. As a result, TEP received fourteen different proposals from nine different bidders. Based on the bid analysis, Gila River Unit 3 was chosen as the final bidder due to the economic and operational advantages of their proposal. Due to the substantial size of the unit, and UNS Electric's need for baseload generating capacity, and the unanticipated and unique opportunity that would benefit UNSE and its customers, a decision was made to include UNS Electric as a potential buyer. In December 2013, both 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 nominal 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. TEP and UNS Electric expect the transaction to close in December 2014.

Figure 35 – Gila River Power Station Overview



Gila River Acquisition versus New Build Construction

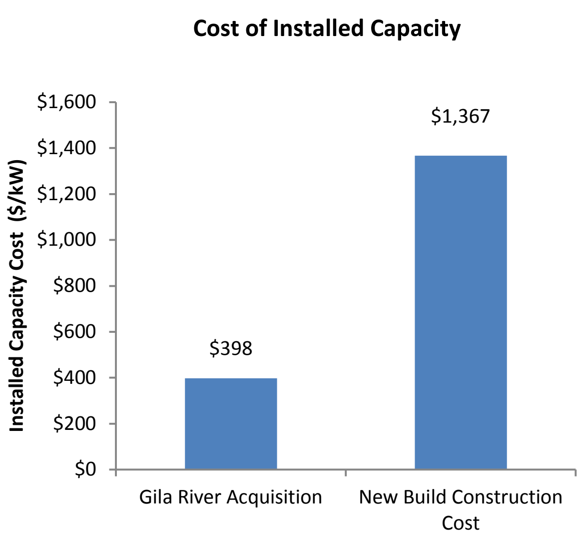
A comparison of the capital costs and life-cycle levelized costs of the proposed acquisition versus new build construction is shown below. Table 28 shows that UNSE's purchase share of the Gila River Power Station is much less expensive than a similar commitment in a newly constructed combined cycle plant. The purchase price of $398/kW for Gila River is 1/3 the cost of new construction at $1367/kW, which results in a $142 million net present value benefit for UNSE customers over the next fifteen years.

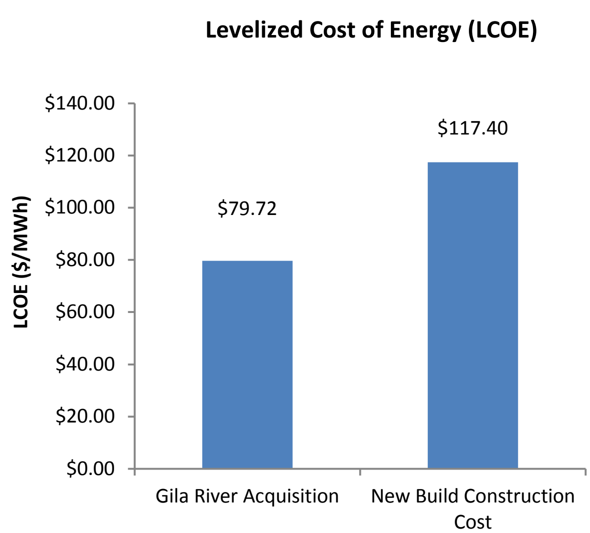
Table 28 – Gila River vs. New Construction Cost Comparison

Unit Capacity, MW	137.5
Weighted Average Cost of Capital, WACC	7.83%
Levelized Cost of Fuel, $/mmBtu	$6.54
Average Capacity Factor, %	41.7%

15 Year NPV and LCOE (2015-2029)	Gila River Acquisition	New Construction
Cost of Installed Capacity	$54,750	$187,963
Cost of Installed Capacity, $/kW	$398	$1,367
NPV Revenue Requirements, $000	$323,851	$466,828
Levelized Cost of Energy (LCOE), $/MWh	$79.72	$117.40

NPV Revenue Requirement Savings, $000	$142,978

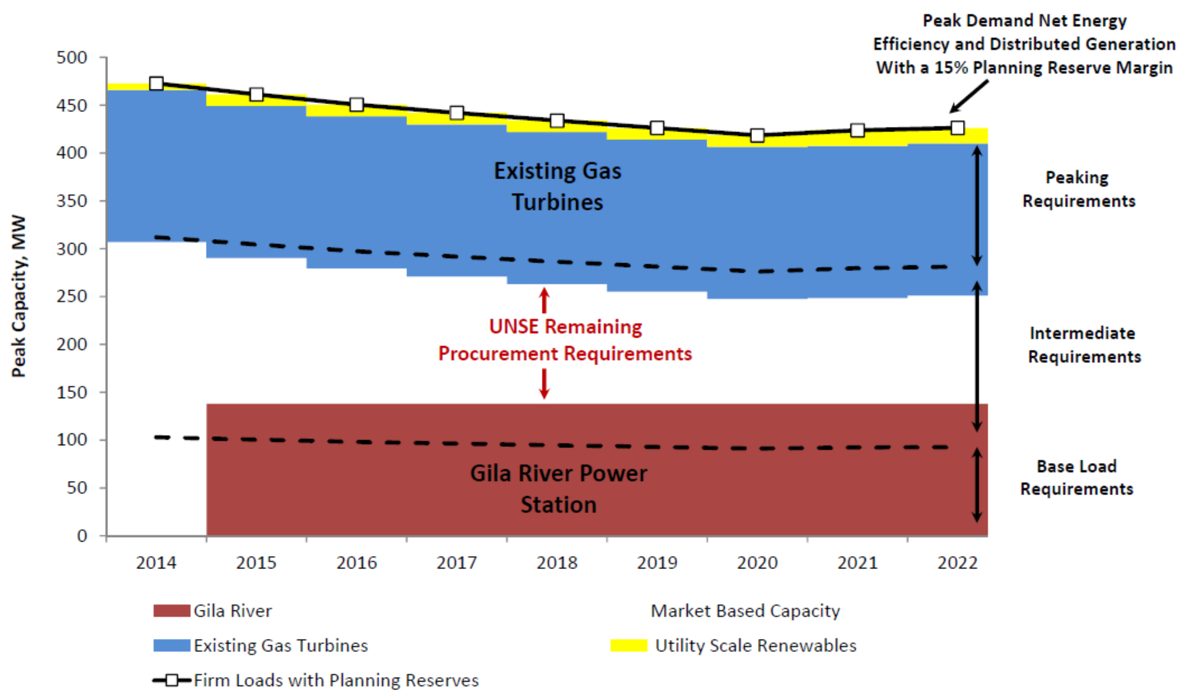




Capacity Requirments After the Gila River Power Station Acquisition

As shown in Chart 55 below, the acquisition of a 138 MW of capacity from the Gila River Power Station locks in a long-term resource to cover UNSE's future baseload and intermediate requirements. As a result, UNSE has approximately 150 - 200 MW of intermediate capacity left to cover on a year basis. These future resources may be a combination of firm long-term purchase power agreements, plant acquisitions, or construction of new local area generating facilities.

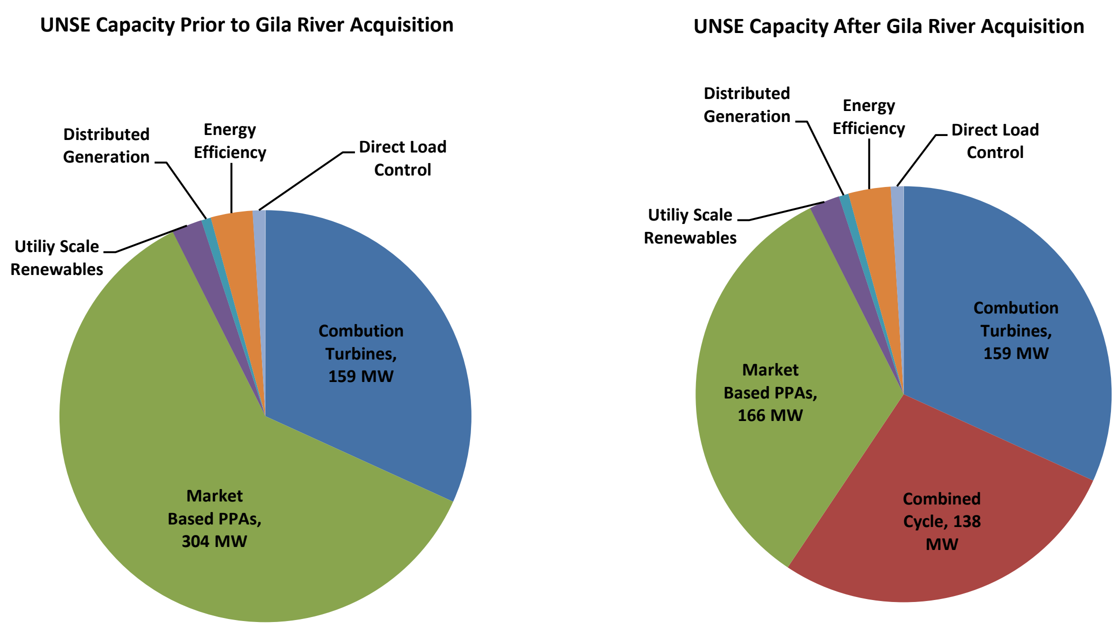
Chart 55 – UNSE 2014 Reference Case Loads and Resources



Reduction of Reliance on Market Based Capacity

Today, UNSE relies on the wholesale market for approximately 300 – 325 MW of its annual resource capacity needs. With UNSE's planned acquisition from the Gila River Power Station, UNSE will reduce its market based capacity exposure by about 45% from approximately 304 MW to 166 MW in 2015. Chart 60 shows the expected change in UNSE's resource capacity mix with the inclusion of a 25% ownership share of Power Block 3 at the Gila River Power Station.

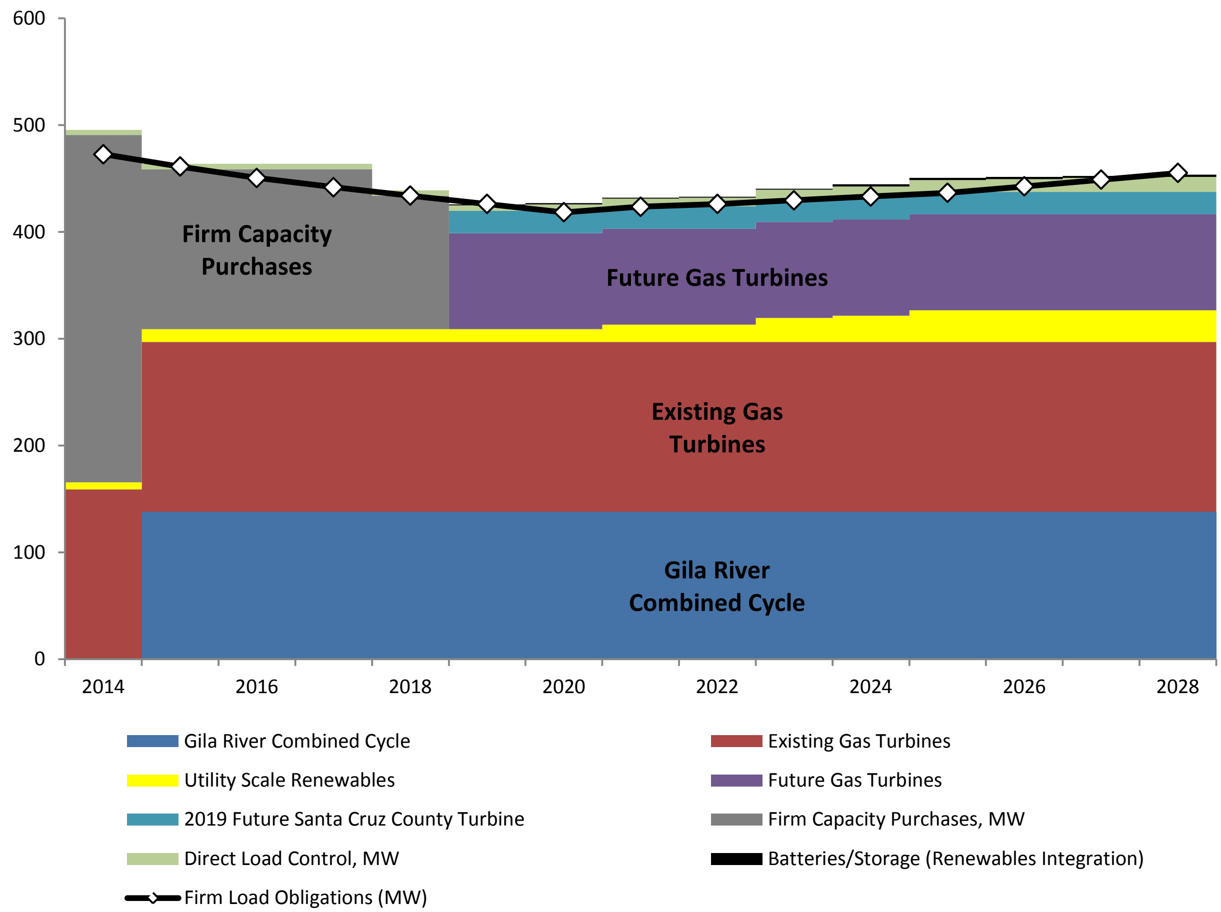
Chart 56 – UNSE's Market Based Resource Capacity Prior to and After the Gila River Acquisition



UNSE 2014 Reference Case Load and Resources

The loads and resources chart shown below details how UNSE's firm load obligations are met under the 2014 UNSE Reference Case. The firm load obligations represent UNSE's retail demand less energy efficiency and distributed generation plus a 15% planning reserve margin.

Chart 57 – UNSE 2014 Reference Case Loads and Resources



Note: Future Gas Turbine resources may be a combination of firm long-term purchase power agreements, plant acquisitions, or construction of new local area generating facilities.

Reference Case Plan Portfolio Composition

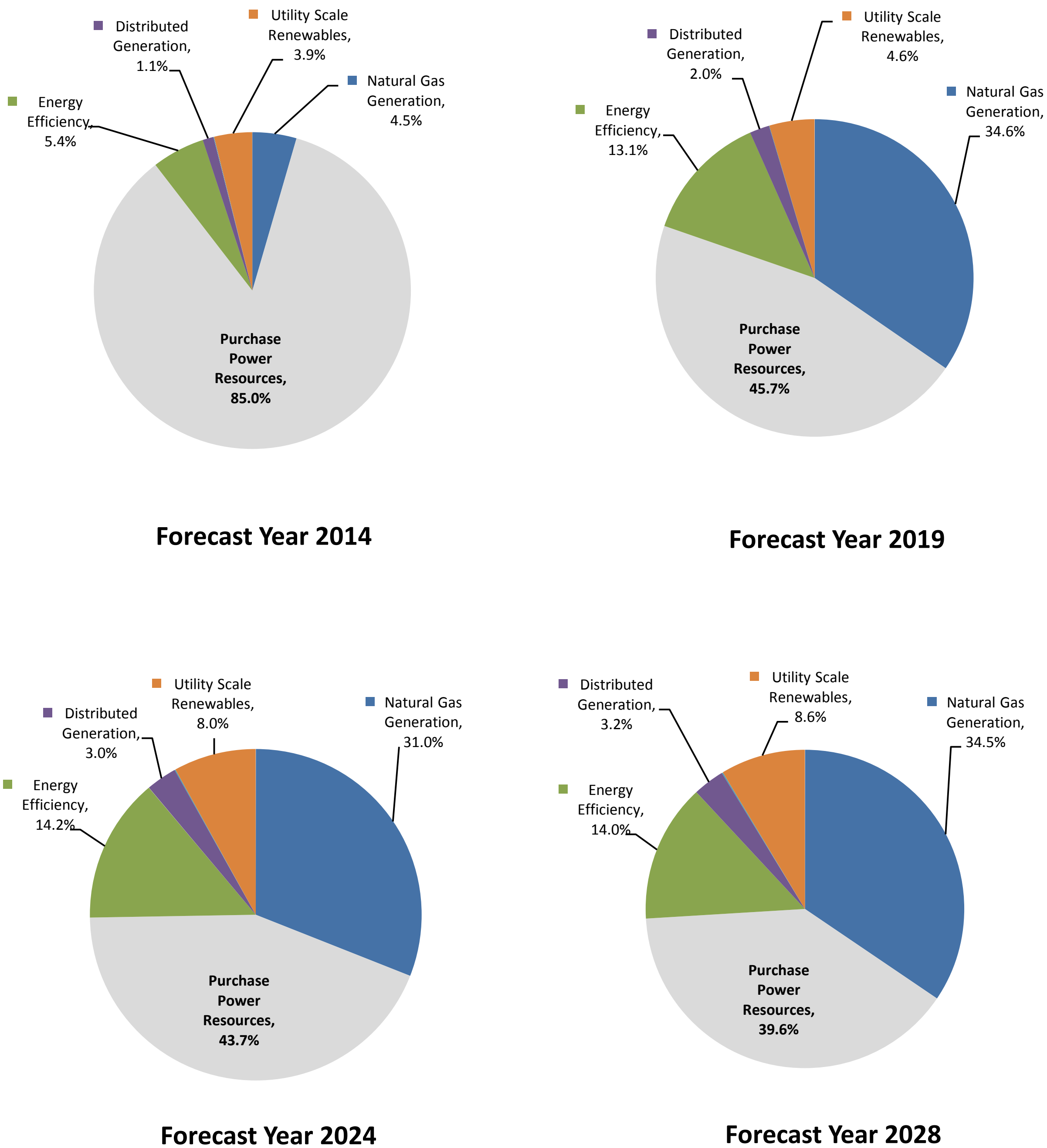
Table 29 below shows the generation mix by resource type under the Reference Case plan. Today, UNSE's resource portfolio is dominated by purchase power and natural gas peaking resources. The Reference Case resource plan anticipates potential investments in natural gas, renewable and energy efficiency resources over the next fifteen years. By 2028, it is projected that UNSE's resource portfolio will be 74% natural gas and purchase power resources with 14% made up of energy efficiency and 12% renewables resources.

Table 29 - Reference Case Portfolio Composition (Percent of Total Energy Resources)

Resource Portfolio % Energy	2014	2019	2023	2028
Natural Gas Generation	4%	35%	41%	34%
Purchase Power Resources	85%	46%	35%	40%
Energy Efficiency	5%	13%	14%	14%
Distributed Generation	1%	2%	3%	3%
Demand Response	0.05%	0.04%	0.07%	0.10%
Utility Scale Renewables	4%	5%	8%	9%
Total Resources	100%	100%	100%	100%
Percent of Net Retail Load	2014	2019	2023	2028
Renewable Resources (Utility Scale and Distributed Generation)	3.50%	7.00%	12.00%	15.00%
Energy Efficiency and Demand Response	3%	10.00%	22.00%	22.00%

Chart 58 below details how the Reference Case plan energy mix changes over the next 15 years.

Chart 58 – UNSE Reference Case Energy Portfolio (2014-2028)



Energy Efficiency and Demand Response

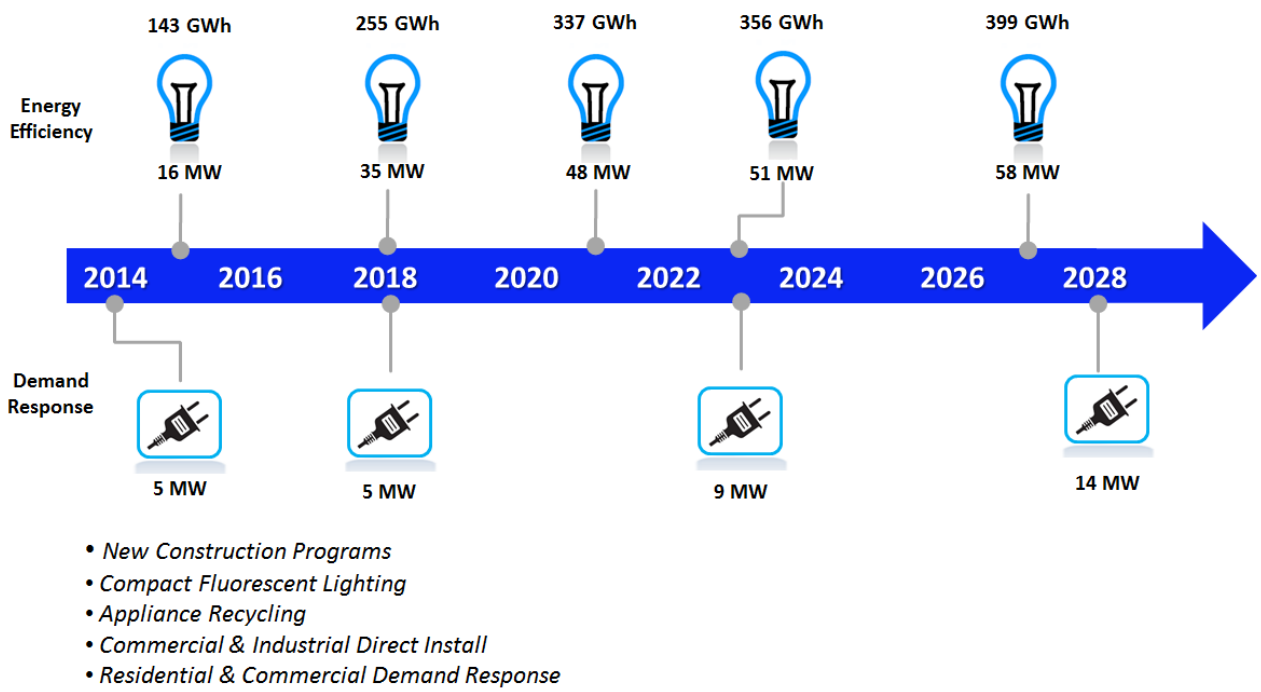
Energy Efficiency

UNSE proposes to pursue a range of cost-effective and industry-proven programs to meet future energy efficiency targets. UNSE'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 2028, this offset to future retail load growth is expected to reduce UNSE's annual energy requirements by approximately 407 GWh and reduce UNSE's system peak demand by 59 MW.

Demand Response

The Reference Case plan targets dispatchable demand response programs that reduce UNSE's summer peak loads. UNSE's future demand response programs are expected to reduce UNSE's system peak demand by 14 MW by 2028. Figure 36 shows the equivalent capacity reductions installed under future energy efficiency and demand response programs for the Reference Case plan from 2014 through 2028.

Figure 36 - Energy Efficiency and Demand Response (Equivalent Capacity Reductions)



Utility Scale Renewables and Distributed Generation

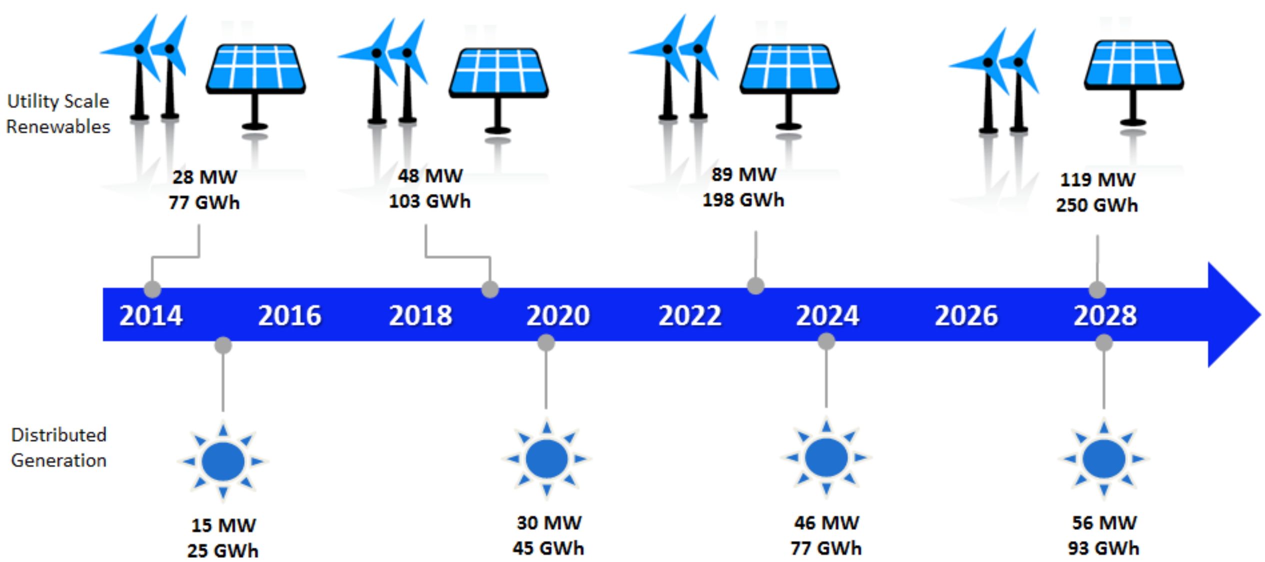
Utility Scale Renewables

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, which requires UNSE to obtain renewable energy which is equivalent to 3.5% of its 2014 retail load requirement, growing to 15% by 2025. By 2028, the Reference Case plan will include over 119 MW of renewable nameplate capacity. These utility scale renewable resources are expected to supply over 250 GWh of energy on an annual basis in 2028.

Distributed Generation

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 RES requirement. By 2028, the Reference Case plan will include 53 MW of distributed generation nameplate capacity. Distributed generation resources are expected to supply at least 93 GWh of energy on an annual basis in 2028. Figure 37below shows the expected cumulative nameplate capacity to be installed under future utility-scale renewable and distributed generation programs from 2014 through 2028.

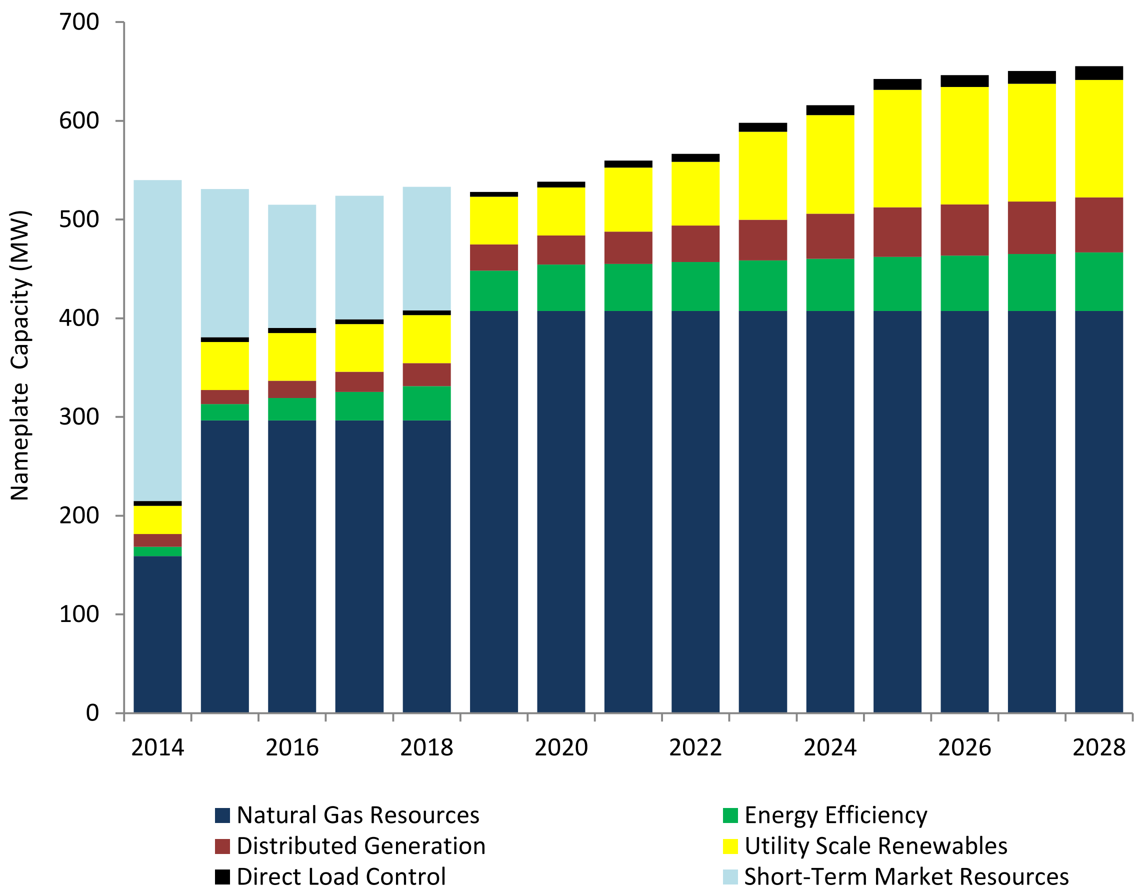
Figure 37 - Utility Scale Renewables and Distributed Generation Resource Capacity



2014 Reference Case Plan - Future Capacity Additions

The Reference Case plan identifies the need for approximately 655 MW of nameplate capacity through 2028. Chart 59 below shows the incremental nameplate capacities installed by year and resource type.

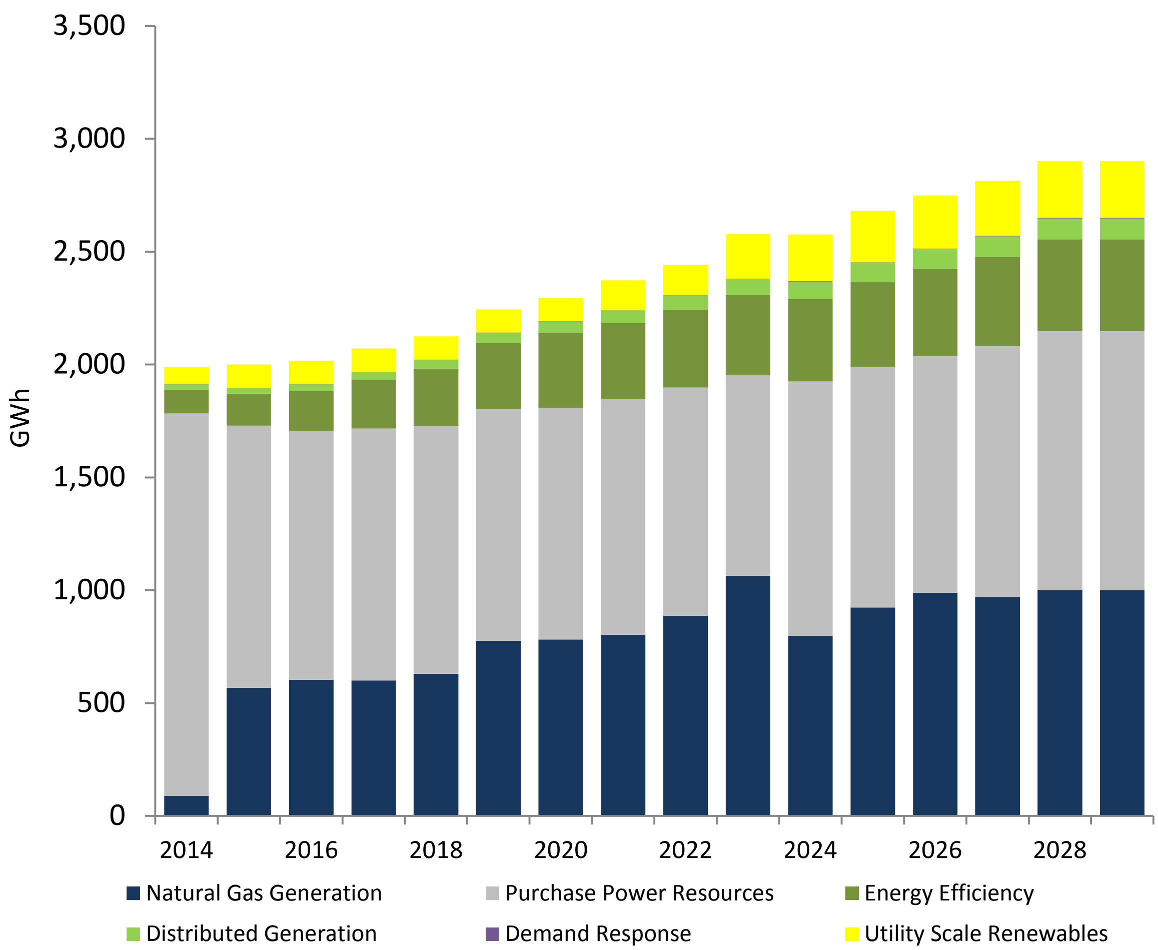
Chart 59 – Reference Case Plan Capacity Additions, Future Nameplate Capacity (MW)



2014 Reference Case Plan – Generation Mix

Chart 60 shows the expected energy contribution required to meet UNSE's firm load obligations by year and resource type. In 2014, UNSE's resource portfolio is comprised of 90% purchase power and natural gas resources. By 2028, it is projected that UNSE's resource portfolio will be comprised of 74% natural gas and purchase power resources with 14% made up of energy efficiency and 12% renewable resources.

Chart 60 – Reference Case Resource Plan, Expected Annual Generation Output (GWh)



2014 IRP Scenario Case Analysis

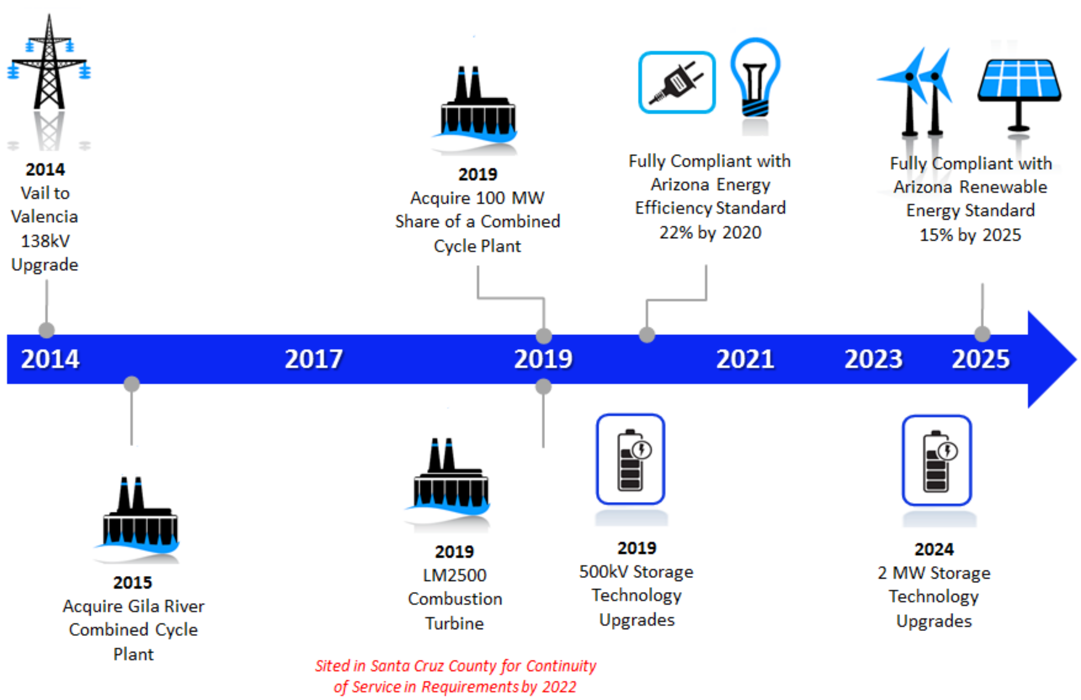
The following section provides a detailed analysis on the 2014 IRP cases analyzed for this report. The 2014 IRP includes three additional scenario cases with an in depth analysis to support the recommend 2014 IRP Reference Case plan.

- Future Combined Cycle Case
- Market Based Reference Case
- High Renewable Case

Overview of the Future Combined Cycle Resource Case

Given UNSE's need for future gas fired resources as early as 2019, the 2014 IRP considers a scenario where UNSE acquires ownership in a new combined-cycle plant. The Future Combined Cycle Resource Case assumes that UNSE replaces the 90 MW of combustion turbines in 2019 with 100 MW from a combined-cycle plant. It is assumed that the 2019 ownership costs of a new combined cycle plant are approximately $1,492/kW. All other assumptions including transmission and storage technology upgrades are the same as the Reference Case.

Figure 38 – Future Combined Cycle Resource Case



Overview of the Market Based Reference Case

For purposes of the 2014 IRP, UNSE developed the Market Based Reference Case. Under this scenario, it is assumed that UNSE relies on the wholesale market for limited amounts of market based capacity purchases to meet its summer peak load requirements. This scenario provides insight on how UNSE'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 UNSE develops a portfolio of long and short-term purchase power agreements through it on-going hedging practices. With exception to 2014 and 2015, it is assumed that UNSE limits its reliance on market based capacity purchases to 100 MW per year. All other assumptions including transmission and storage technology upgrades are the same as the Reference Case.

Figure 39 – Market Based Reference Case Timeline

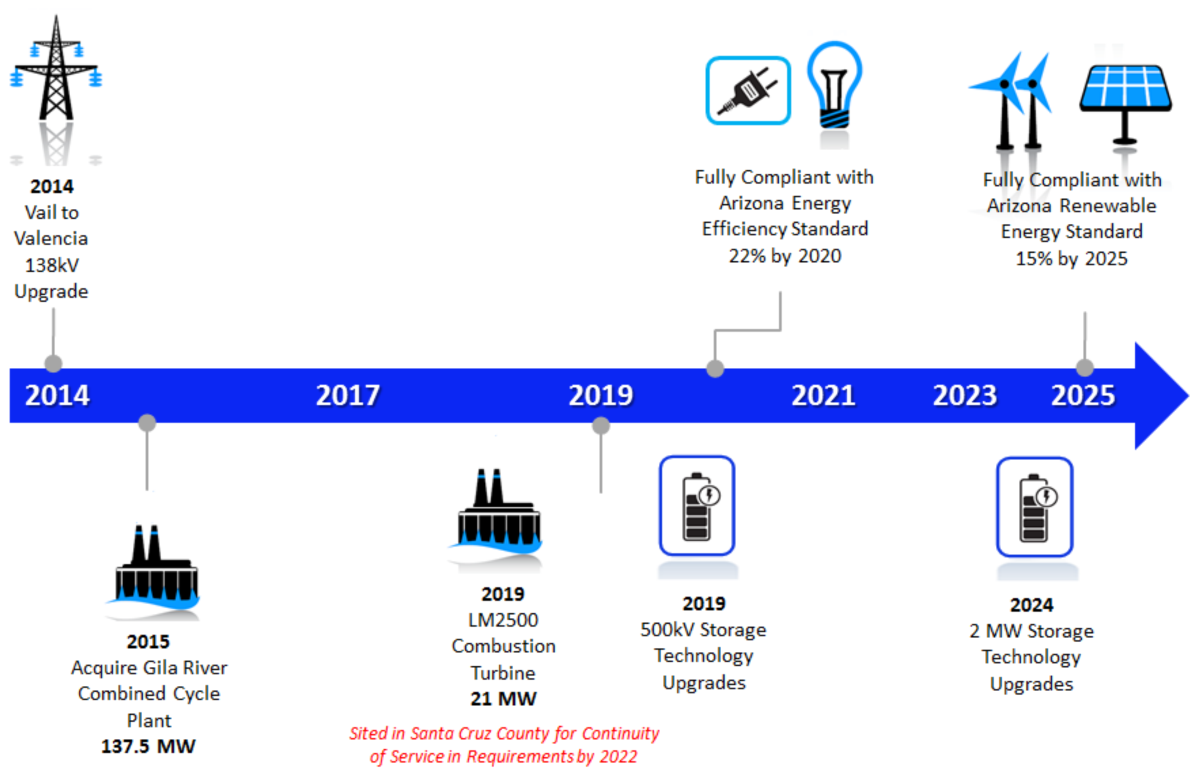


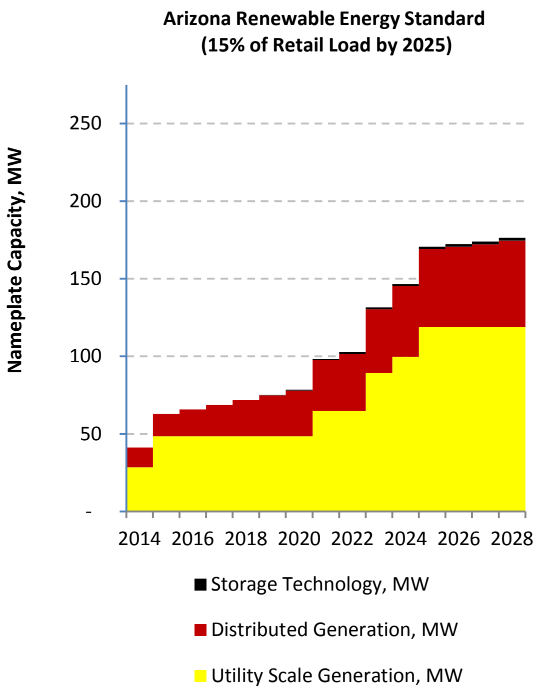
Figure 40 – Firm Market Capacity Requirements by Year

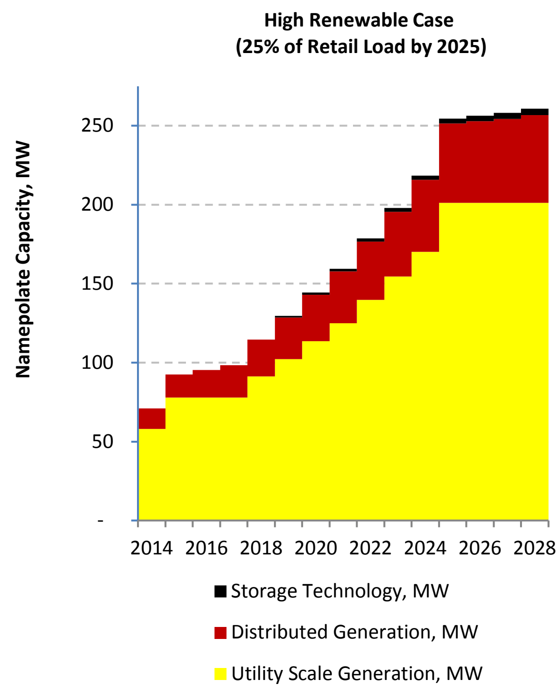
Firm Capacity PPAs	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Firm Capacity Purchases, MW	300	150	125	125	125	100	100	100	100	100	100	100	100	100	100

Overview of Renewable Energy Assumptions by Case

For purposes of the 2014 IRP, all of the scenarios modeled in the 2014 IRP assume that UNSE is compliant with the Arizona REST standard. The REST standard requires UNSE to utilize renewable energy resources to serve 15% of its retail load by 2025. However, for purposes of modeling UNSE developed the High Renewable Case as a potential scenario. Under this scenario it is assumed that UNSE utilizes 25% of renewable energy resources to serve its retail load by 2025. Chart 61 shows the comparison between the compliant Renewable Energy Standard that results in a renewable resource portfolio with 175 MW of renewable nameplate capacity and 1.85 MW storage technologies by 2028 versus the High Renewable Case that that results in a renewable resource portfolio with 257 MW of renewable nameplate capacity and 4.20 MW of storage technology by 2028.

Chart 61 – Renewable Energy Scenario Charts

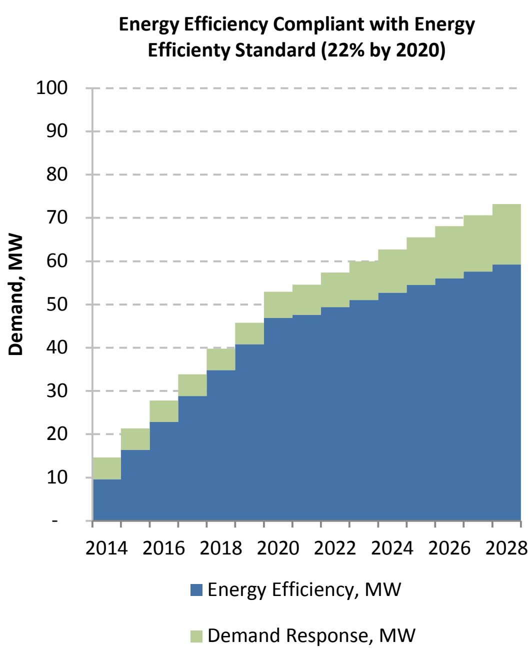


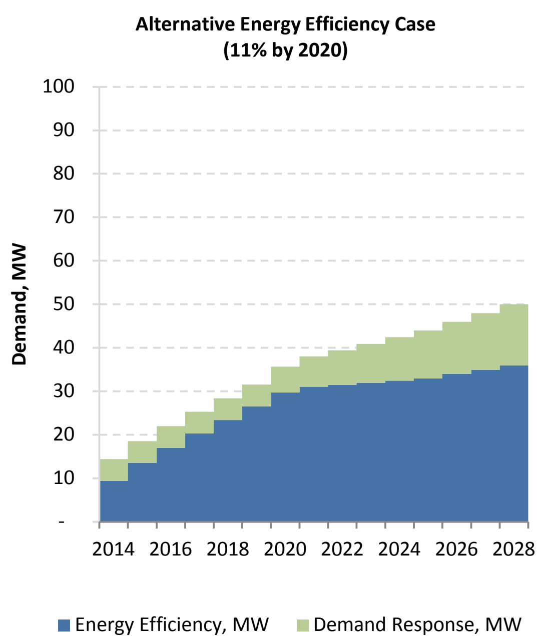


Overview of Energy Efficiency Assumptions in the 2014 IRP

For purposes of the 2014 IRP, all of the scenarios modeled in the 2014 IRP assume that UNSE 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, UNSE 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 62 shows the comparison between the compliant Energy Efficiency scenarios that achieves a 73 MW reduction in demand by 2028 versus the Alternative Energy Efficiency scenario that only realizes a 50 MW reduction in demand.

Chart 62 – Energy Efficiency Scenario Charts





Overview of Major IRP Assumptions by Case

Figure 41 below summaries the major assumptions and environmental upgrades that are included in each case.

Figure 41 – Major IRP Assumptions by Case

Major Assumptions	Reference Case	Market Based Reference	Future Combined Cycle Resource	High Renewable 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
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
Storage Resources	Approximately 2 MW In-Service by 2028	Same as Reference Case	Same as Reference Case	Approximately 4 MW In-Service by 2028
Wholesale Market Firm Capacity	Rely on Firm Wholesale Capacity Purchases through 2019, when Displaced with Gas-Fired Turbines	Rely on Wholesale Market for Firm Capacity through 2028 (Limited to 100 MW per Year)	Rely on Firm Wholesale Capacity Purchases through 2019, when Displaced with a Combined Cycle Resource	Same as Reference Case

Overview of New Resource Additions by Case

Figure 42 below summaries the new resource upgrades that are included in each case.

Figure 42 – New Resource Additions by Case

Reference Case	In-Service
Vail to Valencia Transmission Upgrade	2014
Gila River Acquisition (138 MW)	2015
1 LM2500 CT (21 MW)	2019
2 LM6000 CTs (90 MW)	2019
Battery Storage 2 MW by 2028	2019-2028

Market Based Reference Case	In-Service
Vail to Valencia Transmission Upgrade	2014
Gila River Acquisition (138 MW)	2015
1 LM2500 CT (21 MW)	2019
Battery Storage 2 MW by 2028	2019-2028

Future Combined Cycle Case	In-Service
Vail to Valencia Transmission Upgrade	2014
Gila River Acquisition (138 MW)	2015
1 LM2500 CT (21 MW)	2019
Combined Cycle Unit (100 MW)	2019
Battery Storage 2 MW by 2028	2019-2028

High Renewable Case	In-Service
Vail to Valencia Transmission Upgrade	2014
Gila River Acquisition (138 MW)	2015
2 LM2500 CT (42 MW)	2019
2 LM6000 CTs (135 MW)	2019
Battery Storage 4 MW by 2028	2019-2028

Summary of NPV Revenue Requirements by Case

Figure 43 below summaries the Net Present Value (NPV) revenue requirement in detail for each case.

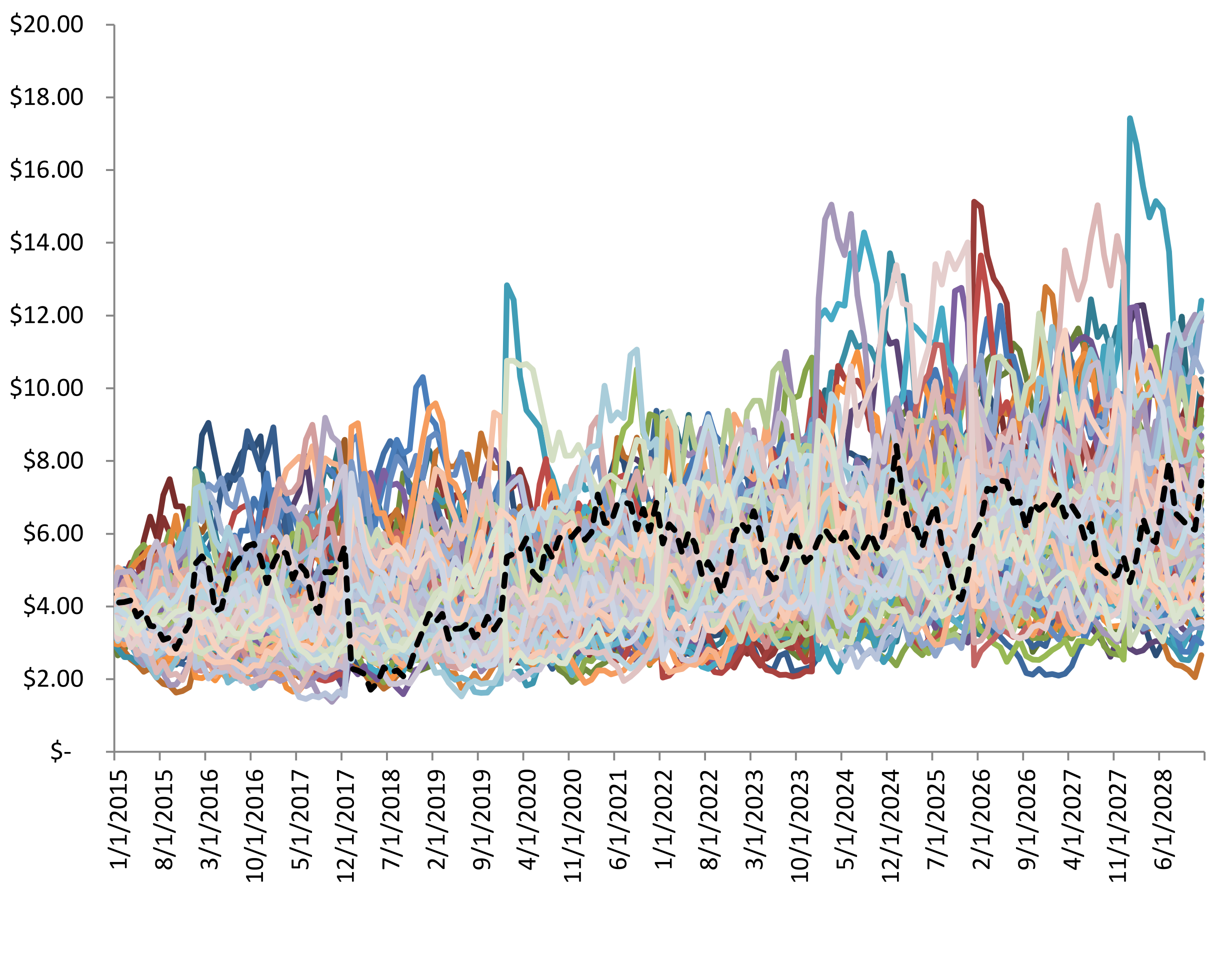
Figure 43 – NPV Revenue Requirements by Case

Non Fuel Revenue Requirements, $000	Reference Case	Combined Cycle Case	Market Based Reference	High Renewables
Existing T&D Resources	$736,722	$736,722	$736,722	$736,722
Existing Generation Resources	$235,414	$235,414	$235,414	$235,414
New Generation Resources	$94,147	$124,411	$20,276	$140,583
Storage Resources	$3,077	$3,077	$3,077	$6,739
New Transmission Resources	$134,195	$134,195	$134,195	$134,195
Total Non-Fuel Revenue Requirements	$1,203,554	$1,233,819	$1,129,683	$1,253,651
Fuel & Purchase Power, $000	**Reference Case**	**Combined Cycle Case**	**Market Based Reference**	**High Renewables**
PPFAC Cost, Fuel & Purchase Power	$963,827	$944,534	$982,210	$899,376
PPFAC Cost, Renewable (Above MCCCG)	$54,165	$54,165	$54,165	$54,165
Total Gas Transportation	$57,158	$58,123	$48,477	$62,518
PPFAC Cost, Demand Charges	$17,631	$17,631	$59,149	$17,631
Total PPFAC Costs	$1,092,781	$1,074,452	$1,144,001	$1,033,690
Environmental Compliance	$21,878	$24,373	$18,017	$24,946
PPFAC Cost including Environmental Compliance	$1,114,658	$1,098,826	$1,162,018	$1,058,636
Energy Efficiency and Renewables, $000	**Reference Case**	**Combined Cycle Case**	**Market Based Reference**	**High Renewables**
Energy Efficiency	$98,253	$98,253	$98,253	$98,253
Demand Response	$7,431	$7,431	$7,431	$7,431
Total Energy Efficiency	$105,684	$105,684	$105,684	$105,684
Utility Scale Renewables	$98,412	$98,412	$98,412	$268,682
Distributed Generation	$13,430	$13,430	$13,430	$13,430
Total Renewables	$111,842	$111,842	$111,842	$282,112
Total Energy Efficiency and Renewables	$217,526	$217,526	$217,526	$387,796
Total System Revenue Requirements	$2,535,739	$2,550,171	$2,509,227	$2,700,084
NPV Delta from Reference Case		$14,432	-$26,511	$164,345

RISK ANALYSIS RESULTS

For the 2014 IRP, UNSE developed market 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 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 63 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 more detail in Chapter 15.

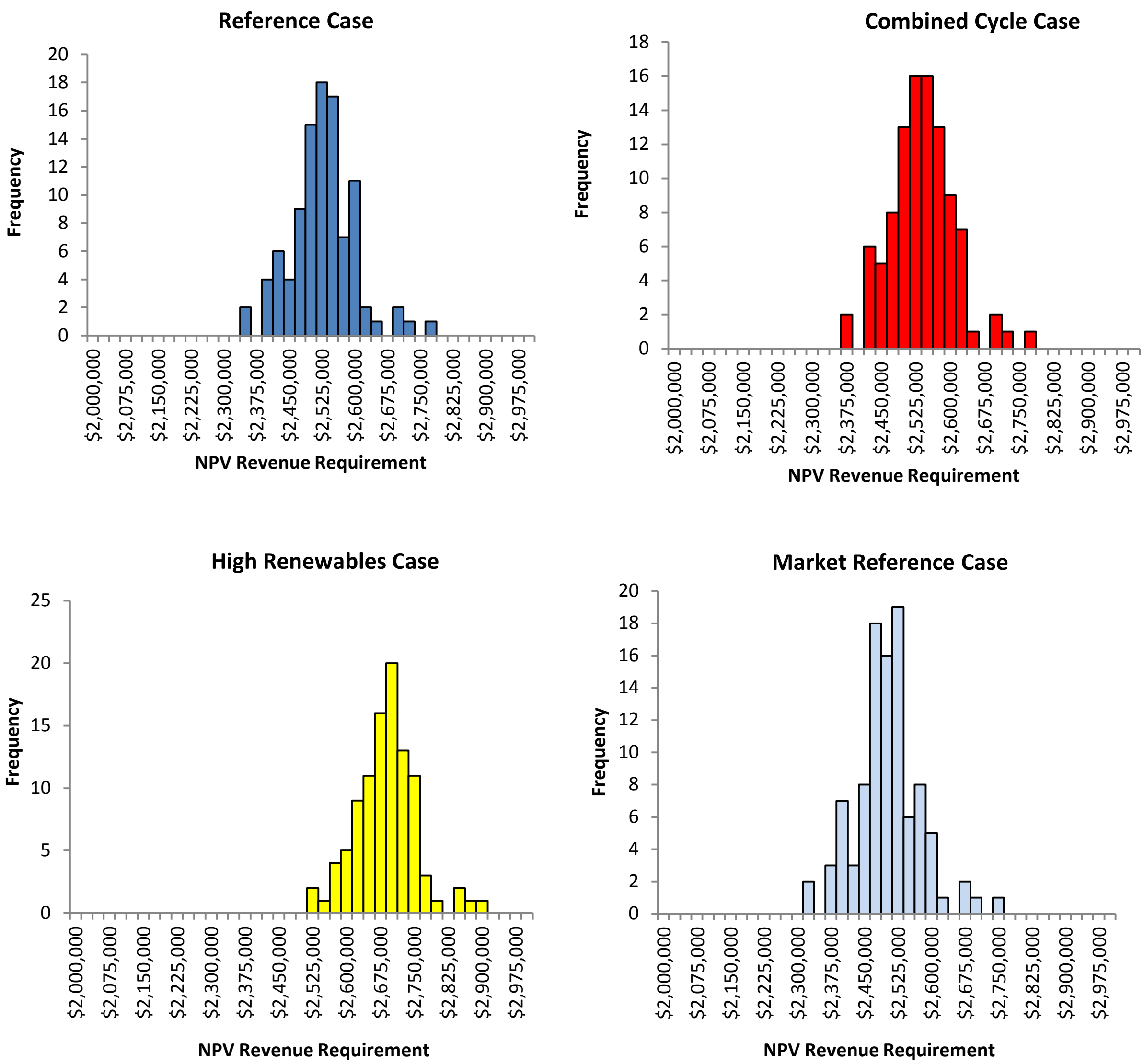
Chart 63 – Permian Gas Prices Iterations



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 64 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.

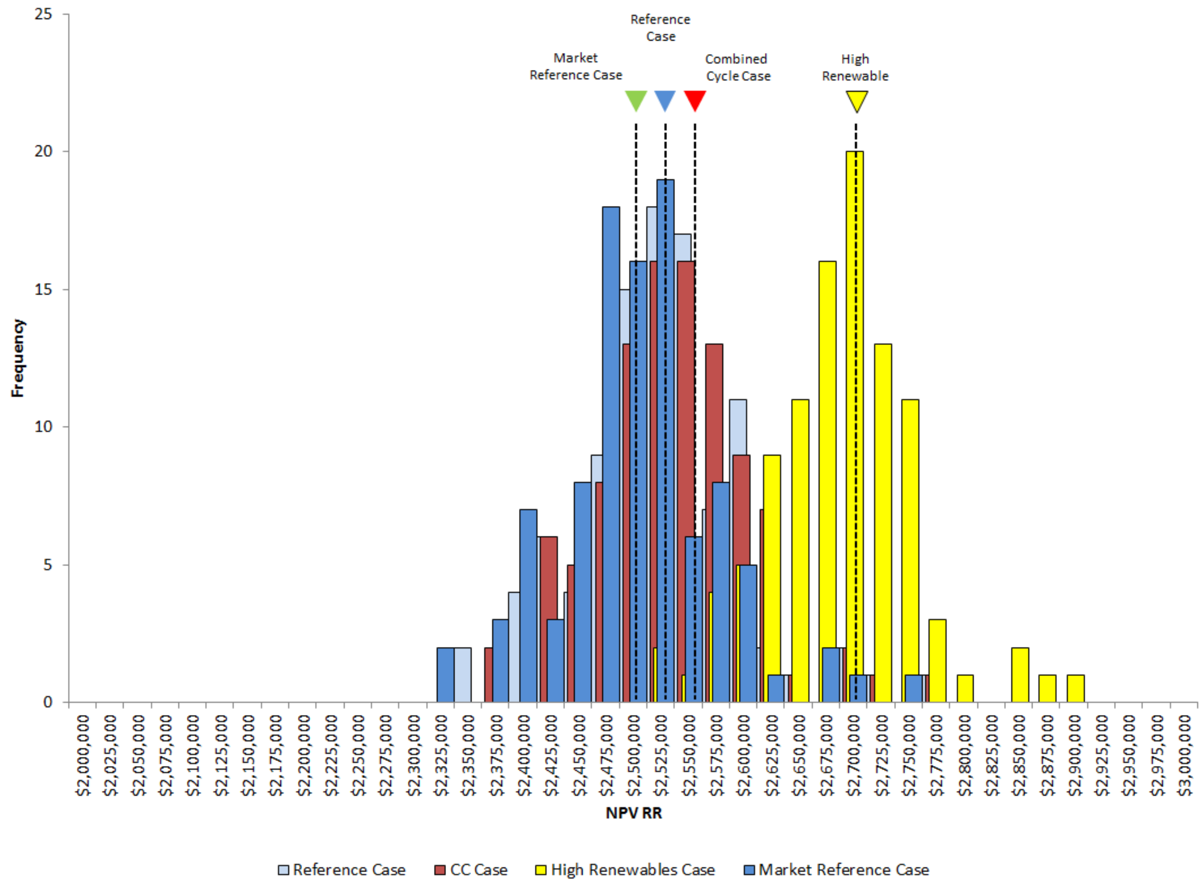
Chart 64 – Distribution of NPVRR by Case



DISTRIBUTION OF NPV REVENUE REQUIREMENTS BY CASE

Chart 65 below shows distribution of Net Present Value Revenue Requirements (NPVRR) on the same chart.

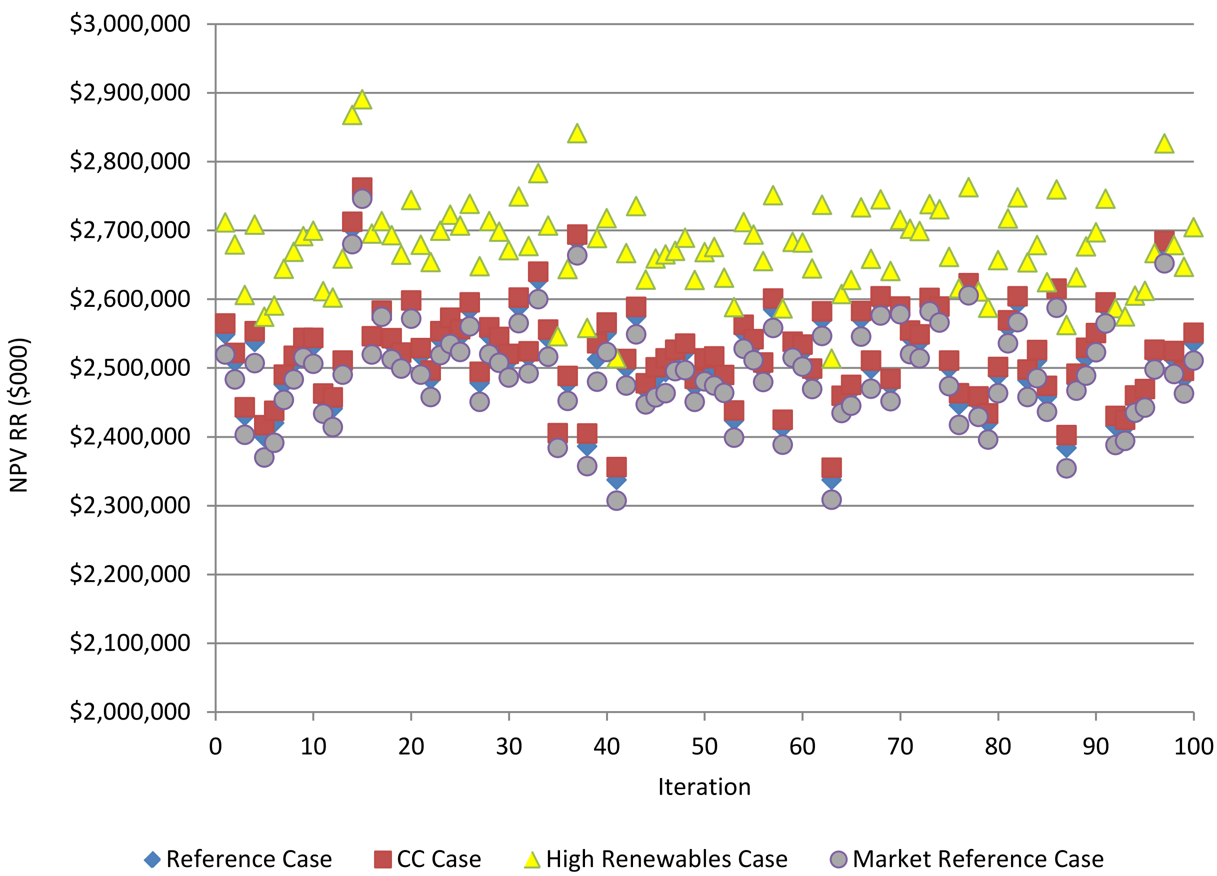
Chart 65 – Aggregated NPVRR by Case



NPVRR SUMMARY OF CASES BY ITERATION

Chart 66 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.

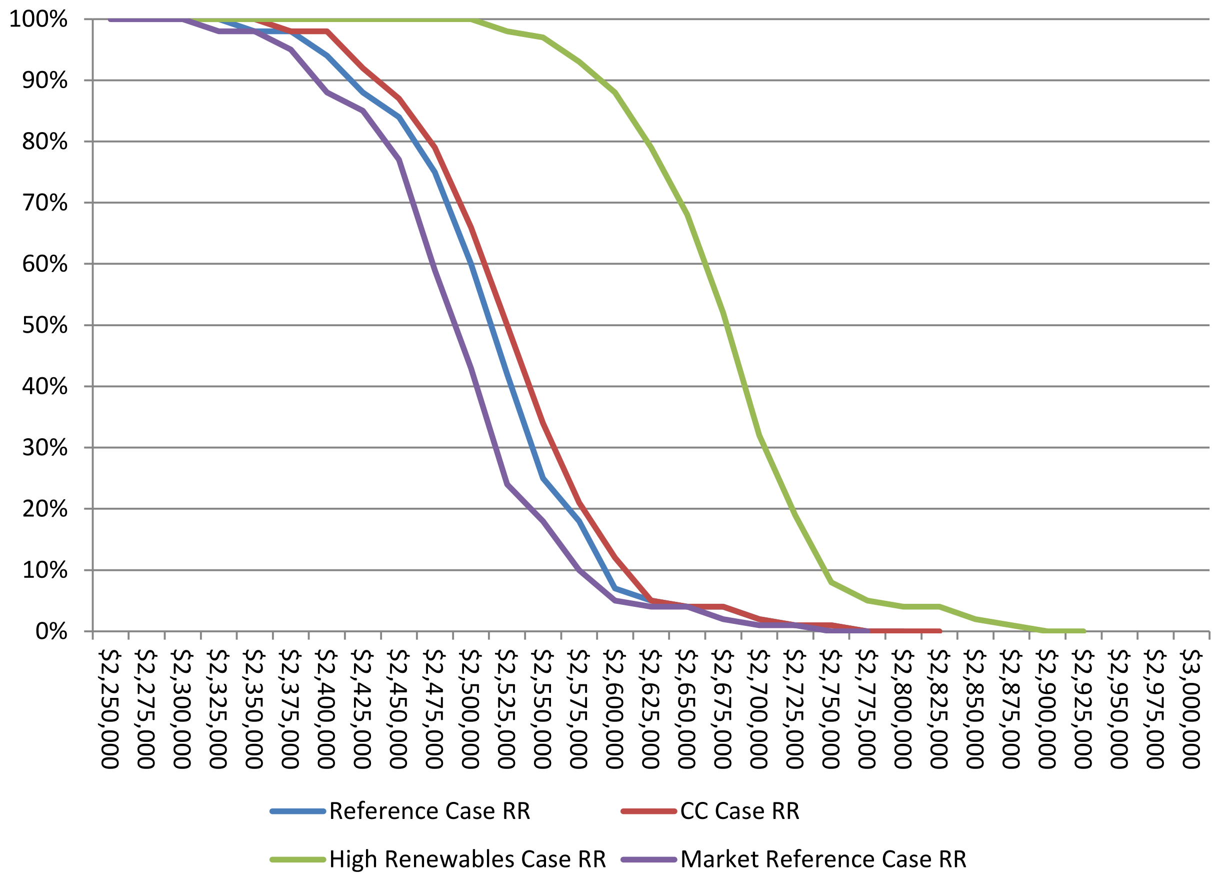
Chart 66 – NPVRR Summary of Cases by Iteration



EXCEEDENCE PROBABILITY BY CASE

Chart 67 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 67 – Exceedence Probability by Case



RISK ANALYSIS CONCLUSIONS

As illustrated in all of the charts shown above, the Reference Cases demonstrates its robustness to market price and load shocks relative to the High Renewable and Future Combined Cycle portfolios. Relative to future market and load uncertainty, the Reference Case represents both a lower cost and lower risk option than the other portfolios. The Market Reference case, 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 UNSE in their utilization relative to building sufficient assets to serve 100% of the peak load in 2019 and beyond.

List of Acronyms

ACRONYMS

APS – Arizona Public Service Company
BART - Best Available Retrofit Technology
BTA – Biennial Transmission Assessment
Btu – British Thermal Unit
CAES - Compressed Air Energy Storage
CCCT – Combined Cycle Combustion Turbine
CFL - Compact Fluorescent Light Bulb
CO2 - Carbon Dioxide
CSP - Concentrating Solar Power
CCS - Carbon Capture and Sequestration; Carbon Capture and Storage
CT - Combustion Turbine
DG - Distributed Generation
DOE - Department of Energy (Federal)
DLC – Direct Load Control
DR – Demand Response
EE – Energy Efficiency
EIA - Energy Information Administration
EPA - Environmental Protection Agency
EPRI - Electric Power Research Institute
FERC - Federal Energy Regulatory Commission
GW- Gigawatt,
GWh - Gigawatt-Hour
HAPS - Hazardous Air Pollutants
HRSG – Heat Recovery Steam Generator
IGCC - Integrated Gasification Combined Cycle
IRP - Integrated Resource Plan
ITC - Investment Tax Credit
kW - Kilowatt
kWh - Kilowatt-Hour
kWyr - Kilowatt-Year
LNG - Liquefied Natural Gas
MACRS - Modified Accelerated Cost Recovery System
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
NERC - North American Electric Reliability Council
NOX - Nitrogen Oxide
NPV – Net Present Value
NTUA - Navajo Tribal Utility Authority
OATT - Open Access Transmission Tariff
O&M - Operations and Maintenance
PM - Particulate matter
PNM – Public Service Company of New Mexico
PPA - Purchased Power Agreement
PTC - Production Tax Credit
REC - Renewable Energy Credit
REC - Renewable Energy Standard
RFP - Request for Proposal
ROW- Right of Way
RTP – Renewable Transmission Project
SJGS - San Juan Generating Station
SRP – Salt River Project
SRSG - Southwest Reserve Sharing Group
SO2 - Sulfur Dioxide
STG - Steam Turbine Generator
SWEEP - Southwest Energy Efficiency Project
TTC – Total Transfer Capacity
TOUA - Tohono O’odham Utility Authority
WECC - Western Electricity Coordinating Council

Glossary

GLOSSARY

Baseload Resource
A generating resource that runs continuously except for maintenance and forced outages. A baseload 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 (CC)
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.

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.

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 greenhouse gas 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 Direct Load Control.

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 baseload, 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 integrated resource plan. 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.

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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