El Paso Electric

300 Galisteo Street, Suite 206
Santa Fe, New Mexico 87501
(505) 982-7391

HAND-DELIVERED

January 3, 2019

Ms. Melanie Sandoval
New Mexico Public Regulation Commission
1120 Paseo de Peralta
Santa Fe, NM 87501

Re: NMPRC Case No. 18-00293-UT and Rule 17.7.3 NMAC
El Paso Electric Company's Amended 2018 Integrated Resource Plan

Dear Ms. Sandoval:

Pursuant to the Commission's *Order Partially Accepting Integrated Resource Plan; Order Requiring Refiling For Deficiencies* (Dec. 5, 2018) ("Order") and Rule 17.7.3 NMAC, enclosed for filing please find the original and fourteen (14) copies of El Paso Electric Company's ("EPE's") amended Integrated Resource Plan ("IRP") for the period 2018-2037 ("2018 IRP").

In accordance with the requirements of the Order, EPE's amended 2018 IRP corrects the deficiencies of its 2018 IRP initially filed on September 17, 2018 and replaces that filing. Portions of the amended 2018 IRP that differ from EPE's initially filed 2018 IRP, including required corresponding changes, are highlighted in yellow. Attachment 1 to this letter identifies the section and page number of each change.

EPE has posted an electronic copy of its amended 2018 IRP on EPE's website at www.epelectric.com/community/2017-18-public-advisory-group-meetings. EPE also has notified by e-mail all active participants in EPE's Public Advisory Group that the amended IRP is available on the website. Additionally, copies are being served electronically to the persons listed on the service list in NMPRC Case No. 18-00293-UT. Please conform and return two (2) copies to our messenger. Thank you for your assistance in this matter.

Very truly yours,

Nancy B. Burns
Senior Attorney
El Paso Electric Company

Enclosures
Service List

Summary and Location of Deficiencies

Deficiency	Description	Location	
Deficiency 1: With respect to 17.7.3.9(C)(11) NMAC, Staff is not able to locate any information that is responsive to this requirement in EPE's 2018 IRP.	*The utility's description of its existing resources used to serve its jurisdictional retail load at the time the IRP is filed shall include: (11) reserve margin and reserve reliability requirements (e.g. FERC, power pool, etc.) with which the utility must comply and the methodology used to calculate its reserve margin;*	Paragraph 2 added to subsection E of Section III DESCRIPTION OF EXISTING RESOURCES and Attachment I	IRP Report: Page 24 and 66
Deficiency 2: With respect to 17.7.3.9(D)(1)(a) NMAC, Staff is not able to locate any information that is responsive to this requirement in EPE's 2018 IRP;	*The utility shall provide a load forecast for each year of the planning period; the load forecast shall incorporate the following information and projections: (a) annual sales of energy and coincident peak demand on a system-wide basis, by customer class, and disaggregated among commission jurisdictional sales, FERC jurisdictional sales, and sales subject to the jurisdiction of other states;*	Paragraph B.1 added to Section IV CURRENT LOAD FORECAST	IRP Report: Page 35
Deficiency 3: With respect to 17.7.3.9(D)(1)(b) NMAC, Staff is not able to locate any information that is responsive to this requirement in EPE's 2018 IRP;	*The utility shall provide a load forecast for each year of the planning period; the load forecast shall incorporate the following information and projections: (b) annual coincident peak system losses and the allocation of such losses to the transmission and distribution components of the system*	Paragraph B.1 added to Section IV CURRENT LOAD FORECAST	IRP Report: Page 35
Deficiency 4: With respect to 17.7.3.9(D)(1)(f) NMAC, Staff is not able to locate any information that is responsive to this requirement in EPE's 2018 IRP;	*The utility shall provide a load forecast for each year of the planning period; the load forecast shall incorporate the following information and projections: (f) typical historic day or week load patterns on a system-wide basis for each major customer class.*	Paragraph B.1 added to Section IV CURRENT LOAD FORECAST	IRP Report: Page 35
Deficiency 5: With respect to 17.7.3.9(E)(6) NMAC, Staff is not able to locate any information that is responsive to this requirement in EPE's 2018 IRP:	*The utility shall provide a load and resources table of its existing loads and resources at the time of its IRP filing. The load and resources table, to the extent practical. shall contain the appropriate components from the load forecast. Resources shall include: (6) other resources relied upon by the utility, such as pooling, wheeling, or coordination agreements effective at the time the plan is filed.*	Paragraph F.7 added to Section III DESCRIPTION OF EXISTING RESOURCES.	IRP Report: Page 31
Deficiency 6: With respect to 17.7.3.9(G)(2)(b) NMAC, Staff is not able to locate any information that is responsive to this requirement in EPE's 2018 IRP.	*Each electric utility shall provide a summary of how the following factors were considered in, or affected, the development of resource portfolios: (b) renewable energy portfolio requirements;*	Added to Paragraph B of Section IX. DETERMINATION OF THE MOST COST-EFFECTIVE RESOURCE PORTFOLIO AND ALTERNATIVE PORTFOLIOS IRP PLANNING OVERVIEW	IRP Report: Page 66
Deficiency 7: With respect to 17.7.3.9(H)(1)(a) NMAC, Staff is not able to locate any information that is responsive to this requirement in EPE's 2018 IRP;	*The utility shall initiate the process by providing notice at least 30 days prior to the first scheduled meeting to the commission, intervenors in its most recent general rate case, and participants in its most recent renewable energy, energy efficiency and IRP proceedings; the utility shall at the same time, also publish this notice in a newspaper of general circulation in every county which it serves and in the utility's billing inserts; this notice shall consist of (a) a brief description of the IRP process;*	Section B.1 added to Section X DESCRIPTION OF PUBLIC PROCESS	IRP Report: Page 81 to 82
Deficiency 8: With respect to 17.7.3.9(H)(1)(c) NMAC, Staff is not able to locate any information that is responsive to this requirement in EPE's 2018 IRP;	*The utility shall initiate the process by providing notice at least 30 days prior to the first scheduled meeting to the commission, intervenors in its most recent general rate case, and participants in its most recent renewable energy, energy efficiency and IRP proceedings; the utility shall at the same time, also publish this notice in a newspaper of general circulation in every county which it serves and in the utility's billing inserts; this notice shall consist of (c) a statement that interested individuals should notify the utility of their interest in participating in the process;*	Section B.1 added to Section X DESCRIPTION OF PUBLIC PROCESS	IRP Report: Page 81 to 82

Summary and Location of Deficiencies

Deficiency	Description	Location	
Deficiency 9: With respect to 9(H)(1)(d) NMAC, Staff is not able to locate any information that is responsive to this requirement in EPE's 2018 IRP;	*The utility shall initiate the process by providing notice at least 30 days prior to the first scheduled meeting to the commission, intervenors in its most recent general rate case, and participants in its most recent renewable energy, energy efficiency and IRP proceedings; the utility shall at the same time, also publish this notice in a newspaper of general circulation in every county which it serves and in the utility's billing inserts; this notice shall consist of* *(d) utility contact information.*	Section B.1 added to Section X DESCRIPTION OF PUBLIC PROCESS	IRP Report: Page 81 to 82
Deficiency 10: With respect to 17.7.3.9(H)(3) NMAC, Staff is not able to locate complete information with regards to who chaired, developed agendas, etc for all of the meetings.	*The utility or its designee shall chair the public participation process, schedule meetings, and develop agendas for these meetings. With adequate notice to the utility, participants shall be allowed to place items on the agenda of public participation process meetings;*	Section B.1 added to Section X DESCRIPTION OF PUBLIC PROCESS	IRP Report: Page 80
Deficiency 11: With respect to 17.7.3.9(I)(2) NMAC, Staff is not able to locate any statement to this effect in EPE's 2018 IRP.	*An action plan does not replace or supplant any requirements for applications for approval of resource additions set forth in New Mexico law or commission regulations.*	Paragraph B added to Section I EXECUTIVE SUMMARY	IRP Report: Page 4
Deficiency 12: With respect to EPE's decision to use a 25% capacity credit for new solar generation, Staff believes that EPE's explanations and support for this decision were not adequate and not easy to understand. EPE should be ordered to correct this in its IRP and support their case in such a manner that is more readily understood by a lay person.		Solar subsection renamed to Solar Capacity Credit Determination and content expanded in Section IX DETERMINATION OF THE MOST COST-EFFECTIVE RESOURCE PORTFOLIO AND ALTNERATIVE PORTFOLIOS	IRP Report: Page 58 to 61

El Paso Electric Company

Integrated Resource Plan
For the Period 2018-2037

El Paso Electric

Amended: January 4, 2019

SAFE HARBOR STATEMENT

This 2018 Integrated Resource Plan ("IRP" or alternatively, "Plan") includes statements that are forward-looking statements made pursuant to the safe harbor provisions of the Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended, including statements regarding load forecasts; statements regarding expected capital expenditures; statements regarding generation facilities' expected retirement dates; and statements regarding the expected remaining useful life of resources. This information may involve risks and uncertainties that could cause actual results to differ materially from such forward-looking statements. Additional information concerning factors that could cause actual results to differ materially from those expressed in forward-looking statements is contained in El Paso Electric Company's ("EPE" or the "Company") most recently filed periodic reports and in other filings made by EPE with the U.S. Securities and Exchange Commission (the "SEC"), and include, but is not limited to:

- Increased prices for fuel and purchased power and the possibility that regulators may not permit EPE to pass through all such increased costs to customers or to recover previously incurred fuel costs in rates
- Full and timely recovery of capital investments and operating costs through rates in Texas and New Mexico
- Uncertainties and instability in the general economy and the resulting impact on EPE's sales and profitability
- Changes in customers' demand for electricity as a result of energy efficiency initiatives and emerging competing services and technologies, including distributed generation
- Unanticipated increased costs associated with scheduled and unscheduled outages of generating plant
- Unanticipated maintenance, repair, or replacement costs for generation, transmission, or distribution facilities and the recovery of proceeds from insurance policies providing coverage for such costs
- The size of our construction program and our ability to complete construction on budget and on time
- Potential delays in our construction schedule due to legal challenges or other reasons
- Costs at Palo Verde Generating Station
- Deregulation and competition in the electric utility industry
- Possible increased costs of compliance with environmental or other laws, regulations and policies
- Uncertainties and instability in the financial markets and the resulting impact on EPE's ability to access the capital and credit markets
- Actions by credit rating agencies

- Possible physical or cyber-attacks, intrusions or other catastrophic events
- Other factors of which we are currently unaware or deem immaterial

EPE's filings are available from the SEC or may be obtained through EPE's website, http://www.epelectric.com. Any such forward-looking statement is qualified by reference to these risks and factors. EPE cautions that these risks and factors are not exclusive. Management cautions against putting undue reliance on forward-looking statements or projecting any future results based on such statements or present or prior earnings levels. Forward-looking statements speak only as of the date of this presentation, and EPE does not undertake to update any forward-looking statement contained herein. The Company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which such statement is made or to reflect the occurrence of unanticipated events, except to the extent the events or circumstances constitute material changes in this IRP that are required to be reported to the New Mexico Public Regulation Commission ("NMPRC" or "Commission") pursuant to its IRP Rule, 17.7.3.10 New Mexico Administrative Code ("NMAC").

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I. EXECUTIVE SUMMARY

EPE presents this Plan pursuant to the requirements of the Commission's IRP Rule, 17.7.3 NMAC ("IRP Rule") and in accordance with the Joint Stipulation in Case No. 15-00241-UT ("Stipulation Agreement") from EPE's 2015 IRP. This document discusses EPE's integrated resource planning process (the "Planning Process") and develops an integrated resource portfolio to safely, reliably and cost-effectively meet the energy needs of EPE's customers for the next twenty years. The IRP public advisory process (the "Public Process"), as set forth in the IRP Rule, was initiated with the first public advisory group (collectively the public advisory group, members of the public, and public participants in the IRP Process will be referred to herein is as either the "PAG" or "Participants") meeting on May 25, 2017, approximately sixteen months prior to the extended filing date of September 17, 2018. EPE is committed to and supportive of the PAG's efforts, which resulted in a total of 17 meetings, 14 pre-scheduled by EPE, and three additional meetings at the request of the PAG. The Participants were active in the Planning Process with questions and suggestions for consideration in the IRP. The Plan identifies the public input which has been incorporated into the IRP analysis within their respective topics.

EPE is located on the southeastern edge of the Western Electric Coordinating Council ("WECC") and is interconnected by three major transmission tie lines. EPE's current supply-side resource mix includes 633 Megawatts ("MW") from the Palo Verde Nuclear Generating Station ("PVNGS") outside Phoenix, Arizona, 1,446 MW of gas-fired local generation inside EPE's service territory, and 115 MW of solar generation, also located within EPE's service territory. EPE's IRP analysis included consideration for the planned retirement of six units within the 20-year planning horizon (the "Planning Horizon"), a total of 578 MW of summer net capacity planned for retirement. The IRP evaluates how to address these planned retirements safely, reliably, and most cost effectively along with EPE's forecasted load growth in order to develop an optimal portfolio. As defined in the Stipulation Agreement, any planned retirements within the first five years of the Planning Horizon[1] were to be analyzed within the capacity expansion model to determine if these units' retirement dates could be extended safely, reliably, and economically. The retirement extensions were not selected in the Planning Process base case.

The Public Process included, in part, a review of the forecasted energy needs, EPE's transmission system, reliability requirements, environmental impacts, rate considerations, and existing energy resources. In consideration of all resource options, EPE incorporated the requirements of New Mexico's Renewable Energy Act ("REA"), New Mexico Statutes Annotated 1978 ("NMSA") § 62-1-16 et seq. and Efficient Use of Energy Act NMSA 1978 § 62-1-17 et seq. ("EUEA") into the Planning Process. The renewable energy and energy efficiency resource options considered were above and beyond the REA and EUEA requirements. The identification of energy resource

[1] Per Final Order in Case No. 17-00317-UT, this will include Rio Grande Unit 6.

options included a mix of energy efficiency, demand-side management, renewable energy, battery storage, and traditional supply-side generating resources.

The Loads and Resources Table ("L&R") includes REA resources and future EUEA growth amounts. The L&R is shown in Table 26. The L&R format has been updated from EPE's previous 2015 IRP to more easily distinguish resource additions and separately identify battery storage.

The resulting resource portfolio additions include a mix of solar, battery storage, and conventional gas generation. The identified resource additions result in the optimal cost-effective resource portfolio. The battery storage and conventional gas generation resources compliment the solar resources, which are intermittent in nature. The table below lists the resource additions by year as selected by the Planning Process. Additionally, the planned solar resources will have adequate capacity to meet the 20 percent RPS requirement in 2023. It is noted that the actual resource additions in the future will be determined by results of competitive requests for proposals and may differ based on future changes to forecasted loads, economic conditions, technological advances, and environmental and regulatory standards.

Table 1 – Most Cost-Effective Portfolio

Year	Resource	Capacity	Contribution to Peak
2018			
2019			
2020			
2021			
2022	Solar PV	25	6.25
	Solar PV	75	18.75
	Solar PV	75	18.75
	Solar PV	75	18.75
	Solar PV	100	25
	Battery Storage	15	15
2023	Combined-Cycle	320	320
2024			
2025			
2026			
2027	Solar PV	100	25
	Combustion Turbine	100	100
	Reciprocating Engine	100	100
	Battery Storage	50	50
2028	Combustion Turbine	100	100
2029			
2030			
2031	Combined-Cycle	320	320
2032			
2033			
2034	Combustion Turbine	100	100
	Reciprocating Engine	100	100
2035	Battery Storage	50	50
2036	Solar PV & Battery	100	0
		30	30
2037	Biofuel	20	20

A. 2018 IRP Four-Year Action Plan

As required in the IRP Rule, EPE's four-year action plan includes the following:

- Finalize the 2017 RFP and EPE complete the regulatory process for the selected RFP winning proposals. These regulatory processes may include approval of Certificate(s) of Public Convenience and Necessity ("CCN(s)") or Long-Term Purchased Power Agreement(s) ("LTPPA(s)") dependent on selected resources.
- EPE will complete the regulatory approval process for the 2018 Annual Renewable Energy Plan filed May 1, 2018 and will file subsequent annual reports and plans in 2019, 2020, 2021, and 2022 pursuant to 17.9.572 NMAC and the REA.
- EPE will complete the regulatory approval process for the 2019-2021 Energy Efficiency and Load Management Plan filed July 1, 2018 and will file a subsequent 3-year plan pursuant to 17.7.2 NMAC and the EUEA.
- Evaluate Demand Response Pilot Program ("DRPP") results at the conclusion of the three-year pilot program or earlier if possible. Based on those results, EPE will determine appropriate course of action.
- EPE will issue RFP(s) in 2021 or 2022 to address the resource need identified in 2027. The exact date for the RFP will be determined based on a continued evaluation of future changes to forecasted loads, economic conditions, technological advances, and environmental and regulatory standards.
- Consider voluntary customer programs for renewable energy.

B. Regulatory Requirements

The IRP's Four-Year Action Plan does not supersede any other regulatory requirements set forth in applicable statutes, rules, or orders.

II. IRP PLANNING OVERVIEW

The Plan was developed pursuant to the requirements of the IRP Rule. The Planning Process took into consideration the following key objectives:

- identifying the most cost-effective portfolio of resources;

- considering various resource options, including supply-side and demand-side options, while taking into consideration environmental impacts, reliability, and risk; and

- conducting the Public Process to provide information to and receive and consider inputs from the public regarding the Planning Process.

The Planning Process can be described as the method to develop the most cost effective integrated resource portfolio in order to supply safe, reliable, and environmentally conscientious energy to meet the needs of EPE's customers for the next twenty years. The purpose of the IRP Rule is:

> *"…to identify the most cost-effective portfolio of resources to supply the energy needs of customers. For resources whose costs and service quality are equivalent, the utility should prefer resources that minimize environmental impacts."*

Section 10 of the EUEA calls for the periodic filing of an IRP with the Commission. The IRP Rule requires that the following information be included in an electric utility's IRP:

- a description of existing electric supply-side and demand-side resources,
- a current load forecast as described in this Rule,
- a load and resources table,
- the identification of resource options,
- a description of the resource and fuel diversity,
- the identification of critical facilities susceptible to supply-source or other failures,
- the determination of the most cost-effective resource portfolio and alternative portfolios,
- a description of the Public Process,
- an action plan, and
- other information that the utility finds may aid the Commission in reviewing the utility's planning processes.

Statutory energy efficiency goals and renewable energy standards are incorporated into the Planning Process. EPE evaluated renewable and energy efficiency resources above the REA and EUEA requirements through the Planning Process. For example, the EUEA establishes energy efficiency goals, and energy efficiency programs are approved by the Commission. EPE met its 2020 statutory Energy Efficiency goal several years ago, in 2016. In addition, the REA establishes a Renewable Portfolio Standard ("RPS") for EPE's New Mexico jurisdiction, requiring an amount of renewable resources based on a percentage of EPE's annual New Mexico retail energy sales, and contains additional diversity requirements. Utilities are not required to add additional REA resources when costs exceed a reasonable cost threshold ("RCT"). EPE's RPS portfolio is currently above the RCT, and EPE has requested and received approval for variances and waivers from further REA procurements through 2019. EPE is in compliance with the REA.

EPE committed a significant amount of time and resources to the Public Process. The Public Process allowed EPE to receive valuable feedback and insight into what different members of the community value in EPE's Planning Process. While the Public Process is required by the IRP Rule, EPE supports the integral role it plays in the IRP.

While the IRP requirement is a three-year cycle, an electric utility company continually evaluates its resource plan. The ongoing Planning Process can be summarized as:

- utilizing the latest load forecast that incorporates data for distributed generation and energy efficiency, and comparing that to the most current information for existing supply-side resources and their expected retirement dates to determine a baseline for future capacity needs,
- if a capacity need is identified, establishing possible demand-side and supply-side resources that may be utilized to serve load safely and reliably. This also requires the consideration of advancements in technology and resource options including the complexities of resource characteristics and costs. The incorporation of data from the prior IRP results, along with publicly available information, to form resource assumptions,
- analyzing resource options to ensure reliability, adequacy and appropriate integration into EPE's system. Select the most cost-effective portfolio of resources to meet EPE's peak load and operational system needs, safely and reliably,
- the incorporation of all applicable forecast data, existing resource information and expansion portfolio into the L&R, and
- annual updates with latest forecast and resource data.

EPE follows the process as summarized above during its annual and continuous resource planning course of business. However, during years where the Planning Process is occurring, there are several key additions:

- performance of sensitivity analyses of various factors, such as load forecast, fuel cost and carbon tax considerations at various rates, along with feasible supply side and demand side resource options as suggested by the PAG, and

- production of the four-year action plan.

A. Service Territory/Company Overview

EPE is a public utility engaged in the generation, transmission and distribution of electricity in an area of approximately 10,000 square miles in west Texas, and southern New Mexico (from Van Horn, Texas to Hatch, New Mexico). The Company serves approximately 417,900 residential, commercial, industrial, public authority and wholesale customers. The Company distributes electricity to retail customers principally in El Paso, Texas, and Las Cruces, New Mexico (representing approximately 64% and 11%, respectively, of the Company's retail revenues for the year ended December 31, 2017). In addition, the

Company's wholesale energy sales include those for resale to other electric utilities and to power marketers. Principal industrial, public authority and other large retail customers of the Company include United States military installations, such as Fort Bliss in Texas, as well as White Sands Missile Range ("White Sands") and Holloman Air Force Base ("HAFB"), both in New Mexico. EPE also serves an oil refinery, several medical centers, two large universities and a steel production facility. Figure 1 shows a geographical representation of EPE's total service territory.

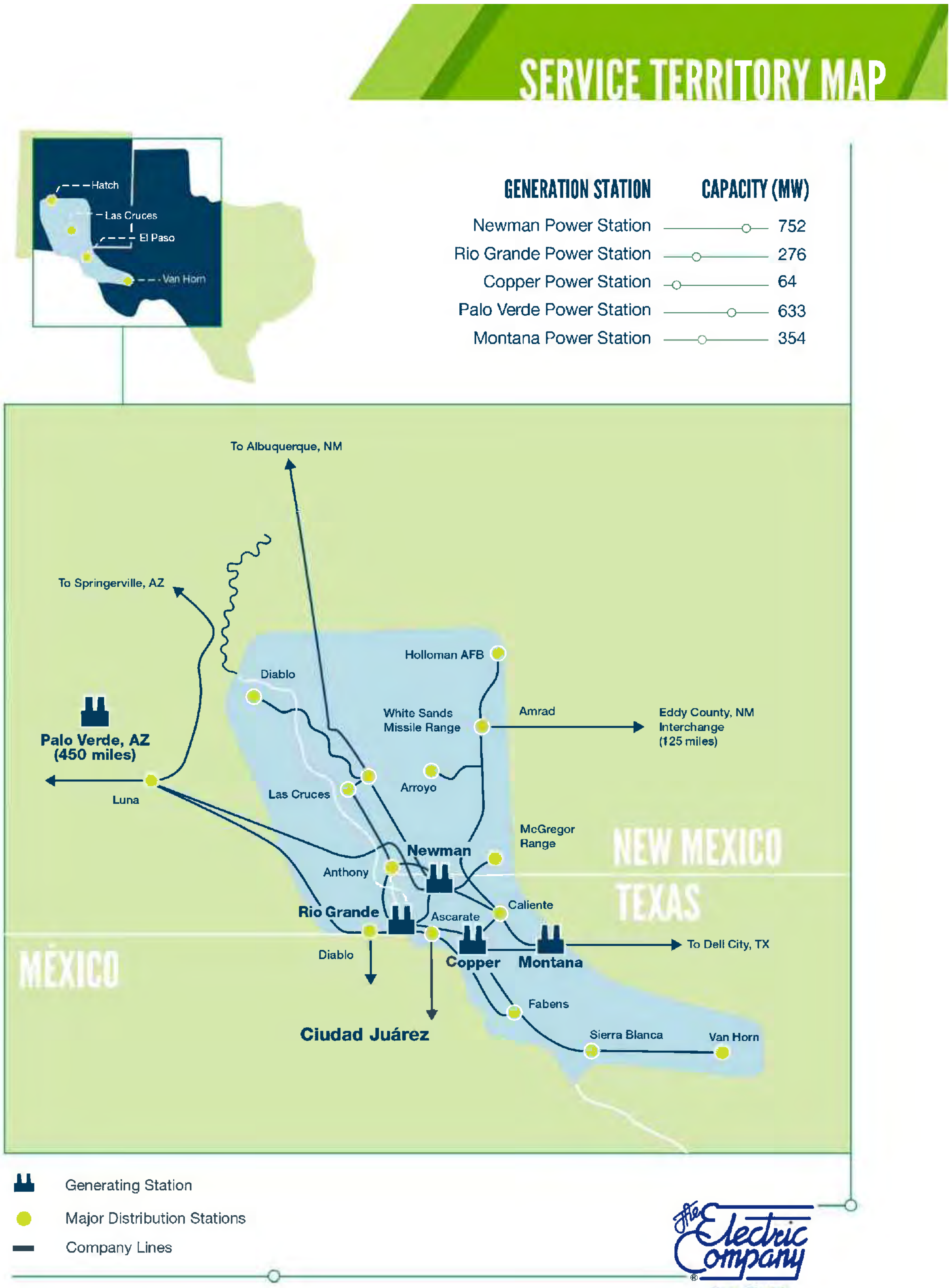

Figure 1 – EPE Service Territory

B. Summary of the 2015 IRP Action Plan and Status

EPE has completed all required items set forth in its 2015 IRP four-year action plan. In July 2016, EPE sold its interests in the Four Corners Power Plant ("FCPP"). EPE filed and received approval of its 2015, 2016, and 2017 RPS pursuant to 17.9.572 NMAC and the REA. EPE filed and obtained approval of its Energy Efficiency programs in 2016 pursuant to 17.7.2 NMAC and the EUEA. EPE received approval for its Demand Response Pilot Program ("DRPP"), which is in its first year of operation, and explained in more detail below. Finally, in 2017, EPE issued an all-source request for proposals ("RFP").

III. DESCRIPTION OF EXISTING RESOURCES

A. Supply Side Resources

EPE's existing supply side resources provide a foundation for integrated resource planning. EPE utilizes its current supply side resources to satisfy the bulk of its customers' electrical demands with power generated from Company owned generating stations fueled by solar, natural gas, and uranium. EPE also purchases renewable energy through various long-term Purchased Power Agreements ("PPAs"). In addition, EPE purchases varying amounts of firm and non-firm energy through the wholesale markets to meet the needs of its customers. These resources, in combination with future low-cost, efficient options will create a portfolio that, taking into consideration reliability and risk, result in the most cost-effective plan.

1. Generating facilities and expected retirement dates

EPE owns and operates a fleet of local and remote generating units. The Rio Grande Generating Station ("Rio Grande"), Newman Generating Station ("Newman"), Montana Power Station ("MPS"), and Copper Generating Station ("Copper") are all located in EPE's service territory, within or near the City of El Paso, Texas. These generating stations are considered EPE's local generation. In addition, EPE owns six small solar photovoltaic ("PV") systems located at (1) Rio Grande in Sunland Park, New Mexico, (2) Newman in northeast El Paso, (3) Wrangler Substation in east El Paso, (4) the El Paso Community College – Valle Verde Campus in El Paso's Lower Valley, (5) EPE's Van Horn customer service center, and (6) the rooftop of EPE's headquarters in downtown El Paso.

EPE recently expanded its renewable portfolio with the addition of two new solar resources. The Texas Community Solar program is a 3 MW Solar PV system located on approximately 21 acres near MPS. The Texas Community Solar program allows customers to voluntarily subscribe to utility scale single-axis tracking PV based on their current usage. This solar project became commercially operational May 31, 2017. On March 20, 2018, EPE filed with the Public Utility Commission of Texas ("PUCT") to expand the Texas Community Solar program by 2 MW, utilizing 2 MW of solar from the 10 MW Newman Solar Facility.

The Holloman Solar Facility is currently under construction. This project will provide an additional 5 MW of capacity to serve HAFB. The facility is an EPE-owned solar resource dedicated to serve HAFB and is expected to become commercially operational by the third quarter of 2018.

PVNGS, located near Phoenix, Arizona, is considered EPE's remote generation. EPE owns 15.8 percent of the PVNGS' Units 1, 2, and 3.

EPE's existing generating stations and fuel types are listed in Table 2 below, together with in-service and currently planned retirement dates. Table 2 includes Rio Grande Unit 6 as required in the Final Order of Case No. 17-00317-UT. As is evident from Table 2, the majority of EPE's generating facilities have been in service for a significant number of years. This is an important consideration for integrated resources planning because aging units being considered for retirement within the Planning Horizon will affect EPE's capacity needs. Additional output data required by the IRP Rule, such as capacity factor, fuel costs, heat rate, and total Operation and Maintenance ("O&M"), is provided hereto in Attachment C-2.

Table 2 – EPE Owned Existing Generation Stations and Fuel Types

Generating Station	Location	Nominal Capacity (MW)	Primary Fuel Type	Secondary Fuel Type	In-Service Date	Planned Retirement Date	Unit Age at Planned Retirement
PVNGS Unit 1 Unit 2 Unit 3	Phoenix, AZ	633	Uranium	N/A	February 1986 September 1986 January 1988	June 2045 April 2046 November 2047	59 60 59
Montana Unit 1 Unit 2 Unit 3 Unit 4	El Paso, TX	354	Natural Gas	Fuel Oil	March 2015 March 2015 May 2016 September 2016	December 2055 December 2055 December 2056 December 2056	40 40 40 40
Rio Grande Unit 6 Unit 7 Unit 8 Unit 9	Sunland Park, NM	321	Natural Gas	N/A	June 1957 June 1958 July 1972 May 2013	December 2018 December 2022 December 2033 December 2058	61 64 61 45
Newman Unit 1 Unit 2 Unit 3 Unit 4 Unit 5 – CTs Unit 5 – HRSG	El Paso, TX	752	Natural Gas	Fuel Oil Units 1-3	May 1960 June 1963 March 1966 June 1975 May 2009 April 2011	December 2022 December 2022 December 2026 December 2026 December 2050 December 2050	62 59 60 51 41 39
Copper Unit 1	El Paso, TX	64	Natural Gas	N/A	July 1980	December 2030	50
EPE Owned Solar Community Solar Holloman Solar Small Solar Systems	EPE Service Territory	3 5 <1	N/A	N/A	May 2017 Q3 2018 2009 – 2011	May 2047 Q3 2048 2029 – 2032	Various

2. Purchased Power Agreements

In addition to relying on its own generating facilities, EPE also relies on resources acquired from wholesale suppliers or other sources. The current long term PPAs that EPE has in place to serve its customers are listed in Table 3 below:

Table 3 – EPE Existing Renewable Generation Resources

Purchase Power Agreement	Location	Nominal Capacity (MW)	In-Service Date	Term
NRG Solar Roadrunner LLC ("NRG")	Santa Teresa, NM	20	August 2011	20 years
Southwest Environmental Center ("SWEC")	Las Cruces, NM	.006	April 2008	20 years
Hatch Solar Energy Center I, LLC ("Hatch")	Hatch, NM	5	July 2011	25 years
SunE EPE1, LLC ("SunEdison")	Chaparral, NM	10	June 2012	25 years
SunE EPE2, LLC ("SunEdison")	Las Cruces, NM	12	May 2012	25 years
Macho Springs Solar, LLC ("Macho Springs")	Luna County, NM	50	May 2014	20 years
Newman Solar LLC ("Newman")	El Paso, TX	10	December 2014	30 years

Additionally, interconnected to EPE's system is a biogas energy qualifying facility ("QF"), Camino Real Landfill Gas to Energy Facility (3.2 MW) located in Sunland Park, New Mexico (at the Camino Real Landfill). Further, EPE offers QF net metering and renewable energy certificate ("REC") programs for customer-owned solar PV and wind generation. The resulting customer-generated energy is used first to supply that customer's needs, then, if excess energy is produced, it is delivered to EPE's system. The RECs obtained through these resources, if located in New Mexico, are used to meet EPE's New Mexico RPS requirements.

In combination with existing EPE owned resources, these PPAs provide diverse capacity to serve load and give EPE and its customers a robust starting point when analyzing the most cost-effective integrated resource plan.

Additionally, EPE has utilized short-term market purchases in order to mitigate the need for new resource additions and to allow for economic resource selections. The firm energy purchase transactions are defined by the Western Systems Power Pool Agreement ("WSPP") Service Schedule C, the service schedule associated with firm energy. However, over the long term, EPE is responsible for securing resources to meet future load requirements. The designation of energy as firm under Schedule C states the interruption of a power transaction cannot be for economic purposes, and is allowable under a limited number of circumstances including the sellers need to reliably serve its native load customers. Each Balancing Authority is responsible for securing adequate resources to serve load.

B. Environmental Impacts of Existing Supply-Side Resources

EPE has a firm commitment to environmental stewardship and consistently evaluates potential impacts to environmental resources during resource planning processes. In general, the environmental considerations for siting renewable generation facilities, conventional generation facilities, and transmission and distribution facilities are similar, though the resources impacted vary greatly based on the type, location, geographic setting, and expanse of any given project. The degree of environmental regulatory guidance and review will also vary based on the location and other project specific parameters; but, in all cases environmental resources are considered.

EPE is subject to extensive laws, regulations and permit requirements with respect to air and greenhouse gas ("GHG") emissions, water discharges, soil and water quality, waste management and disposal, natural resources and other environmental matters by federal, state, regional, tribal, and local authorities.

1. Air Emissions

Emission rates for each of EPE's generation facilities required by 17.7.3.9(C)(13)(b) NMAC are listed in Table 4 below. The Clean Air Act ("CAA"), associated regulations and comparable state and local laws and regulations that relate to air emissions impose, among other obligations, limitations on pollutants generated during the operations of the Company's facilities and assets, including sulfur dioxide ("SO2"), particulate matter ("PM"), nitrogen oxides ("NOx") and mercury.

Table 4 – Environmental Impacts of Existing Supply Side Resources

2017 Data: Based on Rolling Average							
Unit	NOx[1] (lbs/kWh)	CO_2[3] (lbs/kWh)	CO[1] (lbs/kWh)	PM (lbs/kWh)	Hg (lbs/kWh)	SO2[2] (lbs/kWh)	Water Consumption[4, 5] (gal/kWh-site)
Montana 1	0.00012	1.05	0.00004	0.00006	*	0.00001	0.20
Montana 2	0.00012	1.05	0.00005	0.00006	*	0.00001	
Montana 3	0.00015	1.11	0.00003	0.00007	*	0.00001	
Montana 4	0.00011	1.04	0.00003	0.00006	*	0.00001	
Rio Grande 6	0.00218	1.50	0.00031	0.00002	*	0.00001	0.74
Rio Grande 7	0.00156	1.36	0.00003	0.00001	*	0.00001	
Rio Grande 8	0.00231	1.32	0.00012	0.00008	*	0.00001	
Rio Grande 9	0.00013	1.09	0.00005	0.00001	*	0.00001	
Newman 1	0.00216	1.41	0.00024	0.00001	*	0.00001	0.59
Newman 2	0.00197	1.39	0.00099	0.00001	*	0.00001	
Newman 3	0.00253	1.29	0.00000	0.00001	*	0.00001	
Newman 4**	0.00139	1.10	0.00021	0.00001	*	0.00001	
Newman 5***	0.00287	1.23	0.00006	0.00008	*	0.00001	
Copper 1	0.00486	2.05	0.00145	0.00011	*	0.000002	0.10
Palo Verde 1	0	0	0	0	0	0	0.73
Palo Verde 2	0	0	0	0	0	0	
Palo Verde 3	0	0	0	0	0	0	

*No oil burned in 2017; therefore, no Hg emissions were created.

** Newman GT-1 and GT-2

*** Newman SC and CC 6A and 6B

1. Rio Grande, Newman, & Copper NOx & CO emission data from continuous emissions monitoring system.
2. Rio Grande, Newman, & Copper SO_2 emission data calculated from natural gas fuel sulfur content.
3. Rio Grande & Newman CO_2 emission data calculated as per 40 CFR 75 Appendix G Equation G-4; Copper as per 40 CFR 98 Subpart C.
4. Rio Grande & Newman water consumption data calculated based on maximum cooling tower rate and 2017 unit capacity factor.
5. El Paso Electric's water consumption at Palo Verde is estimated as 15.8 percent (EPE's owbership) of water consumed by Units 1, 2, and 3.

Impacts to air quality are evaluated against CAA regulations to determine suitability of a proposed technology and feasibility of permitting. During the permitting phase of a project with potential emissions, ranging from the purchase of an emergency generator to installation of a new conventional generation unit, an emissions review is conducted. During this review, potential emission constituents and rates are evaluated to determine potential impacts and what, if any, emission thresholds are triggered. Technologies and pollution control methods are selected to meet or exceed the requirements set forth by State and Federal regulations, including the National Ambient Air Quality Standards ("NAAQS"). Most of EPE's air emissions result from the combustion of fossil fuels. Consequently, conventional generation projects undergo the most rigorous air quality assessments. However, air quality is considered in the full scope of projects including fugitive dust during construction and large area land clearing, as well as operations and maintenance traffic volume along transmission rights-of-way.

Under the CAA, the Environmental Protection Agency ("EPA") sets NAAQS for six criteria pollutants considered harmful to public health and the environment, including

PM, NO_x, carbon monoxide ("CO"), ozone and SO_2. NAAQS must be reviewed by the EPA at five-year intervals. On October 1, 2015, the EPA released a final rule tightening the primary and secondary NAAQS for ground-level ozone from its 2008 standard levels of 75 parts per billion (ppb) to 70 ppb. Ozone is the main component of smog. While not directly emitted into the air, it forms from precursors, including NO_x and volatile organic compounds, in combination with sunlight. The EPA may designate the areas in which we operate as nonattainment. Specifically, in December 2017, EPA proposed to designate southern Dona Ana County, New Mexico, as a nonattainment area. In June of 2018 the EPA provided public notice of this designation. States that contain any areas designated as nonattainment will be required to complete development of State Implementation Plans in the 2020-2021 timeframe.

Nonattainment areas are expected to have until 2020 or 2023 to meet the primary (health) standard, with the exact attainment dates varying based on the ozone level in the area. The Company continues to evaluate the impact these final and proposed NAAQS could have on operations.

2. Climate Change

There has been a wide-ranging policy debate, at the local, state, national, and international levels, regarding GHGs and possible means for their regulation. Efforts continue to be made in the international community toward the adoption of international treaties or protocols that would address global climate change issues. In April 2016, the United States signed the Paris Agreement, which requires countries to review and "represent a progression" in their intended nationally determined contributions, and sets GHG emission reduction goals every five years, beginning in 2020. In August 2017, the United States formally documented to the United Nations its intent to withdraw from the Paris Agreement. The earliest possible effective withdrawal date from the Paris Agreement is November 2020.

The federal government has either considered, proposed and/or finalized legislation or regulations limiting GHG emissions, including carbon dioxide ("CO_2"). In particular, the U.S. Congress has considered legislation to restrict or regulate GHG emissions. In October 2015, the EPA published a rule establishing guidelines for states to regulate CO_2 emissions from existing power plants, known as the Clean Power Plan ("CPP"). Legal challenges to the CPP are ongoing.

While it is not possible to predict the precise outcome of any pending, proposed or future GHG legislation by Congress, state or multi-state regions or any GHG regulations adopted by the EPA or state agencies, a significant portion of EPE's generation assets are nuclear or gas-fired. As a result, the Company's GHG emissions are low relative to electric power companies who rely more on coal-fired generation, and largely align with proposed GHG regulations.

Climate change also has potential physical effects relevant to the Company's business. In particular, climate change could affect the Company's service area by causing higher temperatures, less winter precipitation and less spring runoff, as well as by causing more extreme weather events. Such developments could change the demand for power in the region and could also impact the price or ready availability of water supplies or affect maintenance needs and the reliability of Company equipment.

3. Modeling Carbon and Emissions Cost.

As discussed, the details of future carbon regulations remain in flux; however, EPE anticipates that carbon regulations will ultimately become formalized at the state and/or federal level. The physical consequences of climate change as well as the regulatory approach to climate change ultimately selected and implemented by governmental authorities, or both, may impact EPE's operation. As such, EPE models the Commission's standardized cost (per ton) of CO_2 emissions, as well as a cost for criteria pollutants, within each resource portfolio. EPE's modeling includes emission rates specific to each conventional resource type and applicable costs as part of the portfolio analysis.

4. Water Resources

Rate of consumptive water use, required by 17.7.3.9(C)(13)(c) NMAC, is summarized for EPE's existing generation resources in Table 4, and is a primary consideration in comparing generation technologies and evaluating resource portfolios. Protection and preservation of water resources is primarily governed by the Clean Water Act. Assessment of potential impacts to water resources includes surface water, ground water, wetlands, and other waters of the United States. Water quality standards must be maintained throughout the life of a project from construction through operation. These standards generally are addressed through design factors to prevent storm water pollution and prevent site run-off and discharge. Protection of wetlands and surface waters, including potentially dry arroyos, is best addressed through site selection and any impacts to wetlands or waters of the U.S. are mitigated during appropriate permitting processes.

5. Biological resources

Biological resources include wildlife, avian, vegetation and habitat resources. Regulation of these resources is driven primarily by the Endangered Species and Migratory Bird Treaty Acts. Procedurally, consideration of these resources requires reconnaissance and detailed surveys of potential project areas to evaluate for the presence of native, rare, or critical habitat; or threatened, endangered or other special status species. Protection of biological resources is most challenging for expansive or large land area projects such as solar facilities, transmission corridors or access roads. EPE seeks to minimize impacts to these resources through careful site selection and avoidance as well as through operational techniques such as timing of vegetation clearing when seasonally appropriate to minimize impacts to nesting birds or conducting salvage removal of cacti species or nest relocations when avoidance is not possible.

6. Cultural resources

Cultural resources are abundant and dense within EPE's service territory. Evaluation of potential impacts to cultural resources follows the process outlined by Section 106 of the National Historic Preservation Act and includes a determination of whether or not cultural resources exist within a project's area of potential effect and whether or not those resources would be adversely affected. These determinations are made in consultation with the State Historic Preservation Office and any appropriate pueblos and tribes, generally upon completion of intensive surveys and records reviews. Where cultural resources cannot be avoided, mitigation plans are developed prior to any construction. As with biological resources, managing the effects to cultural resources is best achieved through careful site selection and avoidance. However, on expansive projects complete avoidance is not always feasible and mitigation, including site specific data recovery, is completed.

Although no less important, the following resources are also protected or otherwise regulated and considered, though are not as frequently applicable to projects. These include: environmental justice, protection of specially designated areas, visual resources, paleontological resources, caves and karst, floodplains, watershed, hazardous and solid wastes, and soils.

EPE evaluates potential impacts to a broad spectrum of environmental resources. The resources and degree of impacts do vary from project to project, but the due consideration of that impact is a consistent factor in EPE's resource planning process.

C. Demand Side Resources

As referenced in Section V of this Plan, demand side resources are included in Section 4.0 of the L&R and are a reduction to the overall forecasted native system demand.

EPE's existing demand side resources are categorized into three primary types as follows:

1. DRPP (New Mexico and Texas)
2. New Mexico Energy Efficiency Programs
3. Texas Energy Efficiency Programs

EPE incorporates demand side resources into its planning process for its New Mexico and Texas jurisdictions. EPE has several programs that promote energy and demand savings for customers. The programs differ by state jurisdiction and are dependent on the goals established by state regulations.

Brief descriptions of the DRPP, the New Mexico Energy Efficiency ("EE") programs and Texas EE portfolio are included below. EPE will continue to consider demand side resource options as part of its IRP as described in Section VI.

1. DRPP

The Commission's Final Order in Case No 17-00016-UT approved EPE's DRPP. Pursuant to that order, EPE implemented its Rate No. 37 - eSmart Thermostat Program. EPE's DRPP (otherwise known as the "eSmart Thermostat Program") engages utility customers to reduce their electricity use (load) during peak hours or under certain conditions using "smart thermostat" technology. Peak electricity demand typically occurs on hot summer days when households turn on their air conditioning ("A/C"). The primary goal of the DRPP is customer reduction of A/C usage on hot summer days, which in turn, can substantially reduce demand for electricity during EPE's peak hours, providing aggregate benefits for the electric grid and households themselves.

This pilot program was limited to 3,000 devices. This cap was reached on November 17, 2017, and the program was closed for new enrollments. Eighty-one percent (81%) of accepted customers were from Texas and nineteen percent (19%) were from New Mexico.

The demand response season begins on June 1 and continues through September 30 each year. During the 2017 season, EPE executed 12 demand response events. Each event lasted a maximum four hours in duration and was executed between 2:00 PM at 8:00 PM Mountain Daylight Time on non-holiday weekdays. EPE tested several load control strategies to determine the DRPP's effectiveness under various conditions. Some of the strategies included temperature offsets of 2 to 4 degrees, different event durations, and pre-cool.

2. New Mexico Energy Efficiency Programs

In New Mexico, the EUEA and the Energy Efficiency Rule, 17.7.2 NMAC ("EE Rule") requires utilities to include cost effective EE and load management programs in their resource portfolios. The EUEA requires EPE to attain a minimum cumulative energy savings goal of eight percent of its 2005 New Mexico jurisdictional retail sales from 2008 through 2020, 105,304,953 kWh. EPE began its CFL Lighting Program and its LivingWise® educational program in late 2008. EPE formally implemented the remainder of its initial New Mexico programs in January 2009. In utilizing Commission-approved portfolios of demand side resources, EPE achieved a cumulative savings of 118,301,310 kWh from 2008 through 2017, which is 112.34% of EPE's 2020 New Mexico statutory goal.

In Case No. 16-00185-UT, EPE received Commission approval to offer its current portfolio of EE and load management programs for its New Mexico retail customers for the 2017 plan year. Pursuant to the EE Rule, EPE continues to offer these programs.

EPE currently offers five residential programs and two commercial programs that have been approved by the Commission. Below is a brief description of EPE's current New Mexico EE programs:

- The Residential Comprehensive Program offers rebates for the installation of ceiling and floor insulation, duct sealing, air infiltration, evaporative coolers, refrigerated A/C units, solar screens and pool pumps.
- The New Mexico EnergySaver (Low Income) Program provides income-qualified customers a variety of EE measures for their homes at no cost. Qualification is based on an annual household income at or below 200% of the federal poverty guidelines.
- The LivingWise® Program is an educational program for students. Participating teachers are provided with educational materials that are presented in the classroom.
- The CFL & LED Program offers discounts at participating retail locations for customers to replace their existing light bulbs with more energy efficient light bulbs.

- The ENERGY STAR® New Homes Program provides incentives for homebuilders to construct energy efficient homes that exceed the current building code.
- The Small Commercial Comprehensive Program provides small commercial customers incentives for lighting, lighting controls, HVAC upgrades, HVAC controls, HVAC tune-ups, cool roofs, vending miser controls, and solar screen/film window treatments.
- The SCORE Plus Program provides incentives to large commercial customers, as well as schools, city and county customers for EE measures including lighting, lighting controls, HVAC upgrades, HVAC controls and custom projects.

Table 5 below provides EPE's New Mexico EE Portfolio of Programs and their Average Estimated Useful Life ("EUL").

Table 5 – Current Portfolio of New Mexico EE Programs and Program EUL

Program	**Estimated Useful Life[1]**
Residential Programs	
LivingWise®	9
Residential Comprehensive	15
CFL & LED	12
ENERGY STAR® New Homes	21
EnergySaver (Low Income)	16
Commercial Programs	
SCORE Plus	14
Small Commercial Comprehensive	14

1. EUL values as identified by the statewide Measurement and Verification Evaluator for program year 2017.

Table 6 provides the actual verified savings for EPE's New Mexico EE programs for 2015 to 2017 and provides anticipated savings for 2018 to 2021. The 2018 projected savings are based on EPE's 2017 Plan approved by Final Order in NMPRC Case No. 16-00185-UT. The 2019 to 2021 projected savings are as originally filed in NMPRC Case No. 18-00116-UT. The gross MW and Megawatt-hour ("MWh") projections do not include a peak demand coincidence factor adjustment that is used for load forecasting purposes reflected in the L&R.

Table 6 – New Mexico Verified and Projected Participation, Impacts and Budget Portfolio

Year	Annual Participants[1]	Annual MW Demand Savings (at Meter)	Annual MWh Energy Savings (at Meter)	Annual Rebate/ Incentive Costs	Annual Admin Costs[2]	Total Annual Program Costs
2015♦	42,654	3.681	15,729	$3,250,299	$1,455,948	$4,706,247
2016♦	44,279	5.897	18,213	$3,827,090	$1,670,719	$5,497,809
2017♦	38,828	2.501	12,729	$2,942,309	$1,508,575	$4,450,884
2018	67,335	3.441	13,247	$3,185,274	$2,005,993	$5,191,267
2019	49,443	8.732	16,921	$3,712,277	$2,010,949	$5,723,226
2020	48,860	8.050	14,770	$3,226,728	$1,886,918	$5,113,646
2021	48,852	7.959	14,405	$3,180,466	$1,933,180	$5,113,646

1. CFL & LED Program assumes 5 bulbs per participant
2. Includes Third Party Costs, Promotion Costs, Program Development Costs, and EM&V Costs

♦ Verified by Commission approved statewide EM&V contractor

3. Texas Energy Efficiency Programs

EPE has offered EE programs in its Texas service territory since 1999. EPE's Texas jurisdictional programs require a minimum annual demand reduction, as well as an associated minimum energy reduction based on a 20% capacity factor. In the Final Order of the PUCT Docket No. 47125, EPE's annual demand reduction goal for 2017 was 11.16 MW and its energy savings goal was 19,552 MWh. EPE achieved a demand reduction of 15.285 MW, which exceeded the demand goal by 36.96%, and an energy reduction of 23,312 MWh, which exceeded the energy goal by 19.23%. Currently, EPE offers six residential and five commercial programs in its Texas service territory.

Table 7 provides the actual verified demand and energy savings for EPE's Texas EE programs for 2015 through 2017 and provides the projections for 2018 and 2019. The 2018 and 2019 projections are based on the information provided in EPE's 2018 Energy Efficiency Plan and Report, PUCT Project No. 48146.

Table 7 – Texas Verified and Projected Demand and Energy Savings

Year	Annual MW Demand Savings (at Meter)	Annual MWh Energy Savings (at Meter)
2015♦	12.305	22,283
2016♦	12.790	22,912
2017♦	15.285	23,312
2018	14.181	21,054
2019	14.181	21,054

♦ Verified by Commission approved statewide EM&V contractor

D. Storage Resources

Currently, EPE's resource portfolio does not contain any storage resources. Battery storage is a new and emerging technology that is beginning to gain entry into utility scale applications. Battery storage is a resource that EPE is considering and will continue to consider for future capacity expansion.

E. Reserve Margin and Reliability Requirements

1. Reliability Requirements

EPE's resource planning efforts also take into consideration the reliability requirements defined by the North American Electric Reliability Corporation ("NERC"), which is granted authority by the Federal Energy Regulation Commission ("FERC") to define reliability standards. The reliability standards are developed to reduce risks to the reliability and security of the grid.[2] There are six reliability standards that are most relevant to the Planning Process.

BAL-001 – "To control Interconnection frequency within defined limits."

BAL-005-0.2b – "…ensures that all facilities and load electrically synchronized to the Interconnection are included within the metered boundary of a Balancing Area so that balancing of resources and demand can be achieved."

[2] NERC. https://www.nerc.com/AboutNERC/Pages/default.aspx

BAL-006-2 – "…process for monitoring Balancing Authorities to ensure that, over the long term, Balancing Authority Areas do not excessively depend on other Balancing Authority Areas in the Interconnection for meeting their demand or Interchange obligations."

BAL-002 - "…to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within the defined limits following a Reportable Disturbance."

BAL-002-WECC - "To specify the quantity and types of Contingency Reserve required to ensure reliability under normal and abnormal conditions."

BAL-003 - "To require sufficient Frequency Response from the Balancing Authority to maintain Interconnection Frequency within predefined bounds by arresting frequency deviations and supporting frequency until the frequency is restored…"

TOP-001-3 - "To prevent instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Interconnection by ensuring prompt action to prevent or mitigate such occurrences."

EPE efforts to ensure resource adequacy to serve peak load in a safe and reliable manner are founded, in part, with the above-mentioned reliability standards. Furthermore, 17.9.560.13 NMAC also addresses an electric utility's requirement to provide reliable service.

> *"The electric plant of the utility shall be constructed, installed, maintained, and operated in accordance with accepted good engineering practice in the electric industry to assure, as far as reasonably possible, continuity of service, uniformity in the quality of service furnished, and the safety of persons and property."*

Additionally, it stresses the importance of resource adequacy to include a reserve margin.

> *"Adequacy of supply. The generating capacity of the utility's plant supplemented by the electric power regularly available from other sources must be sufficiently large so as to meet all normal demands for service and provide a reasonable reserve for emergencies."*

2. Reserve Margin Requirements

Electric utilities work to maintain service at all times to their firm customers. As a result, each system must maintain an adequate supply of generation that not only will meet the maximum forecasted demand of its customers (i.e., the "peak" demand) but also provide for unforeseen events (e.g., transmission line outages, power plant outages, exceedance of peak load forecast, etc.). To accomplish these objectives, utilities acquire and operate more generation capacity than is needed to meet peak demand. The additional generation, above what is needed to meet peak customer demand, is called the reserve margin. Generally, there are two basic types of reserve margins: (i) planning reserve margins, which are the amount of installed capacity required in excess of forecasted annual peak firm demand, and (ii) operating reserve margins, which are the amount of actual generation capacity required in real-time, either with units carrying regulation and/or spinning reserves; or units offline but in reserve and capable of providing additional generation in order to meet real-time changes in load/demand and any unforeseen contingencies (e.g., transmission outage, generator forced outage, gas supply disruptions, etc.).

From a long-term planning standpoint, EPE previously established a reserve margin of 15% which was re-affirmed in 2015 by a third-party firm, E3 (see Attachment I-1).

F. Existing Transmission Capabilities

EPE owns and operates extensive transmission resources to serve customer load from its local and remote generation, and from other interconnected resources throughout the WECC. EPE's high voltage ("HV") transmission system consists of 69 kiloVolt ("kV") and 115 kV lines, and its extra high voltage ("EHV") transmission system consists of 345 kV, and 500 kV lines. These facilities are located in the following locations: within the EPE service territory, interconnected from its service territory to the western grid, or located near EPE's remote PVNGS generation. EPE's 345 kV system is the integral part of the transmission system used to import and export power to and from EPE's service area. EPE's transmission system is comprised of three key components:

- Local transmission - Several 345 kV, 115 kV, and 69 kV transmission lines that are interconnected within EPE's local electrical grid.
- Path 47 - Three major 345 kV transmission lines known as Path 47 used to import/export power between WECC and EPE (plus one 115 kV line wholly owned and utilized by Tri-State); and,
- Eddy County DC Tie - A single 345 kV transmission line that interconnects EPE's local transmission system to SPS, an Xcel Energy Company, system through a 200 MW High

Voltage Direct Current ("HVDC") terminal.

More details on EPE's transmission system are explained in the following sections.

Local Transmission

EPE's local EHV and HV transmission system consists of 345 kV, 115 kV and 69 kV lines in and around El Paso, Texas, and Las Cruces, New Mexico. EPE's local EHV transmission system consists of several 345 kV transmission lines that move the power from EPE's Path 47 import path and the Eddy County HVDC Terminal (see below) and distributes that power for delivery to various points on EPE's local HV system. Most of EPE's major distribution substations are connected to at least two 115 kV and/or 69 kV transmission lines. This high level of networking increases the reliability of the system by allowing the power to re-route to other transmission lines during outages.

EPE's local generation is directly connected to the local HV transmission system at Newman in northeast El Paso; Rio Grande in Sunland Park, New Mexico; MPS in far east El Paso; and Copper in central El Paso. The power generated at these plants flows directly into the EPE HV transmission system and then flows to the customer loads through the distribution system.

Path 47

Path 47 consists of EPE's three major 345 kV transmission interconnections with other utilities that are located at: (1) West Mesa Switching Station near Albuquerque, New Mexico with Public Service Company of New Mexico ("PNM"); (2) Springerville Generating Station ("Springerville"); and, (3) Greenlee Substation ("Greenlee"), (both in Arizona) with Tucson Electric Power Company ("TEP"). Path 47 also includes the Belen to Bernardo 115 kV line owned and wholly used by Tri-State Generation and Transmission Association, Inc. ("Tri-State").

Eddy County DC Tie

EPE connects with SPS at the Eddy County HVDC Terminal near Artesia, New Mexico and has a 67% ownership in the Terminal and accompanying 345 kV transmission line connecting to the EPE system along with the joint owner, PNM. Through this HVDC Terminal, EPE can access resources, when available, in the SPP for delivery to EPE loads.

Along with the three components listed above, EPE has ownership of external EHV transmission, as described below.

EPE partially owns 500 kV transmission lines in the Arizona transmission system in connection with its PVNGS ownership and uses these lines for the delivery of its owned Palo Verde generation entitlement. These transmission lines are designated as the Palo Verde East Path (composed of three lines, two (2) Palo Verde to Westwing lines and the Palo Verde to Jojoba to Kyrene line) and are operated by Salt River Project ("SRP"). EPE utilizes a combination of an exchange and transmission agreement with TEP, transmission wheeling purchased from SRP and PNM. In addition, EPE has a PPA with Phelps Dodge Energy Services, LLP, to import additional resources that are purchased on the market and to allow EPE to import additional Palo Verde power during times Path 47 is curtailed. Once the power is delivered to EPE's Balancing Area, it is delivered to EPE's load area through use of jointly (EPE and PNM) and wholly-owned 345 kV lines in southern New Mexico and locally in the El Paso/Las Cruces area and then to EPE's local HV transmission system through EPE's existing 345/115 kV auto-transformers.

A map of EPE's EHV Transmission system is shown in Figure 2 below.

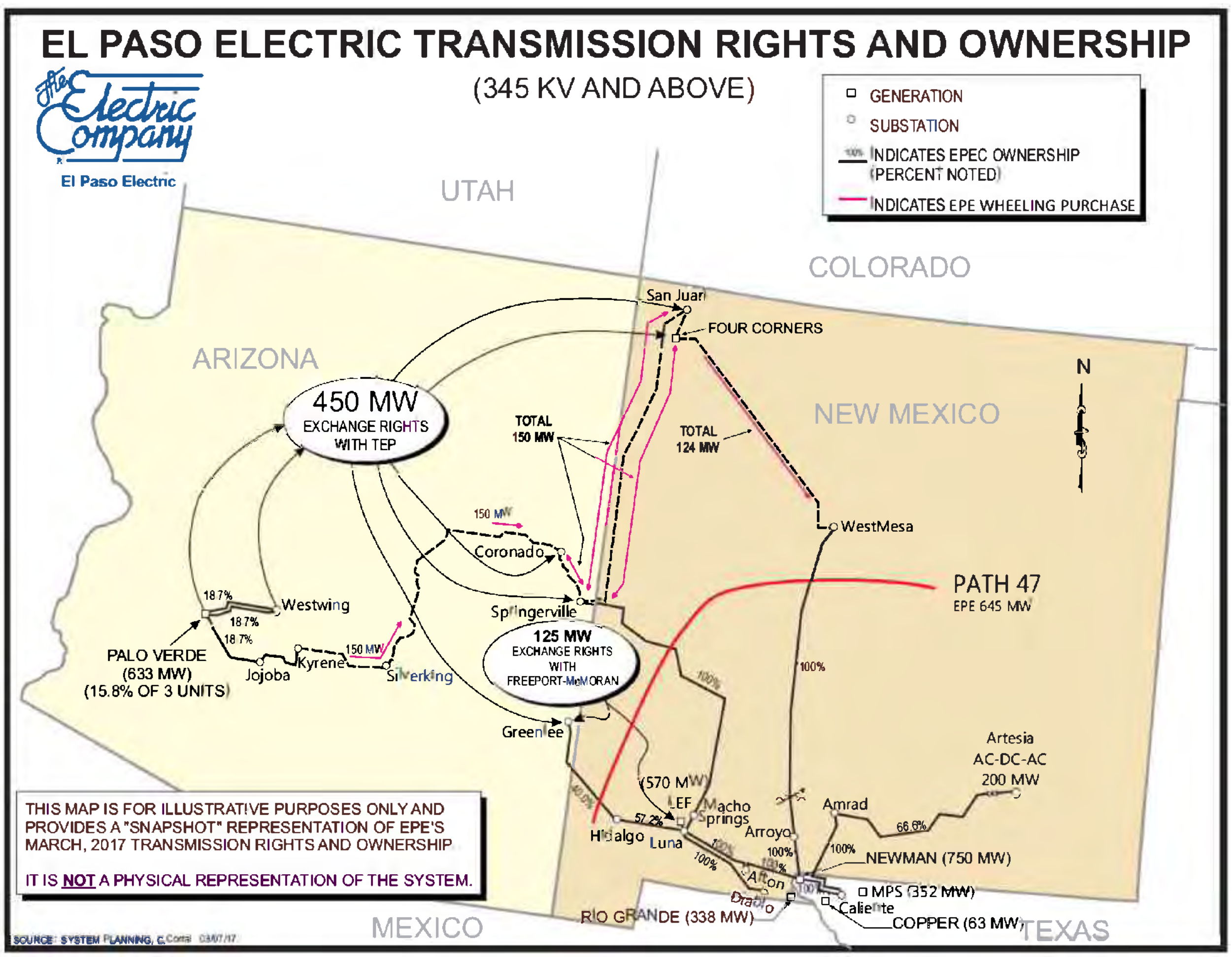

Figure 2 – EPE Transmission Rights and Ownership

Segments Which Comprise the EPE Extra High Voltage Transmission System

1. **Wheeling Agreements**

EPE purchases transmission to serve its native load from PNM and SRP. EPE has executed long-term, firm point-to-point transmission service agreements with PNM and SRP. EPE has also executed a Power Exchange and Transmission Agreement with TEP. These services are described below:

Transmission Services Purchased by EPE from PNM

EPE has a transmission service agreement under PNM's Open Access Transmission Tariff ("PNM OATT") for 104 MW firm, point-to-point transmission from FCPP 345 kV Switchyard to West Mesa 345 kV Switching Station from 07-01-2017 to 07-01-2022. In addition, EPE has rolled over its grandfathered, firm 20 MW long-term rights under Service Schedule I of the 1966 Interconnection Agreement between EPE and PNM into Firm, Point-to-Point Transmission Service under PNM OATT with a term of June 1, 2014 to June 1, 2019. Both transmission purchases have an option to rollover. The Transmission Service described above is utilized by EPE to serve its native load.

Transmission Services Purchased by EPE from SRP

EPE has a non-OATT, firm transmission service agreement for 150 MW from Kyrene 230 kV Switchyard to Coronado 500 kV Switchyard with SRP for the delivery of a portion of EPE's PVNGS entitlement or for the direct substitution of power and energy from any other source to serve EPE's native load. This Agreement remains in effect concurrent with the Arizona Nuclear Power Project Participation Agreement, unless earlier terminated by the parties.

Transmission Service Exchange Agreements between EPE and TEP

Under the Tucson-El Paso Power Exchange and Transmission Agreement, EPE has a non-OATT, executed power exchange and transmission agreement with TEP in which EPE delivers from its share of PVNGS generating units, and TEP receives, amounts of capacity with corresponding energy at the Palo Verde Switchyard or the Westwing Substation of 300 MW. EPE has an additional Exchange for up to 150 MW pursuant to a non-OATT agreement under the EPE-TEP Interconnection Agreement. EPE receives such capacity and energy at Greenlee, Springerville, Coronado, San Juan, or

FCPP in total amounts equal to that scheduled to TEP at the Palo Verde Switchyard or Westwing Substation.

Under the Tucson- El Paso Power Exchange and Transmission Agreement, TEP assigned to EPE 150 MW of transmission rights in TEP's 345 kV system between Springerville and either of FCPP, San Juan, or Coronado; this assignment of rights is bi-directional. The term of this Agreement is consistent with the life of PVNGS Units 1, 2, and 3.

2. Existing and Under Construction Transmission Facilities

EPE's transmission facilities include transmission lines (internal and external to EPE), substation transformers, autotransformers and a Phase Shifting Transformer at Arroyo Substation. EPE owns and operates 224 miles of 69 kV transmission lines, 513 miles of existing 115 kV transmission lines, and 946 miles of 345 kV transmission lines. In addition, EPE jointly owns 165 miles of 500 kV transmission lines in Arizona.

Attachment C-1 provides information on EPE's transmission facilities. This includes a list of EPE's existing and under construction transmission facilities, including associated switching stations and terminal facilities, and transfer capability limitations. Individual line limitations (ratings) on EPE's transmission network may affect future siting of supply-side resources.

EPE engages in various transmission projects in its local area to maintain, upgrade, and expand EPE's transmission system in order to ensure the reliability of the system and to provide for future load growth. EPE produces a 10-year Transmission Expansion Plan every year in accordance with Attachment K of EPE's Open Access Transmission Tariff ("EPE OATT"). A summary of this plan is posted on EPE's web site.

3. Location and Extent of Transfer Capability Limitations

EPE's primary interconnection is to the WECC. EPE's ability to import its remote generation resources is governed by the transmission capacity of its WECC interconnection, termed WECC Path 47 or the Southern New Mexico Transmission System ("SNMTS"). EPE is physically interconnected to the Southwest Power Pool ("SPP") through its HVDC tie. EPE has transmission ownership of 133 MW over the HVDC tie and ownership of 645 MW of firm capacity over Path 47.

The Total Transfer Capability ("TTC") of a transmission path is the maximum amount of power that can be transferred on that path, i.e., from one point on the system to another point on the system in a reliable manner while meeting all of a specific set of defined pre-and post-contingency system conditions. This capability is defined by the worst contingency for the defined point-to-point path and the thermal, voltage, and/or stability limits of that path. The Available Transfer Capacity ("ATC") is a measure of the transfer capability available on a transmission path for commercial activity over and above already committed uses and established capacity and reliability margins.

EPE makes ATC determinations on a real-time basis. ATC values are posted on the OATI OASIS website for the EPE transmission system with all transmission lines in-service. TTC, however, will change from time to time to reflect both scheduled and unscheduled, or forced, outages. The amount of curtailments for EPE's major transmission system outages are given on EPE's OASIS.

Brief descriptions of the Southern New Mexico Import Capability ("SNMIC") and the capacity of EPE's external line segments are provided below.

Additional transmission data pertaining to EPE's transmission facility capability and planning standards are posted on EPE's website at www.epelectric.com. These include "*Principles, Practices and Methods for the Determination of Available Transmission Capacity for El Paso Electric Company*" ("ATC Document") is found on EPE's website. The ATC Document explains EPE transmission facility capabilities and how EPE operates its New Mexico and Texas transmission system as a whole.

4. SNMIC Limitation Determination

Total and available transmission capabilities for the primary 345 kV path which connects the EPE Balancing Area ("BA") to neighboring BAs operated by PNM and TEP are based on the SNMIC. The individual lines into the EPE BA – the West Mesa 345 kV transfer path between EPE and PNM, and the Springerville 345 kV and Greenlee 345 kV transfer paths between EPE and TEP – are collectively referred to as WECC Path 47, or the SNMTS. This is a WECC Accepted Path with a rating that is less than the sum of the capabilities of the individual lines.

The SNMIC is determined through real-time dynamic nomogram equations that incorporate the state and configuration of the southern New Mexico system at any instant of time and by the use of dynamic adjustments, reflect changes in that system state. These dynamic adjustments reflect southern New Mexico system variables such as: the status and output of EPE's and other local generating units, power factor for the EPE load area, status of 345 kV reactors in the SNMTS, and the amount and direction of power flows over selected EPE transmission lines.

The maximum amount of firm import capability into the SNMTS over the 345 kV interconnections (plus the capacity of the Tri-State Belen-Bernardo 115 kV line) is 940 MW. The allocation of this firm capability among the owners of the SNMTS is:

EPE	645 MW
PNM	185 MW
Tri-State	110 MW

To the extent the SNMIC decreases below the maximum firm capacity value due to a change in the status of EPE-owned transmission variables (listed above), EPE is obligated to decrease its portion of SNMIC. Likewise, if the status of the EPE-owned transmission variables allow for a SNMIC greater than the maximum firm capacity of 940 MW, only EPE can use that additional capacity on a non-firm basis.

As the operating agent of the SNMTS, EPE is also responsible for notifying other owners if their imports exceed their rights and whether curtailment of imports is required.

5. External Transmission Limitation Determination

As mentioned above, EPE partially owns 500 kV transmission lines in the Arizona transmission system in connection with its PVNGS ownership and uses these lines for the delivery of its owned Palo Verde generation entitlement. Salt River Project performs the technical studies to evaluate the Palo Verde East rating, with agreement of the other Palo Verde East path owners, PNM, and Arizona Public Service Company ("APS"). EPE posts this path with the ratings determined through these studies on its OASIS. A full explanation on how TTC and ATC on these paths are determined can be found in the ATC Document.

6. Transmission Coordinating Groups

As a Class 1 member (transmission provider) of WECC, EPE's transmission planning activities are coordinated through several regional groups that include WECC committees under the Reliability Assessment Committee ("RAC"). These groups include the Anchor Data Set Task Force ("ADSTF"), the Data Subcommittee ("DS"), Modeling Subcommittee ("MS"), Joint Synchronized Information Subcommittee ("JSIS (RAC)"), Scenario Development Subcommittee ("SDS"), and the Studies Subcommittee ("StS"). In addition, EPE is a member of the General Electric Users Group, the regional group WestConnect and the sub-regional group Southwest Area Transmission ("SWAT") Planning Committee.

Through WestConnect, EPE and other WestConnect members participate in the regional transmission planning process detailed in FERC Order 1000 and in Attachment K of EPE's Transmission Tariff (OATT). The WestConnect footprint includes New Mexico, Arizona, Nevada, Colorado, and part of Wyoming, part of California, and part of Nebraska.

7. Other Resources Relied Upon: Pooling and Coordination Agreements: Reserve Sharing Group

In addition to the wheeling agreements described above in Section III.F.1, EPE is also a member of the Southwest Reserve Sharing Group, ("SRSG"). SRSG is a NERC registered entity that administers compliance with the BAL-002, EOP-001, and EOP-002 requirements. Members of the SRSG share operating contingency reserve requirements to mitigate the amount of contingency reserves individual members would need to carry if not part of the SRSG. EPE follows the SRSG Operating Procedures for calculating and reporting the Spin and Non-Spin hourly reserve values.

Conclusion and Discussion

As described above, EPE is physically located in the far southeastern corner of the WECC region and is constrained by transmission import limits. Firm import transmission capacity is limited to two specific paths: Path 47 and the Eddy County HVDC Tie. In other words, EPE is not in a position to wheel power through its service territory from multiple transmission paths, but is more of a terminal point in the WECC region. Import capacity outside of these paths is non-firm and cannot be considered in long-term resource planning because availability of non-firm transmission capacity is unknown. EPE considers these constraints when performing its long-term planning and when establishing an appropriate reserve margin. These considerations, in conjunction with risk of outages due to transmission maintenance or transmission system failure, require further review when evaluating the siting of future generation. Due to the transfer capability limits of Path 47 and the Eddy County DC Tie, future supply side resources may be more optimally be sited within EPE's service territory. Any resources sited outside EPE's service territory likely would require transmission investments to ensure firm transmission import capacity.

Energy Imbalance Market

As of recent years, there has been a lot of discussion associated with the California Independent System Operator ("CAISO") Energy Imbalance Market ("EIM"). The

CAISO EIM is a real-time market allowing participating entities the ability to leverage each other's online and available resources to regulate and address energy imbalances. The energy imbalances are primarily a result of the increasing variable generation (e.g. solar and wind) which has been added to the system. It is important to clarify that participation in the EIM does not provide additional resources for the purpose of meeting peak load. Each participant is required to have adequate resources to meet its peak load and regulating requirements. The EIM allows for co-utilization of each entities regulating reserves and potentially optimize dispatch/operating costs. It is not permitted for an entity to enter the EIM without adequate resource supply, as it may result in a burden to the EIM. As such, utilities are required to identify and secure adequate firm resources to meet peak load and reserve requirements before entry.

EPE continues to monitor and consider markets such as the EIM, while continuing with its Planning Process to plan for adequate resources to meet EPE's load requirements.

G. Back-Up Fuel Capabilities and Options

Table 2 identifies plants that are dual fuel capable. Further discussion on dual fuel capability is found in Section VII, "Description of the Resource and Fuel Diversity."

IV. CURRENT LOAD FORECAST

A. Forecast Summary

The 2018 Load Forecast predicts expected, upper, and lower bounds for energy and peak demand, for EPE's native and total systems. The forecast is generated for the 20-year period of 2018-2037 (see Attachment D-1). The 2018 expected (base) forecast predicts 10- and 20-year compound annual growth rates ("CAGR") of 1.2% and 1.3% for native system energy, respectively. The 2018 expected forecast predicts 10- and 20-year CAGR of 1.3% and 1.5%, respectively, for native system peak demand. EPE's native system consists of New Mexico and Texas jurisdictional retail load and the contractual Rio Grande Electric Co-Operative ("RGEC") wholesale load EPE serves interconnected to its Texas service territory. Native system load plus line losses incurred from off-system wheeling of EPE's power (losses-to-others) make up EPE's total system. The following information is provided as required by the IRP Rule, 17.7.3.9 (D).

B. Load Forecast Methodology and Inputs

EPE's 2018 Load Forecast is developed from a number of components. The forecast takes into consideration factors such as historical energy sales, average weather, demographic trends, economic activity, existing rate design, distributed solar generation, energy efficiency, saturation of refrigerated air conditioning, and potential changes in customers.

The largest component of the load forecast is the econometric modeling of retail energy sales. Econometrics is the application of mathematics and statistical methods to conduct economic analyses and developing forecast trends. EPE uses econometrics to provide an empirical estimate of the relationship between economic, weather, and demographic data, and electricity consumption. EPE's econometric forecasting models relate customer electricity usage to service area trends in population, weather, and local economic indicators to estimate future electricity sales. For example, population, personal income, and weather are typical drivers of electricity sales; more customers and increased income to purchase appliances will typically result in higher electricity demand. The primary data sources for EPE's econometric models are IHS Economics, NOAA (National Oceanic and Atmospheric Administration), AccuWeather, and EPE's customers' historical usage/load data. IHS Economics provides the underlying assumptions of the economic and demographic data that are used in developing EPE's forecasted energy and peak demand. NOAA and AccuWeather provide EPE with regional weather data used in weather normalizing historical sales and producing "normal" weather values for the forecast period. EPE also uses the historical usage/load data for each of its major customer classes.

The 2018 Load Forecast employs monthly and annual methodologies to develop its models for EPE's major customer classes. The monthly energy forecasts are based on econometric modeling of the residential, small commercial & industrial, and government load sectors in both Texas and New Mexico. The annual energy forecasts are based on econometric modeling of the large commercial & industrial sectors for both Texas and New Mexico for a total of eight separate econometric energy forecasts. Each of the eight models is estimated using Ordinary Least Squares as a function of weather, economic, and demographic variables.

The Residential class energy sales are estimated utilizing a use per customer ("UPC") methodology. The estimated UPC is then multiplied by the customer count forecast to arrive at a total kWh forecast for this customer class. The energy forecasts for small commercial & industrial, large commercial & industrial, and government classes are estimated using total kWh. The final models are selected based on various key measures such as R^2, t-statistics, the Durbin-Watson test, and the F-statistic.

The customer count forecast equations are also estimated for each of the customer classes using econometric models, except for the large commercial & industrial class. This class has a small number of customers, whose energy consumption and demand vary significantly among individual customers. The number of large commercial & industrial customers is set at current levels, unless it is known that specific customers are planning to enter or leave the service territory at a specific future date. For these reasons, EPE maintains a customer count for this class constant with 2017 year ending levels.

In instances where adequate data is not available to support econometric forecasts, EPE relies on sales estimates based upon recent experience, and information from large industrial customers to make adjustments that are based on known or expected changes in load. Examples of these adjustments in the 2018 Load Forecast include changes in load at military installations, distributed solar generation, and energy efficiency.

The econometric sales forecasts are adjusted to reflect energy efficiency and distributed solar generation effects not represented in the historical database. Energy efficiency effects include the results of EPE-sponsored energy efficiency programs that are required in its Texas and New Mexico jurisdictions. The distributed generation effects take into account customer owned solar generation in the residential, small commercial & industrial, and government customer classes. The estimates for energy efficiency energy savings and distributed generation energy impacts are accounted for in the annual retail sales energy forecasts in developing the expected native system energy value. In addition to these adjustments, the contractual RGEC load is also incorporated into the forecast; RGEC is a wholesale/native load customer.

EPE combines annual retail sales with sales to RGEC, company use, energy efficiency, and distributed generation and then calculates native system losses using a system line loss rate. These system losses must be included with sales at the meter to accurately calculate the total energy requirement needed to deliver electricity to EPE's customers. Additionally, line losses are incurred from off-system wheeling of EPE's power (losses-to-others). These losses are estimated based on historical trends of the system and are added to the native system energy to arrive at the total system energy value.

After the energy forecast is calculated, a constant native system load factor is applied to the native system energy to calculate the expected native system peak demand over time.

Mathematically, the load factor equation is:

$$LF = \text{Energy} / (\text{Demand} \times \text{Hours})$$

Solving for Demand, the equation becomes

$$\text{Demand} = \text{Energy} / (LF \times \text{Hours})$$

The constant load factor methodology utilizes the native system load factor from the previous year and applies it to the native system energy forecast to create the annual native system peak demand forecast. As is done with the expected native system energy, the expected native system peak demand is also adjusted for energy efficiency and distributed solar generation measures that impact system demand. The estimated peak demand for both interruptible customers and wheeling losses-to-others are then accounted for to obtain the total system peak demand.

1. Energy and Coincident Peak Demand by Major Customer Class

EPE has provided the load forecast for each year of the planning period. The projected annual sales of energy and coincident peak demand on a system-wide basis, by customer class, and disaggregated among commission jurisdictional sales, FERC jurisdictional sales, and sales subject to the jurisdiction of other states, are provided in Attachments B-2 and B-3, respectively. The projected annual coincident peak system losses and the allocation of such losses to the transmission and distribution components of the system are provided Attachment B-4. The typical historic day load patterns on a system-wide basis for each customer class are provided in Attachment B-5.

C. Weather Adjustment Detail

Weather is a major factor in determining EPE's energy sales and peak demand. The 2018 Load Forecast assumes that 10-year average weather conditions (2008-2017) exist throughout the forecast period (2018-2037). The 10-year average weather data is used as a baseline for comparing current weather data and creating "normal weather" conditions in the forecast period.

The two weather variables most significant to the energy models are Heating Degree Days ("HDD") and Cooling Degree Days ("CDD"). The HDD and CDD variables are based on a 65°F base. That is, if the average temperature for the day (maximum plus minimum, divided by two) is over 65°F, the difference is the number of CDD for that day. Likewise, if the average is less than 65°F, the difference is the number of HDD for that day.

Because CDD and HDD are recorded on a calendar month basis while booked month sales are recorded over 18 billing cycles that normally include portions of two calendar months, it was necessary to adjust these calendar month variables into variables that correspond to EPE's billing cycles. This adjustment was accomplished through the use of two month moving average CDD and HDD variables.

D. Demand-Side Savings Detail

EPE's energy and demand forecasts are adjusted to reflect EPE-sponsored Energy Efficiency programs that are required in EPE's Texas and New Mexico jurisdictions. EPE's Energy Efficiency department develops these savings by jurisdiction and customer class.

EPE does not directly adjust its forecast models for demand-side savings that are not attributable to actions by EPE. Demand-side management that is attributable to actions other than EPE, such as consumers who, without any EPE incentive, decide to transition to lower wattage light bulbs or energy efficient appliances, have savings that are unquantifiable. However, the historical sales data used in EPE's econometric forecasts does have embedded in it any organic or naturally occurring demand-side savings that may have occurred. Therefore, through the use of historical data, EPE's models and forecasted estimates of energy and demand do indirectly account for organic demand-side management.

E. Distributed Generation

EPE's forecast future customer count growth, sales, and generation capacity (nameplate and production at the time of system peak) for customers who own or lease distributed generation solar systems. These projections are made monthly for a 20-year period (2018-2037) by jurisdiction and by impacted customer classes. The econometric sales and demand forecasts are adjusted to reflect these forecasted distributed generation effects that are not represented in the historical database.

The distributed generation effects take into account customer owned or leased solar generation in the residential, small commercial & industrial, and government customer classes. Customer forecasts for the above-mentioned customer classes drive the final energy and demand estimates for distributed generation. The median nameplate capacity for distributed generation systems in the region along with their observed capacity factors are applied to these customer forecasts to arrive at the energy and demand forecasts. A coincidence factor of 47 percent is used to account for the expected production of distributed generation systems at the time of the system peak relative to the maximum total production capacity of these units. Furthermore, an annual degradation factor of 0.5 percent is used to account for the degradation in the output of solar panels over time. The estimates for distributed generation energy impacts are accounted for in the annual retail sales energy forecasts in developing the expected native system energy value.

The econometric sales and demand forecasts are adjusted to reflect future distributed generation effects not represented in the historical database.

F. Load Forecast Scenarios

In addition to the expected (base) estimates, the 2018 Load Forecast also estimates both upper and lower (high and low) scenarios. These upper and lower scenarios are produced for both native system energy and native system peak demand to account for future uncertainty. Upper and lower scenarios around energy and demand base forecasts can be estimated in various ways; such as by using statistical methods as well being driven by extreme weather scenarios. EPE calculates upper and lower scenarios using confidence intervals as well as a variety of extreme weather scenarios. Both the upper and lower scenarios shown in Attachment D-1 are built using a confidence interval with a 95% confidence level. EPE uses confidence intervals with a high confidence level as the preferred method for building upper and lower bands because it captures more uncertainty in future periods. The increased uncertainty helps capture possible future changes to electricity consumption in addition to that of weather, such as: changes in rate structures, economy, demography, and taste and preferences. Although EPE uses confidence intervals to produce the upper and lower-case forecasts in the 2018 Load Forecast, EPE also has provided below upper and lower-case forecasts using extreme historical weather for comparison purposes. These scenarios pull the most extreme historical weather months over a 10-year historical period, both on the high and low side, and combine them to form a calendar year of the most extreme monthly weather. This weather is then applied to future years to produce energy and peak demand estimate bands around the expected case. Figures 3 and 4 below contain a graphical representation of the low and high forecast scenarios of native system energy and native system peak demand.

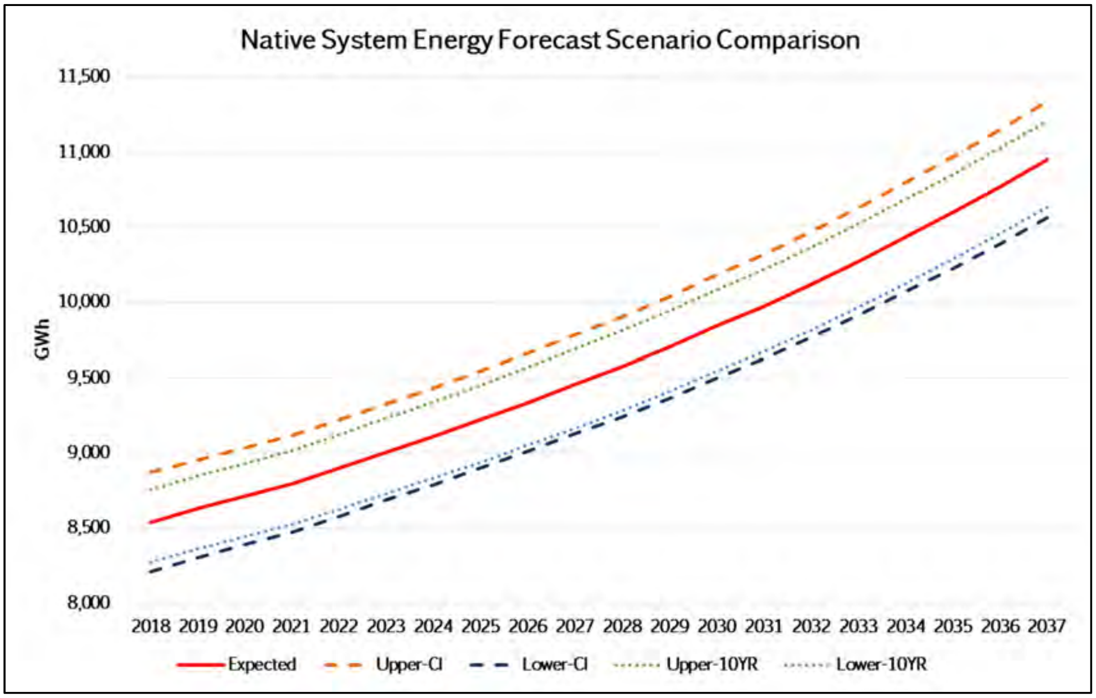

Figure 3 – Native System Energy Forecast Scenario Comparison

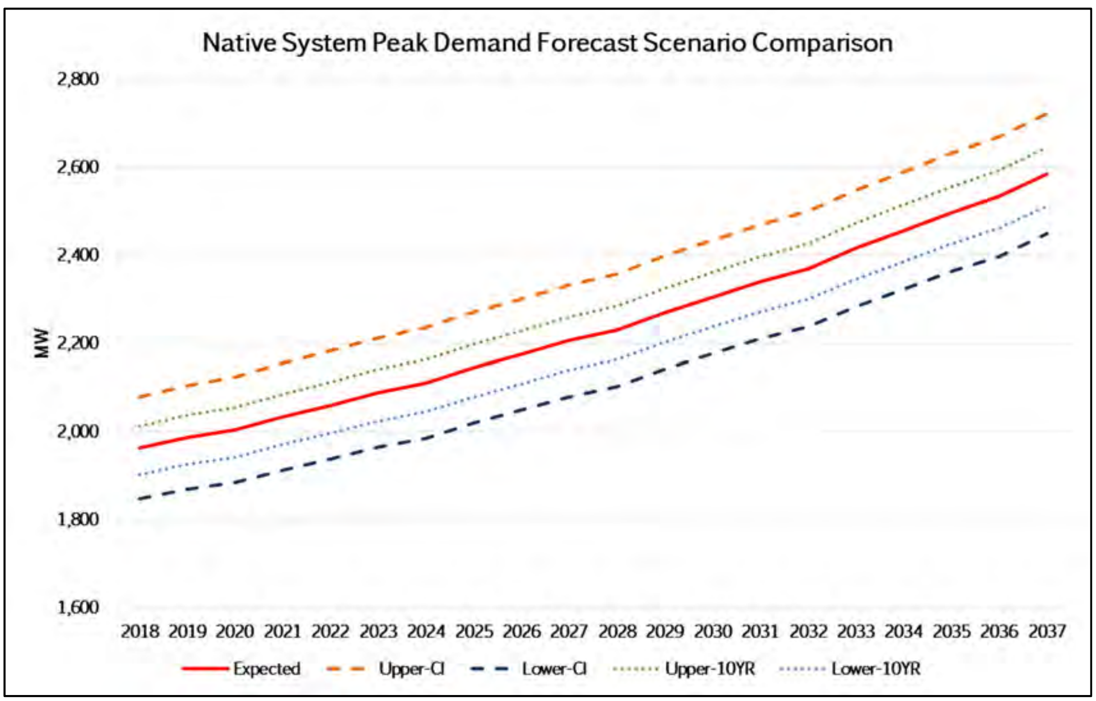

Figure 4 – Native System Peak Demand Forecast Scenario Comparison

From Figures 3 and 4 above, one can see that the extreme weather upper and lower bands (Upper-10 YR and Lower-10 YR) are narrower than that of the confidence interval bands (Upper-CI and Lower-CI). As mentioned previously, EPE constructed confidence intervals with a high confidence level to capture more uncertainty in future periods. The increased uncertainty helps capture possible future changes to electricity consumption in addition to extreme weather, such as: changes in rate structures, economy, demography and taste and preferences.

EPE's expected forecast predicts 10- and 20-year CAGR of 1.2% and 1.3% for native system energy, respectively. The expected forecast also predicts 10- and 20-year CAGR of 1.3% and 1.5%, respectively, for native system peak demand. The upper forecast scenario predicts 10- and 20-year CAGR of 1.5% and 1.5% for native system energy, respectively. The upper forecast also predicts 10- and 20-year CAGR of 1.9% and 1.7%, respectively, for native system peak demand. The lower forecast scenario predicts 10- and 20-year CAGR of 0.8% and 1.1% for native system energy, respectively. The lower forecast scenario predicts 10- and 20-year CAGR of 0.7% and 1.2%, respectively, for native system peak demand.

G. Historical Forecast Accuracy and Comparison

Tables 8 and 9 below contain the annual forecast of energy sales and system peak demand made by EPE to the actual energy sales and system peak demand experienced by EPE for the four years preceding 2018, (2014-2017). Please note that the energy data in Table 8 is total energy sales, which is composed of energy sales "at meter" for both retail and wholesale customers.

Table 8 - Total Sales (MWh) Historical Forecast Accuracy

Total Sales (MWH) Historical Forecast Accuracy				
	2014	**2015**	**2016**	**2017**
Actual	**7,687,369**	**7,867,229**	**7,874,577**	**7,820,929**
2014 Forecast	7,932,225	8,053,832	8,169,030	8,290,368
2015 Forecast		7,825,953	7,918,635	8,046,366
2016 Forecast			7,956,182	8,078,403
2017 Forecast				7,967,828
Percent Difference				
2014 Forecast	3.19%	2.37%	3.74%	6.00%
2015 Forecast		-0.52%	0.56%	2.88%
2016 Forecast			1.04%	3.29%
2017 Forecast				1.88%

Table 9 - Native System Demand (MW) Historical Forecast Accuracy

Native System Demand (MW) Historical Forecast Accuracy				
	2014	**2015**	**2016**	**2017**
Actual	**1,766**	**1,794**	**1,892**	**1,935**
2014 Forecast	1,784	1,812	1,834	1,867
2015 Forecast		1,804	1,822	1,857
2016 Forecast			1,811	1,846
2017 Forecast				1,927
Percent Difference				
2014 Forecast	1.02%	1.00%	-3.07%	-3.51%
2015 Forecast		0.55%	-3.72%	-4.01%
2016 Forecast			-4.29%	-4.60%
2017 Forecast				-0.43%

Table 10 below contains a comparison of the annual forecast of energy sales and system peak demand in EPE's most recently filed resource plan (2015) to the annual forecasts in the current resource plan (2018).

Table 10 - Annual Forecast Energy Sales Versus Peak Demand

Total Energy Sales Forecast Comparison (MWh)			Peak Demand Forecast Comparison (MW)		
	2015 Forecast	2018 Forecast		2015 Forecast	2018 Forecast
2015	7,825,953		2015	1,804	
2016	7,918,635		2016	1,822	
2017	8,046,366		2017	1,857	
2018	8,166,772	8,538,570	2018	1,887	1,964
2019	8,282,077	8,627,426	2019	1,914	1,988
2020	8,391,194	8,710,205	2020	1,935	2,005
2021	8,502,795	8,795,702	2021	1,968	2,034
2022	8,619,449	8,899,003	2022	1,996	2,061
2023	8,738,919	9,007,162	2023	2,025	2,090
2024	8,858,544	9,112,225	2024	2,048	2,111
2025	8,979,482	9,220,050	2025	2,083	2,146
2026	9,102,242	9,334,948	2026	2,113	2,176
2027	9,262,583	9,453,634	2027	2,144	2,206
2028	9,425,859	9,572,353	2028	2,169	2,231
2029	9,589,993	9,700,029	2029	2,206	2,270
2030	9,759,477	9,840,094	2030	2,239	2,306
2031	9,916,510	9,973,737	2031	2,269	2,340
2032	10,084,389	10,118,180	2032	2,295	2,370
2033	10,258,113	10,272,049	2033	2,335	2,416
2034	10,434,535	10,433,457	2034	2,370	2,456
2035		10,598,093	2035		2,498
2036		10,769,465	2036		2,533
2037		10,950,123	2037		2,586

V. LOAD AND RESOURCES TABLE

The L&R illustrates the balance of EPE's available resources versus the annual forecasted loads. EPE's long-term future resource needs are driven by unit retirement and also system load growth. Forecasted loads are based on the 2018 Load Forecast for the L&R

Table 11 - Initial L&R

Loads & Resources 2018-2037
Initial 2018 IRP

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
1.0 GENERATION RESOURCES																				
1.1 RIO GRANDE	321	276	276	276	276	230	230	230	230	230	230	230	230	230	230	230	88	88	88	88
1.2 NEWMAN	752	752	752	752	752	602	602	602	602	278	278	278	278	278	278	278	278	278	278	278
1.3 COPPER	64	64	64	64	64	64	64	64	64	64	64	64	64	-	-	-	-	-	-	-
1.4 MONTANA	354	354	354	354	354	354	354	354	354	354	354	354	354	354	354	354	354	354	354	354
1.5 PALO VERDE	633	633	633	633	633	633	633	633	633	633	633	633	633	633	633	633	633	633	633	633
1.6 RENEWABLES	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
1.7 STORAGE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1.8 POSSIBLE EMERGING TECH EXPANSION[1]	-	-	-	-	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
1.9 NEW BUILD (local)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1.0 TOTAL GENERATION RESOURCES [2]	**2,130**	**2,085**	**2,085**	**2,085**	**2,125**	**1,929**	**1,929**	**1,929**	**1,929**	**1,605**	**1,605**	**1,605**	**1,605**	**1,541**	**1,541**	**1,541**	**1,399**	**1,399**	**1,399**	**1,399**
2.0 RESOURCE PURCHASES																				
2.1 RENEWABLE PURCHASE (SunEdison & NRG)	29	29	29	29	28	28	28	28	27	27	27	27	27	26	26	26	26	26	25	25
2.2 RENEWABLE PURCHASE (Hatch)	4	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
2.3 RENEWABLE PURCHASE (Macho Springs)	35	35	34	34	34	34	34	34	33	33	33	33	33	33	32	32	32	32	32	32
2.4 RENEWABLE PURCHASE (Juwi)	7	7	7	7	7	7	7	7	7	7	7	7	7	7	6	6	6	6	6	6
2.5 RESOURCE PURCHASE	-	-	-	-	10	-		30	65	105	45	90	130	-	-	5	-	-	-	20
2.0 TOTAL RESOURCE PURCHASES [4]	**75**	**74**	**73**	**73**	**82**	**72**	**71**	**101**	**136**	**175**	**114**	**159**	**199**	**68**	**68**	**72**	**67**	**67**	**66**	**86**
3.0 TOTAL NET RESOURCES (1.0 + 2.0)	**2,205**	**2,159**	**2,158**	**2,158**	**2,207**	**2,001**	**2,000**	**2,030**	**2,065**	**1,780**	**1,719**	**1,764**	**1,804**	**1,609**	**1,609**	**1,613**	**1,466**	**1,466**	**1,465**	**1,485**
4.0 SYSTEM DEMAND																				
4.1 NATIVE SYSTEM DEMAND	**1,972**	**2,004**	**2,028**	**2,065**	**2,100**	**2,136**	**2,166**	**2,207**	**2,245**	**2,283**	**2,316**	**2,362**	**2,406**	**2,448**	**2,485**	**2,538**	**2,586**	**2,635**	**2,678**	**2,738**
4.2 DISTRIBUTED GENERATION	(3)	(6)	(9)	(12)	(15)	(18)	(21)	(24)	(27)	(30)	(33)	(36)	(39)	(42)	(45)	(48)	(50)	(53)	(56)	(59)
4.3 ENERGY EFFICIENCY	(5)	(9)	(14)	(19)	(23)	(28)	(33)	(38)	(42)	(47)	(52)	(56)	(61)	(66)	(70)	(75)	(80)	(84)	(89)	(94)
4.4 LINE LOSSES	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)
4.5 INTERRUPTIBLE SALES	(54)	(54)	(54)	(54)	(54)	(54)	(54)	(54)	(54)	(54)	(54)	(54)	(54)	(54)	(54)	(54)	(54)	(54)	(54)	(54)
5.0 TOTAL SYSTEM DEMAND (4.1-(4.2+4.3+4.4+4.	**1,904**	**1,928**	**1,945**	**1,973**	**2,001**	**2,028**	**2,050**	**2,084**	**2,114**	**2,145**	**2,169**	**2,209**	**2,244**	**2,279**	**2,308**	**2,354**	**2,395**	**2,436**	**2,472**	**2,524**
6.0 MARGIN OVER TOTAL DEMAND (3.0 - 5.0)	**301**	**231**	**213**	**184**	**207**	**(27)**	**(49)**	**(54)**	**(49)**	**(365)**	**(450)**	**(444)**	**(440)**	**(669)**	**(700)**	**(742)**	**(929)**	**(970)**	**(1,007)**	**(1,039)**
7.0 PLANNING RESERVE 15%	**286**	**289**	**292**	**296**	**300**	**304**	**307**	**313**	**317**	**322**	**325**	**331**	**337**	**342**	**346**	**353**	**359**	**365**	**371**	**379**
8.0 MARGIN OVER RESERVE (6.0 - 7.0)	**16**	**(58)**	**(78)**	**(112)**	**(94)**	**(332)**	**(357)**	**(367)**	**(367)**	**(686)**	**(775)**	**(775)**	**(777)**	**(1,011)**	**(1,046)**	**(1,095)**	**(1,288)**	**(1,336)**	**(1,378)**	**(1,418)**

1. Emerging technologies may include customer or other distributed resources as well as additional community solar.
2. Generation unit retirements denoted by most recent planned retirement dates at start of the IRP process.
   Retirements planned within 5 years will be analyzed in the capacity expansion model per Joint Stipulation Case No. 15 00241 UT.
3. Rio Grande 6 capacity is denoted in the 2018 plant capacity total, pending conclusion of 2018 IRP.
   Previously identified as retired in 2014 and utilized as inactive reserve. Per Commission order in docket 17-00317-UT Rio Grande 6 is included.
4. Purchases based on existing and estimated future purchases including renewable purchases to meet RPS requirements.
5. System Demand based on2018 Long-term and Budget Year Forecast.
   Includes state-required targets for Energy Efficiency.
   Interruptible load reflects current contracts.

Unit Retirements
Rio Grande 6 (45MW) - Denoted in 2018[3]
Rio Grande 7 (46MW) - December 2022
Newman 1 (74MW) - December 2022
Newman 2 (76MW) - December 2022
Newman 3 (97MW) - December 2026
Newman 4 CC (227MW) - December 2026
Copper (64MW) - December 2030
Rio Grande 8 (142MW) - December 2033

Renewable Purchases
SunEdison, NRG, Macho, Newman and Hatch solar purchases reflect 70% availability at Peak.

Company Owned Renewables
Renewable Resources shown in line item 1.6 consists of EPE Community Solar, Holloman Solar, EPCC, Stanton, Wrangler, Rio Grande & Newman Carports, and Van Horn

The Resource Purchase is supported by firm transmission through (i) simultaneous buy/sell with Freeport McMoRan (formerly Phelps Dodge), (ii) Four Corners switchyard after Four Corners retires, and (iii) SPS via the Eddy Tie.

Section 1.0 – Generation Resources

Lines 1.1 through 1.4 of the L&R reflect EPE's generation resource capacity for EPE's local natural gas units. Line 1.5 identifies the PVNGS unit data.

Line 1.6 illustrates EPE's small company owned solar facilities, including the recently added Texas Community Solar project and the planned HAFB Solar project. Line 1.7 has been added specifically for storage resources which may be added as a future resource. Line 1.8 has been added to denote capacity being designated for emerging technology resources which may include resources such as distributed generation, community solar, battery storage, or other emerging technologies or applications.

Line 1.9, titled New Build, is a placeholder for future expected capacity additions. These additions can be comprised of conventional and renewable resource additions. The results from this Planning Process will be included in this line item. However, new resource additions will be selected through a competitive bid or RFP process. Thus, the resource additions may be modified in the future based on the associated RFP processes and will result in adjustments to the L&R.

Section 2.0 – Resource Purchases

Purchases shown in lines 2.1 through 2.5 of the L&R are based on existing PPA contracts (NRG, Hatch, SunEdison, Macho Springs, and Newman), or estimates of potential purchases needed to cover projected capacity shortfalls to meet EPE's load and reserve requirement in any of the years studied in the L&R. The contribution to peak of the solar purchases are based on 70% of rated capacity based on the historical performance of EPE's existing solar facilities at the time of EPE's system peak. The capacity data for the solar units also reflects the long-term degradation estimated for each facility. The resource purchases shown on line 2.5 are estimated based on the short-term requirements in order to serve load during summer peaking conditions.

Section 3.0 – Total Net Resources

This line is the sum of Sections 1.0 and 2.0.

Section 4.0 – System Demand

System Load Data is based on the 2018 Load Forecast. In addition to expected native system demand, the forecast includes estimates for distributed generation, energy efficiency, and line losses. The 2018 Load Forecast incorporates state-required energy efficiency capacity targets mandated to reduce energy consumption. The 2018 Load Forecast also includes estimates of interruptible load based on current contracts.

Section 5.0 – Total System Demand

This line is the sum of the line items in Section 4.0.

Section 6.0 – Margin Over Total Demand

This line is the difference of between Section 3.0 and Section 5.0.

Section 7.0 – Planning Reserve

This line reflects EPE's 15% planning reserve margin requirement criterion based on Section 5.0.

Section 8.0 – Margin Over Reserve

This line is the difference between EPE's margin over total demand (Section 6.0) and its planning reserve requirement (Section 7.0).

VI. IDENTIFICATION OF RESOURCE OPTIONS (EXISTING CHARACTERISTICS AND INTERACTIONS)

A. Supply Side Resources

The Planning Process included a variety of resource options that are described within this section. However, there were three resource options excluded as part of EPE's IRP consideration. Given EPE's existing resource portfolio, additional baseload generation is not required. Therefore, new coal or nuclear options were not considered. Additionally, given EPE's geographical location, hydro resources were also not considered.

EPE utilized Lazard's 2017 Levelized Cost of Energy Analysis Version 11.0 and Lazard's 2017 Levelized Cost of Storage Analysis Version 3.0 as a reference for capital costs, fixed O&M, and variable O&M. However, adjustments were made based on PAG input and consideration of additionally available public information resulting in reasonable cost assumptions. Resources with cost assumptions different to Lazard's are described within their sections.

1. Solar Photovoltaic Resource Options

EPE included several utility scale solar PV resource options for analysis. The solar PV options included are based on 25, 75, and 100 MW capacity variations. These resources are based on single-axis tracking systems. A generic hourly generation profile based on EPE's existing solar PV facilities was utilized to model the operational characteristics of a solar resource in EPE's region. Solar PV resources are non-dispatchable and dependent on solar irradiance, which is impacted by location and weather (cloud cover, rain, and/or overcast conditions). These characteristics of solar PV lead to the resource creating variability in the electric utility system. This variability requires additional consideration when planning and integrating this type of resource. If a resource has an output that is variable, then contribution at peak, and firm backup capacity must be considered to plan for system reliability. See the Table 12 below for Solar PV resource input assumptions.

EPE initially estimated solar capital investment costs to be $1,450/kw based on Lazard's Levelized Cost of Energy Analysis – Version 11.0. Upon considering the benefits of the federal Solar Investment Tax Credit ("ITC"), EPE adjusted the solar capital costs from $1,450/kw down to $1,384/kw. Given the latest Lazard's Levelized Cost of Energy Analysis ("LCOE") analysis, EPE once again reduced the solar capital costs to $1,100/kw which is the low end of the costs range shown in the report.

EPE also analyzed Solar PPA(s). The PPA option forecasted price drops through 2024 and remains at that level beyond 2024 based on solar PV costs that appear to be flattening. Three solar PPA options were included at 25, 75, and 100 MW capacity variations. The PPA options were modeled at $21.50, and remained at that price throughout the Planning Horizon, based on publicly available information such as forecasts for solar costs[3] and regulatory filings from other jurisdictions.

2. Solar Coupled with Battery Storage

Solar PV coupled with battery storage is currently eligible for ITC benefits when charged by solar. Given this, it is necessary to model this combination of resources as a "resource type" in order to capture the cost benefits. Lazard does not list a solar-battery storage option. EPE introduced a 100 MW solar facility with a 30 MW 4-hour battery storage option into the model for consideration. Based on research of publicly available information[4], EPE determined that the solar and storage resource options' PPA price should be modified to $35.74/MWh.

[3] NREL (National Renewable Energy Laboratory). 2017. 2017 Annual Technology Baseline. Golden, CO: National Renewable Energy Laboratory. http://www.nrel.gov/analysis/data_tech_baseline.html.

[4] Cole, Wesly J. NREL (National Renewable Energy Laboratory). 2016. Utility-scale Lithium-Ion Storage Cost Projections for Use in Capacity Expansion Models. Golden, CO: National Renewable Energy Laboratory.

3. Wind Resource Options

EPE included a 100 MW nameplate wind resource option. EPE utilized a generic hourly generation profile from National Renewable Energy Laboratory to model the operational characteristics of a wind resource in EPE's region. Wind, much like solar PV, is also a variable resource that can be impacted by weather conditions. Wind resources also require consideration for firm peak contribution, and firm back-up capacity for system reliability. See the Table 12 below for Wind resource input assumptions. EPE modeled these Wind projects based on current available price trends and forecasts. Based on NREL research data[5] and the latest Lazard LCOE analysis, EPE incorporated this resource into the model with a capital expenditure price of $1,200/kw and holding that price firm beyond 2024. This approach is based on capital cost forecasts which are predicting flattening cost declines.

4. Biomass Resource Option

A Biomass resource burns renewable waste (solid waste and/or landfill gas) to generate electricity in a combustion turbine or reciprocating engine. This type of resource is considered a base-load resource, usually with a high capacity factor. Generally, biomass resources are dispatchable and typically not subject to much variability. Resources with these types of characteristics are easier to integrate into the electric utility system because their generation is firm, predictable, and dispatchable. EPE modeled a 20 MW Biomass resource for this IRP. See the Table 12 below for Biomass resource input assumptions.

5. Geothermal Resource Option

Geothermal energy is a renewable resource type that uses heat from the Earth to generate electricity. A geothermal resource is generally considered a base-load resource with a high capacity factor. However, geothermal resources can be dispatchable. EPE modeled a 20 MW geothermal resource for this IRP. See the Table 12 below for the geothermal resource input assumptions.

6. Combined Cycle Resource Option

Combined Cycle (CC) power plant units have become larger in capacity as this generation technology has advanced due to economies-of-scale and improvements in efficiency. Traditionally, CCs were developed and utilized as base-load resources.

[5] NREL (National Renewable Energy Laboratory). 2017. 2017 Annual Technology Baseline. Golden, CO: National Renewable Energy Laboratory. http://www.nrel.gov/analysis/data_tech_baseline.html.

However, as technology has advanced, these units have become more flexible with fast-start and quick ramping capabilities. CCs provide low heat rate, high efficiency firm capacity and energy, with the ability to follow load. These operating characteristics pair up well with other resources, especially those whose output is variable and require firming up. For this IRP, EPE modeled a 320 MW CC. See the Table 12 below for the CC resource input assumptions.

7. Combustion Turbine Resource Option

Combustion Turbine ("CT") power plants have had widespread use since the 1940s. CT units also have advanced due to technology improvements. Like the CCs, these improvements have led to lower capital cost and enhanced efficiency. CT units have become more flexible with fast-start and quick ramping capabilities, like the larger CC units. CTs also provide firm capacity and energy with the ability to follow load. For this IRP, EPE modeled a 100 MW CT. See the Table 12 below for the CT resource input assumptions.

8. Gas Reciprocating Resource Options

Gas Reciprocating ("Recips") engines offer characteristics that are similar to CT units. Recips are flexible and also offer fast-start capabilities. Gas recips are modular in size and can create many different capacity configurations. This allows low minimum capacities and wide capacity output ranges. Gas recips also provide firm capacity and energy with the ability to follow load. For this IRP, EPE modeled two gas recip capacity options, 50 and 100 MW. See the Table 12 below for the recip resource input assumptions.

B. Energy Storage

BATTERY RESOURCE OPTION

Energy Storage, specifically Lithium-Ion Battery Storage, is a quickly evolving technology. Battery storage is starting to find its place as a feasible electric utility scale resource. Battery storage offers many benefits that complement renewable resources as well as load shifting or load following during peak hours. However, it is important to note that the round-trip efficiencies of batteries may be between 80 to 85 percent. Batteries are dispatchable and offer capacity that is very similar to traditional peaking units when dispatched to meet daily peak loads. These characteristics complement renewables, like solar, by firming up capacity during peak conditions and offsetting variability. The capital cost of batteries has been trending downward recently as technology and production has improved.

Several inherent characteristics of this technology are important when considering Battery Storage as a resource. First, battery nameplate capacity, or MW available to serve demand which are stored in the battery. Secondly, battery duration, which is the length of time (typically in hours) that the storage system can provide output to the electrical grid system. Lastly, total energy stored in the battery, MWh, typically this is the nameplate capacity times the hours of duration. The battery Storage resource modeled in the 2018 IRP is a 50 MW nameplate battery with a four (4) hour duration. A battery with these characteristics would have a total energy level available for dispatch of 200 MWh.

As battery costs continue to decrease, they will become a more viable resource option in expansion planning and will be further incorporated into future optimal resource portfolios, specifically due to their interaction with renewables and load shifting. See the Table 13 below for the Storage (Battery) resource input assumptions.

C. Demand Side Resources

ENERGY EFFICIENCY RESOURCE OPTION

In addition to EPE's current EE-programs, EPE included an energy efficiency resource based on assumptions for a commercial third-party managed program. This resource represents a summer peak load reduction program. Summer load reduction will be achieved with energy efficiency initiatives focused on daytime Heating, Ventilation, and Air Conditioning ("HVAC"), lighting, and insulation. The modeled program starts at 2 MW and grows to 10 MW at a rate of 2 MWs per year. EPE utilized programs and costs estimates from both Texas and New Mexico to develop a resource option for both jurisdictions. See the Table 12 below for the Energy Efficiency resource input assumptions.

DEMAND RESPONSE RESOURCE OPTION

EPE also included a Demand Response ("DR"). This resource is based on expansion of EPE's current Commission approved DRPP. When considering DR as a resource, it is important that events are limited and subject to customer acceptance. When a DR event is called, customers have the choice to allow for the interruption or to opt out. If customers decide to opt out, the resource's contribution to peak will be limited. Furthermore, if a DR event were to last multiple hours, customers who did not opt out may start using energy before the event ends, which would increase system load.

EPE examined information for viable demand response programs by taking into account adoptions rates within EPE's service territory to determine possible resource assumptions.

EPE modeled a 5 MW expansion DR resource. See the Table 12 below for the DR resource input assumptions.

Table 12 – IRP Resource Options Input Assumptions

Technology	Capital Costs ($/kw)	Heat Rate (Btu/kWh)	Fixed O&M ($/kW-yr.)	Variable O&M ($/MWh)	PPA Price ($/MWh)
Solar(1)	$1,100	-	$9.00	-	
Solar PPA(1)	-	-	-	-	$21.50
Solar & Battery Storage PPA(1)	-	-	-	-	$35.74
Wind(1)	$1,200	-	$30.00	-	-
Biomass(1)	$4,000	14,500	$50.00	$10.00	-
Geothermal(1)	$4,000	-	-	$30.00	-
Gas Fired CC	$1,000	6,600	$5.85	$2.75	-
Gas Fired CT	$1,000	9,000	$20.00	$10.00	-
Gas Reciprocating Engine	$1,100	9,000	$20.00	$15.00	-
Demand Response	$15.25	-	$444.30(2)	-	-
Energy Efficiency	$1,160	-	-	-	-
Rio Grande 6 - 5 yr Extension	$585	11,940	$62.00	$4.68	-
Rio Grande 7 - 5 yr Extension	$444	11,050	$69.85	$4.68	-
Newman 1 - 5 yr Extension	$216	11,140	$44.25	$2.54	-
Newman 2 - 5 yr Extension	$286	10,710	$47.89	$2.54	-
Rio Grande 6 - 15 yr Extension	$1280	11,940	$54.84	$4.68	-
Rio Grande 7 - 15 yr Extension	$1104	11,050	$51.69	$4.68	-
Newman 1 - 15 yr Extension	$648	11,140	$34.74	$2.54	-
Newman 2 - 15 yr Extension	$698	10,710	$35.86	$2.54	-

Note:

(1) Renewables to be considered are in addition to and above Renewable Portfolio Standard requirements, as per Joint Stipulation Case No. 15-00241-UT.

(2) Demand Response O&M costs include customer incentives.

(3) Source is Lazard's Levelized Cost of Energy Analysis – Version 11.0 as well as other publicly available information and EPE relative experience.

Table 13 – Storage Resource Option Input Assumptions

Technology	Capital Costs ($/kwh)	O&M ($/kWh)	Charging Cost ($/MWh)	Battery Replacement after 10 yrs ($/kWh)
Storage	$385	$2.44	$30.00	$120

Note:
(1) Source is Lazard's Levelized Cost of Storage Analysis – Version 3.0.

Table 14 below outlines modeling input assumptions related to number of options the model is available to add throughout the study period. These inputs are necessary to the model in order to improve runtime while providing the model viable options that may address the resource need with either stand alone or an aggregate combination of resource options.

Table 14 – IRP Resource Options Input Assumptions

Technology	Capacity (MW)	Total available to add	Asset Life
Solar	25, 75, 100	2, 3, 2	25 yrs
Solar and Battery	100 Solar, 30 Battery	2	25 yrs
Wind	100	2	25 yrs
Wind and Battery	100 Solar, 15 Battery	1	25 yrs
Biomass	20	1	25 yrs
Geothermal	20	1	25 yrs
Gas Fired CC	320	3	45 yrs
Gas Fired CT	100	3	40 yrs
Gas Reciprocating Engine	50, 100	3, 3	40 yrs
Storage	15, 50	2, 2	25 yrs
Demand Response	5	1	25 yrs
Energy Efficiency	up to 10	1	25 yrs

RATES AND TARIFFS THAT INCORPORATE LOAD MANAGEMENT CONCEPTS

17.7.3.9.F(3) NMAC, ("IRP Rule") requires that EPE describe in its Plan "existing rates and tariffs that incorporate load management or load shifting concepts" as well as "how changes in the rate design might assist in meeting, delaying or avoiding the need for new capacity". This section includes the information required by the Rule for EPE's service territory generally, with more specific information included where rate and rate structure differences exist across jurisdictions. EPE also addresses evaluation of the impact of rate design on peak demand and energy consumption reflected in EPE's load forecast. EPE attempts to provide rates and rate structures consistently across its entire jurisdiction, especially as those rates and rate structures are intended to provide pricing and options designed to enable and incentivize economic decisions by customers with implications for the entire EPE system.

EPE's base rates are designed to recover the cost of providing electric service, including generation, transmission and distribution costs and associated O&M expenses; general and administrative expenses; depreciation expense; taxes and an allowed rate of return on rate base. In New Mexico, fuel and purchased power costs are recovered through a Fuel and Purchased Power Cost Adjustment Clause on a monthly basis, in accordance with 17.9.550 NMAC requirements. In Texas, fuel costs are recovered through a Fixed Fuel Factor in accordance with regulatory requirements. EPE's approved tariff schedules offer options to customers, including time-of-use ("TOU") alternatives that provide pricing intended to communicate differentials in the cost of providing electric service and to encourage customers to shift energy use to off-peak periods. These pricing differentials reflect, to the extent practical and contingent on regulatory approval, the differences in cost associated with serving load at different times of the year (seasonal) and day.

Rate Structures Incorporating Load Management or Load Shifting Concepts

New Mexico rate structures are described as follows:

Seasonal Rates – Rate differentials between summer and winter usage are provided for all non-lighting rates. These seasonal differentials were designed to incentivize energy efficiency and conservation during the summer peak season.

TOU Rates – Rate classes with a TOU rate option are the Residential Service, General Service, Irrigation Service and Military Research & Development Rates. The standard Large Power Service and State University Service rates are TOU rates. TOU rates contain price differentials between kWh during on-peak and off-peak hours to send more accurate price signals by reflecting cost of service differences during specific peak hours. TOU price differentials were designed to enable and incentivize consumption changes. This type of rate requires more sophisticated metering for most customers. Changes in peak use by all customers, but particularly larger commercial, industrial and irrigation customers, may reduce purchased power costs and/or delay additional generation resources.

Interruptible Rates – EPE offers a Noticed Interruptible Rate option for large commercial, industrial and institutional customers. Unlike the other options described above, the Noticed Interruptible program provides for additional system capacity on an emergency basis only. EPE has implemented a curtailable load option for Residential and small commercial customers on a pilot basis, which is discussed in more detail below.

EPE's current rates were implemented pursuant to the Final Order in NMPRC Case No. 15-00127-UT in New Mexico and Docket No. 48631 in Texas. The rates and rate differentials contained in the current rate structures are intended to incentivize energy efficiency, energy conservation and load shifting by customers. Price differentials reflected in rates are established consistent with the cost of associated services; generally, production-related costs. For example, peak period (e.g., on-peak energy) pricing differentials are based on the cost of peak generation production costs. The price signals specifically target the afternoon hours of the summer months, when EPE's system peaks. These higher prices during on-peak periods incentivize increased utilization of energy efficiency and conservation measures and/or increased load shifting, either through demand side management projects, i.e., automated controls, thermal energy storage, or through customers changing the operational hours of their equipment. This in turn works to decrease EPE's summer peak, which can help reduce the need for or delay new capacity resource additions.

<u>DRPP</u>

In Case No. 15-00127-UT, EPE proposed an RFP process to initiate a pilot program to gauge the acceptance and efficacy of demand response utilizing programmable or "smart" thermostats to target air conditioning load. Demand Response is a proposed voluntary program that engages utility customers to reduce their electricity use (load) during peak hours or under certain conditions. Peak electricity demand typically occurs on hot summer days when households turn on their air conditioning ("A/C"). Fundamentally, the main goal of the demand response program is to reduce A/C usage on hot summer days, which in turn, can reduce demand for electricity during peak hours, providing aggregate benefits for the electric grid and households themselves. Following approval by the Commission for EPE's proposal, EPE conducted an RFP, selected a vendor and implemented a 3-year pilot prior to the summer period of 2017.

Load curtailment in the DRPP is accomplished through a combination of continuous monitoring and adjustment of thermostats during the cooling season as well as more dramatic adjustments for short intervals as targeted curtailments. EPE separately meters and analyzes demand response by a sample of participants to measure load reductions and validate data reports provided by the third-party vendor. If the data supports energy efficiency cost effectiveness requirements, EPE could propose such a program as part of an energy efficiency measure or program at the conclusion of the 3-year pilot.

<u>Customer and System Benefits</u>

TOU and other variable pricing and dynamic pricing options provide customers the opportunity to impact their monthly bill by modifying energy consumption in response to price differentials. In the simplest case, this means adjusting usage (energy consumption) during different times of the day, by either reducing consumption or shifting usage to a lower-priced period. The extent to which a customer may benefit is a function of the price of energy in the standard offering, the price differentials offered in the optional pricing structure and the customer's ability to manage their energy consumption. A marginally higher on-peak price, for example, provides a greater incentive to reduce consumption than the lower standard price for consumption in the same period. Likewise, a shifting of consumption from high-price to low-price periods is incentivized by the price differential by providing a benefit not available under a level price standard rate. Dynamic pricing options, which can be constructed as overlays to either a standard or TOU pricing option, can increase customer benefit.

Another fundamental variable in the ability of price response rates to impact customer usage and system load profile is whether the rate structures are voluntary or mandatory. Customer "opt-in" performance, where customers make an affirmative decision to participate in a voluntary pricing program with both potential risk and benefit is typically low, and utility efforts to generate customer participation constitute an additional cost for programs. Generally, speaking, voluntary participation programs consist largely of functional benefiters – customers receiving rate benefit due to the nature of their usage profile with little or no change in their consumption characteristics. Conversely, mandatory TOU rate structures, such as EPE currently provides for its largest commercial and industrial customers have 100% participation rates, with resulting customer and system benefits a function of the ability of customers to adjust their usage profiles over the long-term.

Dynamic pricing programs generally overlay standard or voluntary pricing options. Critical Peak Pricing ("CPP"), Peak Time Rebate ("PTR") and Capacity Bidding are examples of dynamic pricing programs which can overlay mandatory rate structures and require advanced metering capability. All are callable programs which can be initiated on day-ahead or even day-of notice to achieve demand reductions during peak periods. Dynamic pricing as an overlay to a TOU pricing option offers EPE the ability to offer additional savings, based on a near-term need for resources, over and above what can be achieved through peak rate differentials. For example, a PTR option can provide incremental reductions in on-peak usage already reduced in response to TOU pricing differentials, which benefits both the participating customer and the utility.

EPE's 20-Year Rate Initiative

The EPE system load profile is one cost-driver of overall rate levels. The system profile in turn is impacted in the long-term by both permanent changes in customer consumption and short-term response to rate differentials. Permanent changes in customer usage profiles result from long-term exposure to predictable price differentials, and are most directly impacted by mandatory rate structures. Residential, commercial and industrial customers require time to adjust their usage characteristics in response to pricing differentials, and pricing differentials based on cost of service generally change slowly. Dynamic pricing options in contrast are intended as short-term resource options for the utility. The combination of the two pricing approaches can, over the long-term, impact the system profile sufficient to impact resource planning.

The table below shows a long-term plan for rate structure development focused on providing customers increasing levels of price information and menu of rate options, and designed to provide customers the opportunity to benefit from changes in their usage characteristics.

Table 15 - Rate Structure Development

	Current	3-Year	5-Year	10-Year	20-Year
Residential	Energy	Energy	Energy / CPP & PTR	Energy / CPP & PTR	TOU Energy / CPP & PTR
Small Commercial	Demand / Energy	Demand / Energy	Demand / Energy CPP & PTR	Demand / TOU Energy CPP & PTR	Demand / TOU Energy CPP & PTR
Medium Commercial	Demand / Energy	Demand / TOU Energy	Demand / TOU Energy CPP & PTR	Demand / TOU Energy CPP & PTR	Demand / TOU Energy CPP & PTR
Industrial and Military	Demand / TOU Energy	Demand / TOU Energy	TOU Demand / TOU Energy	TOU Demand / TOU Energy Capacity Bidding	TOU Demand / TOU Energy Capacity Bidding
Irrigation and Pumping	Demand / TOU Energy	Demand / TOU Energy	Demand / TOU Energy	Demand / TOU Energy	Demand / TOU Energy

The solid black line indicates the point at which the mandatory rate structure for the class would include TOU energy charges (the TOU line). Generally, large industrial, military, and irrigation and pumping customers already have mandatory TOU pricing tariffs. The vertical double-line indicates approximate timing for completion of a system-wide Advanced

Metering Initiative ("AMI"). Because of the number of customer accounts represented by the Residential and Small Commercial classes, advanced metering on a system-wide basis is critical to the success of expanding TOU and dynamic pricing options.

EPE's assessment of the impact of rate differentials and rate structures is that the net effect of rate structures changes, participation rates driven by mandatory requirements, and dynamic pricing following AMI implementation would not exceed the lower band confidence interval of future native system demand and energy (Figures 3 and 4). Long-term rate and rate structure changes can have an impact on customer demand and average use per customer, but these effects can likewise be offset by increased penetration of technologies such as electric vehicles. EPE's assessment is that the rate impacts discussed here, assuming all other things equal, will have the effect of reducing the slope of demand and energy growth over time. In addition, by establishing rate differentials and dynamic pricing programs based on the cost of peak generation resources, the cost-effectiveness of these rate offerings are comparable to avoided cost of the relevant resource alternative.

Advanced Metering Initiatives (AMI) and Customer Options

System-wide advanced metering enables the maximum availability of pricing options and customer programs designed to provide benefits to customers and the overall system. For purposes of this discussion system-wide "advanced metering" means retail metering capable of providing interval metering data accessible to EPE for analysis and billing purposes on at least a monthly basis, and the data processing systems capable of managing the data and computing bills under complicated pricing programs. Implicit in this definition is EPE's ability to access and process data on an accelerated basis; from acquiring the data from meters, communicating that data to databases, and accessing the data for analysis and billing purposes.

VII. DESCRIPTION OF THE RESOURCE AND FUEL DIVERSITY

EPE primarily meets its customers' electrical demands with power generated from its generating stations, which are powered by natural gas and uranium. Utilizing renewable resources, particularly solar, as part of its system, EPE increases its fuel resource diversity. While EPE no longer has the coal-fired FCPP in its resource fleet, EPE is still able to maintain a diverse resource mix of nuclear, gas-fired, renewables, and purchased power.

EPE's energy mix for 2017, the most recently completed calendar year, is based on MWh generation as shown in Figure 5 below:

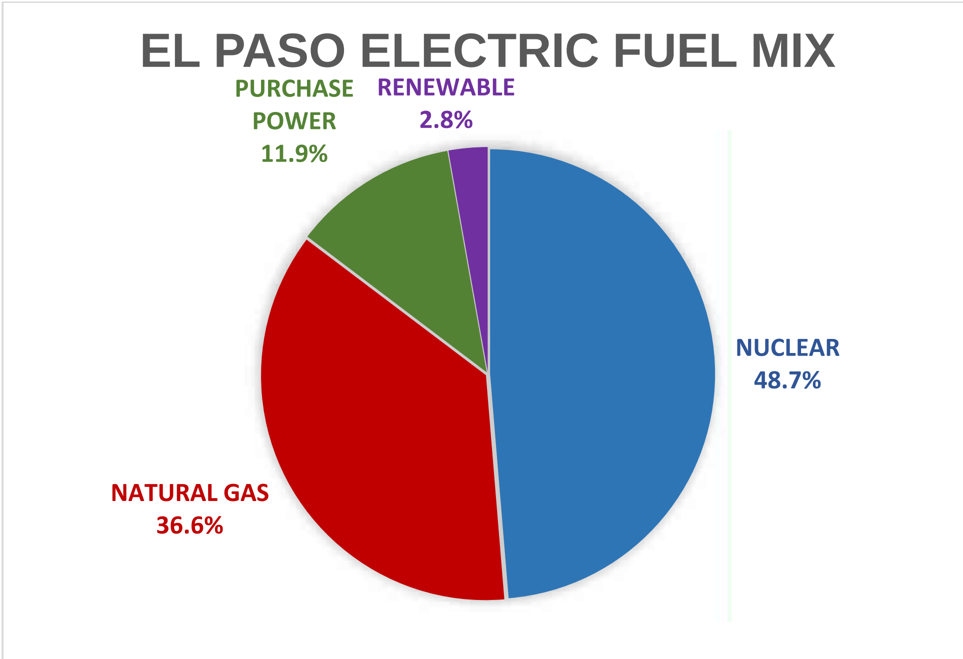

Figure 5 – EPE 2017 Energy Fuel Mix

VIII. IDENTIFICATION OF CRITICAL FACILITIES SUSCEPTIBLE TO SUPPLY-SOURCE OR OTHER FAILURES

EPE's current critical facilities that are susceptible to supply-source or similar failures include its natural gas fired generation plants. These facilities are susceptible to supply-source failures due to the fuel required for unit operation and the resulting power generation. If the natural gas supply-source was to experience a large-scale failure, then some of EPE's critical facilities could be impacted. To mitigate some of this risk, EPE periodically reviews its natural gas transportation and storage capability and any local fuel related concerns. EPE is connected to two major gas pipelines (each with multiple large lines entering the city) on the interstate and on the intrastate system. EPE also has emergency on-site fuel oil backup capability at both of its largest local generating facilities, i.e., Newman and Montana. This multiple gas pipeline configuration, as well as purchased power availability as transmission constraints permits, fuel oil backup, and EPE's ability to activate the HVDC Eddy Tie which is interconnected to the SPP, would contribute to EPE's ability to mitigate local fuel and service requirements given a supply-source failure at a critical facility. In addition, EPE has nuclear units that would not be impacted by a gas pipeline outage.

EPE's existing solar resources are also susceptible to "supply disruptions" given their dependency on solar irradiance. EPE's existing solar nameplate capacity of 115 MW (including the 5 MW

Holloman project) does not present an energy supply risk. However, consideration would need to be given for additional amounts of solar and wind, see Section IX.

IX. DETERMINATION OF THE MOST COST-EFFECTIVE RESOURCE PORTFOLIO AND ALTERNATIVE PORTFOLIOS

EPE has considered all feasible supply, energy storage, and demand-side resource options on a consistent and comparable basis in order to develop the optimal resource portfolio. Given the added complexities and characteristics of today's resource options, it is necessary to describe the planning analysis.

Ultimately, the goal is to ensure that EPE has a portfolio that reliably meets both the peak and energy demands of our customers. Given this goal, it is necessary to analyze what combination of resources, given their respective characteristics, can optimally serve load. EPE utilized a capacity expansion model, Strategist, to perform the analysis.

Strategist

Strategist is a resource expansion planning software application to develop the model that determines the optimal integrated demand-side and supply-side portfolio for a utility system under a prescribed set of inputs and assumptions. Strategist enables EPE to study a wide variety of long-term expansion planning resource options and their costs (described in Section VI), unit retirements, unit capacity variations, demand-side management options, fuel costs, and reliability limits in order to develop a coordinated integrated plan which would be best suited for the EPE system. Strategist simulates the operation of a utility system to determine the cost and reliability effects of adding various resources to the system or modifying the load through marketing or conservation programs. Strategist is also equipped with tools to facilitate the screening of individual alternatives and how they interact with the EPE system. In addition, Strategist can assess the impacts of various scenarios and sensitivities based on total plan costs.

Resource options are ranked by Strategist based on their individual economic impact on the EPE system. For each resource option, EPE's net present value of revenue requirements over the entire planning period, in this case 2018 through 2037, is calculated. Strategist will optimize the resource mix to meet reserve requirements and reliability constraints over the Planning Horizon. The present value of revenue requirements (in Strategist known as the Present Value of Utility Cost) for each plan is evaluated over the Planning Horizon and then ranked against the other plans. This procedure identifies the most cost-effective resource portfolio that provides optimal interactions with the EPE system model in Strategist.

In addition to the key inputs that were defined above for Strategist, there are other resource-specific inputs that are required to correctly capture characteristics inherent to certain technologies which are described below.

Solar Capacity Credit Determination

Solar facilities have operating and load serving characteristics that were analyzed by EPE to be properly considered by the model (reference Attachment F-1). As addressed below, solar contributes 25% of nameplate capacity to serving peak load. This is noteworthy because in EPE's 2015 and earlier IRPs, solar was credited with a 70% of nameplate capacity for contribution to peak.

As is the norm in the industry, the output profile of solar can be viewed as a reduction to load. The resulting difference between load and solar output is referred to as the net load. Given the output profile correlating to sunlight hours, the net load (i.e. reduction of load) only occurs during sunlight hours, and therefore does not reduce load in the hour following sunset. At a certain inflection point, solar resources do not contribute to serving this new net peak load hour, as illustrated in Figure 6. Given EPE's peak load profile, the inflection point occurs at a total of 400 MW of solar resources. The net load at 400 MW is 1,884 MW versus the new evening peak load of 1,886 MW. While the additional solar above the 400 MW will offset energy, it does not contribute to serve the new evening peak. Solar would only be able to serve the new evening peak if coupled with energy storage such as batteries.

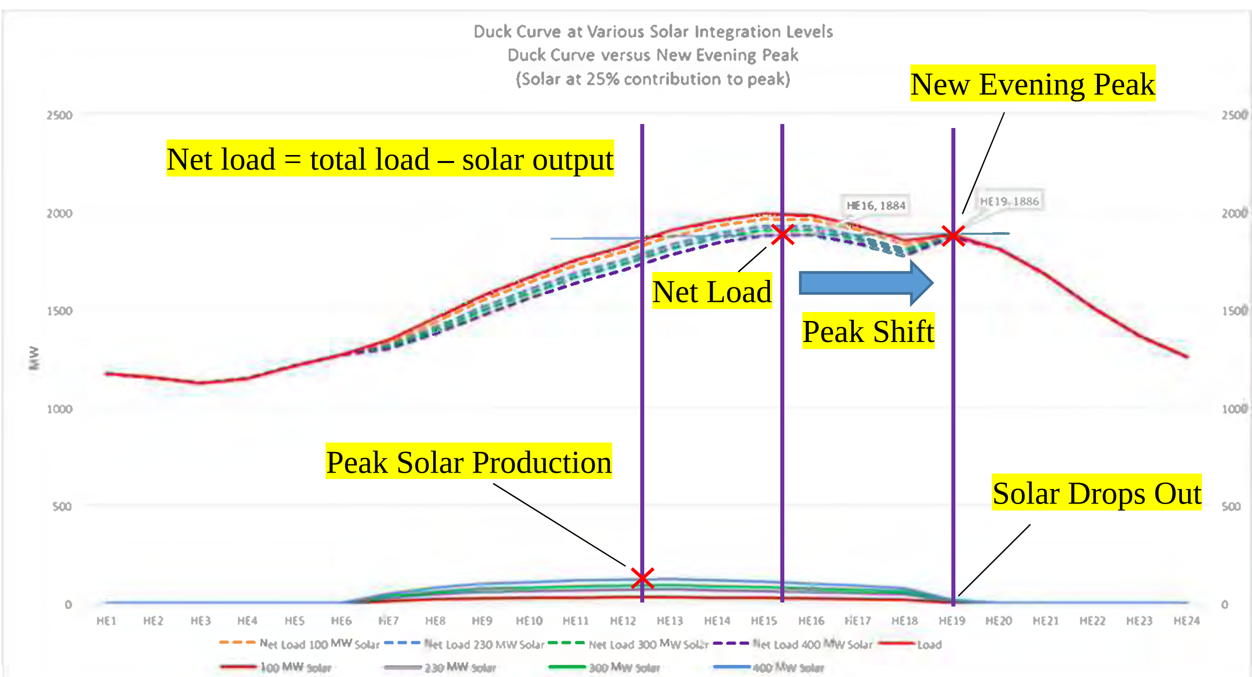

Figure 6 – Duck Curve at Various Solar Integration Levels

Additionally, there is a difference between the expected output profile of solar and its contribution to meeting peak load from a resource planning perspective. Solar output is variable due to its diurnal cycle and due to intermittency from cloud cover. These solar characteristics introduce the risk of output levels falling below the expected output. Given EPE's existing installed solar capacity, the risk of reduced output has been minimal given EPE's current solar capacity. Previously, EPE credited solar contribution to peak at 70%, which is equal to its expected output. With 107 MW of installed solar, EPE credited 74 MW to serving peak load; however, in 2016, EPE registered solar output in the 29 MW range on the second highest peak load day for 2016, which resulted in a 48 MW deficiency. The resulting 48 MW deficiency was manageable since it was within EPE’s planning reserve margin and consumed only a small fraction of the planning reserve. A greater number of solar installations would result in a proportional deficiency and increase the magnitude of that deficiency. The increased magnitude of the deficiency increases the risk for loss of load possibility which reduces system reliability. For example, if the solar installation were 400 MW, the proportional deficiency on a comparable day would have been 179 MW. In this example, the 179 MW deficiency would have consumed a significant amount of the planning reserve. The planning reserve margin is intended to mitigate multiple scenarios such as unplanned transmission or generation outages, forecast error, or unforeseen peak load events. Therefore, as the number of solar installations increases, it is necessary to mitigate the risk of increasing solar deficiency. There are two ways to mitigate the risk, one is to adjust the capacity credit assigned to solar facilities based on the historical performance of existing solar facilities, and the other is to increase the system planning reserve margin to a level that will maintain the existing system reliability when a significant reduction in solar output occurs. El Paso Electric has decided to mitigate the risk by adjusting the capacity credit for solar facilities while maintaining the existing system reserve margin. analysis (see Attachment F-1) indicates that 25% of the nameplate capacity is an appropriate contribution to peak with a 95% confidence level. Also, the analysis shows that there is a probability (risk) of 5% that solar output will fall to or below 25% of nameplate output during the top ten load hours. The 5% risk can be managed with the existing planning reserve margin. The 25% contribution to peak would apply to the first 400 MW of installed solar (inclusive of the 110 MW already installed) through 2023. It is important to note that the energy profile is modeled to the expected levels, in this manner solar resources are credited for their energy contribution. Any solar considered above the 400 MW level would not contribute to the new evening peak unless it is coupled with energy storage through 2023. Therefore, solar above the 400 MW is credited with zero contribution to peak. An additional 100 MW of solar with contribution to peak is allowed in 2027 with the assumption that load profiles may change and allow for additional contribution to peak. This will be revisited in the following IRP cycle for 2021.

Another way of explaining how solar variability affects solar capacity credit, is to characterize the individual sources of variation and describe how they introduce the risk of actual output levels falling below expected output.

Solar power output has two main sources of variation;

1. Solar energy is generated only when the sun is shining in the daytime and none is generated at night.
2. Solar energy can be significantly reduced during substantial cloud cover or other weather-related events. This source of variation is called intermittency.

The risk is accentuated during times of system peak, as EPE's reserve margins are tightest at peak hours. Historically, EPE had determined that at its system peak, its existing solar resources could be counted on to produce energy equivalent to approximately 70% of its nameplate capacity rating to meet that peak. This energy at peak percentage (70% in this case) is also known as the capacity credit. In large measure, EPE's historic 70% capacity credit was a function of the small amount of solar power EPE had on its system and the simplified approximation study that EPE performed to calculate the credit. As the amount of solar on EPE's system grows, its contribution to reliably meet peak demand, or capacity credit, will decrease as described in the following paragraphs.

It is important to note that there is a mismatch between peak solar power generation and EPE's peak system load patterns. Typically, peak solar output occurs several hours in advance of EPE's system peak. This necessarily results in a solar capacity credit of less than 100%, as the maximum nameplate capacity of solar is not available at the time of EPE's system peak. The key questions are: what is the appropriate solar capacity credit and how should it be calculated?

A determination of the appropriate solar capacity credit requires that EPE consider at least two things. First, how solar performance on both sunny and cloudy days affects system reliability, and second, how EPE's system peak is affected as additional amounts of solar are added to the system. To address how solar performance on both sunny and cloudy days can impact system reliability, EPE conducted a study (see Attachment F-1) to determine the solar production output that it can rely upon with a 95% probability to serve its peak load. That is to say, given this 95% load serving probability target, what percentage of solar nameplate output would be available to reliably serve load at least 95% percent of the time. This study was based on more finite data than the simplified average monthly data used to calculate EPE's 70% expected solar output level (capacity credit). The study examined each minute of each peak load hour of each day for the peak load months of June through August 2016 (60 minutes times 92 days equals 5,520 minutes). The results of the study indicated that there is a 5% chance that solar production will fall to, or below, 25% of the solar facility nameplate rating during the peak load hour of each day for the peak load months of June through August. Said differently, there is a 95% chance solar production will be 25% of the nameplate rating or greater. Given that solar resources would play a significant role in meeting EPE's peak load and EPE has an obligation to reliably serve its customers, EPE determined that a

25% solar capacity credit is appropriate to assign to EPE's new solar resources to maintain system reliability.

The second solar capacity credit consideration is how additional amounts of solar affect EPE's system peak, and how that impacts the solar capacity credit. As previously mentioned, EPE, like many other utilities, subtracts solar and other non-dispatchable renewable resources from its system loads to arrive at a "net" load. The peak associated with the "net" load is referred to as the "net" peak. As solar resources are added to the system resource fleet, the "net" peak begins to decline and shift towards the evening hours. If enough such solar resources are added, the original peak is no longer EPE's highest system peak load, but rather the new peak is now later in the day. As the system peak declines and moves to later in the day, closer and closer to the evening hours, the contribution of solar continues to decrease. Furthermore, the time gap between peak solar output and the new system peak will continue to grow, until finally, solar output is no longer available after sunset. At this point, a new "evening" peak is created. This concept is illustrated in Figure 6. At this point, the contribution to peak of additional solar falls to zero since it can no longer contribute to peak reduction.

EPE has determined that given its current load profile and system resources, it has a practical limit regarding the total amount of solar capacity on its system of 400 MW. The first step in determining this limit is to compare the net peak at the time of the system peak to the new evening peak. Solar penetration levels are capped when the net peak, at the time of gross system peak, is equal to the new evening peak. To determine the actual amount of solar that can be added to the system, the previously calculated "equalized" net peak reduction, as represented by the horizontal blue line shown in Figure 6, (reducing system peak to a net peak that equals the new evening peak) is then divided by the assumed solar capacity credit, in this case 25%. To illustrate, in EPE's case it was determined that a 100 MW reduction in its system peak would result in a net peak that was equal to the new evening peak. Dividing the 100 MW system peak reduction by the assumed capacity credit of 25% yields the maximum solar limit of 400 MW (nameplate). Higher assumed capacity credit percentages would result in lower maximum solar limits.

Wind

Wind resources also have unique characteristics. First, its output profile is less consistent and highly variable compared to solar. Wind output profiles are typically provided based on expected (average) profiles for each month. However, it is difficult to credit wind with any significant contribution to peak because of its day-to-day variability. Figure 7 illustrates expected monthly output profiles for wind resource regions that are closest to EPE's service territory. The present profiles demonstrate two important characteristics. First, the months of May to August, which are EPE's peak months, have the lowest average output profiles. Second, during EPE's peak hours, wind output is at their lowest. While wind has come down significantly in cost, it does not offer firm output for meeting peak load. More appropriately, wind may be evaluated as potential fuel savings if its costs are sufficiently low. EPE modeled wind with its respective output profiles, with a zero contribution to peak. The output energy profile allows for consideration of potential fuel savings. Wind, much like solar, may offer peak contribution if coupled with energy storage, and this type of option was modeled in Strategist.

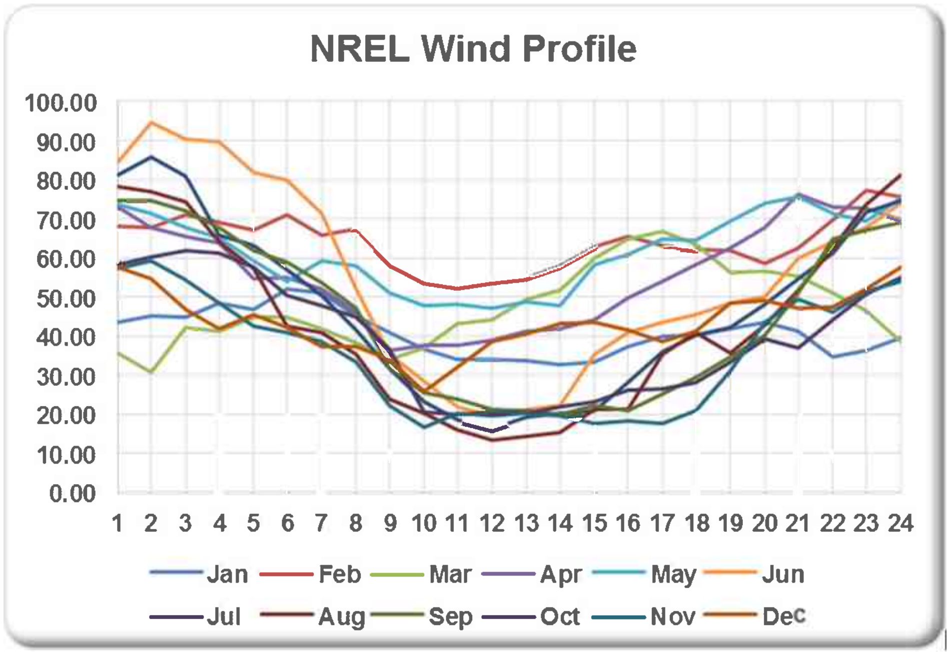

Figure 7 - Monthly Wind Profiles

Storage

Storage is modeled as a lithium ion battery storage system. The standalone storage system is modeled with a dispatch that assumes charging in the early morning hours when system load is at its lowest and system cost are expected to be lower. Storage coupled with solar is assumed to be charged beginning at sunrise, and storage coupled with wind is assumed to be charged throughout the night. As previously mentioned, these storage systems typically have an 80% efficiency and are subject to constraints in Section VI. Accordingly, the dispatch profile assumes a longer charging period to incorporate the efficiency.

Retirement Analysis

Pursuant to the Stipulation Agreement, EPE analyzed any retirements planned within the first five years of the Planning Horizon. This analysis applies to Rio Grande Unit 6[6] which has a planned retirement of 2018 as well as Rio Grande Unit 7, Newman Unit 1, and Newman Unit 2 for this IRP, as they are planned to retire in 2022. In order to facilitate this evaluation, EPE hired the

[6] As ordered in Case No. 17-00317-UT, Rio Grande 6 was also analyzed.

services of Burns and McDonnell to assess the conditions of the units and estimate of investment and operating costs to ensure safe and reliable energy for two-time frames, through 2027 and 2037. The retirement analysis was performed in Strategist where the unit extensions were introduced as options competing against the IRP resource options as part of the Base Case. The respective capital and projected O&M expenditures were utilized for each option.

A. Most Cost-Effective Portfolio (Base Case)

<u>Base Case</u>

The Base Case Portfolio was developed utilizing the planned retirements as defined in Table 2. The Base Case utilized the most likely expected values for inputs and provides the most cost-effective portfolio. All other inputs utilized are as described in the preceding sections. The resulting portfolio is as follows:

Table 16 - Base Case Portfolio

Year	Resource	Capacity	Contribution to Peak
2018			
2019			
2020			
2021			
2022	Solar PV	25	6.25
	Solar PV	75	18.75
	Solar PV	75	18.75
	Solar PV	75	18.75
	Solar PV	100	25
	Battery Storage	15	15
2023	Combined-Cycle	320	320
2024			
2025			
2026			
2027	Solar PV	100	25
	Combustion Turbine	100	100
	Reciprocating Engine	100	100
	Battery Storage	50	50
2028	Combustion Turbine	100	100
2029			
2030			
2031	Combined-Cycle	320	320
2032			
2033			
2034	Combustion Turbine	100	100
	Reciprocating Engine	100	100
2035	Battery Storage	50	50
2036	Solar PV & Battery	100	0
		30	30
2037	Biofuel	20	20

The resulting nameplate resource mix at year 2023 (the next major resource addition year) is:

Table 17 - Base Case Portfolio Nameplate Mix

	Nameplate MW	Percent by Nameplate	Contribution to Peak	Percent by Contribution to Peak
Solar	465	17%	168	7%
Gas	1,570	58%	1,570	65%
Nuclear	633	23%	633	26%
Storage	15	1%	15	1%
Emerging Tech	40	1%	40	1%

Mitigating Ratepayer Risk

Risk mitigation for resource selection is achieved in several ways. First, EPE incorporates risk variables for reliability, operational considerations, fuel supply and price volatility and anticipated environmental regulation in its analysis of competing resource options. EPE also analyzes sensitivities in resource selection for variations in forecasted load over time. Finally, because ultimate resource additions can take a considerable amount of time, ratepayer risk mitigation is achieved by constantly updating underlying assumptions as to capacity needs and timing of resource additions.

B. Considerations – Reliability

The most cost-effective portfolio takes into consideration cost, reliability, safety, environmental, and operating characteristics. It reliably introduces a significant amount of solar renewable energy while addressing the intermittency characteristics of solar. Additionally, it selects solar coupled with battery storage which again allows the addition of solar while providing firm output characteristics during peak hours with the battery storage. Gas generation is also selected to provide firm resources for peak hours.

Throughout the 2018 IRP, EPE accounted for transmission and reserve margin constraints in order to capture these parameters while considering total electric system reliability. Each resource analyzed as a portfolio option on a cost-effective basis must also demonstrate its ability to sustain and complement overall system reliability. EPE took into account its geographical location and its transmission import limits when developing its optimal portfolio. The resulting portfolio ensures an adequate reserve margin that is consistent with EPE's prior IRPs. EPE previously established a reserve margin of 15% which was re-affirmed in 2015 by a third-party firm, E3 (see Attachment I-1). EPE's location and transmission interconnection remains consistent with regards to load serving capability.

EPE's Commission-approved REA portfolio is currently above the RCT, set by the Commission at three percent of customer bills. EPE met its total RPS requirements through 2015 and has a Commission-approved variance and waivers from total RPS and diversity requirements through 2019 based on RCT constraints. EPE currently complies with REA requirements. The IRP accounts for these REA requirements by including EPE’s existing RPS resource in EPE’s L&R and by modeling them as existing resources. The Commission most recently approved EPE’s RPS resources in Case No. 18-00109-UT. As part of the IRP evaluation, similar to EE resource options being modeled above and beyond the EUEA requirements, renewable resources were considered and included in the model, above and beyond the REA requirements.

As stated above, energy efficiency and load management programs were taken into consideration during the IRP, both as a forecasted reduction in load and as a resource option. DR programs and EE are shown in the L&R in Section 4.0. EE resources were considered above the EUEA requirements. The resulting IRP portfolio determined that additional DR and EE currently need not be part of the optimal portfolio above and beyond the EUEA and forecasted DR. Based on the input assumptions for these resource options, the IRP analysis model did not find that the addition of these resources when paired with other resource options would result in the optimal portfolio. This is likely due to the relatively low contribution to peak capacity need and the acceptance rate of this type of resource by EPE customers.

EPE's current generating portfolio provides for minimal exposure to the EPA's guidelines to reduce carbon dioxide emissions. Moving forward, the Plan illustrates that EPE will continue to improve environmental stewardship due to the increased percentage of renewable resources in EPE's optimal portfolio. The inclusion of renewable resources above regulatory requirements demonstrates EPE's efforts to limit its carbon footprint.

Given the increased amount of renewables and the introduction of battery storage, the cost effective portfolio has a greater diversity of resources.

C. Alternative Portfolios (sensitivities, carbon tax)

Sensitivity Analysis

EPE analyzed various sensitivities to capture the cost differences and changes to the resource expansion plan. The sensitivities included variations to projected load, forecasted natural gas prices, and carbon tax costs at different price thresholds. Therefore, EPE modeled and analyzed high and low sensitivities on load, natural gas prices, and low, mid and high carbon tax. Results from the Strategist sensitivities are presented in Section IX, which include the present value utility costs for each plan.

Load Sensitivity Analysis

For EPE's High and Low Load sensitivities, EPE analyzed its 2018 Load Forecast to reflect economic recovery and a more robust economy (increases in customers and businesses) by utilizing the high bound of the 2018 Load Forecast. EPE then analyzed the lower bound of its 2018 Load Forecast to represent a decline of the economy (e.g., closure of businesses, loss of customers and military troops projected to be transferred to the El Paso area). Tables 18 and 19 show the load sensitivity results.

In the Low Load Case, less generation capacity was needed upfront, therefore the first-generation capacity addition was pushed back from 2022 in the Base Case to 2023 in the Low Load case. In the Low Load Case, solar PV was reduced from 350 MW added in 2022 in the Base Case to 250 MW added in 2023 in the Low Load case. Also, for the Low Load Case, the 320 MW combined cycle that was added in 2023 in the Base Case was replaced with a 100 MW combustion turbine in the Low Load Case. Further, 100 MW of battery was added in the Low Load Case as compared to 15 MW of battery storage in the Base Case. Hence, in the Low Load Case, the amount of generation capacity needed to meet EPE's load was reduced in conjunction with the decrease in load.

In the High Load Case, additional generation capacity was needed upfront in 2022. The additional generation capacity need in the High Load Case was met by adding a 100 MW combustion turbine and additional battery storage. Battery storage increased from 15 MW in the Base Case to 80 MW in the high load case. A 320 MW combined cycle was added in 2023 for both, the High Load Case and Base Case. The Solar PV capacity decreased from 350 MW in the Base Case to 275 MW in the High Load Case.

Hence, in the High Load Case, the generation capacity needed to meet EPE's load increased in conjunction with the increase in load. The increased need in generation capacity was met by adding more natural gas generation and battery storage.

Table 18 - Low Load Sensitivity

Year	Resource	Capacity	Contribution to Peak
2018			
2019			
2020			
2021			
2022			
2023	Solar PV	75	18.75
	Solar PV	75	18.75
	Solar PV	100	25
	Combustion Turbine	100	100
	Battery Storage	50	50
2024	Battery Storage	50	50
2025			
2026			
2027	Combined-Cycle	320	320
2028	Solar PV & Battery	100	25
		30	30
2029			
2030			
2031	Combined-Cycle	320	320
2032			
2033			
2034	Combustion Turbine	100	100
	Reciprocating Engine	50	50
	Solar PV & Battery	100	0
		30	30
2035	Reciprocating Engine	50	50
2036	Reciprocating Engine	50	50
2037	Biofuel	20	20

Table 19 - High Load Sensitivity

Year	Resource	Capacity	Contribution to Peak
2018			
2019			
2020			
2021			
2022	Solar PV	75	18.75
	Solar PV	100	25
	Combustion Turbine	100	100
	Battery Storage	50	50
	Solar PV & Battery	100	25
		30	30
2023	Combined-Cycle	320	320
2024			
2025			
2026			
2027	Combined-Cycle	320	320
2028	Combustion Turbine	100	100
2029			
2030			
2031	Combustion Turbine	100	100
	Reciprocating Engine	50	50
	Battery Storage	50	50
2032	Biofuel	20	20
2033	Solar PV & Battery	100	0
		30	30
2034	Combined-Cycle	320	320
2035			
2036			
2037	Geothermal	20	20

Fuel Cost

On the high and low natural gas price sensitivities, EPE analyzed a 15 percent price increase and a 15 percent decrease, respectively.

The Low Fuel Cost sensitivity case resulted in 325 MW of solar PV added in 2022 in the Low Fuel Cost Case as compared to 350 MW of solar PV added in the Base Case. Also, 15 MW more battery storage was added in 2022 in the Low Fuel Cost Case. The 320 MW combined cycle was added in 2023 for both, the Low Fuel Cost case and the Base Case. A lower fuel price makes natural gas generation more economical and thus, less solar was added upfront in the Low Fuel Cost Case.

For the High Fuel sensitivity case, the resulting resource expansion plan was unchanged from the Base Case expansion plan for 2022 and 2023. The only change that occurred was in 2027 where two 50 MW reciprocating engine resources in the High Fuel Case replaced a single 100 MW reciprocating engine resource.

Table 20 - Low Fuel Cost Sensitivity

Year	Resource	Capacity	Contribution to Peak
2018			
2019			
2020			
2021			
2022	Solar PV	75	18.75
	Solar PV	75	18.75
	Solar PV	75	18.75
	Solar PV & Battery	100	25
		30	30
2023	Combined-Cycle	320	320
2024			
2025			
2026			
2027	Combined-Cycle	320	320
2028	Combustion Turbine	100	100
2029			
2030			
2031	Combustion Turbine	100	100
	Battery Storage	50	50
	Battery Storage	50	50
2032			
2033	Reciprocating Engine	100	100
2034	Combustion Turbine	100	100
	Reciprocating Engine	100	100
2035			
2036	Solar PV & Battery	100	0
		30	30
2037	Biofuel	20	20
	Geothermal	20	20

Table 21 - High Fuel Cost Sensitivity

Year	Resource	Capacity	Contribution to Peak
2018			
2019			
2020			
2021			
2022	Solar PV	25	6.25
	Solar PV	75	18.75
	Solar PV	75	18.75
	Solar PV	75	18.75
	Solar PV	100	25
	Battery Storage	15	15
2023	Combined Cycle	320	320
2024			
2025			
2026			
2027	Solar PV	100	25
	Combustion Turbine	100	100
	Reciprocating Engine	50	50
	Reciprocating Engine	50	50
	Battery Storage	50	50
2028	Combustion Turbine	100	100
2029			
2030			
2031	Combined Cycle	320	320
2032			
2033			
2034	Combustion Turbine	100	100
	Reciprocating Engine	100	100
2035	Battery Storage	50	50
2036	Solar PV & Battery	100	0
		30	30
2037	Biofuel	20	20

Carbon Tax

EPE used the carbon tax price thresholds as defined in Case No. 06-00448-UT of $8, $20 and $40 escalated at 2.5% annually from 2011. EPE used the $0 carbon tax price as part of its Base Case, with the $8 and $40 sensitivities representing the lower and upper bounds of the carbon tax. Since EPE's resource plan doesn't consist of any coal units, the effect of a carbon tax is minimized. As shown in TABLE 22-24 below, there were no major changes to the Carbon sensitivity cases as compared to the Base Case.

Table 22 - $8 Carbon Tax Sensitivity

Year	Resource	Capacity	Contribution to Peak
2018			
2019			
2020			
2021			
2022	Solar PV	25	6.25
	Solar PV	75	18.75
	Solar PV	75	18.75
	Solar PV	75	18.75
	Solar PV	100	25
	Battery Storage	15	15
2023	Combined Cycle	320	320
2024			
2025			
2026			
2027	Solar PV	100	25
	Combustion Turbine	100	100
	Reciprocating Engine	50	50
	Reciprocating Engine	50	50
	Battery Storage	50	50
2028	Combustion Turbine	100	100
2029			
2030			
2031	Combined Cycle	320	320
2032			
2033			
2034	Combustion Turbine	100	100
	Reciprocating Engine	100	100
2035	Solar PV & Battery	100	0
		30	30
2036	Battery Storage	50	50
2037	Biofuel	20	20

Table 23 - $20 Carbon Tax Sensitivity

Year	Resource	Capacity	Contribution to Peak
2018			
2019			
2020			
2021			
2022	Solar PV	25	6.25
	Solar PV	75	18.75
	Solar PV	75	18.75
	Solar PV	75	18.75
	Solar PV	100	25
	Battery Storage	15	15
2023	Combined Cycle	320	320
2024			
2025			
2026			
2027	Solar PV	100	25
	Combustion Turbine	100	100
	Reciprocating Engine	50	50
	Reciprocating Engine	50	50
	Battery Storage	50	50
2028	Combustion Turbine	100	100
2029			
2030			
2031	Combined Cycle	320	320
2032			
2033			
2034	Combustion Turbine	100	100
	Reciprocating Engine	100	100
2035	Solar PV & Battery	100	0
		30	30
2036	Battery Storage	50	50
2037	Biofuel	20	20

Table 24 - $40 Carbon Tax Sensitivity

Year	Resource	Capacity	Contribution to Peak
2018			
2019			
2020			
2021			
2022	Solar PV	25	6.25
	Solar PV	75	18.75
	Solar PV	75	18.75
	Solar PV	75	18.75
	Solar PV	100	25
	Battery Storage	15	15
2023	Combined Cycle	320	320
2024			
2025			
2026			
2027	Solar PV	100	25
	Combustion Turbine	100	100
	Reciprocating Engine	50	50
	Reciprocating Engine	50	50
	Battery Storage	50	50
2028	Combustion Turbine	100	100
2029			
2030			
2031	Combined Cycle	320	320
2032			
2033			
2034	Combustion Turbine	100	100
	Reciprocating Engine	100	100
2035	Solar PV & Battery	100	0
		30	30
2036	Battery Storage	50	50
2037	Biofuel	20	20

Table 25- Sensitivity Analysis Plan Summary

Year	Base Case	Low Load	High Load	Low Fuel	High Fuel	$8 Carbon	$20 Carbon	$40 Carbon
2018								
2019								
2020								
2021								
2022	Solar PV 25		Solar PV 75	Solar PV 75	Solar PV 25	Solar PV 25	Solar PV 25	Solar PV 25
	Solar PV 75		Solar PV 100	Solar PV 75	Solar PV 75	Solar PV 75	Solar PV 75	Solar PV 75
	Solar PV 75		Combustion Turbine	Solar PV 75	Solar PV 75	Solar PV 75	Solar PV 75	Solar PV 75
	Solar PV 75		Battery Storage	Solar PV & Battery	Solar PV 75	Solar PV 75	Solar PV 75	Solar PV 75
	Solar PV 100		Solar PV & Battery		Solar PV 100	Solar PV 100	Solar PV 100	Solar PV 100
	Battery Storage				Battery Storage	Battery Storage	Battery Storage	Battery Storage
2023	Combined-Cycle	Solar PV 75	Combined-Cycle	Combined-Cycle	Combined Cycle	Combined Cycle	Combined Cycle	Combined Cycle
		Solar PV 75						
		Solar PV 100						
		Combustion Turbine						
		Battery Storage						
2024		Battery Storage						
2025								
2026								
2027	Solar PV 100	Combined-Cycle	Combined-Cycle	Combined-Cycle	Solar PV 100	Solar PV 100	Solar PV 100	Solar PV 100
	Combustion Turbine				Combustion Turbine	Combustion Turbine	Combustion Turbine	Combustion Turbine
	Reciprocating Engine				Reciprocating Engine	Reciprocating Engine	Reciprocating Engine	Reciprocating Engine
	Battery Storage				Reciprocating Engine	Reciprocating Engine	Reciprocating Engine	Reciprocating Engine
					Battery Storage	Battery Storage	Battery Storage	Battery Storage
2028	Combustion Turbine	Solar PV & Battery	Combustion Turbine	Combustion Turbine	Combustion Turbine	Combustion Turbine	Combustion Turbine	Combustion Turbine
2029								
2030								
2031	Combined-Cycle	Combined-Cycle	Combustion Turbine	Combustion Turbine	Combined Cycle	Combined Cycle	Combined Cycle	Combined Cycle
			Reciprocating Engine	Battery Storage				
			Battery Storage	Battery Storage				
2032			Biofuel					
2033			Solar PV & Battery	Reciprocating Engine				
2034	Combustion Turbine	Combustion Turbine	Combined-Cycle	Combustion Turbine	Combustion Turbine	Combustion Turbine	Combustion Turbine	Combustion Turbine
	Reciprocating Engine	Reciprocating Engine		Reciprocating Engine	Reciprocating Engine	Reciprocating Engine	Reciprocating Engine	Reciprocating Engine
		Solar PV & Battery						
2035	Battery Storage	Reciprocating Engine			Battery Storage	Solar PV & Battery	Solar PV & Battery	Solar PV & Battery
2036	Solar PV & Battery	Reciprocating Engine		Solar PV & Battery	Solar PV & Battery	Battery Storage	Battery Storage	Battery Storage
2037	Biofuel	Biofuel	Geothermal	Biofuel	Biofuel	Biofuel	Biofuel	Biofuel
				Geothermal				
Plan Cost (000)	$ 3,244,995.00	$ 3,022,817.00	$ 3,452,985.00	$ 3,170,557.80	$ 3,315,031.50	$ 3,536,867.80	$ 3,839,871.20	$ 4,221,251.50

D. Recommended Portfolio

The IRP provided a comprehensive review of EPE's resource needs and options for the Planning Horizon. It included considerations of costs, reliability, safety, operating characteristics, environmental, and risks resulting in the recommendation of the optimal portfolio. As a result, EPE's recommends the Base Case resource plan, as set forth in the following Table 26. The planned solar resources will have adequate capacity to meet the 20 percent RPS requirement in 2023.

It is noted that the actual resource additions in the future will be determined by results of competitive requests for proposals and may differ based on future forecasted loads, economic conditions, technological advances, specific generation resource proposals, and environmental and regulatory standards. The Planning Process utilized publicly available information to analyze resource options.

Table 26- L&R Most Cost-Effective Portfolio

Loads & Resources 2018-2037
2018 IRP Portfolio

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
					SOLAR BATTERY	CC 320				SOLAR BATTERY CT/RECIF	CT			CC 320			CT/RECIF	BATTERY	SOLAR BATTERY	BIO
1.0 GENERATION RESOURCES																				
1.1 RIO GRANDE	321	276	276	276	276	230	230	230	230	230	230	230	230	230	230	230	88	88	88	88
1.2 NEWMAN	752	752	752	752	752	602	602	602	602	278	278	278	278	278	278	278	278	278	278	278
1.3 COPPER	64	64	64	64	64	64	64	64	64	64	64	64	64	-	-	-	-	-	-	-
1.4 MONTANA	354	354	354	354	354	354	354	354	354	354	354	354	354	354	354	354	354	354	354	354
1.5 PALO VERDE	633	633	633	633	633	633	633	633	633	633	633	633	633	633	633	633	633	633	633	633
1.6 RENEWABLES	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
1.7 Storage	-	-	-	-	15	15	15	15	15	65	65	65	65	65	65	65	65	115	115	115
1.8 POSSIBLE EMERGING TECHNOLOGY EXPANSION[1]	-	-	-	-	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
1.9 NEW BUILD (local)	-	-	-	-	-	320	320	320	320	520	620	620	620	940	940	940	1,140	1,140	1,140	1,160
1.0 TOTAL GENERATION RESOURCES [2]	**2,130**	**2,085**	**2,085**	**2,085**	**2,140**	**2,264**	**2,264**	**2,264**	**2,264**	**2,190**	**2,290**	**2,290**	**2,290**	**2,546**	**2,546**	**2,546**	**2,604**	**2,654**	**2,654**	**2,674**
2.0 RESOURCE PURCHASES																				
2.1 RENEWABLE PURCHASE (SunEdison & NRG)	29	29	29	29	28	28	28	28	27	27	27	27	27	26	26	26	26	26	25	25
2.2 RENEWABLE PURCHASE (Hatch)	4	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
2.3 RENEWABLE PURCHASE (Macho Springs)	35	35	34	34	34	34	34	34	33	33	33	33	33	33	32	32	32	32	32	32
2.4 RENEWABLE PURCHASE (Juwi)	7	7	7	7	7	7	7	7	7	7	7	7	7	7	6	6	6	6	6	6
2.5 NEW RENEWABLE PURCHASE					88	88	88	88	88	113	113	113	113	113	113	113	113	113	143	143
2.6 RESOURCE PURCHASE	-	60	80	115	5	-	-	-	10	95	25	90	130	-	-	5	-	-	-	25
2.0 TOTAL RESOURCE PURCHASES [4]	**75**	**134**	**153**	**188**	**165**	**159**	**159**	**159**	**168**	**278**	**207**	**272**	**312**	**181**	**180**	**184**	**179**	**179**	**208**	**233**
3.0 TOTAL NET RESOURCES (1.0 + 2.0)	**2,205**	**2,219**	**2,238**	**2,273**	**2,305**	**2,423**	**2,423**	**2,423**	**2,432**	**2,468**	**2,497**	**2,562**	**2,602**	**2,727**	**2,726**	**2,730**	**2,783**	**2,833**	**2,862**	**2,907**
4.0 SYSTEM DEMAND																				
4.1 NATIVE SYSTEM DEMAND	1,972	2,004	2,028	2,065	2,100	2,136	2,166	2,207	2,245	2,283	2,316	2,362	2,406	2,448	2,485	2,538	2,586	2,635	2,678	2,738
4.2 DISTRIBUTED GENERATION	(3)	(6)	(9)	(12)	(15)	(18)	(21)	(24)	(27)	(30)	(33)	(36)	(39)	(42)	(45)	(48)	(50)	(53)	(56)	(59)
4.3 ENERGY EFFICIENCY	(5)	(9)	(14)	(19)	(23)	(28)	(33)	(38)	(42)	(47)	(52)	(56)	(61)	(66)	(70)	(75)	(80)	(84)	(89)	(94)
4.4 LINE LOSSES	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)
4.5 INTERRUPTIBLE SALES	(54)	(54)	(54)	(54)	(54)	(54)	(54)	(54)	(54)	(54)	(54)	(54)	(54)	(54)	(54)	(54)	(54)	(54)	(54)	(54)
5.0 TOTAL SYSTEM DEMAND (4.1-(4.2+4.3+4.4+4.	**1,904**	**1,928**	**1,945**	**1,973**	**2,001**	**2,028**	**2,050**	**2,084**	**2,114**	**2,145**	**2,169**	**2,209**	**2,244**	**2,279**	**2,308**	**2,354**	**2,395**	**2,436**	**2,472**	**2,524**
6.0 MARGIN OVER TOTAL DEMAND (3.0 - 5.0)	**301**	**291**	**293**	**299**	**304**	**395**	**373**	**338**	**318**	**323**	**328**	**353**	**358**	**448**	**418**	**376**	**388**	**397**	**390**	**383**
7.0 PLANNING RESERVE 15% OF TOTAL SYSTEM	**286**	**289**	**292**	**296**	**300**	**304**	**307**	**313**	**317**	**322**	**325**	**331**	**337**	**342**	**346**	**353**	**359**	**365**	**371**	**379**
8.0 MARGIN OVER RESERVE (6.0 - 7.0)	**16**	**2**	**2**	**3**	**4**	**91**	**66**	**26**	**1**	**1**	**2**	**22**	**21**	**107**	**72**	**23**	**29**	**32**	**20**	**4**

1. Emerging technologies may include customer or other distributed resources as well as additional community solar.
2. Generation unit retirements denoted by most recent planned retirement dates at start of the IRP process.
Retirements planned within 5 years will be analyzed in the capacity expansion model per Joint Stipulation Case No. 15 00241 UT.
3. Rio Grande 6 capacity is denoted in the 2018 plant capacity total, pending conclusion of 2018 IRP.
Previously identified as retired in 2014 and utilized as inactive reserve. Per Commission order in docket 17-00317-UT Rio Grande 6 is included.
4. Purchases based on existing and estimated future purchases including renewable purchases to meet RPS requirements.
5. System Demand based on2018 Long-term and Budget Year Forecast.
Includes state-required targets for Energy Efficiency.
Interruptible load reflects current contracts.

Unit Retirements
Rio Grande 6 (45MW) - Denoted in 2018[3]
Rio Grande 7 (46MW) - December 2022
Newman 1 (74MW) - December 2022
Newman 2 (76MW) - December 2022
Newman 3 (97MW) - December 2026
Newman 4 CC (227MW) - December 2026
Copper (64MW) - December 2030
Rio Grande 8 (142MW) - December 2033

Renewable Purchases
SunEdison, NRG, Macho, Newman and Hatch solar purchases reflect 70% availability at Peak.

Company Owned Renewables
Renewable Resources shown in line item 1.6 consists of EPE Community Solar, Holloman Solar, EPCC, Stanton, Wrangler, Rio Grande & Newman Carports, and Van Horn

The Resource Purchase is supported by firm transmission through (i) simultaneous buy/sell with Freeport McMoRan (formerly Phelps Dodge), (ii) Four Corners switchyard after Four Corners retires, and (iii) SPS via the Eddy Tie.

X. DESCRIPTION OF PUBLIC PROCESS

A. Overview of the Public Process

The purpose of the Public Process is for the utility to provide information to, and receive and consider input from, the public regarding the development of its IRP (17.7.3.9.H NMAC).

A member of EPE's Regulatory Case Management group chaired the public participation process. Maritza Perez, Regulatory Case Manager, chaired the first 13 public meetings, then Curtis Hutcheson, Supervisor-Regulatory Case Management, chaired the remaining meetings. Ms. Perez scheduled the original public meetings and then coordinated the development of the final meeting schedule and meeting agendas with input from the facilitator and public participants. The public participants were allowed to place items on the agenda for discussion at the public meetings. The result was two additional public led meetings, and an additional EPE informational meeting. As discussed in more detail later, the first meeting was held at EPE's Compress facility, two meetings were held in Santa Fe at the NMPRC, and the remaining meetings were held at the Doña Ana County Government Center in Las Cruces. An email group of EPE employees, NMIRP@epelectric.com, was created specifically for the IRP process to provide the public participants with updates on available presentation materials and future meetings. Public participants also communicated with EPE through this email address to ask questions and to place items on the agenda of the public participation meetings. Multiple EPE employees received the emails to ensure the messages were received.

EPE encouraged public involvement in its Public Process and hosted a total of 17 public advisory meetings over the course of approximately sixteen months. During the public meetings, EPE presented information and material on its Planning Process by Company subject matter experts and EPE also received feedback from the Participants. On several occasions, Participants presented their own information and material for consideration by EPE and other members of the public. EPE, with direct assistance from the Commission Staff-selected facilitator, Myra Segal (the "Facilitator") structured the Public Process to be an inclusive and interactive manner. Participants were able to attend in person, call into the meetings, or participate remotely through web-based meetings using Skype for Business ("Skype"). The Skype meetings were set up so that the PAG could view presentation materials taking place during each meeting and hear audio. These remote Participants were able to submit questions through the Skype conversation panel.

EPE recorded the meetings and posted each recording on EPE's IRP website. This additional feature allowed Participants to go back at any time to a meeting they may have missed or wanted to hear again.

The Facilitator communicated between EPE and the PAG so that all feedback was communicated clearly to EPE and responded to in a timely manner by EPE. Ms. Segal also coordinated the dispute resolution process discussed below in accordance with the Rule.

Additional discussion and feedback also took place outside of scheduled meetings. The Participants submitted questions, requests, articles, and essays for consideration by EPE and other members of the public. EPE responded to all written requests for information in writing as described in the Stipulation Agreement. In total, EPE and the PAG developed over 60 pages of written requests for information and responses.

By attending any public meeting, the Participants were automatically enrolled in EPE's PAG list, where they were notified of upcoming meeting information, new website material, written questions and responses, and other IRP updates. Another available resource for the PAG was EPE's IRP website which includes helpful information and resources, such as IRP presentation material, written questions and responses, meeting schedule information, remote participation information, past IRP information, and rules and statutes information.

The sections below will describe the Public Process in more detail.

B. Notice and Public Outreach

EPE initiated the Public Process by publishing notice in the Las Cruces Sun-News, a newspaper of general circulation in every New Mexico County in which EPE serves, 30 days prior to the first scheduled meeting, which was May 25, 2017. EPE also included notice of the PAG meetings in New Mexico customer bill inserts. Additionally, EPE provided notice 30 days prior to the first scheduled meeting to the Commission, intervenors in its most recent general rate case, intervenors in its most recent renewable energy procurement case at the time, and intervenors in its most recent energy efficiency case. The notice and certificates of service were filed with the Commission's Records Bureau. EPE also posted a notice on the home page banner of its website. The notice has stayed on the home page of EPE's website for the entire duration of the Public Process. In June 2017, EPE sent an additional notice to its New Mexico customers via EPE's Connections newsletter included in monthly bills as a reminder that the meetings had started.

1. Copy of Published Public Notice

A copy of the published Public Notice, which was also used for bill inserts, publication in the Las Cruces Sun News, and email notifications, 30 days prior to the first scheduled meeting, is attached as Attachment A-10. The attachment also contains the Proof of

Publication, Affidavit of notification to customers, and Certificate of Service filed with the Commission on May 10, 2017. The notice was served to intervenors in its most recent general rate case, and participants in EPE's most recent renewable energy, energy efficiency, and IRP proceedings. The notice contained a brief description of the IRP process, time, date and location of the first meeting, a statement that interested individuals should notify the utility of their interest in participating in the process, and utility contact information.

C. Attendance

Approximately 60 people attended EPE's public advisory meetings, either remotely or in person, over the course of the approximately 16-month Public Process. The average in-person participation was 10 people. The average Skype participation was 4 people.

Public participation consisted of continuous attendance from a small group of participants who were very active and engaged throughout the entire Public Process. These Participants submitted the vast majority of written questions and requests, submitted resource input templates with sources, participated in the dispute resolution process, attended most meetings, and some presented their own material as well. There were other Participants who attended less frequently but also contributed to discussion and brought their own issues to the public meetings. These Participants tended to be more interested in DG rates. There were also representatives from certain groups and companies, such as Coalition for Clean Affordable Energy, First Solar, Positive Energy Solar, Western EIM, City of Las Cruces, and others. NMPRC Staff was represented at each meeting.

Participants demonstrated interest and a disparate level of understanding of the Planning Process, and an appreciation, to some degree, of the complexity involved.

D. Meeting Schedule and Format

EPE's original public advisory meeting schedule included 14 meetings; but, with the addition of three meetings requested by public participants, the final schedule consisted of 17 meetings. EPE modified its initial meeting schedules to accommodate several requests of the PAG. For example, EPE re-organized or postponed scheduled topics to be covered to accommodate increased time dedicated for requested public discussion. EPE included two meetings at the NMPRC offices in Santa Fe in order to facilitate direct NMPRC Staff participation in the Public Process. Attachment A shows the original and final public advisory group meeting schedule.

Meetings were typically held on Thursday's at 2 pm, for the duration of 2.5 hours. In EPE's experience, meetings held outside of normal business hours did not increase public participation. In addition, EPE received largely positive feedback from the PAG regarding the 2 pm meeting time. All meetings were at the Doña Ana County Government Center, except the first meeting and the two meetings held at the NMPRC offices. This new venue received positive reviews from the PAG. It provided ample parking space, was easily accessible, and is a well-known location in Las Cruces.

EPE had originally scheduled two meetings where the PAG members could present their own material and get EPE feedback in January and February 2018. In response to public feedback, EPE added two additional meetings of this type; first on September 22, 2017, and second on October 20, 2017. EPE also added a meeting on plant retirements as a result of public interest on the topic. This resulted in 3 additional public meetings, for a total of five public meetings to specifically address issued raised by the Participants, which are shown in Attachment A-2.

EPE presented topics required in the Rule for the Public Process (see Attachment A-1), as well as more detailed information on those topics in order to better inform the Participants on the issues addressed in the IRP. These detailed topics were covered at the beginning of the Public Process so that more time could be dedicated to the development of the most cost-effective portfolio and review of the IRP report.

During the October 5, 2017, meeting, EPE went into more detail on the modeling process and assumptions. During this time, the Participants were encouraged to submit Resource Input Templates, which were developed by EPE as a result of public interest in proposing resource types with specific costs and production characteristics. More information on the Resource Input Templates is found in the Public Input section below.

The remainder of the meetings consisted of more detailed discussion of the IRP modeling processes and evaluation of the most cost-effective portfolio. The schedule was structured so as to cover the required data as quickly and fully as possible to allow more time for development of the cost-effective portfolio. EPE has learned from past IRPs that Participants tend to be more focused on this portion of the IRP public process.

The structure of the PAG meetings varied. Some meetings were "open discussion" where EPE had some presentation material and discussion was allowed throughout. Other meetings had designated discussion periods, while other meetings consisted of the PAG presenting material and EPE providing feedback.

E. Public Input

EPE structured the Public Process to solicit, receive and consider public comment regarding the development of its IRP in a number of ways. EPE encouraged Participants to:

- attend public advisory meetings in person and give their input during the meetings,
- submit written notecard requests for information in person; during the meetings,
- send EPE their written input or requests by email, during or after scheduled meeting,
- fill out and submit feedback forms via written and/or phone, and,
- fill out and submit Resource Input Templates if they wanted EPE to consider a specific resource type.

In total, EPE received over 215 individual written questions on notecards or email, totaling over 80 pages of questions and responses.

EPE developed Resource Input Templates in response to public interest in proposing resource types with specific costs and characteristics. In response to this interest, EPE developed a template form for the PAG to complete, so that EPE could receive and consider public requests for specific resource types, in an organized and efficient manner in developing its IRP. EPE requested background and source documents to be submitted with templates if utilized. Attachment A-5 was provided to Participants during the October 5, 2018, meeting as an example of what a filled in template looks like, and the template for was posted on EPE's IRP webpage. In total, EPE evaluated 16 Resource Input Templates and provided responses to each of these. An explanation was given as to whether the resource proposal was a feasible option or not. Attachment A-6 is a summary of EPE's responses to the evaluated Resource Input Templates.

EPE received and considered all views and opinions expressed during the Public Process. Some of the most prominent themes expressed by Participants included:

- the incorporation of an increased amount, and in some cases up to 100%, of renewable and battery storage resources into the IRP resource portfolio,
- the incorporation of an increased amount of energy efficiency initiatives and demand response option into the IRP portfolio,
- L&R: increase energy efficiency and DG forecasts, reconsider retirement dates, and increase amount of renewables,
- rates: increase TOU price differentials and other rate changes in order to influence load,
- interest in Strategist, modeling inputs, and resource cost assumptions,
- interest in removing nuclear energy from the resource portfolio, and,
- interest in off-system sales.

All of these opinions were expressed during public advisory meetings as well as in writing. A complete list of the written questions and requests from Participants with EPE's responses can be found on EPE's IRP webpage:

https://www.epelectric.com/community/2017-18-public-advisory-group-meetings

The feedback forms are also a source of insight into input EPE solicited, received and considered from the PAG. These are summarized in Attachment A-4.

Below is a list of specific PAG input that EPE agreed to incorporate in the development of the most cost-effective portfolio for its IRP:

- create a portfolio for analysis that is heavily renewable favored,
  - the resulting base case portfolio was inherently heavy in renewable energy (solar) up to the maximum amount contributing to peak load hour,
- conduct a second Strategist run excluding the first selected (combined cycle) resource from the base case and compare the results,
  - the first option selected was solar; however, the combined cycle option was removed from the 2023 in line with the PAG request (results provided in the following paragraph F),
- identify and evaluate solar, wind and storage options with declining costs drops for assets to be added in the 2021-2023 timeframe for use in the model,
  - solar, wind and solar-storage options included consideration for cost declines as projected by NREL
  - additionally, solar and solar-storage PPA options were introduced,
- introduce a resource option of solar coupled with storage,
  - introduced as a PPA option,
- use an independent evaluator to verify that the resource prices between EPE's RFP and IRP are consistent,
  - independent evaluator provided evaluation and reasonableness assessment,
- include a discussion on T&D costs through locational resources,
  - EPE evaluated ten-year transmission and distribution plans and did not identify any transmission or distribution plans that would be eliminated due to resource options,
- have its consultant Burns & McDonnell perform an analysis of generation unit retirements using shorter intervals than originally planned,
  - Burns & McDonnell studies were provided, and results utilized for modeling retirement extension options in Strategist,
- perform sensitivity excluding New Mexico's jurisdictional allocation of PVNGS 3 (42 MW) as a resource option.
  - Results are provided in the following paragraph G.

In accordance with the recent Rule Amendment, the public will be able to file written comments after EPE files the IRP. EPE is required to file a written response.

F. "No Combined Cycle" Option

Based on a request from the New Mexico PAG, EPE ran a sensitivity in which the 320 MW combined cycle generation resource was taken out of the optimization run for the 2022-2023 time period. The No Combined Cycle sensitivity case resulted in the selection of the 15-year 74 MW Newman Unit 1 Extension, 15-year 46 MW Rio Grande Unit 7 Extension, and 100 MW combustion turbine along with 50 MW of battery storage being added in 2023. Results are provided in Attachment A-7.

G. PVNGS 3

EPE ran a sensitivity analysis of New Mexico's 42 MW portion of Palo Verde Unit 3 ("PV3") which is excluded from rate base in New Mexico. The base case analysis included the 42 MW of PV3 as an existing resource consistent with the treatment of EPE's other base case existing resources. The analysis assumed the 42 MW were no longer committed to serve New Mexico load beginning in year 2020 and is consistent with the solar contribution to the peak load discussion in Section IX of this Report. The PV3 sensitivity case resulted in the selection of solar in 2020 to replace the 42 MW, as well as mix resource additions from 2022 forward, essentially moving a modified base case portfolio forward at a higher cost than the base case. Results are provided in Attachment A-8.

H. Facilitator

EPE was assisted in the Public Process by a Commission Staff-selected facilitator, Myra Segal, who was recommended by a few public advisory participants.

Over time, the Facilitator's role adapted to the changing dynamic of the public advisory process. During the first few meetings, she observed, took notes on follow-up items, and solicited initial feedback from the public via a July feedback form she created and distributed. During subsequent meetings, the Facilitator assisted with the organization and the flow of the meetings. The Facilitator supported EPE's decision to designate discussion periods following presentations for the purpose of limiting interruptions of presentations, so that presenters could convey information within the time constraints of the scheduled meetings. During the later meetings, Ms. Segal assumed a more active role of guiding public advisory group discussions asking questions throughout the meetings, making clarifications, and adding her input. She also was better able to manage discussion time.

In order to promote discussion within the public advisory process, EPE adopted several suggestions from the Facilitator. One of the recommendations that EPE adopted was to form the tables into a "U"-shape in order to promote discussion. The group dynamic became more conversational as a result, and EPE received positive feedback on this change.

The Facilitator distributed two feedback forms, one in July 2017, and another in October 2017. A summary of the results is shown in Attachment A-4.

1. Dispute Resolution

Another key role of the Facilitator is dispute resolution, as described in the IRP Rule (17.7.3.9.H.2).

The Facilitator developed a process for dispute resolution that included a written request from the Participant seeking dispute resolution, an EPE response, an evaluation using a dispute resolution matrix, and hosting web meetings as necessary for discussion. The Facilitator documented the dispute, communications, and outcome of each dispute. In total, there were 6 disputes sent to the facilitator by the PAG. A summary of each dispute is provided below:

1. RFP Bids

"I am asking that the information on resource options represented by the proposals available since October 4, 2017, from the all-source RFP be included in the analysis for constructing El Paso Electric's 2018 Integrated Resource Plan."

EPE Compromise: Use an Independent Evaluator to confirm that resource prices used in Strategist are consistent with RFP resource prices.

<u>Outcome</u>: In progress: Compromise resolution submitted by EPE, awaiting best and final RFP bid package for Independent Evaluator assessment and affidavit.

2. Distribution Plan

"I am requesting the Distribution Expansion plan referenced below the legend on the second map page of EPE's 10-year transmission plan."

EPE Compromise: EPE will include in its IRP Report a discussion on T&D costs through locational resources.

Outcome: In progress; EPE to evaluate how avoided T&D costs may be attributed to locational resources modeled in Strategist. EPE will identify any publicly available data on distribution capital investment projects.

3. Retirements

"I am asking that EPE evaluate the continued operation of units slated for retirement within five years on a consistent and comparable basis with other resource options. I believe that means evaluating the option of life extension on a year-by year basis until and unless it is established that a one-year life extension is not feasible. If there are costs for maintenance, repair, or retrofit they should appropriately be included in the analysis and evaluated within Strategist just as all other resource options, existing or potentially new additions, are evaluated."

EPE Compromise: Burns &McDonnell will do a 5-year assessment (2027, which is 5 years after scheduled retirement) and 15-year assessment (2037) for evaluation on retirement of units.

Outcome: In progress; EPE to respond on whether or not shorter time intervals (e.g., 1-year, 3-year, 5-year, 10-year) will be assessed by the contracted firm (Burns & McDonnell) along with its planned 20-year retirement assessment.

4. DG as a Resource

"I am asking that EPE evaluate Distributed Generation as a resource option. I am proposing that for $20/MWh an additional 5 MW of usable capacity at peak per year every year can be added to the system over and above the current assumptions built into the forecast. Distributed Generation as a demand side resource must be evaluated on a consistent and comparable basis as other resource options. I believe that EPE's decision to unilaterally refuse to evaluate DG as a feasible resource option does not meet the requirement or intent of the IRP Rule."

EPE Compromise: EPE will consider modeling of customer-sited DG in Strategist runs. Compromise alternative- model DG based on Lazard pricing for solar DG, comparable to other supply-side resources.

Outcome: EPE to consider modeling of customer-sited DG in Strategist runs. Compromise alternative-model DG based on Lazard pricing for solar DG, comparable to other supply-side resources.

5. Resource life

"We are asking that EPE conduct its base analysis of resource options to determine the most cost-effective resource portfolio using the information from Lazard's Levelized Cost of Energy – V. 11.0 for all resource options that Lazard's contains information that will be modeled by Strategist. We are asking that the Lazard's information be utilized without modification for the base analysis. We are specifically requesting that the Lazard's values for facility life be utilized in the base analysis."

EPE Compromise: EPE does not agree that modifying resource inputs from public sources based on internal information and experience or other data is inconsistent with the IRP Rule, but agrees on providing the rationale behind the decision for each resource life.

Outcome: In progress; no resolution met.

6. Purchased Power Resources

> "I am asking that EPE conduct all of its Strategist analyses with purchased power as a resource option, beginning with 2019 through 2038 and define the purchase price assumptions to be used. This is necessary to demonstrate that the preferred resource portfolio identified by the Strategist analysis is the least cost resource portfolio as required by the rule."

EPE Compromise:

Outcome: In progress; no resolution met.

I. IRP Resource Cost Inputs versus RFP

EPE had an active RFP during the process during the same timeframe of the IRP process. While EPE could not disclose actual RFP bids during the process, EPE was able to utilize publicly available information to develop resource cost inputs that were reasonably in line with current market pricing and EPE's RFP options. EPE solicited the review of the RFP independent evaluator to review the reasonableness of EPE's IRP inputs relative RFP bid prices. The independent evaluator's conclusion is provided as Attachment A-9.

J. Conclusion of Public Advisory Process

EPE made a significant effort to improve the Public Process in order to make it a more inclusive and interactive process. By providing the Participants with additional features such as meeting recordings, adding a facilitator, increasing the number of meetings and public discussion time, providing Resource Input Templates, and including a written request and response option, EPE made this its most accessible Public Process to date, and is working to continuously improve its IRP process.

XI. CONCLUSION

The identified resource additions result in the optimal cost-effective resource portfolio and were identified through a robust and comprehensive Planning Process. The resulting resource portfolio additions include a mix of solar, battery storage, and conventional gas generation. The battery storage and conventional gas generation resources compliment the solar resources, which are intermittent in nature. It is noted that the actual resource additions in the future will be determined by results of competitive requests for proposals and may differ based on future changes to forecasted loads, economic conditions, technological advances, specific generation resource proposals, and environmental and regulatory standards.

ATTACHMENT A: PUBLIC ADVISORY PROCESS

Attachment A-1: Original Public Advisory Meeting Schedule

Meeting	Date	Subject
(1)	5/25/2017	Kick-off and Introduction Explanation of IRP Process and Goals Resource Planning Process and Overview Preliminary Listing of Resource Options to Consider
(2)	6/8/2017	Summary of IRP process and introduction to system
(3)	7/6/2017	Operational Considerations/Requirements for Future Resources Assessment of need for additional resources System Operations - Reliability, Import Limits and Balancing Existing Conventional Resources System generation retirement plan and process Transmission & Distribution Systems Overview and Projects
(4)	8/8/2017	Existing Renewable Resources and Distributed Generation (DG) Demand Response (DR) Programs and Options Energy Efficiency (EE) Rate Considerations and Potential Impacts on Resource Planning Decisions Load Forecast Load Forecast - Impacts from EE/DR and Rate Structure
(5)	9/7/2017	Conventional Capacity and Generation Option Considerations Demand Side Resource Options Renewable Energy Options (Solar, Wind, Geothermal, Storage, DG) Operational Considerations for Intermittent Resources and Balancing Renewable Portfolio Standard Impacts Renewable & Conventional Power Plant Siting and Environmental Considerations
(6)	10/5/2017	DEADLINE FOR OPTION SUBMITTAL FROM PUBLIC Resource Planning Base Case Assumptions Initial Cost Estimates for Resource Planning Options Modeling and risk assumptions and the cost & general attributes of potential additional resources
(7)	10/12/2017	Resource Planning Overview and Modeling for Cost of Potential Additional Resources
(8)	11/16/2017	Preliminary Results with 2017 Load Forecast Presentation of Resulting 20-year Expansion Plan Development of the most cost-effective portfolio of resources for utility's IRP
(9)-(10)	Jan 19, Feb 16	Informational Meetings or Discussions as Requested
(11)	4/30/2018	IRP Draft Presentation
(12)	5/16/2018	Follow-up meeting to receive and respond to public feedback
(13)	6/8/2018	Final IRP presentation showing new load forecast
(14)	6/29/2018	Follow-up meeting to receive and respond to public feedback
	7/15/2018	**IRP Filing Date**

Attachment A-2: Final Public Advisory Meeting Schedule

Meeting	Date	Subject
(1)	5/25/2017	Kick-off and Introduction
		Explanation of IRP Process and Goals
		Resource Planning Process and Overview
		Preliminary Listing of Resource Options to Consider
(2)	6/8/2017	Summary of IRP process and introduction to system
(3)	7/6/2017	Operational Considerations/Requirements for Future Resources
		Assessment of need for additional resources
		System Operations - Reliability, Import Limits and Balancing
		Existing Conventional Resources
		System generation retirement plan and process
		Transmission & Distribution Systems Overview and Projects
(4)	8/8/2017	Existing Renewable Resources and Distributed Generation (DG)
		Demand Response (DR) Programs and Options
		Energy Efficiency (EE)
		Load Forecast
(5)	9/7/2017	Conventional Capacity and Generation Option Considerations
		Demand Side Resource Options
		Renewable Energy Options (Solar, Wind, Geothermal, Storage, DG)
		Operational Considerations for Intermittent Resources and Balancing
		Renewable Portfolio Standard Impacts
		L&R Table
		Strategist Introduction
		Resource Input Template
		Renewable & Conventional Power Plant Siting and Environmental Considerations
(6)	9/22/2017	Presentation by PAG members Merrie Lee Soules and Don Kurtz: "Public Advisory Group Special Session on Analysis for 2018 IRP"
(7)	10/5/2017	Initial Resource Options Submittal from PAG Due for November Run
		Rate Considerations and Potential Impacts on Resource Planning Decisions
		Resource Planning Base Case Assumptions
		Initial Cost Estimates for Resource Planning Options
		Modeling and risk assumptions and the cost & general attributes of potential additional resources
(8)	10/20/2017	Presentation by PAG Members Merrie Lee Soules, Phil Simpson, Allen Downs, and Steve Fischmann: Special Session on Resource Analysis for 2018 IRP
(9)	10/26/2017	Retirements, Cost Modeling Assumptions, and other topics of interest to PAG
(10)	11/2/2017	SANTA FE - Overview on Public Advisory Process
(11)	11/16/2017	Recap of IRP Process
		Assumptions For Resource Options
		Preliminary Results
		Development of the most cost-effective portfolio of resources for utility's IRP
(12)	1/11/2018	PAG Presentations and Discussions as Requested
	2/2/2018	Last Resource Input Submittals from PAG Due
(13)	2/23/2018	PAG Presentations and Discussions as Requested
(14)	7/19/2018	IRP Draft Presentation
(15)	8/2/2018	Follow-up meeting to receive and respond to public feedback
(16)	8/17/2018	Final IRP presentation showing new load forecast
(17)	8/29/2018	Follow-up meeting to receive and respond to public feedback
	9/17/2018	**IRP Filing Date**

Attachment A-3: Public Advisory Schedule with IRP Rule Requirements

Public Advisory Group Meeting Schedule

Past Meetings

Meeting	Date	Subject	Location
(1)	5/25/2017 2:00 PM - 4:00 PM	Kick-off and Introduction Explanation of IRP Process and Goals Resource Planning Process and Overview Preliminary Listing of Resource Options to Consider	EPE Office 555 S. Compress Rd. Las Cruces, NM
(2)	6/8/2017 2:00 PM- 3:30 PM	Summary of IRP process and introduction to system	NMPRC Offices 4th Floor Hearing Room P.E.R.A. Building 1120 Paseo de Peralta Santa Fe, NM
(3)	7/6/2017 2:00 PM - 4:30 PM	Operational Considerations/Requirements for Future Resources Assessment of need for additional resources System Operations - Reliability, Import Limits and Balancing Existing Conventional Resources System generation retirement plan and process Transmission & Distribution Systems Overview and Projects	Dona Ana County Conference Room 113 845 N. Motel Blvd. Las Cruces, NM
(4)	8/8/2017 2:00 PM - 4:30 PM	Existing Renewable Resources and Distributed Generation (DG) Demand Response (DR) Programs and Options Energy Efficiency (EE) Load Forecast	Dona Ana County Conference Room 113 845 N. Motel Blvd. Las Cruces, NM
(5)	9/7/2017 2:00 PM - 4:30 PM	Conventional Capacity and Generation Option Considerations Demand Side Resource Options Renewable Energy Options (Solar, Wind, Geothermal, Storage, DG) Operational Considerations for Intermittent Resources and Balancing Renewable Portfolio Standard Impacts L&R Table Strategist Introduction Resource Input Template Renewable & Conventional Power Plant Siting and Environmental Considerations	Dona Ana County Conference Room 113 845 N. Motel Blvd. Las Cruces, NM
(6)	9/22/2017	Presentation by PAG members Merrie Lee Soules and Don Kurtz: "Public Advisory Group Special Session on Analysis for 2018 IRP"	Dona Ana County Conference Room 113 845 N. Motel Blvd, Las Cruces, NM
(7)	10/5/2017 2:00 PM - 4:30 PM	Initial Resource Options Submittal from PAG Due for November Run Rate Considerations and Potential Impacts on Resource Planning Decisions Resource Planning Base Case Assumptions Initial Cost Estimates for Resource Planning Options Modeling and risk assumptions and the cost & general attributes of potential additional resources	Dona Ana County Conference Room 113 845 N. Motel Blvd. Las Cruces, NM
(8)	10/20/2017	Presentation by PAG Members Merrie Lee Soules, Phil Simpson, Allen Downs, and Steve Fischmann: Special Session on Resource Analysis for 2018 IRP	Dona Ana County Conference Room 113 845 N. Motel Blvd. Las Cruces, NM
(9)	10/26/2017 2:00 PM - 4:30 PM	Retirements, Cost Modeling Assumptions, and other topics of interest to PAG	Dona Ana County Conference Room 113 845 N. Motel Blvd. Las Cruces, NM
(10)	11/2/2017	SANTA FE - Overview on Public Advisory Process	Santa Fe

PAG-designed meetings highlighted

Additional Meeting on Retirements (based on PAG feedback)

17.7.3.9 NMAC

Public Advisory Process Required Topics

Identification of Resource Options

Assessment of Need for Additional Resources

Load Forecast

Evaluation of Supply and Demand Side Resources

Modeling and Risk Assumptions

Cost and general attributes of potential additional resources

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EPE Proprietary Material

El Paso Electric

Public Advisory Group Meeting Schedule

Future Meetings

Meeting	Date	Subject	Location
(11)	11/16/2017 2:00 PM - 4:30 PM	Preliminary Results with 2017 Load Forecast Presentation of Resulting 20-year Expansion Plan Development of the most cost-effective portfolio of resources for utility's IRP	Dona Ana County Conference Room 113 845 N. Motel Blvd. Las Cruces, NM
(12)	1/19/2018	PAG Presentations and Discussions as Requested	Las Cruces
	2/2/2018	Last Resource Input Submittals from PAG Due	
(13)	2/16/2018	PAG Presentations and Discussions as Requested	Las Cruces
(14)	4/30/2018	IRP Draft Presentation	Las Cruces
(15)	5/16/2018	Follow-up meeting to receive and respond to public feedback	Las Cruces
(16)	6/8/2018	Final IRP presentation showing new load forecast	Las Cruces
(17)	6/29/2018	Follow-up meeting to receive and respond to public feedback	Las Cruces
	7/15/2018	**IRP Filing Date**	

Final Review Meetings*

17.7.3.9 NMAC

Public Advisory Process Required Topics

Development of the most cost-effective portfolio of resources for utility's IRP

*Joint Stipulation Case No. 15-00241-UT

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EPE Proprietary Material

El Paso Electric

Attachment A-4: Feedback Forms Summary

July 6, 2017 Feedback Form Summary

Consolidated feedback list by question:

What do you hope to get out of the IRP Public Advisory Process?

- A better understanding of EPE's thinking on Renewable generation, Demand Peak control and the future direction of the company.
- Lots of information! You are doing a good job! Please see card for other questions.
- Understanding rate case
- Understanding how to plan for a reliable source plan with a higher use of solar, storage changes for community solar
- Understanding of why rate increase is needed?
- Learn about transmission of power
- Long term impact of growth need for power in your service area
- Will EPE consider use of wind power and more solar power
- A better understanding of the IRP process and my role as a member of the PAG
- A good integrated plan that optimally provides reliability with pricing that helps our community develop economically
- I hope to build my knowledge and understanding of how EPE supplies reliable low cost electricity to NM customers
- A well-reviewed (360º) least cost portfolio scenarios

What topics on the meeting schedule are you most interested in?

- From agenda
  - Generation retirement process
  - Import limits and reliability
  - Demand response options
  - Solar and storage options
  - Intermittent resource operational considerations
  - Modeling
  - 20-year expansion plan

- Other topics:
  - Off-system purchases, solar, and other topics addressed in July 5, 2017 emails
  - Curious about how "solar" homes are going to be impacted differently from other homes in the future?
  - Capital spend in context of changing resources
  - Retirement EPE Generation
  - You tried to cover too much material which didn't allow more time for questions
  - Observation: Folks from EPE seem defensive.
  - Solar, including community solar
  - Cost allocation by rate groups. Cost allocation and pricing allocation should be close in practice. Currently 4CP allocates cost but rates are very different
  - Retirement justification
  - Loads and Resource table
  - Just resource type

October 19, 2017 Feedback Form Summary

Q1: Has IRP content been addressed to depth that you wanted?

Too Much	Too Little	Just Right
2	3	3

Comments:

- We're getting there

- Initial presentations were superficial, EPE seems evasive, real consideration being deferred to a later meeting or written questions. Written answers explained in numerical order instead of topical basis. Prior meetings rehashed which takes some air out of scheduled presentation and done in a fragmented way.

- Presentations too much to the point there is no time for questions/input from public. With recent presentations, public input has been encouraged. Please continue this format.

- Sometimes one or two people take most of the time (attendees)

- Too much irrelevant stuff. Too little satisfying requirements of IRP and PAG process. Presentations are mostly PR documents. Load forecast was designed to impress but not elucidate. Didn't provide explanation of the numbers in L&R. EE didn't provide numbers on L&R.

- Too little for what I wanted. I wanted it to be free and open. Utility is trying to increase its rate-base assets. I understand that this is how they best serve their stockholders, so it is an implicitly adversarial process with the ratepayers. They want to increase assets more than what is actually needed. Need to make sure Strategist is not run in a slanted way. EPE bonuses related to increased profits - conflict of interest.

- Learned a great deal from IRP meetings. Have been attending since they started. Not keen on rate issue as grid reliability. As long as have a feedback opportunity, it serves a useful purpose.

Q2 If you are no longer attending IRP meetings, please explain why.

Comments:

Due to no answers on this question, EPE made follow up calls on February to those participants who dropped off in participation.

Q3 To date, has there been something you wanted to discuss that was not discussed?

Comments:

- Energy storage in conjunction with solar. Challenges and possibilities? Electric vehicles
- No. Speakers should identify themselves. PAG appear to be informed so level of discourse should be higher.
- How does EPE see the future of batteries for energy use in our area
- More storage alternatives
- Retirements are scheduled for October
- No
- No
- How rates are calculated based on few peak hours. Most customers don't know that 65% of their rate is driven by peak to serve a couple of hours. Cost of refrigerated air should not be spread to all customers
- Demand Response needs to be evaluated as a resource not just a technique. Document signed by 12 PAG members outlined what's required by statute for EE. If DR not treated as a resource, strong area of protest on IRP. EPE is under pressure to provide profit to investors. We recommend EPE hires consultant to look at DR options.
- Interested in reliability of grid and integrity of it. EPE grid is fragile compared to others. Look at things that can be done to enhance integrity and reliability.

Q4 Are there topics you want to cover in more depth?

- Retirements.
- Yes, most of them
- Details of decreasing payments for solar customers. Why payments are lower.
- Distribution expansion plan needs to be shared. How will EPE incorporate solar, wind, batteries to facilitate cost reduction for customers. Willingness to reduce carbon footprint is needed. More attention to EE programs desired by customers.
- More on the solar discussion. How will it affect future billing?
- More understanding environmental impacts
- Load forecast, resource options, modeling & analysis process, inputs, output, scenarios
- Yes
- No, I'm a consumer concerned about rates being raised. I'm concerned about private solar panel ownership and solar panel benefits being reduced (surcharge)
- Rates, results of all-source RFP, results of Burns & McDonnell study which should include extension for 3, 5, 7, 10 years, and 440 filings for T&D construction to be reviewed in PAG process to assess which ones are needed.
- Sorely lacking is real time management for Demand Management. Real time info for demand resource is needed.

Feedback Calls Summary February 2018

Is there a reason why you stopped attending PAG meetings?	**Were the meetings what you expected them to be like?**	**What can we do to improve the Public Advisory Process next time around?**
Scheduling	Likes the content, but feels meeting is dominated by few PAG participants.	Break down into smaller groups for more personalized attention. Interest in DG. You're doing a great job.
Content not what PAG participant expected.	It is educational, but has problems with City inspectors.	Include Spanish translators (but I understand it may be costly)
Scheduling	Very informative.	Nothing critical on content and format. Wasn't clear if/how EPE would implement PAG's input.
Doesn't feel like input will be listened to.	No. People need to feel they're heard and addressed. The result seemed to be pre-determined.	People who know more than their one subject. It feels like EPE is just doing this because they have to.
Scheduling	Yes, some of it is kind of over my head, but they're very informative. Some PAG participants are distracting.	Increase publicity of meetings
Content not what PAG participant expected.	No. Wanted to discuss tariff on solar panels.	Every department should be present to answer questions on everything.

Attachment A-5: Resource Input Template Example

IRP Generic Resource Option Template

Basic Project Data	Example	Information
Generation Technology:	Solar, Wind, Demand Side, etc.	**Solar**
Resource Description (Overview of project):	Thin-film, single-axis tracking PV Solar	**Thin-film PV Project on single axis tracking system for improved generation and capacity factor**
Commercial Structure:	Company Owned, PPA, Other	**EPE Owned Resource**
Resource/Program Location (Where is the project located and will it serve both of EPE's jurisdictions):	TX or NM or Both	**Resource to be located in NM and will be a system resource.**
Resource Life or Term (What is the useful life of this project):	20 -yr, 40-yr, etc.	**25-yr Project life**
Maximum Net Capacity (MW)(Total amount of Megawatts this project will provide at time of peak):	50 MW, 100 MW, 300 MW, etc.	**50MW**
Minimum Net Output (MW)(The lowest Megawatt value that the resource can operate at):	25 MW, 50 MW, 150 MW, etc.	**See typical output profile (attached)**
Output Profile Availability (include as attachment)	If availability is constrained, provide "Output Profile" (e.g. solar, wind, biomass with fuel limitations, storage, demand response with limitations on use and duration,...)	
Availability Capacity Factor (%)(Percentage of unit output over the entire year. The capacity factor is the average power generated, divided by the rated peak power):	30%, 50%, 75%, etc.	**Resource has a forecasted capacity factor of 35% based solar output profile and tracking system.**
Project Costs Data	Information	Source (e.g. EIA, NREL, Lazard, NMPRC Approved projects in operation, etc.)
Total Capital Cost ($)(The entire upfront capital investment for the project):	**$72.5 Million**	**Lazard**
Variable Operation & Maintenance Cost ($/MWh)(Operating cost that are driven by unit generation):	---	---
Fixed Operations & Maintenance Cost ($/kW-yr)(Cost that are fixed no matter how much the resource operates):	**$12.00/kW-yr.**	**Lazard**
Outage Costs(Cost for a planned repair of the resource):	---	---
PPA Costs Data	Information	Source (e.g. EIA, NREL, Lazard, NMPRC Approved projects in operation, etc.)
All-In PPA price ($/MWh)	**N/A, Company Owned Resource**	---
Fixed or Escalating (Yes or No)	**Escalating, 1.95%**	**EPE's Forecasted Escalation Factors**

Note:

Additional detail or data maybe required based on project information provided above

Attachment A-6: Template Responses

First and foremost, EPE would like to convey its appreciation of the PAG participation in the IRP process. The participants' involvement in the meetings and research of resource options is greatly appreciated. We have reviewed the templates and have identified those which are viable, including several that are viable with modifications.

Additionally, the responses to the below templates also serve as EPE's feedback to the PAG October 20, 2017 meeting when these proposals were presented by the PAG.

1. **Template(s):**

   AD Swamp Cooler Motors submitted 10-26-17

   It is understood in discussion with the submitter of the proposal that the product as it is described in the submitted template is not in production or available for purchase to model the proposal, at a minimum, would require some product development in the form of package configuration for swamp cooler application, configuration for US power system and software control programming development. EPE, as a regulated utility, does not have a business model for investing in product development. EPE evaluates the implementation of technology and products that are available for the market. Therefore, EPE will not model this particular template recommendation.

2. **Template(s):**

   AD Customer Generation Resource submitted 10-26-17

   EPE does not view this program as a viable option as a regular resource to be used for meeting peak load on a regular basis. As mentioned by the PAG submitter on the form, customer sited combustion generators are typically limited in hours of operation due to environmental emission controls. This is the case because they are not equipped with optimal emission control equipment, such as Selective Catalytic Reduction, which are installed on utility scale generators. EPE will not model this particular template recommendation because the option presented is not viable.

3. **Template(s):**

   AD TOU Resource Template submitted 10-30-17

   As required by the IRP rule, EPE discussed how rate design would be reflected in customer demand sensitivities as a component of modeling in the IRP in a PAG meeting presentation. TOU rates themselves, including this resource template, will not be modeled as a resource in the Strategist model. However, EPE will be modeling low demand and high demand sensitivities which provide a reference for a reduction if demand growth due to TOU impacts.

4. **Template(s):**

PBS IRP Resource Options - Demand Response (enhanced eSmart) submitted 10-22-17

EPE's demand response option is modeled based on the eSmart pilot program. However, EPE is not forcing in selection of the demand response option, rather the demand response option will be included in the portfolio of resource options for analysis. EPE will model at least 5 MW in the initial portfolio analysis, and EPE will consider the 16.9 MW recommendation when assessing whether to increase the amount above 5 MW. To clarify, EPE had already committed to increase the DR amount available if the model selected DR. It needs to be re-iterated that the challenge with some DR programs are the availability for repetitive deployment which limits their availability to serve load. EPE will model the Demand Response template recommendation with some modifications.

5. **Template(s):**

PBS Option 1 IRP Resource Options - Demand Response submitted 10-22-17

EPE appreciates the demand response proposal and associated documentation provided from the NWPCC. They are beneficial in reviewing their efforts and results. EPE requires more time to review the demand response options presented with this template. EPE will investigate further viable programs for EPE's service territory and expected levels of adoption for further consideration in the IRP. Review of viable options would be more specific to our region, for instance space heating conservation would be less impactful and the levels of irrigation pumping may be different than those in the NWPCC.

6. **Template(s):**

MLS Purchase Power Spot Buy Template submitted 10-23-17

It should first be noted that EPE already contemplates utilizing up to 125 MW of purchase power spot buys in order to address load growth in the years between resource additions. It is not the norm in resource planning to assume that large amounts of power will be available at time of peak in order to meet load requirements. If everyone was to plan in this manner, there wouldn't be adequate capacity to meet the system's load requirements. Each entity has to ensure and plan for the acquisition of resources either through ownership or purchase power agreements that secure identified resources for the serving of load. Additionally, the planning of any resources remote to EPE requires consideration for firm transmission capacity to import the power to EPE's service territory. As such, EPE Resource Planning believes that planning for 125 MW of purchase power spot buys is a manageable risk and do not believe higher amounts would be appropriate. It is also necessary to clarify that EPE's RFP process allows for entities to bid in purchase power proposals for any existing resources which EPE would evaluate. Therefore, EPE will not model this particular template recommendation.

7. Template(s):

MLS Wind with Declining Costs Template submitted 10-23-17

EPE has researched the topic of forecasts for future wind capital costs and will incorporate some price drops for pricing in the 2022 to 2024 range. Beyond 2024 it will hold the capital costs for wind flat given that the declines appear to be tapering off. EPE subsequent IRP is planned for 2021 per the current rule schedule and pricing beyond 2024 may be adjusted at that time. Please reference page 18 of NREL (National Renewable Energy Laboratory). 2016. *2016 Annual Technology Baseline*. Golden, CO: National Renewable Energy Laboratory. http://www.nrel.gov/analysis/data_tech_baseline.html. EPE will model this proposal with some modifications.

8. Template(s):

MLS Solar with Declining Costs Template submitted 10-23-17

EPE has researched the topic of forecasts for future solar photovoltaic capital costs and will incorporate some price drops for pricing in the 2022 to 2024 range. Beyond 2024 it will hold the capital costs for solar PV flat given that the declines appear to be tapering off. Additionally, there are presently discussions related to the elimination of the ITC and the potential for tariffs in the near term. EPE subsequent IRP is planned for 2021 per the current rule schedule and pricing beyond 2024 may be adjusted at that time. Please reference page 34 of NREL (National Renewable Energy Laboratory). 2016. *2016 Annual Technology Baseline*. Golden, CO: National Renewable Energy Laboratory. http://www.nrel.gov/analysis/data_tech_baseline.html. EPE will model this proposal with some modifications.

9. Template(s):

MLS Energy Efficiency - Texas Template submitted 10-23-17

EPE will model energy efficiency as a resource option. The recommended inputs from this template will be taken into consideration but initial review indicate some adjustments may be required. As stated, the template recommended cost per kW is referenced as the average cost numbers for the Texas energy efficiency programs. EPE understands the referenced sources but EPE will need to review costs for energy efficiency options which will be in addition to the already existing programs. The already existing programs were selected with respect to existing energy efficiency rules and requirements. EPE's current estimates indicate $1,500 to $1,750 per kW may be more appropriate for additional energy efficiency programs, but will investigate further. EPE will also review reasonable adoption and implementation rates. Energy efficiency programs build up over time, and a 10 MW assumption in year one may be too optimistic.

10. Template(s):

MLS Solar with storage PPA Template submitted 10-23-17

EPE will model the solar with storage proposal with modifications. EPE agrees it is appropriate to model a solar project with storage and will run an option with a PPA price of $0.039/kWh which is recommended in the template as the 2023 price projection. EPE will hold the $0.039/kWh price flat for future years beyond 2023. As mentioned in other responses, future price reductions beyond 2023 will be re-evaluated in EPE's 2021 IRP.

11. Template(s):

MLS Distributed Generation Template submitted 10-23-17

EPE does not agree that the recommended template is an option that offers the best benefit for ratepayers and believes it is not a viable option to model. The distributed generation template is recommending the subsidizing of solar DG, which is less optimal than utility scale solar, for customers at a cost to all customers. Solar DG is less optimal with regard to solar production given topics discussed during the PAG meetings highlighting their orientation is fixed and typically not optimal. This is the case due to the fact that building construction and rooflines constrain the orientation of the panels. Considering that DG provides a contribution to peak that is below 50% versus utility scale that is at 70% on average, it does not make sense for ratepayers to subsidize DG installations, especially at the $80/MWh value recommended by the template. The $80/MWh is greater than current utility scale PPA prices.

12. Template(s):

AD 171220 Stranded Scenario submitted 12-20-17.docx

EPE does not agree that the recommended template is an option that offers the best benefit for ratepayers and believes it is not a viable option to model. Currently, there is no regulatory or legislative requirement that would drive the scenario being proposed. While there may be proposals that would promote or potentially mandate higher renewable energy targets, none have been passed. Renewables have become more cost competitive and are considered appropriately within the IRP framework. Therefore, EPE will not model this particular template recommendation.

13. Template(s):

AD 180107InterptTempl submitted 1-16-18.xlsx

EPE will explore the possibility of modeling a demand response option of this type; however, the amount of capacity that may be attainable and reasonable will be considered. EPE does already have a demand response modeled based on the demand response pilot program approved in New Mexico. The rates topic will be a separate discussion to be included in the IRP report.

14. Template(s):

14 CLC 2018 EPE IRP PV3 Replacement Resource Template v2 submitted 3-12-18.pdf

EPE conducted a sensitivity analysis associated with Palo Verde Unit 3 ("PV3") and its nameplate capacity (MW) available to New Mexico customers. This is presently quantified at 42 MW based on jurisdictional allocation factors. The Strategist sensitivity analysis assumed 42 MW of PV3 were no longer available to serve load beginning in year 2020.

15. Template(s):

PBS EE like APS submitted 2-2-18.xlsx

EPE has agreed to model EE programs in excess of the goal if they are viable and result in a least cost option. EPE reviewed the most recent IRP filed by Arizona Public Service (APS) in relation to their Energy Efficiency programs and forecasts. Based on this review, there are several key considerations to keep in mind when comparing to EPE's Energy Efficiency forecasts. The Arizona Corporation Commission (ACC) Energy Efficiency Standard (EES) requires a 22% cumulative energy savings by 2020. This varies greatly to New Mexico's goal which is 8% by 2020. This difference, which is driven by regulatory initiatives is a cause of the higher EE penetration forecast from APS. APS is forecasting its energy efficiency to grow to 534 MW to meet the 22% goal based on the ACC regulations. EPE has already met its 2020 EE goal of 8% for New Mexico.

16. Template(s):

PBS Solar with Storage V11 Template submitted 2-2-18.xlsx

EPE has committed to run a resource option based on solar generation coupled with battery scenario. This scenario is being considered based on PAG input and template submittal(s). EPE is modeling this resource as a PPA with input derived from publicly available information. The PPA price for this resource is $39/MWh. EPE is introducing a 100 MW solar project coupled with a 30 MW battery.

Attachment A-7: "No Combined Cycle" Results

Year	Resource	Capacity	Contribution to Peak
2018			
2019			
2020			
2021			
2022	Solar PV	25	6.25
	Solar PV	75	18.75
	Solar PV	75	18.75
	Solar PV	75	18.75
	Solar PV	100	25
	Battery Storage	15	15
2023	Newman 1 Extension	74	74
	Rio Grande 7 Extension	46	46
	Combustion Turbine	100	100
	Battery Storage	50	50
2024			
2025			
2026			
2027	Combined Cycle	320	320
2028	Combustion Turbine	100	100
	Reciprocating Engine	100	100
	Battery Storage	15	15
2029			
2030			
2031	Combined Cycle	320	320
2032			
2033			
2034	Combustion Turbine	100	100
	Reciprocating Engine	100	100
2035	Battery Storage	50	50
2036	Solar PV & Battery	100	0
		30	30
2037	Biofuel	20	20
	Geothermal	20	20

No Combined Cycle Sensitivity

PROVIEW LEAST COST OPTIMIZATION SYSTEM
PLANNING PERIOD PLAN COMPARISON

PLAN RANK	1	2	3	4	5	6	7	8
2018								
2019								
2020								
2021								
2022	25S (1)	25S (1)	25S (1)	25S (1)	25S (1)	25S (1)	25S (1)	25S (1)
	75S (3)	75S (3)	75S (3)	75S (3)	75S (3)	75S (3)	75S (3)	75S (3)
	100S(1)	100S(1)	100S(1)	100S(1)	100S(1)	100S(1)	100S(1)	100S(1)
	STOR(1)	STOR(1)	STOR(1)	STOR(1)	STOR(1)	STOR(1)	STOR(1)	STOR(1)
2023	NM1X(1)	NM1X(1)	NM1X(1)	NM1X(1)	NM1X(1)	NM1X(1)	NM1X(1)	NM2X(1)
	RG7X(1)	RG7X(1)	RG7X(1)	RG7X(1)	RG6X(1)	RG6X(1)	RG6X(1)	RG7X(1)
	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)
	BS1G(1)	BS1G(1)	BS1G(1)	BS1G(1)	BS1G(1)	BS1G(1)	BS1G(1)	BS1G(1)
2024								
2025								
2026								
2027	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)
2028	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)
	RCP1(1)	RCP1(1)	RCP1(1)	RCP1(1)	RCP1(1)	RCP1(1)	RCP1(1)	RCP1(1)
	STOR(1)	STOR(1)	STOR(1)	STOR(1)	STOR(1)	STOR(1)	STOR(1)	STOR(1)
2029								
2030								
2031	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)
2032								
2033								
2034	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)
	RCP1(1)	RCP1(1)	RCP1(1)	RCP1(1)	RCP1(1)	RCP1(1)	RCP1(1)	RCP1(1)
2035	BS1G(1)	PVS (1)	BS1G(1)	BS1G(1)	BS1G(1)	PVS (1)	BS1G(1)	BS1G(1)
2036	PVS (1)	BS1G(1)	BIO1(1)	GEO1(1)	PVS (1)	BS1G(1)	BIO1(1)	PVS (1)
2037	BIO1(1)	BIO1(1)	GEO1(1)	BIO1(1)	BIO1(1)	BIO1(1)	GEO1(1)	BIO1(1)
	GEO1(1)	GEO1(1)	PVS (1)	PVS (1)	GEO1(1)	GEO1(1)	PVS (1)	GEO1(1)
P.V. UTILITY COST:								
PLANNING PERIOD	3270295.5	3270484.0	3272023.5	3272402.2	3273437.2	3273625.8	3275165.2	3275398.8
% DIFFERENCE	0.00%	0.01%	0.05%	0.06%	0.10%	0.10%	0.15%	0.16%
STUDY PERIOD RANK	1	2	3	4	5	6	7	8

Attachment A-8: PVNGS Unit 3 Sensitivity Results

Year	Resource	Capacity	Contribution to Peak
2018			
2019			
2020	Solar PV	75	18.75
	Solar PV	75	18.75
	Solar PV	100	25
2021			
2022	Solar PV	75	18.75
	Battery Storage	15	15
	Battery Storage	50	50
2023	Combined Cycle	320	320
2024			
2025			
2026			
2027	Combined Cycle	320	320
2028	Combustion Turbine	100	100
2029			
2030			
2031	Combustion Turbine	100	100
	Reciprocating Engine	50	50
	Battery Storage	50	50
2032	Battery Storage	15	15
2033	Reciprocating Engine	100	100
2034	Combustion Turbine	100	100
	Reciprocating Engine	100	100
2035			
2036	Solar PV & Battery	100	0
		30	30
2037	Biofuel	20	20
	Geothermal	20	20

PVNGS Unit 3 Sensitivity Results

PROVIEW LEAST COST OPTIMIZATION SYSTEM
PLANNING PERIOD PLAN COMPARISON

PLAN RANK	1	2	3	4	5	6	7	8
2018								
2019								
2020	75S (2)	75S (2)	75S (2)	75S (2)	75S (2)	75S (2)	75S (2)	75S (2)
	100S(1)	100S(1)	100S(1)	100S(1)	100S(1)	100S(1)	100S(1)	100S(1)
2021								
2022	75S (1)	75S (1)	75S (1)	75S (1)	75S (1)	75S (1)	75S (1)	75S (1)
	STOR(1)	STOR(1)	STOR(1)	STOR(1)	STOR(1)	STOR(1)	STOR(1)	STOR(1)
	BS1G(1)	BS1G(1)	BS1G(1)	BS1G(1)	BS1G(1)	BS1G(1)	BS1G(1)	BS1G(1)
2023	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)
2024								
2025								
2026								
2027	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)
2028	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)
2029								
2030								
2031	CT_L(1)	CT_L(1)	CT_L(1)	RCP1(1)	CT_L(1)	CT_L(1)	RCP1(1)	RCP1(1)
	RCP2(1)	RCP2(1)	RCP2(1)	RCP2(1)	RCP1(1)	RCP1(1)	RCP2(1)	RCP2(1)
	BS1G(1)	BS1G(1)	BS1G(1)	BS1G(1)			BS1G(1)	BS1G(1)
2032	STOR(1)	STOR(1)	STOR(1)	STOR(1)	STOR(1)	STOR(1)	STOR(1)	STOR(1)
2033	RCP1(1)	RCP1(1)	RCP1(1)	RCP1(1)	RCP2(1)	RCP2(1)	RCP1(1)	RCP1(1)
2034	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)
	RCP1(1)	RCP1(1)	RCP1(1)	RCP1(1)	RCP1(1)	RCP1(1)	RCP1(1)	RCP1(1)
2035					BS1G(1)	PVS (1)		
2036	PVS (1)	BIO1(1)	GEO1(1)	PVS (1)	PVS (1)	BS1G(1)	BIO1(1)	GEO1(1)
2037	BIO1(1)	GEO1(1)	BIO1(1)	BIO1(1)	BIO1(1)	BIO1(1)	GEO1(1)	BIO1(1)
	GEO1(1)	PVS (1)	PVS (1)	GEO1(1)	GEO1(1)	GEO1(1)	PVS (1)	PVS (1)
P.V. UTILITY COST:								
PLANNING PERIOD	3264705.2	3266531.5	3266928.0	3267574.8	3268940.0	3269022.5	3269405.8	3269798.0
% DIFFERENCE	0.00%	0.06%	0.07%	0.09%	0.13%	0.13%	0.14%	0.16%
STUDY PERIOD RANK	1	2	3	4	5	6	7	8

Attachment A-9: Independent Evaluator Assessment

MERRIMACK ENERGY GROUP, INC

September 12, 2018

Omar Gallegos
Director – Resource Planning and Management
El Paso Electric Company
P.O. Box 982
El Paso, Texas 79960

Re: Review and Assessment of El Paso Electric's IRP Resource Options Input Assumptions Relative to the Information Provided Through the 2017 All Source Request for Proposals ("RFP") For Electric Power Supply and Load Management Resources ("2017 All Source RFP")

Dear Mr. Gallegos:

Merrimack Energy Group, Inc. ("Merrimack Energy") has served as Independent Evaluator for El Paso Electric's 2017 All Source RFP. Through this solicitation process we have reviewed and summarized all the proposals received and are therefore very familiar with the pricing and other information provided by the bidders under the competitive solicitation process. El Paso Electric has asked Merrimack Energy to review the input assumptions for pricing and other information developed by El Paso Electric as the basis for comparing resource options as part of its Integrated Resource Planning ("IRP") process and assess whether the input assumptions are consistent with the actual information provided by bidders in response to the 2017 All Source RFP. Merrimack Energy has reviewed the pricing of similar resources submitted into the RFP compared to the IRP resource options input assumptions as well as other benchmark resource costs. Based on this review and assessment, Merrimack Energy confirms that the IRP input assumptions are reasonably consistent with the actual pricing submitted by the bidders for the same resource options with similar project sizes. We had questions about the capital cost assumptions for only two resource options; wind and gas reciprocating engines. In both cases, we felt the IRP input assumptions were slightly on the low side compared to actual market costs from El Paso Electric's 2017 All Source RFP results and from my knowledge and experience.

Very Truly Yours,

Wayne Oliver

Wayne Oliver
President
Merrimack Energy Group, Inc.
26 Shipway Place
Charlestown, Mass. 02129

26 SHIPWAY PLACE
CHARLESTOWN, MASSACHUSETTS 02129
TELEPHONE: 781-856-0007

Attachment A-10: Public Notice

El Paso Electric

300 Galisteo Street, Suite 206
Santa Fe, New Mexico 87501
(505) 982-7391

HAND-DELIVERED

May 10, 2017

Ms. Melanie Sandoval
New Mexico Public Regulation Commission
1120 Paseo de Peralta
Santa Fe, NM 87501

Re: Rule 17.7.3 NMAC Filing; 2018 IRP Notice
El Paso Electric Company's ("EPE") Proof of Publication, Affidavit of Maritza Perez of Notice to Customers

Dear Ms. Sandoval:

Enclosed please find the original and five (5) copies of El Paso Electric Company's Proof of Publication and Affidavit of Maritza Perez of Notice to Customers in accordance with Rule 17.7.3.9H(1) NMAC. Also, on April 20, 2017 EPE filed and served Rule 17.7.3 NMAC: Notice of IRP Process; Notice of Integrated Resource Planning Public Advisory Group Meetings.

Please conform and return two (2) copies to our messenger. Thank you for your assistance in this matter.

Very truly yours,

Nancy B. Burns
Senior Attorney
El Paso Electric Company

Enclosures
cc: Service List

www.lcsun-news.com

LAS CRUCES SUN-NEWS

PROOF OF PUBLICATION

I, being duly sworn, Maria Del Villar deposes and says that she is the Legal Coordinator of the Las Cruces Sun-News, a newspaper published daily in the county of Dona Ana, State of New Mexico; that the 1185032 is an exact duplicate of the notice that was published once a week/day in regular and entire issue of said newspaper and not in any supplement thereof for 1 consecutive week(s)/day(s), the first publication was in the issue dated April 20, 2017, the last publication was April 20, 2017. Despondent further states this newspaper is duly qualified to publish legal notice or advertisements within the meaning of Sec. Chapter 167, Laws of 1937.

Signed

Maria Del Villar

Legal Coordinator
Official Position

STATE OF NEW MEXICO
ss.
County of Dona Ana
Subscribed and sworn before me this

20th **day of** Apr. 17

Diana Jaramillo

Notary Public in and for
Dona Ana County, New Mexico

June 24, 2019

My Term Expires

OFFICIAL SEAL
DIANA JARAMILLO
Notary Public
State of New Mexico
My Comm. Expires 06/24/19

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

RULE 17.7.3 NMAC FILING

EL PASO ELECTRIC
COMPANY
NOTICE OF 2018
INTEGRATED RESOURCE PLAN

2017-2018 PLANNING PROCESS AND
PUBLIC ADVISORY GROUP MEETINGS

Notice is hereby given that:
El Paso Electric Company ("EPE") invites members of the public to attend a series of public advisory group meetings. With public participation, EPE will develop its Integrated Resource Plan ("IRP"), pursuant to the New Mexico Efficient Use of Energy Act and the New Mexico Public Regulation Commission's ("Commission" or "NMPRC") IRP Rule. EPE's IRP will identify cost-effective demand-side and supply-side electricity resources to serve EPE's customers over the next 20 year planning period. The IRP will be submitted to the Commission no later than July 2018. Public input is critical to the development and implementation of EPE's integrated resource planning in New Mexico. EPE encourages all members of the public to attend these public meetings to provide public input and public commentary, whether as a residential or business customer or a representative of a trade, non-profit, neighborhood, shareholder, civic or other group.
The first scheduled meeting will be held on May 25, 2017, at 2:00 P.M. MDT in El Paso Electric Company's office located at 555 S. Compress Road, Las Cruces, NM. The IRP process will be explained and additional meeting dates will be set at that time. The public may also participate in meetings through the internet. Prior to each meeting, the presentation for that meeting will be posted on EPE's website, www.epeletric.com. If you are interested in attending the meeting or otherwise participating in the process, please contact EPE by emailing Maritza Perez, Regulatory Case Manager at Maritza.Perez@epelectric.com or calling at (915) 543-2057.
Pub#1185032
Run Date: April 20, 2017

80 Thursday, April 20, 2017 lcsun-news.com Las Cruces Sun-News

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Legal Notices 152

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

RULE 17.7.3 NMAC FILING

EL PASO ELECTRIC COMPANY
NOTICE OF 2018 INTEGRATED RESOURCE PLAN

2017-2018 PLANNING PROCESS AND
PUBLIC ADVISORY GROUP MEETINGS

AFFIDAVIT OF MARITZA PEREZ OF NOTICE TO CUSTOMERS

My name is Maritza Perez and I am personally acquainted with the facts herein stated:

1. I am employed by El Paso Electric Company ("EPE" or the "Company") as a Regulatory Case Manager. My business address is 100 N. Stanton Street, El Paso, Texas 79901.

2. My responsibilities include the preparation of rate and regulatory filings and compliance with the various regulatory requirements of the jurisdictions in which EPE operates.

3. Pursuant to Rule 17.7.3.9H(1) NMAC, the New Mexico Public Regulation Commission ("Commission") requires EPE to provide notice of EPE's 2018 Integrated Resource Plan's 2017-2018 Planning Process and Public Advisory Group Meetings in the utility's billing inserts.

4. EPE directly mailed the required notice to all existing New Mexico customers in a bill insert between March 27, 2017 and April 24, 2017. A copy of the bill insert is attached as Exhibit A to this Affidavit.

5. EPE also posted a notice on its website on April 29, 2017.

State of Texas)
)
County of El Paso)

I have read the foregoing Affidavit and it is true to the best of my knowledge, information and belief.

Before me this 8th day of May, 2017.

Maritza Perez

SUBSCRIBED AND SWORN to before me this 5th day of May, 2017.

Notary: Julieta E. Cordero

My Commission Expires: October 2, 2018

JULIETA E. CORDERO
Notary Public, State of Texas
My Commission Expires
October 02, 2018

Page 2 of 2

Exhibit A

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

RULE 17.7.3 NMAC FILING

EL PASO ELECTRIC COMPANY
NOTICE OF 2018 INTEGRATED RESOURCE PLAN

2017-2018 PLANNING PROCESS AND
PUBLIC ADVISORY GROUP MEETINGS

Notice is hereby given that:

El Paso Electric Company ("EPE") invites members of the public to attend a series of public advisory group meetings. With public participation, EPE will develop its Integrated Resource Plan ("IRP"), pursuant to the New Mexico Efficient Use of Energy Act and the New Mexico Public Regulation Commission's ("Commission" or "NMPRC") IRP Rule. EPE's IRP will identify cost-effective demand-side and supply-side electricity resources to serve EPE's customers over the next 20 year planning period. The IRP will be submitted to the Commission no later than July 2018.

Public input is critical to the development and implementation of EPE's integrated resource planning in New Mexico. EPE encourages all members of the public to attend these public meetings to provide public input and public commentary, whether as a residential or business customer or a representative of a trade, non-profit, neighborhood, shareholder, civic or other group.

The first scheduled meeting will be held on May 25, 2017, at 2:00 P.M. MDT in El Paso Electric Company's office located at 555 S. Compress Road, Las Cruces, NM. The IRP process will be explained and additional meeting dates will be set at that time. The public may also participate in meetings through the internet. Prior to each meeting, the presentation for that meeting will be posted on EPE's website, www.epeletric.com. If you are interested in attending the meeting or otherwise participating in the process, please contact EPE by emailing Maritza Perez, Regulatory Case Manager at Maritza.Perez@epelectric.com or calling at (915) 543-2057.

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

MAY 10 '17 AM10:24

CERTIFICATE OF SERVICE

RULE 17.7.3 NMAC: NOTICE OF IRP PROCESS

I HEREBY CERTIFY that the foregoing copy of **El Paso Electric Company's ("EPE") Proof of Publication and Affidavit of Maritza Perez of Notice to Customers** was served on the New Mexico Public Regulation Commission, Intervenors in EPE's most recent rate case (NMPRC Case No.15-00127-UT), renewable energy procurement plan case (NMPRC Case No.16-00109-UT), energy efficiency case (NMPRC Case No.16-00185-UT) and IRP Proceedings (Case No. 15-00241-UT) on May 10, 2017, as indicated below to each of the following:

Via Email to:

Nancy B. Burns	nancy.burns@epelectric.com;
Patricia Griego	patricia.griego@epelectric.com;
Maritza Perez	Maritza.perez@epelectric.com
Carol A. Clifford	carol@thejonesfirm.com;
Joseph Yar	jyar@nmag.gov;
Alicia Armijo	aarmijo@nmag.gov;
J. Cotton/Andrea Crane	ctcolumbia@aol.com;
Joan E. Drake	Jdrake@modrall.com;
Lizbeth Ellis	Lellis@nmsu.edu;
Glen Haubold	ghaubold@ad.nmsu.edu;
Doug Gegax	dgegax@nmsu.edu;
Dan Neidlinger	dneid@cox.net;
Charles Noble	noble.ccae@gmail.com;
Noel J. Schaefer	schaefno@gmail.com;

1

Steve Michel	smichel@westernresources.org;
David Van Winkle	david@vw77.com;
Anastasia Stevens	ast@keleher-law.com;
Kurt Wihl	kw@keleher-law.com
William R. Babington, Jr.	rbabington@las-cruces.org;
Marcia B. Driggers	marcyd@las-cruces.org;
Jorge A. Garcia	JAG@las-cruces.org;
Daniel Avila	davilla@las-cruces.org;
Jose F. Provencio	joprovencio@las-cruces.org;
Stuart C. Ed	Sed@las-cruces.org;
David Dollahon	ddollahon@las-cruces.org;
Robert Garza	rgarza@las-cruces.org;
Tom Figart	tomf@donaanacounty.org;
Nann M. Winter	nwinter@stelznerlaw.com;
Rebekah Gallegos	rgallegos@stelznerlaw.com
Dahl Harris	dahlharris@hotmail.com;
Rick Gilliam	rick@votesolar.org;
Tom Solomon	tasolomon6@gmail.com;
Don Hancock	sricdon@earthlink.net;
Jason Marks	lawoffice@jasonmarks.com;
Rocky Bacchus	rocky.bacchus@gmail.com;
Allen Downs	ecomaxac@lifeisgood2.com;
Merrie Lee Soules	mlsoules@hotmail.com;

Stephen Fischmann	Stephen.Fischmann@gmail.com;
Robert Ganton	Robert.a.ganton.civ@mail.mil;
Kyle J. Smith	Kyle.j.smith124.civ@mail.mil;
Ramona Blaber	ramona.blaber@ sierraclub.org;
Howard Geller	hgeller@swenergy.org;
Adam Bickford	abickford@swenergy.org;
Joshua L. Smith	Jsmith.watsonlawlc@gmail.com
Bruce Throne	bthroneatty@newmexico.com;
Megan O'Reilly	acresearchandanalysis@gmail.com;
Jim Dittmer	jdittmer@utilitech.net
Kelly Crandall	kcrandall@kfwlaw.com;
John Welinghoff	jon.wellinghoff@stoel.com;
Arnulfo Castaneda	acastaneda@cityofanthonynm.com
Jill Tauber	jtauber@earthjustice.org
Sara Gersen	sgersen@earthjustice.org;
Joe Herz, PE	jaherz@sawvel.com;
Andrew Harriger	akharriger@sawvel.com;
William Steele	wa.stelle@hotmail.com;
Carla Sonntag	Carla@nmusa.org;

Hand-Delivered
Jack Sidler
NMPRC Utility Division
1120 Paseo de Peralta
Santa Fe, NM 87501
Jack.Sidler@state.nm.us;

Hand-Delivered
Charles Gunter
NMPRC Utility Division
1120 Paseo de Peralta
Santa Fe, NM 87501
Charles.Gunter@state.nm.us;

Hand-Delivered
John Reynolds
NMPRC Utility Division
1120 Paseo de Peralta
Santa Fe, NM 87501
John.Reynolds@state.nm.us;

Hand-Delivered
Bradford Borman
NMPRC Legal Division
1120 Paseo de Peralta
Santa Fe, NM 87501
Bradford.Borman@state.nm.us;

Hand-Delivered
Michael C. Smith
NMPRC General Counsel
1120 Paseo de Peralta
Santa Fe, NM 87501
MichaelC.Smith@state.nm.us;

DATED this 10th day of May, 2017.

Trish Griego

Trish Griego
Legal Assistant

Attachment B-1: 2018 Long Term Forecast

2018 LONG-TERM FORECAST
EL PASO ELECTRIC COMPANY
2018-2027 DEMAND AND ENERGY FORECAST

ENERGY (GWH)	2017 (1)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	10-YR (6) CAGR
Native System Forecast (NFL) (2)												
Upper Bound		8,917	9,053	9,185	9,322	9,477	9,639	9,799	9,963	10,134	10,310	
Expected:	8,427	8,588	8,726	8,858	8,993	9,145	9,303	9,457	9,613	9,777	9,945	**1.7**
Lower Bound		8,259	8,399	8,531	8,664	8,814	8,966	9,114	9,264	9,420	9,579	
Less: DG (3)		14	28	43	57	71	85	98	112	126	140	
Less: EE (4)		35	70	105	141	176	211	246	281	316	351	
Native System Energy												
Upper Bound		8,867	8,953	9,033	9,117	9,220	9,328	9,434	9,543	9,660	9,782	
Expected:	**8,427**	**8,539**	**8,627**	**8,710**	**8,796**	**8,899**	**9,007**	**9,112**	**9,220**	**9,335**	**9,454**	**1.2**
Lower Bound		8,210	8,302	8,387	8,474	8,578	8,687	8,791	8,897	9,010	9,125	
Total System Net Energy (5)												
Upper Bound		8,835	8,920	9,001	9,085	9,188	9,296	9,402	9,512	9,629	9,751	
Expected:	**8,399**	**8,512**	**8,601**	**8,684**	**8,769**	**8,873**	**8,981**	**9,086**	**9,194**	**9,309**	**9,427**	**1.2**
Lower Bound		8,190	8,282	8,367	8,454	8,558	8,666	8,770	8,876	8,988	9,104	
DEMAND (MW)												
Native System Forecast (NFL)												
Upper Bound		2,087	2,122	2,149	2,188	2,225	2,262	2,294	2,337	2,376	2,416	
Expected:	1,935	1,972	2,004	2,028	2,065	2,100	2,136	2,166	2,207	2,245	2,283	**1.7**
Lower Bound		1,857	1,886	1,908	1,942	1,975	2,010	2,037	2,078	2,114	2,151	
Less: DG		3	6	9	12	15	18	21	24	27	30	
Less: EE		5	9	14	19	23	28	33	38	42	47	
Native System Demand:												
Upper Bound		2,079	2,106	2,125	2,155	2,184	2,213	2,236	2,271	2,302	2,333	
Expected:	**1,935**	**1,964**	**1,988**	**2,005**	**2,034**	**2,061**	**2,090**	**2,111**	**2,146**	**2,176**	**2,206**	**1.3**
Lower Bound		1,849	1,870	1,885	1,913	1,939	1,966	1,987	2,020	2,050	2,080	
Total System Demand												
Upper Bound		2,072	2,099	2,118	2,148	2,177	2,206	2,229	2,264	2,295	2,326	
Expected:	**1,932**	**1,958**	**1,982**	**1,999**	**2,028**	**2,055**	**2,084**	**2,105**	**2,140**	**2,170**	**2,200**	**1.3**
Lower Bound		1,844	1,865	1,880	1,907	1,934	1,961	1,982	2,015	2,045	2,075	
Interruptible Load		54	54	54	54	54	54	54	54	54	54	
Upper Bound		2,018	2,043	2,061	2,090	2,117	2,146	2,168	2,203	2,233	2,264	
Expected:	**1,932**	**1,904**	**1,928**	**1,945**	**1,973**	**2,001**	**2,029**	**2,051**	**2,085**	**2,115**	**2,146**	**1.1**
Lower Bound		1,790	1,813	1,829	1,857	1,884	1,912	1,934	1,968	1,997	2,028	

Footnotes:
(1) 2017 are Actual data, Native System Peak occurred on June 22.
(2) Net For Load is forecasted load before the removal of DG and EE.
(3) Impact from Distributed Generation.
(4) Impact from Energy Efficiency.
(5) Total System includes transmission wheeling Losses To Others.
(6) 10-Year Compounded Average Growth Rate.

/s/ Adrian J. Rodriguez
Adrian J. Rodriguez
Senior Vice President & General Counsel

2018 LONG-TERM FORECAST
EL PASO ELECTRIC COMPANY
2028-2037 DEMAND AND ENERGY FORECAST

ENERGY (GWH)	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**20-YR (1) CAGR**
Native System Forecast (NFL)											
Upper Bound	10,487	10,673	10,872	11,065	11,269	11,483	11,705	11,931	12,163	12,406	
Expected:	10,112	10,288	10,477	10,659	10,852	11,054	11,264	11,477	11,696	11,925	**1.8**
Lower Bound	9,737	9,904	10,082	10,253	10,435	10,625	10,823	11,023	11,229	11,444	
Less: DG	153	167	180	193	207	220	233	246	259	272	
Less: EE	386	422	457	492	527	562	597	632	667	703	
Native System Energy:											
Upper Bound	9,904	10,036	10,180	10,319	10,470	10,630	10,798	10,970	11,150	11,339	
Expected:	**9,572**	**9,700**	**9,840**	**9,974**	**10,118**	**10,272**	**10,433**	**10,598**	**10,769**	**10,950**	**1.3**
Lower Bound	9,241	9,364	9,500	9,628	9,767	9,914	10,069	10,226	10,389	10,561	
Total System Net Energy:											
Upper Bound	9,873	10,005	10,150	10,289	10,439	10,600	10,768	10,941	11,120	11,310	
Expected:	**9,546**	**9,674**	**9,814**	**9,948**	**10,092**	**10,246**	**10,407**	**10,572**	**10,743**	**10,924**	**1.3**
Lower Bound	9,219	9,342	9,478	9,606	9,744	9,892	10,046	10,203	10,366	10,538	
DEMAND (MW)											
Native System Forecast											
Upper Bound	2,450	2,498	2,543	2,586	2,626	2,681	2,731	2,781	2,827	2,889	
Expected:	2,316	2,362	2,406	2,448	2,485	2,538	2,586	2,635	2,678	2,738	**1.8**
Lower Bound	2,181	2,227	2,269	2,309	2,344	2,396	2,442	2,489	2,530	2,588	
Less: DG	33	36	39	42	45	48	50	53	56	59	
Less: EE	52	56	61	66	70	75	80	84	89	94	
Native System Demand:											
Upper Bound	2,358	2,398	2,435	2,470	2,501	2,547	2,589	2,632	2,668	2,722	
Expected:	**2,231**	**2,270**	**2,306**	**2,340**	**2,370**	**2,416**	**2,456**	**2,498**	**2,533**	**2,586**	**1.5**
Lower Bound	2,103	2,142	2,177	2,210	2,239	2,284	2,324	2,364	2,398	2,449	
Total System Demand:											
Upper Bound	2,351	2,391	2,428	2,463	2,494	2,540	2,582	2,625	2,662	2,715	
Expected:	**2,225**	**2,264**	**2,300**	**2,334**	**2,364**	**2,410**	**2,450**	**2,492**	**2,527**	**2,580**	**1.5**
Lower Bound	2,098	2,137	2,172	2,205	2,234	2,279	2,318	2,359	2,393	2,444	
Interruptible Load:	54	54	54	54	54	54	54	54	54	54	
Upper Bound	2,289	2,329	2,366	2,401	2,431	2,478	2,520	2,562	2,599	2,653	
Expected:	**2,170**	**2,210**	**2,245**	**2,280**	**2,309**	**2,355**	**2,396**	**2,437**	**2,473**	**2,525**	**1.3**
Lower Bound	2,051	2,090	2,125	2,159	2,188	2,232	2,272	2,312	2,346	2,397	

Footnotes:
(1) 20-Year Compounded Average Growth Rate.

Attachment B-2: 2018 Long Term Energy Forecast by Customer Class and Jurisdiction (MWh)

	Texas						New Mexico								
Year	Residential	Commercial & Industrial, Small	Commercial & Industrial, Large	Street Lighting	OPA	Total Texas	Residential	Commercial & Industrial, Small	Commercial & Industrial, Large	Street Lighting	OPA	Total New Mexico	Company Use	FERC	Total Native System
2018	2,346,717	2,048,546	1,055,446	39,858	1,228,568	6,719,135	734,397	531,888	65,847	2,995	399,673	1,734,799	14,484	70,151	8,538,570
2019	2,386,037	2,061,822	1,061,392	40,453	1,249,350	6,799,054	741,841	534,098	63,724	3,041	399,146	1,741,850	14,760	71,763	8,627,426
2020	2,427,310	2,075,299	1,063,930	41,101	1,264,893	6,872,533	749,222	534,302	61,670	3,095	400,510	1,748,799	15,040	73,833	8,710,205
2021	2,471,166	2,086,808	1,064,623	41,730	1,280,068	6,944,395	760,099	535,234	60,507	3,150	401,871	1,760,861	15,326	75,120	8,795,702
2022	2,523,156	2,098,645	1,064,049	42,324	1,304,508	7,032,684	770,800	538,142	59,349	3,206	402,422	1,773,920	15,617	76,783	8,899,003
2023	2,575,235	2,112,307	1,062,607	42,905	1,329,749	7,122,803	783,274	541,377	58,118	3,261	402,959	1,788,989	15,914	79,456	9,007,162
2024	2,627,844	2,126,106	1,060,569	43,471	1,355,515	7,213,505	795,039	544,144	56,401	3,317	403,878	1,802,779	16,216	79,724	9,112,225
2025	2,682,185	2,141,493	1,058,121	44,023	1,377,687	7,303,510	807,380	547,651	54,886	3,373	404,849	1,818,139	16,524	81,876	9,220,050
2026	2,740,466	2,158,356	1,055,394	44,600	1,400,925	7,399,741	819,902	552,034	53,541	3,431	405,546	1,834,454	16,838	83,916	9,334,948
2027	2,799,545	2,176,304	1,052,473	45,187	1,424,338	7,497,847	834,277	556,732	52,339	3,491	406,355	1,853,194	17,158	85,434	9,453,634
2028	2,862,217	2,196,779	1,049,421	45,758	1,440,470	7,594,646	848,906	562,678	51,258	3,551	407,173	1,873,566	17,484	86,657	9,572,353
2029	2,928,312	2,218,770	1,046,278	46,317	1,459,399	7,699,076	864,212	569,308	50,279	3,611	408,025	1,895,436	17,816	87,701	9,700,029
2030	2,998,442	2,242,455	1,043,073	46,876	1,481,407	7,812,253	881,331	577,025	49,387	3,672	409,557	1,920,972	18,155	88,714	9,840,094
2031	3,068,975	2,266,771	1,039,825	47,451	1,497,905	7,920,926	897,555	583,884	48,568	3,735	411,090	1,944,831	18,500	89,480	9,973,737
2032	3,142,855	2,293,000	1,036,548	48,042	1,516,975	8,037,419	916,494	591,603	47,810	3,800	411,981	1,971,688	18,851	90,222	10,118,180
2033	3,220,375	2,321,476	1,033,251	48,632	1,537,899	8,161,633	936,357	599,974	47,103	3,866	412,903	2,000,204	19,209	91,003	10,272,049
2034	3,300,567	2,352,506	1,029,940	49,218	1,560,698	8,292,928	956,109	608,854	46,441	3,933	413,843	2,029,179	19,574	91,775	10,433,457
2035	3,383,444	2,385,020	1,026,619	49,790	1,582,114	8,426,987	976,273	617,729	45,815	3,999	414,789	2,058,606	19,946	92,554	10,598,093
2036	3,468,458	2,419,036	1,023,292	50,364	1,603,213	8,564,364	999,400	626,981	45,221	4,067	415,739	2,091,408	20,325	93,368	10,769,465
2037	3,557,031	2,455,120	1,019,961	50,939	1,625,836	8,708,887	1,023,907	636,905	44,653	4,136	416,713	2,126,313	20,711	94,211	10,950,123

Attachment B-3: 2018 Long Term Demand Forecast by Customer Class and Jurisdiction (MW)

	Texas						New Mexico								
Year	Residential	Commercial & Industrial, Small	Commercial & Industrial, Large	Street Lighting	OPA	Total Texas	Residential	Commercial & Industrial, Small	Commercial & Industrial, Large	Street Lighting	OPA	Total New Mexico	Company Use	FERC	Total Native System
2018	539	472	243	9	282	1,544	169	123	15	1	92	400	3	16	1,964
2019	547	476	245	9	287	1,564	172	125	15	1	92	404	3	16	1,988
2020	555	479	245	9	290	1,578	174	126	14	1	92	406	3	17	2,005
2021	566	484	247	10	294	1,601	178	127	14	1	92	412	4	17	2,034
2022	578	488	247	10	300	1,623	181	129	14	1	92	417	4	18	2,061
2023	590	492	248	10	305	1,645	185	131	14	1	93	423	4	18	2,090
2024	600	495	247	10	310	1,663	188	132	13	1	92	427	4	18	2,111
2025	614	502	248	10	316	1,690	192	135	13	1	93	433	4	19	2,146
2026	627	507	248	10	322	1,713	196	137	13	1	93	439	4	19	2,176
2027	640	512	248	10	327	1,738	200	139	13	1	93	445	4	20	2,206
2028	653	517	247	10	330	1,756	203	141	12	1	93	451	4	20	2,231
2029	669	524	247	11	335	1,787	208	144	12	1	94	459	4	20	2,270
2030	685	531	247	11	340	1,815	213	147	12	1	94	467	4	20	2,306
2031	701	538	247	11	344	1,841	218	149	12	1	94	474	4	21	2,340
2032	716	543	246	11	347	1,864	222	152	12	1	94	481	4	21	2,370
2033	736	553	247	11	353	1,900	228	155	12	1	95	491	4	21	2,416
2034	754	561	247	11	358	1,931	233	158	12	1	95	499	4	21	2,456
2035	772	570	247	11	363	1,964	239	162	12	1	95	508	5	21	2,498
2036	789	577	246	12	367	1,991	244	164	11	1	95	516	5	21	2,533
2037	812	588	246	12	373	2,032	251	168	11	1	96	528	5	22	2,586

Attachment B-4: 2018 Forecasted Coincident Peak Demand System Losses (MW)

	Retail				
Year	Secondary	Primary	Transmission	FERC	Total Losses
2018	121	5	4	0	131
2019	123	5	4	0	133
2020	125	5	5	0	135
2021	127	5	5	0	137
2022	129	5	5	0	139
2023	131	5	5	0	142
2024	133	5	5	0	144
2025	136	5	5	0	147
2026	138	5	5	0	149
2027	141	5	5	0	152
2028	143	6	5	0	154
2029	145	6	5	0	157
2030	148	6	5	0	160
2031	151	6	5	0	162
2032	153	6	6	0	165
2033	156	6	6	0	168
2034	159	6	6	0	172
2035	162	6	6	1	175
2036	165	6	6	1	178
2037	169	7	6	1	182

Attachment B-5: 2018 Typical Day for Each Major Customer Class (kW)

Typical Days Report

New Mexico Residential

For the year ending December 31, 2017

Time	Sunday	Monday	Tuesday	Wednesday	Thursday	Friday	Saturday	Average
1:00	0.62	0.61	0.61	0.61	0.60	0.62	0.64	0.62
2:00	0.56	0.56	0.55	0.56	0.55	0.57	0.58	0.56
3:00	0.53	0.53	0.53	0.53	0.53	0.54	0.54	0.53
4:00	0.50	0.51	0.52	0.52	0.52	0.53	0.52	0.52
5:00	0.50	0.54	0.54	0.54	0.54	0.55	0.52	0.53
6:00	0.53	0.62	0.63	0.65	0.64	0.63	0.56	0.61
7:00	0.61	0.70	0.72	0.74	0.72	0.72	0.64	0.69
8:00	0.72	0.73	0.74	0.76	0.75	0.77	0.75	0.75
9:00	0.82	0.77	0.77	0.77	0.76	0.80	0.84	0.79
10:00	0.93	0.84	0.80	0.80	0.81	0.86	0.92	0.85
11:00	1.01	0.92	0.89	0.85	0.87	0.93	0.99	0.92
12:00	1.09	1.00	0.96	0.92	0.95	0.96	1.04	0.99
13:00	1.13	1.05	1.00	0.98	1.01	1.04	1.12	1.05
14:00	1.19	1.11	1.05	1.05	1.06	1.09	1.16	1.10
15:00	1.23	1.19	1.13	1.14	1.14	1.16	1.20	1.17
16:00	1.26	1.26	1.21	1.20	1.22	1.22	1.24	1.23
17:00	1.28	1.31	1.25	1.24	1.25	1.25	1.22	1.26
18:00	1.31	1.33	1.27	1.26	1.26	1.24	1.20	1.27
19:00	1.27	1.27	1.22	1.21	1.23	1.18	1.17	1.22
20:00	1.24	1.23	1.18	1.19	1.20	1.12	1.11	1.18
21:00	1.16	1.15	1.11	1.12	1.12	1.07	1.04	1.11
22:00	1.01	1.00	1.00	0.98	0.99	0.98	0.93	0.99
23:00	0.84	0.83	0.83	0.81	0.83	0.86	0.82	0.83
0:00	0.71	0.70	0.70	0.69	0.71	0.73	0.71	0.71
Average	**0.92**	**0.91**	**0.88**	**0.88**	**0.89**	**0.89**	**0.89**	**0.89**

Typical Days Report

New Mexico Small General Service

For the year ending December 31, 2017

Time	Sunday	Monday	Tuesday	Wednesday	Thursday	Friday	Saturday	Average
0:00	1.60	1.54	1.57	1.60	1.59	1.61	1.63	1.59
1:00	1.55	1.50	1.54	1.56	1.55	1.57	1.57	1.55
2:00	1.53	1.50	1.53	1.55	1.53	1.55	1.55	1.53
3:00	1.55	1.52	1.54	1.57	1.55	1.55	1.56	1.55
4:00	1.56	1.58	1.60	1.63	1.61	1.62	1.59	1.60
5:00	1.54	1.62	1.64	1.67	1.65	1.66	1.61	1.63
6:00	1.53	1.77	1.82	1.85	1.83	1.82	1.64	1.75
7:00	1.52	2.02	2.10	2.15	2.12	2.11	1.73	1.96
8:00	1.65	2.33	2.42	2.48	2.45	2.45	1.93	2.25
9:00	1.81	2.56	2.68	2.72	2.71	2.70	2.16	2.48
10:00	1.94	2.69	2.83	2.84	2.87	2.86	2.28	2.61
11:00	2.04	2.73	2.88	2.92	2.94	2.92	2.33	2.68
12:00	2.09	2.79	2.95	3.01	3.04	3.01	2.35	2.75
13:00	2.07	2.89	3.06	3.11	3.13	3.10	2.31	2.81
14:00	2.04	2.91	3.07	3.14	3.16	3.10	2.28	2.81
15:00	2.00	2.84	2.97	3.05	3.09	2.99	2.25	2.74
16:00	1.92	2.53	2.63	2.69	2.75	2.66	2.18	2.48
17:00	1.91	2.27	2.36	2.39	2.49	2.41	2.10	2.27
18:00	1.93	2.16	2.23	2.30	2.36	2.25	2.07	2.19
19:00	1.98	2.09	2.17	2.25	2.29	2.19	2.07	2.15
20:00	1.91	1.94	2.02	2.07	2.09	2.07	1.99	2.01
21:00	1.80	1.83	1.87	1.88	1.90	1.95	1.88	1.87
22:00	1.68	1.71	1.76	1.75	1.78	1.83	1.77	1.76
23:00	1.60	1.62	1.66	1.65	1.67	1.71	1.66	1.65
Average	**1.78**	**2.12**	**2.20**	**2.24**	**2.26**	**2.24**	**1.94**	**2.11**

Typical Days Report

New Mexico General Service

For the year ending December 31, 2017

Time	Sunday	Monday	Tuesday	Wednesday	Thursday	Friday	Saturday	Average
0:00	35.43	34.66	39.14	39.66	39.64	39.74	38.18	38.07
1:00	34.20	34.01	38.07	38.35	38.43	38.46	36.64	36.88
2:00	33.21	33.67	37.04	37.40	37.32	37.18	35.20	35.86
3:00	33.39	35.48	37.64	38.23	37.97	37.94	35.35	36.57
4:00	33.61	39.86	41.97	42.47	42.15	41.92	38.18	40.02
5:00	35.47	44.07	46.26	46.95	46.64	46.07	40.55	43.72
6:00	36.77	48.64	51.02	51.78	51.06	50.02	42.05	47.33
7:00	39.47	53.08	55.37	55.86	55.17	54.36	44.27	51.08
8:00	42.20	57.25	59.27	59.56	58.76	58.08	46.91	54.58
9:00	43.95	60.16	61.87	62.04	61.86	60.75	49.12	57.11
10:00	45.47	61.67	63.27	63.66	63.55	62.65	50.52	58.68
11:00	46.37	62.03	63.51	63.71	63.91	62.69	51.08	59.04
12:00	46.50	63.33	64.83	65.09	65.30	63.49	51.21	59.97
13:00	47.03	64.27	65.43	66.17	65.84	64.22	51.44	60.63
14:00	47.08	63.80	64.47	65.44	64.86	63.20	51.12	59.99
15:00	46.94	61.32	61.70	62.33	62.62	60.99	50.99	58.13
16:00	46.76	58.15	58.81	59.07	59.61	57.90	50.48	55.83
17:00	47.04	55.89	56.60	57.34	57.35	55.81	50.35	54.34
18:00	46.23	54.48	54.91	55.88	55.56	54.42	49.99	53.07
19:00	45.05	53.58	54.06	54.58	54.66	53.50	49.50	52.13
20:00	42.89	51.35	51.66	51.92	52.32	51.25	47.53	49.84
21:00	40.84	47.64	47.97	48.14	48.63	48.22	44.55	46.57
22:00	37.93	43.47	43.87	43.71	44.13	44.68	41.15	42.71
23:00	36.23	41.13	41.64	41.41	41.65	41.11	37.94	40.16
Average	**41.25**	**50.96**	**52.52**	**52.95**	**52.88**	**52.03**	**45.18**	**49.68**

Typical Days Report

New Mexico City and County

For the year ending December 31, 2017

Time	Sunday	Monday	Tuesday	Wednesday	Thursday	Friday	Saturday	Average
0:00	7.30	7.31	7.49	7.52	7.52	7.53	7.42	7.44
1:00	7.28	7.33	7.46	7.51	7.47	7.54	7.38	7.43
2:00	7.24	7.26	7.40	7.43	7.44	7.46	7.34	7.37
3:00	7.24	7.44	7.57	7.64	7.62	7.62	7.36	7.50
4:00	7.38	8.95	8.90	8.99	8.94	8.88	7.50	8.51
5:00	7.37	10.97	10.91	11.02	10.86	10.48	7.55	9.88
6:00	7.01	12.65	12.78	12.84	12.64	11.95	7.39	11.04
7:00	6.84	14.78	15.14	15.18	14.99	13.85	7.33	12.59
8:00	6.92	16.09	16.56	16.56	16.41	15.22	7.52	13.61
9:00	7.02	16.73	17.33	17.24	17.20	15.93	7.75	14.17
10:00	7.12	17.17	17.90	17.74	17.86	16.41	7.85	14.58
11:00	7.31	17.47	18.33	18.19	18.29	16.75	8.06	14.91
12:00	7.47	17.70	18.53	18.44	18.53	16.92	8.14	15.10
13:00	7.67	17.52	18.23	18.25	18.29	16.67	8.27	14.99
14:00	7.71	16.45	16.99	17.14	17.10	15.42	8.20	14.15
15:00	7.75	14.03	14.27	14.39	14.34	12.91	8.19	12.27
16:00	7.70	11.65	11.84	11.88	11.89	10.85	8.10	10.56
17:00	8.00	10.76	10.90	10.91	10.98	10.12	8.17	9.98
18:00	8.14	10.26	10.41	10.28	10.43	9.78	8.31	9.66
19:00	8.40	10.03	10.10	9.96	10.05	9.67	8.54	9.54
20:00	8.26	9.28	9.36	9.29	9.30	9.10	8.38	9.00
21:00	7.71	8.30	8.34	8.30	8.31	8.16	7.77	8.13
22:00	7.27	7.65	7.57	7.57	7.58	7.47	7.30	7.49
23:00	7.31	7.58	7.58	7.57	7.60	7.45	7.35	7.49
Average	**7.48**	**11.89**	**12.16**	**12.16**	**12.15**	**11.42**	**7.80**	**10.72**

Typical Days Report

New Mexico Large Power

For the year ending December 31, 2017

Time	Sunday	Monday	Tuesday	Wednesday	Thursday	Friday	Saturday	Average
0:00	15,942.57	15,746.60	17,136.13	16,899.77	17,368.22	16,772.50	17,055.87	16,703.09
1:00	15,846.35	15,705.20	17,204.56	16,815.09	17,383.56	16,706.43	17,008.75	16,667.13
2:00	15,801.23	15,693.98	17,123.31	16,846.24	17,261.02	16,672.47	17,053.37	16,635.95
3:00	15,780.71	15,854.82	17,271.84	17,119.50	17,349.97	16,791.02	16,928.25	16,728.02
4:00	15,815.42	16,433.28	17,646.20	17,600.51	17,804.20	17,053.48	16,802.56	17,022.24
5:00	15,457.89	16,696.73	17,616.40	17,741.86	17,953.39	17,047.87	16,568.43	17,011.80
6:00	14,925.93	16,803.12	17,714.60	17,795.04	17,848.51	17,004.14	16,047.25	16,876.94
7:00	14,590.67	17,153.59	17,820.05	17,965.96	17,850.40	17,164.50	15,705.71	16,892.98
8:00	14,515.88	17,702.83	18,323.36	18,420.95	18,178.58	17,694.64	15,851.03	17,241.04
9:00	14,596.62	18,186.93	18,655.65	18,822.39	18,508.71	18,130.87	16,124.94	17,575.16
10:00	14,957.70	18,510.78	18,785.82	19,024.10	18,708.99	18,279.90	16,137.44	17,772.11
11:00	15,388.42	18,756.68	18,916.59	19,216.74	18,822.18	18,348.29	16,249.33	17,956.89
12:00	15,685.81	18,966.24	18,914.78	19,338.26	18,903.82	18,414.30	16,312.03	18,076.46
13:00	15,854.19	19,093.25	18,892.53	19,362.92	18,963.22	18,466.97	16,423.71	18,150.97
14:00	15,960.66	19,027.00	18,798.34	19,291.54	18,837.00	18,466.94	16,513.02	18,127.79
15:00	16,044.59	18,860.73	18,582.68	18,998.33	18,555.66	18,462.24	16,726.53	18,032.97
16:00	16,259.55	18,548.34	18,228.57	18,587.96	18,243.49	18,348.80	16,895.69	17,873.20
17:00	16,319.22	18,596.31	18,280.28	18,646.44	18,312.71	18,498.65	17,209.13	17,980.39
18:00	16,205.59	18,672.13	18,309.04	18,802.84	18,324.14	18,585.16	17,312.61	18,030.22
19:00	16,321.35	18,784.98	18,376.06	18,854.34	18,402.31	18,699.80	17,460.25	18,128.44
20:00	16,264.03	18,424.73	18,057.41	18,434.63	18,073.48	18,343.14	17,127.92	17,817.91
21:00	16,063.14	17,885.26	17,575.51	17,959.39	17,540.85	17,819.31	16,696.53	17,362.86
22:00	15,920.81	17,569.52	17,241.31	17,709.23	17,152.86	17,543.72	16,364.01	17,071.64
23:00	15,736.95	17,241.85	17,032.24	17,507.12	16,894.83	17,296.73	16,106.10	16,830.83
Average	**15,677.30**	**17,704.79**	**18,020.97**	**18,240.05**	**18,051.75**	**17,775.49**	**16,611.69**	**17,440.29**

Typical Days Report

Texas Residential

For the year ending December 31, 2017

Time	Sunday	Monday	Tuesday	Wednesday	Thursday	Friday	Saturday	Average
0:00	0.59	0.57	0.56	0.57	0.56	0.57	0.58	0.57
1:00	0.53	0.52	0.52	0.51	0.50	0.52	0.54	0.52
2:00	0.49	0.49	0.48	0.48	0.47	0.50	0.50	0.49
3:00	0.46	0.47	0.47	0.48	0.46	0.48	0.48	0.47
4:00	0.45	0.49	0.49	0.50	0.49	0.49	0.47	0.48
5:00	0.46	0.54	0.54	0.55	0.55	0.54	0.50	0.53
6:00	0.51	0.60	0.60	0.60	0.61	0.61	0.56	0.58
7:00	0.60	0.61	0.61	0.61	0.61	0.63	0.63	0.62
8:00	0.66	0.64	0.63	0.61	0.63	0.66	0.69	0.65
9:00	0.75	0.72	0.72	0.69	0.70	0.73	0.78	0.73
10:00	0.87	0.83	0.82	0.78	0.81	0.84	0.91	0.84
11:00	0.96	0.93	0.90	0.86	0.91	0.93	1.01	0.93
12:00	1.07	1.02	0.98	0.94	0.98	1.02	1.07	1.01
13:00	1.15	1.09	1.04	1.00	1.02	1.09	1.13	1.07
14:00	1.20	1.15	1.10	1.05	1.06	1.13	1.18	1.12
15:00	1.19	1.22	1.16	1.11	1.12	1.17	1.18	1.16
16:00	1.19	1.25	1.19	1.16	1.18	1.20	1.16	1.19
17:00	1.18	1.23	1.20	1.17	1.18	1.18	1.12	1.18
18:00	1.15	1.20	1.17	1.14	1.15	1.13	1.06	1.14
19:00	1.14	1.21	1.16	1.13	1.15	1.08	1.05	1.13
20:00	1.10	1.15	1.11	1.09	1.11	1.03	1.00	1.08
21:00	0.96	0.98	0.98	0.97	0.98	0.94	0.91	0.96
22:00	0.79	0.79	0.80	0.78	0.79	0.79	0.79	0.79
23:00	0.66	0.64	0.66	0.64	0.66	0.66	0.67	0.66
Average	**0.84**	**0.85**	**0.83**	**0.81**	**0.82**	**0.83**	**0.83**	**0.83**

Typical Days Report

Texas Small General Service

For the year ending December 31, 2017

Time	Sunday	Monday	Tuesday	Wednesday	Thursday	Friday	Saturday	Average
0:00	0.95	0.94	0.96	0.97	0.97	0.99	0.98	0.97
1:00	0.93	0.92	0.93	0.94	0.94	0.95	0.94	0.93
2:00	0.89	0.88	0.90	0.91	0.91	0.92	0.90	0.90
3:00	0.87	0.87	0.89	0.90	0.90	0.90	0.90	0.89
4:00	0.87	0.88	0.89	0.91	0.91	0.91	0.91	0.90
5:00	0.83	0.88	0.89	0.91	0.91	0.92	0.90	0.89
6:00	0.76	0.88	0.89	0.91	0.92	0.93	0.87	0.88
7:00	0.72	0.99	1.00	1.01	1.02	1.05	0.88	0.96
8:00	0.81	1.26	1.29	1.30	1.31	1.34	1.08	1.20
9:00	0.95	1.42	1.49	1.51	1.51	1.56	1.28	1.39
10:00	1.03	1.52	1.63	1.65	1.64	1.70	1.41	1.51
11:00	1.04	1.56	1.72	1.74	1.74	1.77	1.47	1.58
12:00	1.02	1.59	1.80	1.81	1.84	1.80	1.48	1.62
13:00	1.02	1.62	1.85	1.84	1.92	1.82	1.48	1.65
14:00	1.02	1.63	1.83	1.86	1.92	1.78	1.46	1.64
15:00	1.00	1.62	1.77	1.80	1.88	1.71	1.41	1.60
16:00	0.97	1.52	1.64	1.66	1.71	1.59	1.36	1.49
17:00	1.07	1.45	1.53	1.58	1.58	1.52	1.28	1.43
18:00	1.14	1.37	1.43	1.44	1.44	1.40	1.25	1.35
19:00	1.18	1.32	1.36	1.36	1.35	1.33	1.23	1.30
20:00	1.15	1.22	1.25	1.25	1.24	1.24	1.16	1.22
21:00	1.08	1.12	1.14	1.15	1.14	1.14	1.09	1.12
22:00	1.02	1.05	1.06	1.07	1.07	1.07	1.04	1.05
23:00	0.98	1.02	1.03	1.03	1.04	1.04	1.01	1.02
Average	**0.97**	**1.23**	**1.30**	**1.31**	**1.33**	**1.31**	**1.16**	**1.23**

Typical Days Report

Texas General Service

For the year ending December 31, 2017

Time	Sunday	Monday	Tuesday	Wednesday	Thursday	Friday	Saturday	Average
0:00	17.12	16.73	17.61	17.68	17.81	18.04	17.98	17.57
1:00	16.31	16.42	16.90	16.99	17.12	17.40	17.07	16.89
2:00	15.82	16.35	16.59	16.70	16.85	17.11	16.52	16.56
3:00	15.62	16.78	17.06	17.18	17.34	17.51	16.36	16.84
4:00	16.02	18.93	19.35	19.33	19.60	19.46	17.43	18.59
5:00	16.26	21.10	21.85	21.80	21.92	21.74	18.44	20.44
6:00	16.26	23.78	24.62	24.65	24.65	24.23	18.76	22.42
7:00	16.68	26.55	27.28	27.35	27.32	27.14	19.78	24.59
8:00	17.88	28.82	29.76	29.75	29.66	29.48	21.42	26.68
9:00	19.87	31.07	32.17	32.12	32.13	31.95	23.53	28.98
10:00	21.34	32.53	33.64	33.51	33.66	33.45	24.75	30.41
11:00	22.18	33.37	34.56	34.45	34.60	34.13	25.12	31.20
12:00	22.60	33.99	34.89	35.01	35.04	34.48	25.29	31.61
13:00	22.61	34.03	34.73	35.04	34.89	34.31	25.38	31.57
14:00	22.86	33.88	34.50	34.74	34.51	33.83	25.32	31.38
15:00	22.98	32.67	33.18	33.38	33.25	32.45	24.96	30.41
16:00	22.91	30.68	31.16	31.57	31.38	30.74	24.76	29.03
17:00	23.23	29.11	29.48	30.04	29.90	29.57	24.95	28.04
18:00	23.52	28.19	28.56	29.21	29.04	28.81	25.13	27.49
19:00	23.61	27.63	28.08	28.61	28.35	28.29	25.33	27.13
20:00	22.15	25.54	25.95	26.18	26.14	26.38	23.78	25.16
21:00	20.31	23.34	23.64	23.83	23.86	23.88	21.74	22.94
22:00	18.88	21.06	21.19	21.40	21.37	21.34	19.75	20.71
23:00	17.90	19.37	19.38	19.49	19.52	19.54	18.43	19.09
Average	**19.79**	**25.91**	**26.51**	**26.67**	**26.66**	**26.47**	**21.75**	**24.82**

Typical Days Report

Texas Large Power

For the year ending December 31, 2017

Time	Sunday	Monday	Tuesday	Wednesday	Thursday	Friday	Saturday	Average
0:00	67,948.41	67,138.22	73,385.33	74,779.55	75,360.97	75,137.87	73,497.88	72,464.03
1:00	67,308.53	66,740.88	72,635.76	73,942.97	74,358.38	74,279.12	72,497.84	71,680.50
2:00	66,759.07	66,846.50	72,552.14	73,770.29	74,276.12	73,929.76	71,850.45	71,426.33
3:00	66,647.63	68,713.87	73,916.83	74,638.42	75,396.74	74,904.81	71,747.32	72,280.80
4:00	67,013.02	72,368.46	76,927.18	77,716.28	78,226.92	77,367.02	72,686.43	74,615.04
5:00	67,687.49	76,466.82	80,956.46	81,065.17	81,801.41	80,542.81	73,922.97	77,491.88
6:00	67,707.90	80,243.56	84,328.74	84,203.28	84,832.66	83,089.42	74,568.39	79,853.42
7:00	68,637.84	84,833.51	88,077.24	87,861.38	88,151.53	86,814.68	76,088.16	82,923.48
8:00	70,489.13	88,567.31	91,438.09	90,959.96	91,099.79	90,223.62	78,555.34	85,904.75
9:00	72,625.47	91,285.43	93,964.66	93,259.67	93,954.76	92,591.25	80,816.06	88,356.76
10:00	74,497.09	92,813.26	95,288.73	94,947.47	95,647.21	94,251.85	82,080.86	89,932.35
11:00	75,616.90	93,020.04	95,673.14	95,082.14	95,783.14	94,284.48	81,893.25	90,193.30
12:00	76,237.17	94,022.38	96,485.22	95,804.88	96,721.38	94,919.02	81,921.88	90,873.13
13:00	76,601.72	94,878.29	97,115.89	96,446.00	97,238.74	95,430.30	82,131.30	91,406.03
14:00	76,818.46	94,582.67	96,385.96	96,048.87	96,711.67	94,854.54	81,785.29	91,026.78
15:00	76,673.04	93,357.75	95,312.59	95,005.46	95,458.02	93,348.00	81,369.69	90,074.93
16:00	75,834.05	91,008.75	93,113.65	92,825.34	93,505.14	91,078.37	80,473.01	88,262.62
17:00	74,264.44	89,569.20	91,448.04	91,603.17	92,034.03	89,670.57	79,922.15	86,930.23
18:00	72,679.56	88,411.66	89,795.39	90,016.68	90,592.23	88,514.12	79,192.27	85,600.27
19:00	71,572.86	87,421.64	88,544.84	88,860.70	89,361.38	87,273.59	78,600.86	84,519.41
20:00	70,317.75	84,167.55	85,487.08	85,696.41	85,949.73	84,079.84	75,976.98	81,667.91
21:00	69,330.17	80,478.73	81,519.71	81,723.26	82,008.08	80,008.34	72,871.15	78,277.06
22:00	68,352.45	77,100.48	78,402.67	78,465.19	78,733.90	76,882.35	70,767.18	75,529.17
23:00	67,490.36	74,618.39	76,146.44	76,313.60	76,394.05	74,821.10	69,295.45	73,582.77
Average	**71,212.94**	**83,277.31**	**86,204.24**	**86,293.17**	**86,816.58**	**85,345.70**	**76,854.67**	**82,286.37**

Typical Days Report

Texas City and County

For the year ending December 31, 2017

Time	Sunday	Monday	Tuesday	Wednesday	Thursday	Friday	Saturday	Average
0:00	19.84	24.58	21.01	20.91	20.78	21.07	20.50	21.24
1:00	19.67	26.33	21.52	21.35	21.22	21.41	20.22	21.68
2:00	19.68	27.93	22.55	22.36	22.25	22.20	20.21	22.46
3:00	19.86	29.79	24.96	24.73	24.58	24.31	20.45	24.10
4:00	20.30	32.98	29.41	29.24	29.03	28.34	21.12	27.20
5:00	20.44	37.58	37.31	36.98	36.93	35.41	21.93	32.37
6:00	19.82	44.63	45.58	45.15	44.84	42.53	22.01	37.79
7:00	19.52	51.74	53.61	52.91	52.63	49.48	22.90	43.25
8:00	19.90	56.08	58.42	57.46	57.44	53.72	23.70	46.68
9:00	20.22	58.23	60.87	59.73	60.16	55.84	24.30	48.48
10:00	20.61	59.53	62.30	61.20	61.78	57.15	24.66	49.61
11:00	21.00	60.07	62.71	61.59	62.28	57.58	24.63	49.98
12:00	21.30	60.58	63.24	62.03	62.84	58.08	24.29	50.34
13:00	21.59	60.64	63.14	62.04	62.97	58.08	24.12	50.37
14:00	21.96	58.81	61.19	60.17	61.00	56.04	24.01	49.03
15:00	22.05	50.64	52.77	52.13	52.84	47.98	23.59	43.14
16:00	21.83	40.57	42.29	41.95	42.52	38.72	23.27	35.88
17:00	21.96	33.80	35.30	34.97	35.63	32.65	23.16	31.07
18:00	22.24	30.67	31.89	31.43	32.25	29.96	23.26	28.82
19:00	22.58	28.96	29.99	29.30	30.20	28.65	23.33	27.58
20:00	22.65	26.85	27.71	27.03	27.87	27.04	22.96	26.02
21:00	22.92	24.36	24.90	24.46	25.10	24.48	21.89	24.01
22:00	22.90	22.54	22.75	22.51	22.90	22.42	21.05	22.44
23:00	23.43	21.49	21.45	21.26	21.53	21.06	20.42	21.52
Average	**21.18**	**40.39**	**40.70**	**40.12**	**40.48**	**38.09**	**22.58**	**34.79**

Attachment C-1: Transmission Facilities

TABLE 1. Existing EPE Transmission Lines 115 kV and Above

EL PASO ELECTRIC COMPANY								
Existing 115 kV and Above Internal Lines				RATING		LENGTH	STATE	
From	To	kV	Circuit	MVA Normal	MVA Emerg	Miles	From	To
AMRAD	ARTESIA	345	1	278	278	125.4	NM	NM
CALIENTE	AMRAD	345	1	785	785	56.0	TX	NM
CALIENTE	PICANTE	345	1	789	789	7.3	TX	TX
HIDALGO	GREENLEE	345	1	763	763	60.0	NM	AZ
LUNA	AFTON	345	1	930	989	57.3	NM	NM
LUNA	DIABLO	345	1	939	939	84.2	NM	NM
LUNA	HIDALGO	345	1	658	658	50.5	NM	NM
MACHO SPRINGS	LUNA	345	1	1033	1390	24.9	NM	NM
MACHO SPRINGS	SPRINGERVILLE	345	1	728	728	201.4	NM	AZ
NEWMAN	ARROYO	345	1	700	700	30.3	TX	NM
NEWMAN	AFTON	345	1	930	1028	29.9	TX	NM
PICANTE	NEWMAN	345	1	787	787	16.2	TX	TX
WESTMESA	ARROYO	345	1	681	681	201.8	NM	NM
AIRPORT TAP	AIRPORT	115	1	115	153	2.7	NM	NM
AMRAD	LARGO	115	1	113	113	7.7	NM	NM
ANTHONY	ARROYO	115	1	105	105	24.4	NM	NM
ANTHONY	BORDER STEEL	115	1	155	207	5.2	NM	TX
ANTHONY	SALOPEK	115	1	155	207	17.3	NM	NM
ANTHONY	NEWMAN	115	1	155	199	12.3	NM	TX
ANTHONY	MONTOYA	115	1	155	207	10.2	NM	TX
ASCARATE	TROWBRIDGE	115	1	171	171	0.5	TX	TX
ASCARATE	COPPER	115	1	173	233	1.4	TX	TX
ASCARATE	RIVERENA	115	1	173	233	1.4	TX	
AUSTIN	MARLOW	115	1	209	209	1.2	TX	TX
BIGGS	BLISS INDUSTRIAL	115	1	173	233	2.4	TX	TX
BLISS INDUSTRIAL	LIBERTY	115	1	173	233	2.2	TX	TX
BUTTERFIELD	FT. BLISS	115	1	120	120	1.9	TX	TX
CALIENTE	DIAMOND HEAD	115	1	173	233	6.0	TX	TX
CALIENTE	MPS	115	1	64	82	8.7	TX	TX
CALIENTE	MPS	115	2	254	343	2.5	TX	TX
CALIENTE	MPS	115	3	254	343	2.5	TX	TX
CALIENTE	VISTA	115	1	155	208	6.6	TX	TX
CHAPARRAL	ORO GRANDE	115	1	120	120	35.4	NM	NM
COPPER	PENDALE	115	1	127	165	5.0	TX	TX
COYOTE	RGC_DEL CITY	115	1	19	19	10.8	TX	TX
CROMO	RIO GRANDE	115	1	127	169	0.9	TX	TX
DIABLO	RIO GRANDE	115	1	311	417	2.9	NM	TX

EL PASO ELECTRIC COMPANY								
Existing 115 kV and Above Internal Lines				RATING		LENGTH	STATE	
From	To	kV	Circuit	MVA Normal	MVA Emerg	Miles	From	To
DIABLO	RIO GRANDE	115	2	311	417	2.9	NM	NM
DIABLO	ANAPRA	115	1	173	233	2.28	NM	
DIAMOND HEAD	LANE	115	1	173	233	2.6	TX	TX
DURAZNO	ASCARATE	115	1	127	169	3.3	TX	NM
DYER	SHEARMAN	115	1	127	169	9.6	TX	TX
DYER	AUSTIN	115	1	173	233	2.1	TX	TX
FT. BLISS	AUSTIN	115	1	120	120	1.8	TX	TX
GLOBAL REACH	VISTA	115	1	313	313	3.0	TX	TX
HATCH	JORNADA	115	1	39	39	33.4	NM	NM
HOLLOMAN	LARGO	115	1	113	113	14.9	NM	NM
JORNADA	ARROYO	115	1	74	74	4.9	NM	NM
LANE	WRANGLER	115	1	155	207	1.0	TX	TX
LAS CRUCES	ARROYO	115	1	155	207	4.1	NM	NM
LAS CRUCES	SALOPEK	115	1	155	207	5.0	NM	NM
LEO EAST	DYER	115	1	173	233	4.3	TX	TX
LEO EAST	MILAGRO	115	1	173	233	3.8	TX	TX
LIBERTY	GLOBAL REACH	115	1	173	233	2.6	TX	TX
MAR	LARGO	115	1	23	23	11.4	NM	NM
MARLOW	TROWBRIDGE	115	1	171	171	1.1	TX	TX
MESA	AUSTIN	115	1	155	207	6.1	TX	TX
MESA	RIO GRANDE	115	1	254	254	2.2	TX	NM
MILAGRO	NEWMAN	115	1	173	233	6.3	TX	TX
MONTWOOD	CALIENTE	115	1	173	233	5.0	TX	TX
MONTWOOD	COYOTE	115	1	173	233	7.8	TX	TX
MPS	COYOTE	115	1	235	369	2.9	TX	TX
MPS	MONTWOOD	115	1	235	369	6.0	TX	TX
NEWMAN	CHAPARRAL	115	1	127	169	2.9	TX	NM
NEWMAN	BUTTERFIELD	115	1	127	169	16.7	TX	TX
NEWMAN	SHEARMAN	115	1	127	169	7.3	TX	TX
NEWMAN	PIPELINE	115	1	173	233	9.8	TX	TX
NEWMAN	PICANTE	115	1	173	233	13.6	TX	TX
ORO GRANDE	AMRAD	115	1	120	120	12.3	NM	NM
ORO GRANDE	WHITE SANDS	115	1	69	69	22.8	NM	NM
PATRIOT	NEWMAN	115	1	127	169	2.2	TX	TX
PATRIOT	CROMO	115	1	127	169	17.7	TX	TX
PELICANO	HORIZON	115	1	173	233	6.7	TX	TX
PELICANO	MONTWOOD	115	1	173	233	3.8	TX	TX
PENDALE	LANE	115	1	173	233	1.5	TX	TX
PICANTE	GLOBAL REACH	115	1	173	233	6.0	TX	TX
PICANTE	BIGGS	115	1	173	233	2.3	TX	TX
PIPELINE	BIGGS	115	1	127	169	13.6	TX	TX
RIO GRANDE	RIPLEY	115	1	155	207	3.0	NM	TX
RIPLEY	THORN	115	1	127	169	1.9	TX	TX

EL PASO ELECTRIC COMPANY								
Existing 115 kV and Above Internal Lines				RATING		LENGTH	STATE	
From	**To**	**kV**	**Circuit**	**MVA Normal**	**MVA Emerg**	**Miles**	**From**	**To**
SALOPEK	ARROYO	115	1	127	169	10.7	NM	NM
SANTA TERESA	MONTOYA	115	1	173	233	7.4	NM	TX
SANTA TERESA	DIABLO	115	1	158	212	8.9	NM	NM
SCOTSDALE	VISTA	115	1	112	129	5.2	TX	TX
SOL	LANE	115	1	127	169	2.1	TX	TX
SOL	VISTA	115	1	173	233	2.0	TX	TX
SPARKS	HORIZON	115	1	173	233	3.8	TX	TX
SUNSET NORTH	DURAZNO	115	1	127	169	4.6	TX	TX
SUNSET NORTH	RIO GRANDE	115	1	254	339	5.1	TX	NM
THORN	MONTOYA	115	1	127	169	3.0	TX	TX
WRANGLER	SPARKS	115	1	173	233	4.0	TX	TX

- "Internal" refers to lines within EPE's Balancing Area including lines connecting EPE to neighboring utilities, however, not including line segments partially owned by EPE external to EPE's control area.
- Some transmission lines were identified to be capacity limited by smaller jumpers connected at the substations. The line ratings reflected in the above table are based on line jumper upgrade assumptions.
- The ratings are generally based on conductor thermal capacities but may be derated due to sag limitations or other factors.
- RGC_DC is Rio Grande Electric Cooperative, Dell City.
- Emerg is short for Emergency

TABLE 2. Existing 115 kV EPE Substation Transformers

EL PASO ELECTRIC COMPANY				
Existing 115 kV Load & Step-up Substation Transformers		**RATING**		**State**
		Normal	**Emergency**	
		MVA	**MVA**	
AIRPORT	115/23.9	33.6	37.6	NM
AMRAD	115/24.9	8.4	9.4	NM
ANTHONY #1	115/23.9	33.6	37.6	NM
ANTHONY #2	115/23.9	56.0	62.7	NM
ARROYO #1	115/23.9	33.6	37.6	NM
ARROYO #2	115/23.9	33.6	37.6	NM
ASCARATE #4	115/69	112	125.4	TX
ASCARATE #5	115/69	112	125.4	TX
AUSTIN NORTH #1	115/13.8	50.0	56.0	TX
AUSTIN NORTH #2	115/13.8	56.0	62.7	TX
BORDER STEEL 115 #1	115/13.8	39.2	43.9	TX
BORDER STEEL 115 #1	115/13.8	39.2	43.9	TX
BUTTERFIELD #1	115/13.8	30.0	33.6	TX
BUTTERFIELD #2	115/13.8	30.0	33.6	TX
CALIENTE #3	115/13.8	33.6	37.6	TX
CHAPARRAL #1	115/13.8	33.6	37.6	NM
CHAPARRAL #2	115/13.8	33.6	37.6	NM
COPPER #1	115/13.8	30.0	33.6	TX
COPPER GEN #2	13.8/115	84.0	94.1	TX
COYOTE #1	115/13.8	30.0	33.6	TX
CROMO #1	115/13.8	30.0	33.6	TX
CROMO #2	115/13.8	30.0	33.6	TX
DIAMOND HEAD #1	115/13.8	33.6	37.6	TX
DURAZNO #1	115/13.8	33.6	37.6	TX
DYER #3	115/69	112	125.4	TX
EMRLD #1	115/13.8	12.5	14.0	NM
FT. BLISS #1	115/13.2	27.5	30.8	TX
FT. BLISS #2	115/13.2	28.0	31.4	TX
GLOBAL REACH #1	115/13.8	33.6	37.6	TX
HATCH #1	115/24.9	30.0	33.6	NM
HORIZON #1	115/13.8	33.6	37.6	TX
JORNADA #1	115/23.9	33.6	37.6	NM
LANE #1	115/69	100	112	TX
LANE #2	115/13.8	30.0	33.6	TX

EL PASO ELECTRIC COMPANY				
Existing 115 kV Load & Step-up Substation Transformers		RATING		State
		Normal	Emergency	
		MVA	MVA	
LAS CRUCES # 1	115/23.9	67.2	75.3	NM
LAS CRUCES # 2	115/23.9	67.2	75.3	NM
LEO EAST #1	115/13.8	33.6	37.6	TX
LEO EAST #2	115/13.8	33.6	37.6	TX
MAR #1	115/4.2	11.2	12.5	NM
MESA # 1	115/13.8	30.0	33.6	TX
MESA # 2	115/13.8	30.0	33.6	TX
MILAGRO #1	115/13.8	33.6	37.6	TX
MILAGRO #2	115/13.8	33.6	37.6	TX
MILAGRO #3	115/13.8	33.6	37.6	TX
MONTOYA #1	115/24.9	33.6	37.6	TX
MONTOYA #2	115/23.9	56.0	62.7	TX
MONTOYA #3	115/23.9	56.0	62.7	TX
MONTWOOD #1	115/23.9	33.6	37.6	TX
MONTWOOD #2	115/23.9	56.0	62.7	TX
MPS #1	13.8/115	140.0	156.8	TX
MPS #2	13.8/115	140.0	156.8	TX
MPS #3	13.8/115	140.0	156.8	TX
MPS #4	13.8/115	140.0	156.8	TX
NEWMAN G1(T2)	13.8/115	125.4	140.5	TX
NEWMAN G2 (T6)	13.8/115	125.4	140.5	TX
NEWMAN G3 (T8)	13.8/115	125.4	140.5	TX
NEWMAN 4G1 (T11)	13.8/115	125.0	140.0	TX
NEWMAN 4G2 (T9)	13.8/115	125.0	140.0	TX
NEWMAN 4S1 (T13)	13.8/115	125.0	140.0	TX
NEWMAN 5G1 (T15)	13.8/115	130.0	145.6	TX
NEWMAN 5G2 (T16)	13.8/115	130.0	145.6	TX
NEWMAN 5S1 (T14)	13.8/115	175.0	196	TX
PATRIOT #1	115/13.8	33.6	37.6	TX
PELICANO #1	115/23.9	33.6	37.6	TX
PELICANO #2	115/23.9	56.0	62.7	TX
PENDALE	115/13.8	33.6	37.6	TX
PICACHO	115/24.9	56.0	62.7	NM
REDEYE	115/13.8	14.0	15.7	NM
RIO GRANDE T1	115/69	112	125.4	TX
RIO GRANDE T2	115/69	112	125.4	TX

EL PASO ELECTRIC COMPANY				
Existing 115 kV Load & Step-up Substation Transformers		RATING		State
		Normal MVA	Emergency MVA	
RIO GRANDE G8 (T7)	17.5/115	168.0	188.2	NM
RIO GRANDE G9 (T17)	13.8/115	132.0	147.8	NM
RIPLEY	115/13.8	33.6	37.6	TX
SALOPEK #1	115/24.9	28.0	31.4	NM
SALOPEK #2	115/24.9	28.0	31.4	NM
SALOPEK #3	115/24.9	28.0	31.4	NM
SANTA TERESA #1	115/23.9	30.0	33.6	NM
SANTA TERESA #2	115/23.9	30.0	33.6	NM
SCOTSDALE #1	115/69	112	125.4	TX
SHEARMAN #1	115/13.8	30.0	33.6	TX
SOL #1	115/13.8	33.6	37.6	TX
SOL #2	115/13.8	30.0	33.6	TX
SPARKS #1	115/13.8	33.6	37.6	TX
SPARKS #2	115/13.8	56.0	62.7	TX
SPARKS #3	115/69	100	112	TX
SUNSET NORTH #1	115/13.8	33.6	37.6	TX
SUNSET NORTH #2	115/13.8	33.6	37.6	TX
SUNSET NORTH T3	115/69	70	78.4	TX
TALAVERA	115/23.9	16.5	18.5	NM
THORN #1	115/13.8	33.6	37.6	TX
THORN #2	115/13.8	33.6	37.6	TX
TRANSMOUNTAIN	115/23.9	22.4	25.1	TX
VISTA #1	115/13.8	30.0	33.6	TX
VISTA #2	115/13.8	30.0	33.6	TX
WHITE SANDS #1	115/13.8	30.0	33.6	NM
WRANGLER #1	115/13.8	50.0	56.0	TX

TABLE 3. EPE 345/115 kV Autotransformers

Existing Auto Transformers 115 kV and Above	Voltage kV	RATING Normal MVA	Emergency MVA	State
AMRAD T1	345/115	290	333	NM
ARROYO T1	345/115	224	258	NM
ARROYO T5	345/115	224	258	NM
ARROYO T6	345/115	224	258	NM
ARROYO T3	345/345	400	460	NM
CALIENTE T1	345/115	224	258	TX
CALIENTE T2	345/115	224	258	TX
DIABLO T1	345/115	224	258	NM
DIABLO T2	345/115	224	258	NM
DIABLO T3	345/115	224	258	NM
NEWMAN T1	345/115	230	265	TX
PICANTE T1	345/115	224	258	TX

TABLE 4. EPE External Line Segments

EPE External Transmission Segments (Arizona) Point of Receipt	Point of Delivery	EPE share of TTC (MW)	EPE share of ATC (MW)	TTC of PV East Path (MW)	Path Description
Palo Verde 500 kV	Westwing 500 kV (1)	*	TTC-		Two-line segment in which EE has
Westwing 500 kV	Palo Verde 500 kV (2)	**	TTC-CST		an 18.7% ownership interest
Palo Verde 500 kV	Jojoba 500 kV (3)	555	TTC-CST		One-line segment in which EE has
Jojoba 500 kV	Palo Verde 500 kV (4)	555	TTC-		an 18.7% ownership interest
Jojoba 500 kV	Kyrene 500 kV (3)	*	TTC-CST		One-line segment in which EE has
Kyrene 500 kV	Jojoba 500 kV (4)	**	TTC-		an 18.7% ownership interest

Note: EPE's share of TTC on the Palo Verde East System is 1118 MW
(1) EPE has retained 439 MW (AREF Set Aside) ATC for native load uses
(2) EPE has retained 400 MW (AREF Set Aside) ATC for use by TEP
(3) EPE has retained 203 MW (AREF Set Aside) ATC for native load uses
(4) At the present time, there are no Committed Uses on this segment
* TTC for PV East System
** TTC for PV East System in east to west direction CST - Common Segment Transactions

TABLE 5. Under-Construction EPE Transmission Facilities

Under Construction / Status *	Transmission Facility	State
Under Construction	Lane - Pendale 115 kV Line Reconductor	TX
Under Construction	Rio Bosque Substation 69 kV Capacitor Bank	TX
Under Construction	Sunset N-Durazno Transmission line	TX
Under Construction	Pendale - Copper 16900 Line Rebuild	TX
Under Construction	Sunset N-Durazno 115 KV Transmission Line Upgrade	TX
Planned	Hidalgo Substation Reactor Substation Reactor Replacement	NM
Planned	Ft. Bliss 30 MVAR Cap Addition 115KV BUS	TX

*Refers to the project status during the development of this filing.

Attachment C-2: Existing Units Operating Characteristics

TABLE C-2a

Unit Copper	Fuel Costs	Heat Rate	Fixed and Variable O&M	Non-Availability Factor
Year	**$000**	**MMBtu/MWh**	**$000**	**%**
2018	1,012.88	14.26	1,385.33	0.91
2019	929.59	14.24	2,562.85	0.91
2020	1,152.43	14.34	1,516.62	0.91
2021	1,186.97	14.35	1,543.61	0.91
2022	1,129.00	14.44	1,527.23	0.91
2023	1,116.75	14.40	2,536.75	0.91
2024	1,454.68	14.77	1,992.21	0.91
2025	925.01	14.33	3,470.68	0.91
2026	1,511.57	14.47	2,053.28	0.91
2027	2,657.92	14.28	4,806.28	0.91
2028	1,961.85	14.21	4,165.32	0.91
2029	1,787.88	14.18	4,829.97	0.91
2030	2,112.83	14.23	4,380.56	0.91

TABLE C-2b

Unit Newman 1	Fuel Costs	Heat Rate	Fixed and Variable O&M	Non-Availability Factor
Year	**$000**	**MMBtu/MWh**	**$000**	**%**
2018	1318.74	11.14	1420.33	0.75
2019	1459.26	11.14	1454.05	0.75
2020	1736.36	11.14	1493.68	0.75
2021	1793.15	11.14	1517.32	0.75
2022	1394.23	11.14	2728.77	0.75

TABLE C-2c

Unit Newman 2	Fuel Costs	Heat Rate	Fixed and Variable O&M	Non-Availability Factor
Year	**$000**	**MMBtu/MWh**	**$000**	**%**
2018	2345.27	10.72	1493.48	6.79
2019	2162.07	10.70	3679.86	6.79
2020	2610.72	10.71	1562.22	6.79
2021	2702.66	10.71	1587.68	6.79
2022	2506.69	10.72	1608.49	6.79

TABLE C-2d

Unit Newman 3	Fuel Costs	Heat Rate	Fixed and Variable O&M	Non-Availability Factor
Year	**$000**	**MMBtu/MWh**	**$000**	**%**
2018	8,793.14	10.80	2,052.80	2.41
2019	8,952.61	10.72	2,115.69	2.41
2020	9,929.56	10.65	2,191.80	2.41
2021	8,591.36	10.62	3,366.99	2.41
2022	10,179.21	10.66	2,256.45	2.41
2023	7,633.94	11.03	2,522.87	2.41
2024	6,194.26	11.00	5,335.92	2.41
2025	8,048.12	11.04	2,608.79	2.41
2026	8,899.88	10.95	2,680.62	2.41

TABLE C-2e

Unit Newman 4	Fuel Costs	Heat Rate	Fixed and Variable O&M	Non-Availability Factor
Year	**$000**	**MMBtu/MWh**	**$000**	**%**
2018	37,406.77	9.16	6,138.79	8.08
2019	37,758.85	9.11	5,440.12	8.08
2020	34,474.98	9.10	7,466.85	8.08
2021	38,491.21	9.09	7,603.56	8.08
2022	38,483.76	9.10	5,677.21	8.08
2023	39,312.61	9.22	8,731.43	8.08
2024	31,486.93	9.24	9,295.32	8.08
2025	35,382.59	9.26	8,409.45	8.08
2026	38,287.18	9.26	6,081.16	8.08

TABLE C-2f

Unit Newman 5	Fuel Costs	Heat Rate	Fixed and Variable O&M	Non-Availability Factor
Year	$000	MMBtu/MWh	$000	%
2018	31528.01	8.37	6512.20	1.50
2019	30541.83	8.38	9155.73	1.50
2020	31406.27	8.40	6818.73	1.50
2021	32165.39	8.39	6937.38	1.50
2022	31216.38	8.39	10896.14	1.50
2023	31435.95	8.30	10916.71	1.50
2024	32443.07	8.30	8396.92	1.50
2025	33685.11	8.31	8561.34	1.50
2026	33091.14	8.32	9994.95	1.50
2027	35260.28	8.37	18177.75	1.50
2028	38831.31	8.38	15895.95	1.50
2029	39673.43	8.38	16203.21	1.50
2030	39569.68	8.38	22466.35	1.50
2031	39226.49	8.33	22394.46	1.50
2032	39610.16	8.32	16883.20	1.50
2033	40736.38	8.33	20440.06	1.50
2034	37452.38	8.32	18713.72	1.50
2035	38395.52	8.33	17424.55	1.50
2036	43993.16	8.35	25095.10	1.50
2037	44490.91	8.35	20368.90	1.50

TABLE C-2g

Unit Rio Grande 7	Fuel Costs	Heat Rate	Fixed and Variable O&M	Non-Availability Factor
Year	$000	MMBtu/MWh	$000	%
2018	1125.43	11.06	1512.21	2.24
2019	1263.20	11.05	1545.43	2.24
2020	1983.36	11.04	1599.43	2.24
2021	2059.70	11.04	1625.17	2.24
2022	1551.80	11.04	4400.25	2.24

TABLE C-2h

Unit Rio Grande 8	Fuel Costs	Heat Rate	Fixed and Variable O&M	Non-Availability Factor
Year	$000	MMBtu/MWh	$000	%
2018	10,694.57	11.73	6,873.63	6.41
2019	13,194.93	11.72	4,308.90	6.41
2020	13,736.40	11.68	4,414.16	6.41
2021	14,058.09	11.68	4,483.44	6.41
2022	14,354.78	11.69	4,557.58	6.41
2023	13,406.81	11.85	5,232.57	6.41
2024	11,476.66	11.87	9,100.75	6.41
2025	14,213.53	11.88	5,414.48	6.41
2026	14,993.43	11.85	5,519.29	6.41
2027	17,631.96	11.77	5,674.19	6.41
2028	19,070.53	11.75	5,773.61	6.41
2029	19,774.87	11.74	5,873.23	6.41
2030	15,884.36	11.72	11,463.74	6.41
2031	18,429.32	11.80	6,031.65	6.41
2032	18,192.04	11.83	6,143.75	6.41
2033	18,766.90	11.82	6,253.79	6.41

TABLE C-2i

Unit Rio Grande 9	Fuel Costs	Heat Rate	Fixed and Variable O&M	Non-Availability Factor
Year	$000	MMBtu/MWh	$000	%
2018	4890.98	8.93	2432.93	8.96
2019	5242.90	8.91	3740.88	8.96
2020	6248.98	8.89	2595.21	8.96
2021	6285.39	8.90	2628.30	8.96
2022	6572.54	8.92	2679.54	8.96
2023	3469.40	9.07	2989.94	8.96
2024	3294.54	9.07	4616.92	8.96
2025	3488.13	9.06	3087.61	8.96
2026	4521.47	9.04	3176.01	8.96
2027	5688.34	9.00	3271.47	8.96
2028	6149.69	8.94	3326.09	8.96
2029	6476.65	8.92	4864.29	8.96
2030	7441.42	8.91	3479.11	8.96
2031	4925.61	8.98	3443.83	8.96
2032	4256.91	8.99	3490.08	8.96
2033	4639.92	8.98	3558.47	8.96
2034	8471.30	8.89	5672.99	8.96
2035	9201.19	8.89	3858.86	8.96
2036	6114.13	8.94	3815.53	8.96
2037	6260.75	8.94	3879.23	8.96

TABLE C-2j

Unit Palo Verde 1	Fuel Costs	Heat Rate	Fixed and Variable O&M	Non-Availability Factor
Year	$000	MMBtu/MWh	$000	%
2018	14,393.95	10.21	29,387.79	1.00
2019	13,724.63	10.21	34,775.01	1.00
2020	15,433.57	10.21	34,140.09	1.00
2021	17,346.17	10.21	29,361.16	1.00
2022	15,014.63	10.21	34,808.89	1.00
2023	14,449.32	10.21	34,776.61	1.00
2024	15,218.28	10.21	29,904.77	1.00
2025	14,391.25	10.21	35,458.46	1.00
2026	14,622.78	10.21	34,798.66	1.00
2027	16,681.21	10.21	29,832.09	1.00
2028	15,658.05	10.21	36,104.24	1.00
2029	15,876.73	10.21	35,431.63	1.00
2030	17,688.69	10.21	30,368.51	1.00
2031	16,617.64	10.21	36,140.36	1.00
2032	16,971.34	10.21	35,454.69	1.00
2033	18,835.96	10.21	30,940.24	1.00
2034	17,700.08	10.21	36,824.36	1.00
2035	18,055.93	10.21	36,125.38	1.00
2036	20,127.58	10.21	30,863.48	1.00
2037	18,772.44	10.21	36,862.05	1.00

TABLE C-2k

Unit Palo Verde 2	Fuel Costs	Heat Rate	Fixed and Variable O&M	Non-Availability Factor
Year	$000	MMBtu/MWh	$000	%
2018	12,932.19	10.19	34,085.79	1.00
2019	14,060.72	10.19	29,408.01	1.00
2020	15,299.66	10.19	34,786.23	1.00
2021	15,925.14	10.19	34,147.23	1.00
2022	16,385.56	10.19	29,337.52	1.00
2023	14,484.49	10.19	35,435.30	1.00
2024	14,276.51	10.19	34,783.90	1.00
2025	15,325.21	10.19	29,880.69	1.00
2026	14,637.51	10.19	35,470.17	1.00
2027	15,111.31	10.19	34,806.11	1.00
2028	16,771.07	10.19	30,418.00	1.00
2029	15,593.60	10.19	36,116.20	1.00
2030	15,840.49	10.19	35,439.26	1.00
2031	17,532.29	10.19	30,343.54	1.00
2032	16,394.84	10.19	36,152.57	1.00
2033	16,604.85	10.19	36,109.60	1.00
2034	18,378.29	10.19	30,914.81	1.00
2035	17,134.80	10.19	36,836.84	1.00
2036	17,458.05	10.19	36,133.36	1.00
2037	19,265.11	10.19	30,837.57	1.00

TABLE C-2l

Unit Palo Verde 3	Fuel Costs	Heat Rate	Fixed and Variable O&M	Non-Availability Factor
Year	**$000**	**MMBtu/MWh**	**$000**	**%**
2018	13288.89	10.21	34846.79	1.00
2019	13104.71	10.21	34133.01	1.00
2020	16210.98	10.21	29384.66	1.00
2021	15284.71	10.21	34797.52	1.00
2022	15228.52	10.21	34154.41	1.00
2023	15734.80	10.21	29928.69	1.00
2024	14224.92	10.21	35446.84	1.00
2025	14399.73	10.21	34791.25	1.00
2026	15954.47	10.21	29856.47	1.00
2027	14793.28	10.21	35481.95	1.00
2028	14996.51	10.21	35424.05	1.00
2029	16465.49	10.21	30393.33	1.00
2030	15274.17	10.21	36128.24	1.00
2031	15437.91	10.21	35446.95	1.00
2032	17047.31	10.21	30318.41	1.00
2033	15770.68	10.21	36811.98	1.00
2034	15939.75	10.21	36117.46	1.00
2035	17553.37	10.21	30889.21	1.00
2036	16331.95	10.21	36849.40	1.00
2037	16457.90	10.21	36141.39	1.00

TABLE C-2m

Unit Montana 1	Fuel Costs	Heat Rate	Fixed and Variable O&M	Non-Availability Factor
Year	**$000**	**MMBtu/MWh**	**$000**	**%**
2018	8450.58	8.84	1265.22	0.75
2019	8900.54	8.82	1352.71	0.75
2020	9676.99	8.79	2701.88	0.75
2021	10082.38	8.80	1502.74	0.75
2022	10853.45	8.81	1580.27	0.75
2023	7290.62	8.91	1426.33	0.75
2024	7232.42	8.91	1461.20	0.75
2025	7135.25	8.90	3094.30	0.75
2026	8997.74	8.88	1644.59	0.75
2027	10535.03	8.85	1796.11	0.75
2028	10625.22	8.84	1829.05	0.75
2029	11032.18	8.83	1872.77	0.75
2030	11782.63	8.81	3450.74	0.75
2031	9270.00	8.87	1795.42	0.75
2032	8285.68	8.90	1755.31	0.75
2033	8858.32	8.89	1814.69	0.75
2034	13715.84	8.80	2191.78	0.75
2035	13871.54	8.79	4131.68	0.75
2036	10819.07	8.86	2025.45	0.75
2037	10981.46	8.85	2054.64	0.75

TABLE C-2n

Unit Montana 2	Fuel Costs	Heat Rate	Fixed and Variable O&M	Non-Availability Factor
Year	$000	MMBtu/MWh	$000	%
2018	6,726.91	8.88	1,196.89	1.46
2019	7,220.69	8.86	1,275.69	1.46
2020	8,267.29	8.84	2,631.50	1.46
2021	8,354.52	8.84	1,412.44	1.46
2022	8,897.14	8.86	1,474.06	1.46
2023	5,205.89	8.97	1,308.94	1.46
2024	5,246.49	8.98	1,344.02	1.46
2025	5,358.08	8.97	2,984.41	1.46
2026	6,790.86	8.95	1,502.06	1.46
2027	8,209.51	8.91	1,637.68	1.46
2028	8,474.41	8.88	1,682.36	1.46
2029	8,543.96	8.86	1,704.35	1.46
2030	9,933.49	8.85	3,323.46	1.46
2031	7,089.01	8.92	1,647.49	1.46
2032	6,205.01	8.94	1,614.51	1.46
2033	6,696.94	8.93	1,667.81	1.46
2034	11,088.37	8.84	2,014.37	1.46
2035	12,002.18	8.83	4,004.38	1.46
2036	8,469.67	8.89	1,866.91	1.46
2037	8,632.49	8.89	1,899.28	1.46

TABLE C-2o

Unit Montana 3	Fuel Costs	Heat Rate	Fixed and Variable O&M	Non-Availability Factor
Year	$000	MMBtu/MWh	$000	%
2018	10,303.39	8.78	1,195.78	0.12
2019	10,624.45	8.76	1,264.11	0.12
2020	11,506.29	8.74	1,342.25	0.12
2021	11,448.47	8.74	2,658.50	0.12
2022	12,746.21	8.75	1,464.36	0.12
2023	9,414.85	8.82	1,365.49	0.12
2024	9,383.24	8.82	1,399.49	0.12
2025	9,367.27	8.82	1,430.62	0.12
2026	2,310.20	8.78	2,771.46	0.12
2027	9,489.47	8.77	1,516.88	0.12
2028	12,850.28	8.77	1,707.92	0.12
2029	13,267.45	8.77	1,743.31	0.12
2030	14,222.65	8.75	1,809.53	0.12
2031	11,226.27	8.80	3,214.82	0.12
2032	10,671.10	8.83	1,677.74	0.12
2033	13,593.22	8.78	1,841.67	0.12
2034	17,674.73	8.71	2,080.95	0.12
2035	16,517.44	8.73	2,044.16	0.12
2036	15,229.60	8.75	3,956.91	0.12
2037	15,752.21	8.76	2,046.77	0.12

TABLE C-2p

Unit Montana 4	Fuel Costs	Heat Rate	Fixed and Variable O&M	Non-Availability Factor
Year	$000	MMBtu/MWh	$000	%
2018	11,940.07	8.75	1,033.82	0.15
2019	12,058.24	8.73	1,098.23	0.15
2020	12,798.49	8.72	1,170.49	0.15
2021	13,054.14	8.72	1,213.29	0.15
2022	2,433.04	8.70	2,138.02	0.15
2023	8,294.99	8.78	1,089.88	0.15
2024	11,301.77	8.78	1,248.71	0.15
2025	11,294.20	8.78	1,280.05	0.15
2026	11,633.46	8.78	1,331.15	0.15
2027	13,819.07	8.74	3,148.00	0.15
2028	14,720.73	8.74	1,545.28	0.15
2029	15,133.39	8.74	1,581.85	0.15
2030	15,996.89	8.72	1,638.63	0.15
2031	13,710.95	8.77	1,540.09	0.15
2032	12,606.43	8.78	3,066.95	0.15
2033	11,299.07	8.82	1,453.02	0.15
2034	15,969.82	8.74	1,737.52	0.15
2035	18,270.22	8.71	1,848.78	0.15
2036	13,387.64	8.79	1,620.69	0.15
2037	13,181.98	8.79	3,615.50	0.15

TABLE C-2q – Purchase Power

Year	Purchase Power $/MWh
2018	46.39
2019	45.35
2020	47.04
2021	48.30
2022	49.60
2023	50.79
2024	52.39
2025	54.18
2026	56.16
2027	57.66
2028	59.23
2029	60.83
2030	62.46
2031	64.14
2032	65.87
2033	67.64
2034	69.47
2035	71.35
2036	73.27
2037	75.25

Note: The Purchase Power forecast shown in the table above represents the maximum annual market value. A market profile is used in conjunction with this forecast to shape the market on an hourly basis downward based on this peak value.

TABLE C-2r – Fuel Prices

Year	Fuel Prices ($/MBTU)		
	GasInter(1)	NewInter(2)	GasIntra(3)
2018	2.68	2.61	2.74
2019	2.53	2.47	2.60
2020	2.55	2.49	2.66
2021	2.62	2.56	2.73
2022	2.70	2.64	2.80
2023	2.77	2.70	2.86
2024	2.85	2.78	2.95
2025	2.94	2.87	3.05
2026	3.05	2.97	3.15
2027	3.13	3.04	3.23
2028	3.19	3.10	3.29
2029	3.24	3.15	3.36
2030	3.30	3.21	3.42
2031	3.36	3.26	3.48
2032	3.42	3.32	3.55
2033	3.48	3.38	3.62
2034	3.54	3.44	3.68
2035	3.61	3.50	3.75
2036	3.67	3.56	3.82
2037	3.74	3.62	3.90

Notes:

(1) GasInter is interstate gas with service provided by EPNG. This gas is utilized at the Rio Grande Power Plant.

(2) NewInter is also interstate gas provided by EPNG that is utilized at Montana and Newman Power Stations as well as the fuel source for generic resources.

(3) GasIntra is intrastate gas with service provided by Oneok and is utilized at Newman and Copper Power Stations.

TABLE C-2s – Capacity Factors

CAPACITY FACTORS 2018-2027

UNIT		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
BIOMASS	1	---	---	---	---	---	---	---	---	---	---
CC_M	1	---	---	---	---	---	72.09	69.17	70.30	71.30	69.02
CC_M	2	---	---	---	---	---	---	---	---	---	---
COPPER	1	2.63	2.42	2.56	2.53	1.90	1.53	1.70	1.97	2.03	1.59
CT_L	1	---	---	---	---	---	---	---	---	---	46.48
CT_L	2	---	---	---	---	---	---	---	---	---	---
CT_L	3	---	---	---	---	---	---	---	---	---	---
MONTANA	1	35.34	38.65	55.88	43.14	40.85	38.99	32.72	28.69	34.51	42.01
MONTANA	2	24.32	27.47	36.54	31.20	27.41	23.88	21.23	22.67	22.40	25.73
MONTANA	3	46.49	55.26	64.30	59.79	54.19	51.32	40.59	44.31	47.82	53.69
MONTANA	4	29.61	28.84	37.06	32.62	33.84	34.04	25.64	26.00	27.32	38.51
NEWMAN	1	26.40	36.89	31.89	38.76	34.87	---	---	---	---	---
NEWMAN	2	18.47	35.62	38.25	30.15	37.05	---	---	---	---	---
NEWMAN	3	35.58	41.84	36.02	43.28	42.90	39.90	30.93	40.49	40.69	---
NEWMAN	4	55.02	52.60	48.93	53.32	52.63	51.78	48.15	51.33	51.63	---
NEWMAN	5	58.85	38.48	36.32	35.63	39.08	35.22	38.08	34.52	37.40	38.82
PALO VER	1	98.90	89.34	85.29	98.80	90.53	90.41	99.00	90.65	90.62	98.90
PALO VER	2	86.55	99.20	90.75	89.24	98.82	90.67	90.81	99.00	90.86	90.86
PALO VER	3	89.78	86.77	99.00	90.86	89.97	98.98	90.63	90.80	99.00	90.86
RECP	1	---	---	---	---	---	---	---	---	---	38.00
RECP	2	---	---	---	---	---	---	---	---	---	---
RIO GRAN	7	27.83	31.53	24.18	34.26	31.12	---	---	---	---	---
RIO GRAN	8	39.64	32.28	28.21	35.59	29.25	32.80	33.27	33.78	26.24	34.25
RIO GRAN	9	11.19	13.64	16.15	16.58	13.04	8.39	8.77	9.65	9.16	12.32

CAPACITY FACTORS 2028-2037

UNIT		2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
BIOMASS	1	---	---	---	---	---	---	---	---	---	88.20
CC_M	1	74.87	77.94	79.29	67.86	79.89	81.62	84.02	81.03	85.84	86.66
CC_M	2	---	---	---	68.84	71.74	73.81	75.94	73.62	76.98	77.09
COPPER	1	1.31	1.42	1.34	---	---	---	---	---	---	---
CT_L	1	45.62	48.50	49.08	43.37	43.31	46.28	46.63	49.07	48.20	48.53
CT_L	2	49.99	43.77	44.18	38.34	34.99	36.97	39.76	42.91	40.97	42.30
CT_L	3	---	---	---	---	---	---	37.90	36.24	35.30	36.88
MONTANA	1	40.73	37.50	38.90	25.73	20.77	22.19	15.64	16.32	14.66	15.24
MONTANA	2	19.34	21.17	20.75	13.22	7.84	9.95	6.17	6.59	5.23	5.77
MONTANA	3	47.58	50.80	49.01	37.94	25.36	27.00	22.67	26.55	20.43	23.78
MONTANA	4	26.65	25.65	26.17	17.61	14.34	16.12	10.56	9.24	8.95	10.10
NEWMAN	1	---	---	---	---	---	---	---	---	---	---
NEWMAN	2	---	---	---	---	---	---	---	---	---	---
NEWMAN	3	---	---	---	---	---	---	---	---	---	---
NEWMAN	4	---	---	---	---	---	---	---	---	---	---
NEWMAN	5	39.26	32.12	39.57	37.35	33.75	33.01	39.55	38.85	39.54	37.01
PALO VER	1	90.81	90.79	98.79	90.83	90.85	98.98	90.84	90.84	98.98	90.85
PALO VER	2	99.00	90.86	90.86	99.00	90.89	90.86	99.00	90.86	90.89	99.00
PALO VER	3	90.88	99.00	90.86	90.86	99.00	90.86	90.86	99.00	90.89	90.86
RECP	1	35.69	35.66	36.95	30.34	29.18	29.46	29.03	29.09	28.83	29.09
RECP	2	---	---	---	---	---	---	24.50	24.72	22.66	24.46
RIO GRAN	7	---	---	---	---	---	---	---	---	---	---
RIO GRAN	8	25.94	33.79	27.96	29.33	27.90	28.47	---	---	---	---
RIO GRAN	9	10.17	9.90	9.41	5.71	2.25	3.26	2.61	3.07	1.90	2.56

Attachment D-1: Lazard's

For the 2018 IRP Process EPE utilized Lazard's Levelized Cost of Energy Analysis –Version 11.0 which can be found at the link below:

https://www.lazard.com/perspective/levelized-cost-of-energy-2017/

For the 2018 IRP Process EPE utilized Lazard's Levelized Cost of Storage Analysis –Version 3.0 which can be found at the link below:

https://www.lazard.com/perspective/levelized-cost-of-storage-2017/

Attachment E-1: Expansion Plan Results – Base Case and Sensitivities
TABLE E-01a Base Case

PROVIEW LEAST COST OPTIMIZATION SYSTEM
PLANNING PERIOD PLAN COMPARISON

PLAN RANK	1	2	3	4	5	6	7	8
2018								
2019								
2020								
2021								
2022	25S (1)	25S (1)	25S (1)	25S (1)	25S (1)	25S (1)	75S (3)	25S (1)
	75S (3)	75S (3)	75S (3)	75S (3)	75S (3)	75S (3)	PVBS(1)	75S (3)
	100S(1)	100S(1)	100S(1)	100S(1)	100S(1)	100S(1)		100S(1)
	STOR(1)	STOR(1)	STOR(1)	STOR(1)	STOR(1)	STOR(1)		STOR(1)
2023	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)
2024								
2025								
2026								
2027	27PV(1)	27PV(1)	27PV(1)	27PV(1)	27PV(1)	27PV(1)	CC_M(1)	27PV(1)
	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)		CT_L(1)
	RCP1(1)	RCP2(2)	RCP1(1)	RCP2(2)	RCP2(2)	RCP1(1)		RCP2(2)
	BS1G(1)	BS1G(1)	BS1G(1)	BS1G(1)	BS1G(1)	BS1G(1)		BS1G(1)
2028	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)
2029								
2030								
2031	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CT_L(1)	CC_M(1)
							BS1G(2)	
2032								
2033							RCP1(1)	
2034	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)
	RCP1(1)	RCP1(1)	RCP1(1)	RCP1(1)	RCP1(1)	RCP1(1)	RCP1(1)	RCP1(1)
2035	BS1G(1)	BS1G(1)	BS1G(1)	BS1G(1)	PVS (1)	PVS (1)		PVS (1)
2036	PVS (1)	PVS (1)	PVS (1)	PVS (1)	BS1G(1)	BS1G(1)	PVS (1)	BS1G(1)
2037	BIO1(1)	BIO1(1)	GEO1(1)	GEO1(1)	BIO1(1)	BIO1(1)	BIO1(1)	GEO1(1)
							GEO1(1)	
P.V. UTILITY COST:								
PLANNING PERIOD	3244995.0	3244995.2	3245240.2	3245240.5	3245249.5	3245249.8	3245369.5	3245494.8
% DIFFERENCE	0.00%	0.00%	0.01%	0.01%	0.01%	0.01%	0.01%	0.02%
STUDY PERIOD RANK	1	2	3	4	5	6	7	8

TABLE E-01b Low Load Sensitivity

PROVIEW LEAST COST OPTIMIZATION SYSTEM
PLANNING PERIOD PLAN COMPARISON

PLAN RANK	1	2	3	4	5	6	7	8
2018								
2019								
2020								
2021								
2022								
2023	75S (2)	75S (2)	75S (2)	75S (2)	75S (2)	75S (2)	75S (2)	75S (2)
	100S(1)	100S(1)	100S(1)	100S(1)	100S(1)	100S(1)	100S(1)	100S(1)
	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)
	BS1G(1)	BS1G(1)	BS1G(1)	BS1G(1)	BS1G(1)	BS1G(1)	BS1G(1)	BS1G(1)
2024	BS1G(1)	BS1G(1)	BS1G(1)	BS1G(1)	BS1G(1)	BS1G(1)	BS1G(1)	BS1G(1)
2025								
2026								
2027	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)
2028	PVBS(1)	PVBS(1)	PVBS(1)	PVBS(1)	PVBS(1)	PVBS(1)	PVBS(1)	PVBS(1)
2029								
2030								
2031	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)
2032								
2033								
2034	CT_L(1)	CT_L(1)	RCP1(1)	CT_L(1)	CT_L(1)	RCP1(1)	CT_L(1)	CT_L(1)
	RCP2(1)	RCP2(1)	RCP2(1)	RCP1(1)	RCP1(1)	RCP2(1)	RCP1(1)	STOR(2)
	PVS (1)	PVS (1)	PVS (1)			PVS (1)		RCP2(1)
2035	RCP2(1)	RCP2(1)	RCP2(1)	PVS (1)	PVS (1)	RCP2(1)	PVS (1)	RCP2(1)
2036	RCP2(1)	RCP2(1)	RCP2(1)	RCP2(1)	RCP2(1)	RCP2(1)	RCP2(1)	PVS (1)
2037	BIO1(1)	GEO1(1)	BIO1(1)	RCP2(1)	BIO1(1)	GEO1(1)	GEO1(1)	RCP2(1)
P.V. UTILITY COST:								
PLANNING PERIOD	3022817.0	3023059.8	3024519.8	3024532.5	3024709.2	3024762.0	3024952.2	3025822.0
% DIFFERENCE	0.00%	0.01%	0.06%	0.06%	0.06%	0.06%	0.07%	0.10%
STUDY PERIOD RANK	1	2	3	4	5	6	7	8

TABLE E-01c High Load Sensitivity

PROVIEW LEAST COST OPTIMIZATION SYSTEM
PLANNING PERIOD PLAN COMPARISON

PLAN RANK	1	2	3	4	5	6	7	8
2018								
2019								
2020								
2021								
2022	75S (1) 100S(1) CT_L(1) BS1G(1) PVBS(1)	75S (1) 100S(1) CT_L(1) BS1G(1) PVBS(1)	75S (1) 100S(1) CT_L(1) BS1G(1) PVBS(1)	75S (1) 100S(1) CT_L(1) BS1G(1) PVBS(1)	25S (1) 75S (2) 100S(1) CT_L(1) STOR(1) PVBS(1)	25S (1) 75S (2) 100S(1) CT_L(1) STOR(1) PVBS(1)	25S (1) 75S (2) 100S(1) CT_L(1) STOR(1) PVBS(1)	25S (1) 75S (2) 100S(1) CT_L(1) STOR(1) PVBS(1)
2023	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)
2024								
2025								
2026								
2027	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	27PV(1) CT_L(1) RCP2(2) BS1G(1)	27PV(1) CT_L(1) RCP1(1) BS1G(1)	27PV(1) CT_L(1) RCP2(2) BS1G(1)	27PV(1) CT_L(1) RCP1(1) BS1G(1)
2028	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	RCP1(1)	RCP1(1)	RCP1(1)	RCP1(1)
2029								
2030								
2031	CT_L(1) RCP2(1) BS1G(1)	CT_L(1) RCP2(1) BS1G(1)	RCP1(1) RCP2(1) BS1G(1)	RCP1(1) RCP2(1) BS1G(1)	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)
2032	BIO1(1)	GEO1(1)	BIO1(1)	GEO1(1)				
2033	PVS (1)	PVS (1)	PVS (1)	PVS (1)				
2034	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CT_L(1) RCP1(1)	CT_L(1) RCP1(1)	CT_L(1) RCP1(1)	CT_L(1) RCP1(1)
2035					BS1G(1)	BS1G(1)	PVS (1)	PVS (1)
2036					PVS (1)	PVS (1)	BS1G(1)	BS1G(1)
2037	GEO1(1)	BIO1(1)	GEO1(1)	BIO1(1)	BIO1(1) GEO1(1)	BIO1(1) GEO1(1)	BIO1(1) GEO1(1)	BIO1(1) GEO1(1)
P.V. UTILITY COST:								
PLANNING PERIOD	3452985.0	3454319.0	3455567.0	3456897.2	3457851.8	3457852.2	3458076.2	3458076.8
% DIFFERENCE	0.00%	0.04%	0.07%	0.11%	0.14%	0.14%	0.15%	0.15%
STUDY PERIOD RANK	1	2	3	4	5	6	7	8

TABLE E-01d Low Natural Gas Price Sensitivity

PROVIEW LEAST COST OPTIMIZATION SYSTEM
PLANNING PERIOD PLAN COMPARISON

PLAN RANK	1	2	3	4	5	6	7	8
2018								
2019								
2020								
2021								
2022	75S (3)	75S (2)	75S (3)	75S (2)	75S (2)	75S (3)	75S (2)	75S (2)
	PVBS(1)	100S(1)	PVBS(1)	100S(1)	100S(1)	PVBS(1)	100S(1)	100S(1)
		BS1G(1)		BS1G(1)	BS1G(1)		BS1G(1)	BS1G(1)
2023	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)
2024								
2025								
2026								
2027	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)
2028	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)
2029								
2030								
2031	CT_L(1)	CT_L(1)	RCP1(1)	RCP1(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)
	BS1G(2)	RCP2(1)	BS1G(2)	RCP2(1)	RCP1(1)	BS1G(2)	RCP2(1)	RCP1(1)
		BS1G(1)		BS1G(1)			BS1G(1)	
2032								
2033	RCP1(1)	RCP1(1)	RCP1(1)	RCP1(1)	RCP2(1)	RCP1(1)	RCP1(1)	CT_L(1)
2034	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	RCP1(1)
	RCP1(1)	RCP1(1)	RCP1(1)	RCP1(1)	RCP1(1)	RCP1(1)	RCP1(1)	RCP2(1)
2035					BS1G(1)			BS1G(1)
2036	PVS (1)	PVS (1)	PVS (1)	PVS (1)	PVS (1)	BIO1(1)	BIO1(1)	PVS (1)
						GEO1(1)	GEO1(1)	
2037	BIO1(1)	BIO1(1)	BIO1(1)	BIO1(1)	BIO1(1)	PVS (1)	PVS (1)	BIO1(1)
	GEO1(1)	GEO1(1)	GEO1(1)	GEO1(1)	GEO1(1)			GEO1(1)
P.V. UTILITY COST:								
PLANNING PERIOD	3170557.8	3170599.0	3173444.2	3173570.5	3174549.8	3174853.2	3174996.0	3176938.0
% DIFFERENCE	0.00%	0.00%	0.09%	0.10%	0.13%	0.14%	0.14%	0.20%
STUDY PERIOD RANK	1	2	3	4	5	6	7	8

TABLE E-01e High Natural Gas Price Sensitivity

PROVIEW LEAST COST OPTIMIZATION SYSTEM
PLANNING PERIOD PLAN COMPARISON

PLAN RANK	1	2	3	4	5	6	7	8
2018								
2019								
2020								
2021								
2022	25S (1)	25S (1)	25S (1)	25S (1)	25S (1)	25S (1)	25S (1)	25S (1)
	75S (3)	75S (3)	75S (3)	75S (3)	75S (3)	75S (3)	75S (3)	75S (3)
	100S(1)	100S(1)	100S(1)	100S(1)	100S(1)	100S(1)	100S(1)	100S(1)
	STOR(1)	STOR(1)	STOR(1)	STOR(1)	STOR(1)	STOR(1)	STOR(1)	STOR(1)
2023	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)
2024								
2025								
2026								
2027	27PV(1)	27PV(1)	27PV(1)	27PV(1)	27PV(1)	27PV(1)	27PV(1)	27PV(1)
	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)
	RCP2(2)	RCP2(2)	RCP2(2)	RCP2(2)	RCP1(1)	RCP1(1)	RCP1(1)	RCP1(1)
	BS1G(1)	BS1G(1)	BS1G(1)	BS1G(1)	BS1G(1)	BS1G(1)	BS1G(1)	BS1G(1)
2028	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)
2029								
2030								
2031	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)
2032								
2033								
2034	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)
	RCP1(1)	RCP1(1)	RCP1(1)	RCP1(1)	RCP1(1)	RCP1(1)	RCP1(1)	RCP1(1)
2035	BS1G(1)	PVS (1)	BS1G(1)	PVS (1)	BS1G(1)	PVS (1)	BS1G(1)	PVS (1)
2036	PVS (1)	BS1G(1)	PVS (1)	BS1G(1)	PVS (1)	BS1G(1)	PVS (1)	BS1G(1)
2037	BIO1(1)	BIO1(1)	GEO1(1)	GEO1(1)	BIO1(1)	BIO1(1)	GEO1(1)	GEO1(1)
P.V. UTILITY COST:								
PLANNING PERIOD	3315031.5	3315100.5	3315373.5	3315442.5	3315464.5	3315534.0	3315806.8	3315876.2
% DIFFERENCE	0.00%	0.00%	0.01%	0.01%	0.01%	0.02%	0.02%	0.03%
STUDY PERIOD RANK	1	2	3	4	5	6	7	8

TABLE E-01f $8 CO2 Tax Price Sensitivity

PROVIEW LEAST COST OPTIMIZATION SYSTEM
PLANNING PERIOD PLAN COMPARISON

PLAN RANK	1	2	3	4	5	6	7	8
2018								
2019								
2020								
2021								
2022	25S (1)	25S (1)	25S (1)	25S (1)	25S (1)	25S (1)	25S (1)	25S (1)
	75S (3)	75S (3)	75S (3)	75S (3)	75S (3)	75S (3)	75S (3)	75S (3)
	100S(1)	100S(1)	100S(1)	100S(1)	100S(1)	100S(1)	100S(1)	100S(1)
	STOR(1)	STOR(1)	STOR(1)	STOR(1)	STOR(1)	STOR(1)	STOR(1)	STOR(1)
2023	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)
2024								
2025								
2026								
2027	27PV(1)	27PV(1)	27PV(1)	27PV(1)	27PV(1)	27PV(1)	27PV(1)	27PV(1)
	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)
	RCP2(2)	RCP1(1)	RCP2(2)	RCP1(1)	RCP2(2)	RCP1(1)	RCP2(2)	RCP1(1)
	BS1G(1)	BS1G(1)	BS1G(1)	BS1G(1)	BS1G(1)	BS1G(1)	BS1G(1)	BS1G(1)
2028	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)
2029								
2030								
2031	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)
2032								
2033								
2034	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)
	RCP1(1)	RCP1(1)	RCP1(1)	RCP1(1)	RCP1(1)	RCP1(1)	RCP1(1)	RCP1(1)
2035	PVS (1)	PVS (1)	BS1G(1)	BS1G(1)	PVS (1)	PVS (1)	BS1G(1)	BS1G(1)
2036	BS1G(1)	BS1G(1)	PVS (1)	PVS (1)	BS1G(1)	BS1G(1)	PVS (1)	PVS (1)
2037	BIO1(1)	BIO1(1)	BIO1(1)	BIO1(1)	GEO1(1)	GEO1(1)	GEO1(1)	GEO1(1)
P.V. UTILITY COST:								
PLANNING PERIOD	3536867.8	3537012.8	3537046.2	3537191.5	3537272.2	3537417.5	3537450.8	3537596.2
% DIFFERENCE	0.00%	0.00%	0.01%	0.01%	0.01%	0.02%	0.02%	0.02%
STUDY PERIOD RANK	1	2	3	4	5	6	7	8

TABLE E-01g $20 CO2 Tax Price Sensitivity

PROVIEW LEAST COST OPTIMIZATION SYSTEM
PLANNING PERIOD PLAN COMPARISON

PLAN RANK	1	2	3	4	5	6	7	8
2018								
2019								
2020								
2021								
2022	25S (1)	25S (1)	25S (1)	25S (1)	25S (1)	25S (1)	25S (1)	25S (1)
	75S (3)	75S (3)	75S (3)	75S (3)	75S (3)	75S (3)	75S (3)	75S (3)
	100S(1)	100S(1)	100S(1)	100S(1)	100S(1)	100S(1)	100S(1)	100S(1)
	STOR(1)	STOR(1)	STOR(1)	STOR(1)	STOR(1)	STOR(1)	STOR(1)	STOR(1)
2023	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)
2024								
2025								
2026								
2027	27PV(1)	27PV(1)	27PV(1)	27PV(1)	27PV(1)	27PV(1)	27PV(1)	27PV(1)
	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)
	RCP2(2)	RCP1(1)	RCP2(2)	RCP1(1)	RCP2(2)	RCP1(1)	RCP2(2)	RCP1(1)
	BS1G(1)	BS1G(1)	BS1G(1)	BS1G(1)	BS1G(1)	BS1G(1)	BS1G(1)	BS1G(1)
2028	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)
2029								
2030								
2031	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)
2032								
2033								
2034	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)
	RCP1(1)	RCP1(1)	RCP1(1)	RCP1(1)	RCP1(1)	RCP1(1)	RCP1(1)	RCP1(1)
2035	PVS (1)	PVS (1)	BS1G(1)	BS1G(1)	PVS (1)	PVS (1)	BS1G(1)	BS1G(1)
2036	BS1G(1)	BS1G(1)	PVS (1)	PVS (1)	BS1G(1)	BS1G(1)	PVS (1)	PVS (1)
2037	BIO1(1)	BIO1(1)	BIO1(1)	BIO1(1)	GEO1(1)	GEO1(1)	GEO1(1)	GEO1(1)
P.V. UTILITY COST:								
PLANNING PERIOD	3839871.2	3839876.8	3840299.2	3840304.8	3840345.8	3840351.2	3840773.8	3840779.2
% DIFFERENCE	0.00%	0.00%	0.01%	0.01%	0.01%	0.01%	0.02%	0.02%
STUDY PERIOD RANK	1	2	3	4	5	6	7	8

TABLE E-01h $40 CO2 Tax Price Sensitivity

PROVIEW LEAST COST OPTIMIZATION SYSTEM
PLANNING PERIOD PLAN COMPARISON

PLAN RANK	1	2	3	4	5	6	7	8
2018								
2019								
2020								
2021								
2022	25S (1)	25S (1)	25S (1)	25S (1)	25S (1)	25S (1)	25S (1)	25S (1)
	75S (3)	75S (3)	75S (3)	75S (3)	75S (3)	75S (3)	75S (3)	75S (3)
	100S(1)	100S(1)	100S(1)	100S(1)	100S(1)	100S(1)	100S(1)	100S(1)
	STOR(1)	STOR(1)	STOR(1)	STOR(1)	STOR(1)	STOR(1)	STOR(1)	STOR(1)
2023	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)
2024								
2025								
2026								
2027	27PV(1)	27PV(1)	27PV(1)	27PV(1)	27PV(1)	27PV(1)	27PV(1)	27PV(1)
	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)
	RCP2(2)	RCP1(1)	RCP2(2)	RCP1(1)	RCP2(2)	RCP1(1)	RCP2(2)	RCP1(1)
	BS1G(1)	BS1G(1)	BS1G(1)	BS1G(1)	BS1G(1)	BS1G(1)	BS1G(1)	BS1G(1)
2028	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)
2029								
2030								
2031	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)	CC_M(1)
2032								
2033								
2034	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)	CT_L(1)
	RCP1(1)	RCP1(1)	RCP1(1)	RCP1(1)	RCP1(1)	RCP1(1)	RCP1(1)	RCP1(1)
2035	PVS (1)	PVS (1)	PVS (1)	PVS (1)	BS1G(1)	BS1G(1)	BS1G(1)	BS1G(1)
2036	BS1G(1)	BS1G(1)	BS1G(1)	BS1G(1)	PVS (1)	PVS (1)	PVS (1)	PVS (1)
2037	BIO1(1)	BIO1(1)	GEO1(1)	GEO1(1)	BIO1(1)	BIO1(1)	GEO1(1)	GEO1(1)
P.V. UTILITY COST:								
PLANNING PERIOD	4221251.5	4221251.5	4221687.5	4221687.5	4222004.5	4222004.5	4222440.5	4222440.5
% DIFFERENCE	0.00%	0.00%	0.01%	0.01%	0.02%	0.02%	0.03%	0.03%
STUDY PERIOD RANK	1	2	3	4	5	6	7	8

Attachment F-1: Solar Data Plots

EPE analyzed the solar output for its existing solar facilities in 2016 for analysis of contribution to peak.

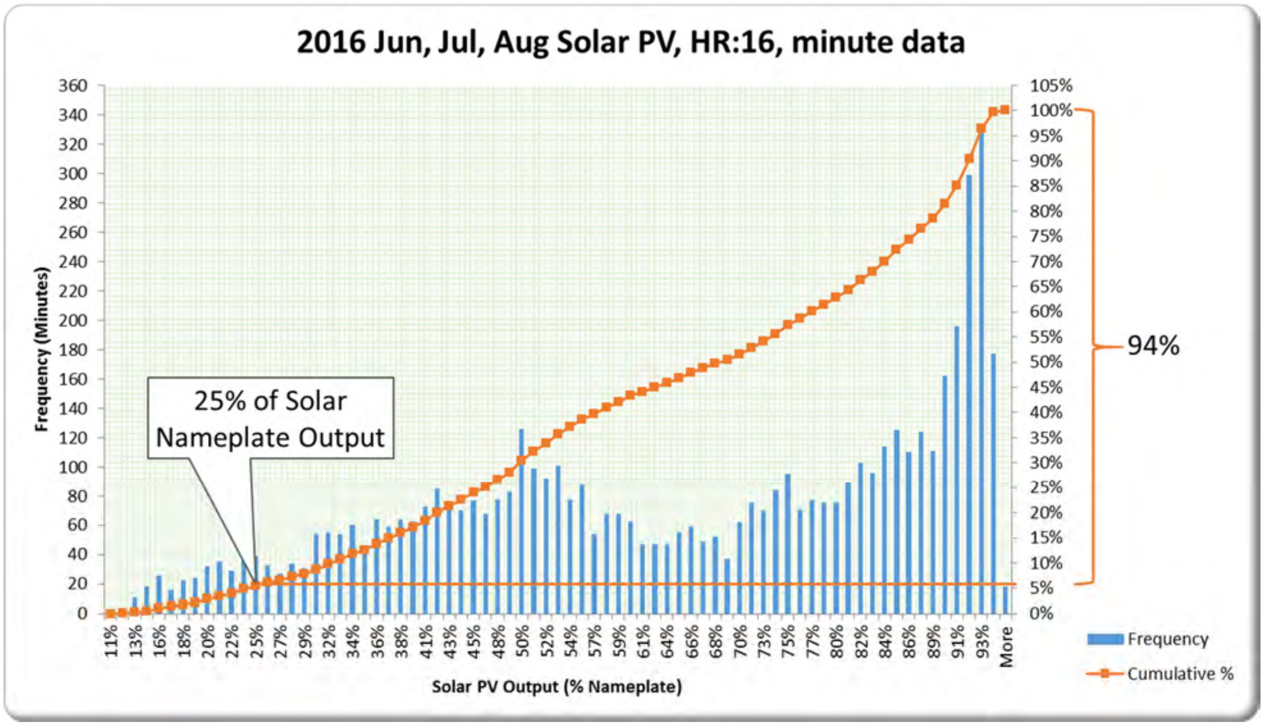

FIGURE F-01a –Solar PV Output Histogram with Cumulative %

The above graph is based on 2016 minute data for solar output during hour ending 16 (peak hour) during June, July, and August. The data indicates that 94% of the time, solar output would be 25% of nameplate or greater.

The following graph indicates solar output during the top 600 minutes of load (top ten hours of load). The graph is organized by descending order of load (i.e., it is not in sequential minutes in time). This illustrates that solar output may drop to lower outputs in the range of 20% to 30%.

Attachment F-2: Load and PV Output versus Time

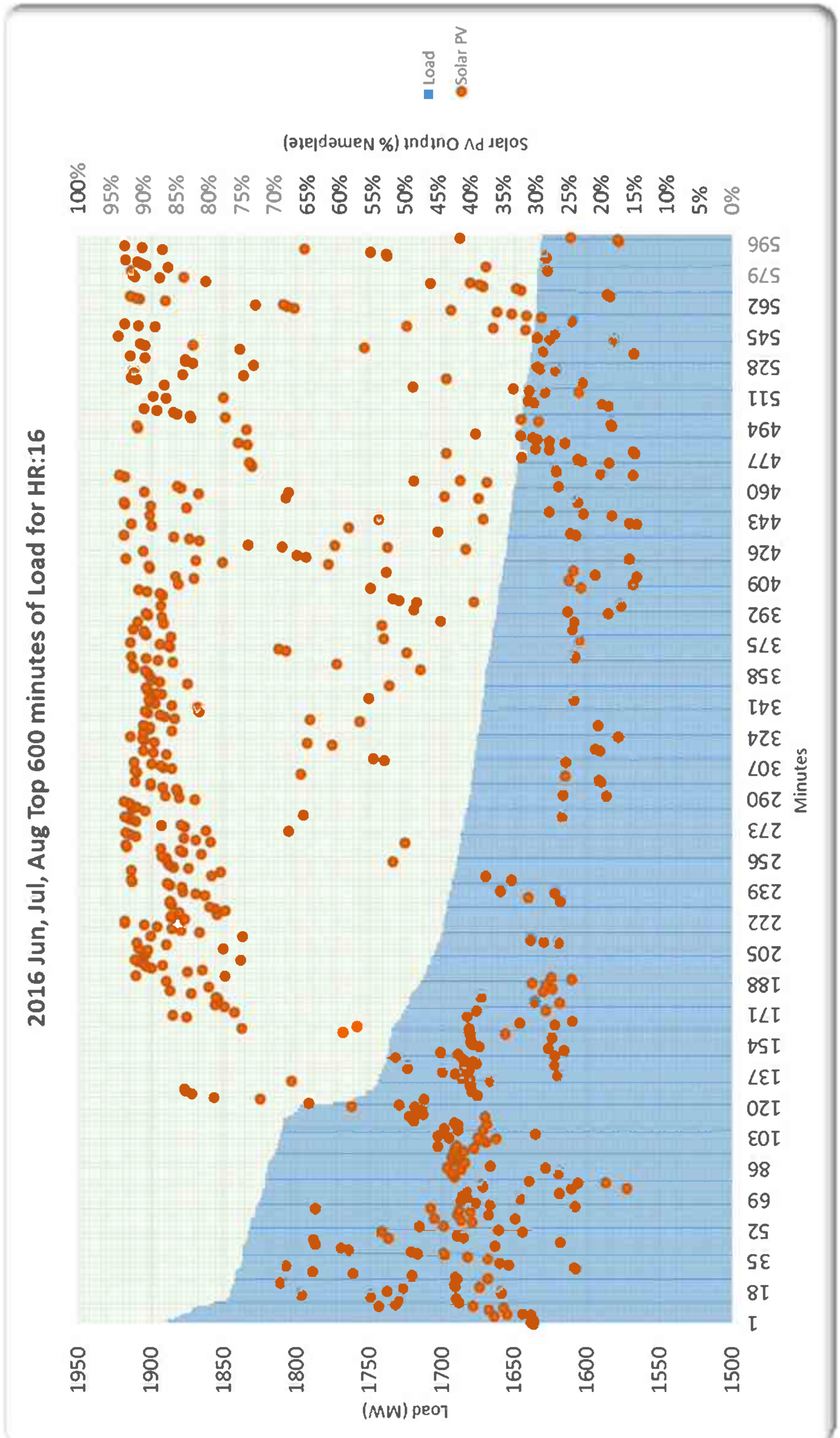

FIGURE F-01b – Load & Corresponding Solar PV Output vs. Time (minute)

Attachment G-1: Acronyms

ADSTF	-	Anchor Data Set Task Force
AMI	-	Advanced Metering Initiative
APS	-	Arizona Public Service Company
ATC	-	Available Transfer Capacity
BA	-	Balancing Area
Btu	-	British thermal unit
CAA	-	Clean Air Act
CAGR	-	Compound Annual Growth Rates
CAISO	-	California Independent System Operator
CC	-	Combined Cycle
CCN	-	Certificate of Convenience and Necessity
CDD	-	Cooling Degree Days
CPP	-	Clean Power Plan
CPP	-	Critical Peak Pricing
CT	-	Combustion Turbine
CWIP	-	Construction Work in Progress
DR	-	Demand Response
DRPP	-	Demand Response Pilot Program
DS	-	Data Subcommittee
EE	-	Energy Efficiency
EHV	-	Extra High Voltage
EIM	-	Energy Imbalance Market
EPA	-	Environmental Protection Agency
ERCOT	-	Electric Reliability Council of Texas
EUEA	-	Efficient Use of Energy Act
EUL	-	Average Estimated Useful Life
FCPP	-	Four Corners Power Plant
FERC	-	Federal Energy Regulatory Commission
FPPCAC	-	Fuel and Purchased Power Cost Adjustment Clause
GHG	-	Greenhouse Gas
HDD	-	Heating Degree Days
HV	-	High Voltage
HVAC	-	Heating, Ventilation, and Air Conditioning
HVDC	-	High Voltage Direct Current
IOU	-	Investor Owned Utility
IRP	-	Integrated Resource Plan
ITC	-	Investment Tax Credit
JSIS	-	Joint Synchronized Information Subcommittee
kV	-	kiloVolt
kVA	-	kiloVolt-Ampere
kW	-	kiloWatts
kWh	-	kiloWatthours
L&R	-	Loads and Resources Table
LCOE	-	Levelized Cost of Energy
LTPPA	-	Long-Term Purchased Power Agreement
MMBtu	-	One million British thermal units
MMcf	-	One Million cubic feet (gas)
MS	-	Modeling Subcommittee
MW	-	MegaWatts (1,000 kW)
MWh	-	MegaWatthours (1,000 kWh)
NAAQS	-	National Ambient Air Quality Standards
NARUC	-	National Association of Regulatory Utility Commissioners
NERC	-	North American Electric Reliability Council
NMAC	-	New Mexico Administrative Code
NMPRC	-	New Mexico Public Regulation Commission
NMSA	-	New Mexico Statutes Annotated
NOAA	-	National Oceanic and Atmospheric Administration
O&M	-	Operation and Maintenance Expenses
OASIS	-	Open Access Same Time Information Systems
OATT	-	Open Access Transmission Tariff
PNM		Public Service Company of New Mexico
PPA	-	Power Purchase Agreement
PTP	-	Point to Point Transmission Service
PTR	-	Peak Time Rebate
PUCT	-	Public Utility Commission of Texas
PUHCA	-	Public Utility Holding Company Act
PURPA	-	Public Utility Regulatory Policies Act
PV	-	solar photovoltaic
PVNGS	-	Palo Verde Nuclear Generating Station
QF	-	Qualifying Facility
RAC	-	Reliability Assessment Committee
RCT	-	Reasonable Cost Threshold
REA	-	New Mexico Renewable Energy Act
REC	-	Renewable Energy Certificate
RFP	-	Request For Proposal
RGEC	-	Rio Grande Electric Co-Operative
RPS	-	Renewable Portfolio Standard
RTO	-	Regional Transmission Organization
SDS	-	Scenario Development Subcommittee
SEC	-	Securities and Exchange Commission
SNMIC	-	Southern New Mexico Import Capability
SNMTS	-	Southern New Mexico Transmission System
SPP	-	Southwest Power Pool
SRP	-	Salt River Project
StS	-	Studies Subcommittee
SWAT	-	Southwest Area Transmission
TEP	-	Tucson Electric Power Company
TOU	-	Time-of-Use
TTC	-	Total Transfer Capability
UPC	-	use per customer
WECC	-	Western Electricity Coordinating Council
WSCC	-	Western Systems Coordinating Council
WSPP	-	Western Systems Power Pool

Attachment H-1: Public Participants' Comments

Comments Identifying Deficiencies of EPE's 2018-2037 Integrated Resource Plan

Introduction

This Integrated Resource Plan being submitted by El Paso Electric does not identify the most cost effective resource portfolio for the period of 2018 through 2037. It should not be accepted by the Commission as compliant with Rule 17.7.3 ("the Rule"), nor should it be deemed to satisfy the objectives of the Rule. This is the informed conclusion of the undersigned members of the Public Advisory Group who have actively participated in the planning process over the last 16 months. These Comments are intended to clarify the basis for this conclusion and recommendation.

According to the Rule as codified in the New Mexico Administrative Code (NMAC) the purpose of the IRP process is **"…to identify the most cost effective portfolio of resources to supply the energy needs of customers."** (17.7.3.6) with the "most cost effective resource portfolio" **defined as "…those supply-side resources and demand-side resources that minimize the net present value of revenue requirements proposed by the utility to meet electric system demand during the planning period consistent with reliability and risk considerations"** (17.7.3.7.J). The NMAC further states that **"To identify the most cost-effective resource portfolio, utilities shall evaluate all feasible supply, energy storage, and demand-side resource options on a consistent and comparable basis…"** (17.7.3.9.G(1))

The IRP being submitted is not compliant with these provisions because EPE did not evaluate all feasible supply, energy storage, and demand-side resource options on a consistent and comparable basis as required by 17.7.3.9.G(1). Second, EPE did not adequately incorporate the requirements of the Renewable Energy Act in its planning, and its submitted IRP does not satisfy provisions of the Rule that require IRP planning to reflect environmental requirements and concerns. Third, EPE produced an IRP that essentially starts in 2022 rather than 2019 by avoiding a Strategist analysis for the 2019-2022 period. Fourth, EPE did not comply with key elements of the Joint Stipulation agreed to in NMPRC Case 15-00241-UT.

These deficiencies are detailed in the outline below and accompanied by end notes that provide supporting evidence and details.

1. **In creating this IRP, EPE did not evaluate all feasible supply, energy storage, and demand-side resource options on a consistent and comparable basis as required by 17.7.3.9.G(1).**
    a. EPE artificially and severely limited the capacity options for all resources other than gas power to meet future needs in its model (Strategist)[i].
    b. EPE severely and arbitrarily discounted solar capacity from the 70% of nameplate used in the 2015 IRP, stating only 25% of nameplate is applicable to peak demand.[ii]

c. There is no evidence that EPE incorporated load management, load shifting concepts, or "changes in rate design in its resource option analysis to achieve delay or avoidance of the need for new capacity" as required by the Rule at 17.7.3.9.F(3).[iii]

d. EPE did not analyze life extension of existing generation plants as a resource option on a consistent and comparable basis with other resource options.[iv] They only analyzed life extensions for those plants scheduled to retire within 5 years, and they only considered life extensions of 5 years and 15 years. It appears they did not use the Burns & McDonnell study results to project the optimum life extension of each plant individually, and on a year by year basis.

e. EPE refused to disclose or model bids received from EPE's 2017 all-source RFP process.[v]

f. EPE distorted results by ignoring the standard, Lazard, in modeling of resource lifetimes. They increased lifetimes for gas from Lazard's 20 years to 40 or 45 years while reducing the lifetime for solar resources from 30 to 25 years[vi].

g. EPE did not consider reduction in Transmission and Distribution (T&D) costs from Distributed Generation, Energy Efficiency, Demand Response, or Distributed Storage.[vii]

2. EPE did not incorporate the requirements of the Renewable Energy Act in its integrated resource planning. Additionally, the Rule states that the utility is required to provide a summary of how **"renewable energy portfolio requirements" (17.7.3.9.G(2)(b)** and **"existing and anticipated environmental laws and regulations" (17.7.3.9.G(2)(c)** were **"considered in, or affected, the development of resource portfolios." (17.7.3.9.G(2)).** The Rule also holds that **"For resources whose costs and service quality are equivalent, the utility should prefer resources that minimize environmental impacts." (17.7.3.6).**

    a. EPE provides no indication as to when, if ever, the preferred resource portfolio would satisfy the renewable energy portfolio requirements. Essentially, the renewable energy portfolio requirements were not considered and did not affect the development of the resource portfolio proposed in the IRP.

    b. There is no analysis of what it would cost to satisfy the renewable energy portfolio requirements. Therefore, there is no way to understand how the costs and service quality of what EPE has chosen as the "least cost resource portfolio"[viii] compare to a resource portfolio that satisfies the renewable energy requirements. EPE has, in fact, done no analysis regarding equivalence as indicated by the Rule despite a requirement to prefer resources that minimize environmental impacts.

c. EPE evaluated carbon impact only by cost. There was no scenario to account for likely legislative or administrative regulation that would limit carbon discharged into the atmosphere[ix].

3. **EPE did not create a 20 year IRP beginning in 2019. They created an IRP that starts in 2022, by arbitrarily inserting pre-programed power purchases in 2019, 2020 and 2021 rather than allowing Strategist to analyze the best way to meet the resource shortfall.**

   a. EPE included power purchases as part of their existing "total net resources". Forcing these choices outside of the Strategist model eliminated Strategist's ability to control timing and size of purchases as part of a least cost portfolio. The costs of these purchases appear not to be included in the Strategist model.[x]

4. **EPE violated the requirements it agreed to in the Joint Stipulation, NMPRC Case No. 15-00241-UT, which settled protests against its 2015-2034 IRP.**

   a. EPE did not "conduct quantitative modeling for cost effectiveness using STRATEGIST" of the units scheduled for retirement in a responsible manner as required by Term 4.d of the Joint Stipulation[xi]. Despite objections by PAG participants, EPE arbitrarily chose 2027 and 2037 for the dates of potential retirements instead of analyzing the costs associated with incremental life extensions. This represented a 5 year and 15 year life extension for 3 of the units and an 8 year and 18 year life extension for Rio Grande 6. This was the subject of a formal dispute resolution that was never resolved.

   b. EPE did not "model and assess cost-effectiveness of reasonably available energy efficiency and load management resources" as required by 4.g of the Joint Stipulation[xii]. Despite ample evidence that energy efficiency (EE) is the lowest cost resource for meeting load requirements[xiii], EPE refused to model even a reasonable and very detailed EE program, formally submitted by PAG participants, that would have reduced demand by over 100 MW based on a scaled-down version of the 2017 Arizona Power System IRP[xiv]. Rather than model and assess the demand-side EE resource as required, EPE responded[xv] only that they met their 2020 EE goal – this, despite the Stipulation agreement (4.g) that "statutory Energy Efficiency goals are not considered ceilings".

   c. EPE did not "evaluate rate design in IRP analyses" as required by 4.h. of the Joint Stipulation[xvi]. The IRP (pages 78-84) describes rate structures, including Time of Use (TOU) and Interruptible Rates, but never quantifies the impact to allow “comparison to supply-side and other demand-side measures on cost-effectiveness” as required.

For the reasons outlined above we, the undersigned participants in the Public Advisory Group process, respectfully request that the Commission conclude that El Paso Electric's proposed Integrated Resource Plan does not comply with requirements of the Rule and with key provisions of the Joint Stipulation, and that the Commission return it to El Paso Electric with instructions to correct its deficiencies.

Respectfully,

Philip B. Simpson
Allen H. Downs
Merrie Lee Soules
Don Kurtz
Rocky Bacchus

[i] EPE claimed that its analysis modeling software, Strategist, would choose the Most Cost-Effective Portfolio, but then artificially limited the inputs available to the software, so that gas-fired resources were required in order to meet the predicted demand. At peak load, EPE provided Strategist the ability to choose from a grand total of only 360 MW of non-gas resources (Solar, Wind, Storage, Solar/Storage, Wind/Storage, Biomass, Geothermal, Energy Efficiency, and Distributed Generation) while providing Strategist 1710 MW of gas-fired capacity, as shown in the table below. This artificial limitation ensured that non-gas resources could not satisfy the predicted need for 1418 MW by 2037. Note that the undersigned noticed this problem very soon after seeing the initial draft IRP, and requested that additional solar plus storage capacity be provided so that Strategist could choose the most cost-effective portfolio, as intended, but EPE refused.

Resource Options from IRP Table 14, with EPE Discounting

Technology	**Capacity (MW)**	**Total Available to Add**	**Total Capacity**	**Capacity at Peak**
Solar	25, 75, 100	2, 3, 2	475	100*
Solar and Battery	100 Solar, 30 Battery	2	260	60
Wind	100	2	200	0
Wind and Battery	100 Wind, 15 Battery	1	115	15
Biomass	20	1	20	20
Geothermal	20	1	20	20
Gas Fired CC	320	3	960	960
Gas Fired CT	100	3	300	300
Gas Reciprocating Engine	50, 100	3, 3	450	450
Storage	15, 50	2, 2	130	130
Demand Response	5	1	5	5
Energy Efficiency	up to 10	1	10	10
Limit on total gas capacity made available to Strategist at Peak Load				**1710**
Limit on total of all other capacity made available to Strategist at Peak Load				**360**

* EPE discounted solar power output by 75% of nameplate, as discussed below, and also limited solar contribution at peak to 100 MW (page 88, where 400 MW nameplate solar equates to 100 MW peak contribution) and limited wind contribution at peak demand to zero (page 91). Similarly, solar plus storage was limited to storage only (once the 400 MW nameplate solar maximum was reached).

[ii] EPE used 25% as the portion of nameplate solar capacity that can be relied upon at peak load with a 95% confidence level without sufficient reason. Some discussion was provided in the IRP Section IX, based on data from its current solar resources, where almost half of total capacity is at a single location, and thus vulnerable to localized cloud cover. However, EPE declined to consider the beneficial effect of geographic dispersion of its solar facilities, for example by using its existing data but examining the smaller facilities on a percentage of nameplate basis, to simulate performance of a set of larger dispersed solar resources.

[iii] EPE made no attempt to quantify the reductions in peak demand and the corresponding delays in additional generation resources enabled by their planned changes to rate structures. EPE described, at the end of IRP Section VI, IDENTIFICATION OF RESOURCE OPTIONS (EXISTING CHARACTERISTICS AND INTERACTIONS), multiple changes to rate structures that it said "can, over the long term, impact the system profile sufficient to impact resource planning". Table 15, Rate Structure Development, shows the Advanced Metering Initiative (AMI) to be implemented in 3 to 5 years, which EPE stated will enable TOU as well as dynamic pricing (Critical Peak Pricing and Peak Time Rebate) to "provide incremental reductions in on-peak usage already reduced in response to TOU pricing differentials." Time of Use (TOU) rates and dynamic pricing incentivize customers to shift energy usage from peak to non-peak times, thus shifting load to non-peak times and reducing peak demand. However, EPE made no attempt to quantify the impact of these load-reducing developments, which violates **17.7.3.F(3)** NMAC requirement to describe **"how changes in the rate design might assist in meeting, delaying or avoiding the need for new capacity"**.

[iv] The need for new capacity was exaggerated by forcing simultaneous retirement of multiple power-plants. EPE contrived a large and sudden predicted resource need by forcing three power plants to retire simultaneously at the end of 2022. During the Public Advisory Process, EPE was asked to evaluate retirements on a year-by-year basis to identify the optimal time period, or to evaluate retirements at two-year intervals as was done in previous Burns and McDonnell studies. EPE instead only evaluated (via Burns and McDonnell) periods of 5 or 15-years, eliminating other possibilities. The resulting simultaneous retirement of all 3 power plants, at two locations, creates false spikes in projected needs for new power. When combined with the artificially low amounts of renewable and demand-side resources provided as inputs to Strategist, the model had no option but gas power plants to meet the projected jumps in demand.

[v] Great Divide Wind Farms 2 & 3 have filed a formal complaint with the PRC (case #18-00268-UT) requesting that they be connected to EPE as a qualifying facility (QF). The complaint states that they submitted a PPA proposal for the projects as a response to the "EPE All Source RFP" issued June 30, 2017, after which EPE unilaterally extended the deadline for an award from July 2018 until December 2018 at the earliest. Each of the two Great Divide Wind Farms is planned to have a maximum output of 79.8MW, so this formal complaint proceeding could result in 159.6MW of wind generation connecting to EPE's system in 2020.

[vi] EPE refused to use standardized, publicly available, well-accepted data in its Strategist modeling and analysis. After repeatedly referring to Lazard's as the definitive data source for resource parameters, EPE now says it will use internal EPE information for one specific and very significant factor, the resource lifetime. This does not meet the requirement of rule **17.7.3.9.G(1)** to: **"evaluate all feasible supply, energy storage, and demand-side resource options on a consistent and comparable basis"**. In addition, EPE's response and proposed plan of action does not support the rule **17.7.3.9.H(5)** in that it does not provide adequate information to the public on: **"modeling and risk assumptions and the cost and general attributes of potential additional resources; and development of the most cost-effective portfolio of resources for the utility's IRP"**, because it uses internal EPE information not available to the public, without presenting any data to support that information. This was the subject of a formal dispute resolution that was never resolved. The table below summarizes lifetimes from Lazard's Levelized Cost of Energy Analysis – Version 11.0, November 2017, and from the IRP Table 14.

Technology	Lazard's Life	EPE Life
Combined Cycle	20 years	45 years
Gas Turbine (Peaker)	20 years	40 years
Reciprocating Engine	20 years	40 years
Solar	30 years	25 years
Wind	20 years	25 years

[vii] Distributed Generation, for example residential solar, reduces the need for T&D infrastructure, since power is generated at or near the place of demand. Energy Efficiency and Demand Response reduce the need for T&D infrastructure, since demand for power at the place of use is reduced, requiring less infrastructure. Distributed Storage reduces the need for T&D infrastructure, because batteries can be located at critical points in the

network to reduce congestion and enhance system stability. **17.7.3.9.C(11)(a)** says the utility must identify transmission limitations that affect the location of future supply side resources. **17.7.3.9.G(2)** says they must consider transmission constraints.

[viii] Because EPE has a Fuel and Purchased Power Cost Adjustment Clause (FPPCAC) EPE bears little fuel price risk for gas fired generation. As a result, EPE may undervalue the fuel price risk avoidance advantages of renewable energy.

[ix] According to the Associated Press, "California Governor Jerry Brown wants the state to reach "carbon neutrality" by the year 2045. He signed a measure Monday [10 September 2018] that calls for a phasing out of fossil fuels from the state's electricity sector by the same year." In New Mexico, PRC case 17-00211-UT is a petition by the New Mexico Attorney General's Office, Western Energy Advocates, and Prosperity works, proposing a Clean Energy Standard that would have New Mexico investor-owned electric utilities reduce CO^2 emissions from their New Mexico dedicated generation by 4 percent per year for twenty years.

[x] EPE manually inserted significant amounts of purchased power (up to 130 MW annually), without letting Strategist choose whether that was part of the lowest cost portfolio. While the 15-00241-UT Stipulated Term 4.f states that "…EPE at its discretion, will use purchase power as a resource in a measured approach to periodically delay new resource additions.", we argue that these power purchases should be resource inputs to Strategist to allow it to pick the least cost portfolio, rather than forcing purchased power in certain years. It appears that, by making retirement and power purchase decisions outside of Strategist, and not providing sufficient non-gas resource options to meet the predicted need, Strategist was forced to select gas power. The Recommended L&R incorporating the IRP portfolio (Table 26, page 113) shows power purchases in years 2019-2021, 2026-2030, 2033, and 2037. These pre-programmed purchases are combined with planned retirements to create large sudden increases in power needs. The IRP does not explain why these power purchases are planned, but when questioned on 29 August 2018, EPE stated this would allow larger power sources to be selected, with benefit due to economy of scale. Noting that the largest resource (approximately 3 times the size of any other resource) is a gas fired combustion turbine, there is an appearance that EPE is manipulating the Strategist output in favor of gas fired resources by artificially controlling the timing and size of resource needs.

[xi] NMPRC Case No. 15-00241-UT, Stipulated Terms, 4.d "EPE agrees to review continued operation [of] units slated for retirement within five years based on cost effectiveness, operational risk, reliability, safety of personnel, environmental and engineering considerations. EPE is required to conduct quantitative modeling for cost effectiveness

using STRATEGIST or other capacity expansion program in conjunction with the qualitative analyses described in the preceding sentence."

[xii] NMPRC Case No. 15-00241-UT, Stipulated Terms, 4.g. "EPE agrees that the statutory Energy Efficiency goals are not considered ceilings on demand-side resources included in the EPE portfolio for the purposes of the IRP analysis. EPE shall model and assess cost-effectiveness of reasonably available energy efficiency and load management resources. EPE will provide specific parameters used in modeling load management resources in the same manner as with all other resources evaluated."

[xiii] See page 4 of Comments from (PAG participant) Don Kurtz 9/13/18, Slide 7 of PAG presentation 9/22/17, the entire PAG participant letter of 10/23/17, and Slide 18 of PAG Presentation 1/11/18 (embedded hyperlinks are to EPE webpage for New Mexico Integrated Resource Plan, 2017-2018 Public Advisory Group meetings).

[xiv] Template submitted 2-22-18 by Philip Simpson, which included costs and showed how, with regionally appropriate measures and conservative annual EE growth, a coincident peak demand reduction of 103 MW was achievable by 2023. The submission including the EPE-specified template form, two additional pages of supporting tables, references to the Arizona Public Service Company's April 2017 Integrated Resource Plan, and links to the EPA Technical Support Document: tsd-cpp-demand-side-ee.pdf, available at https://19january2017snapshot.epa.gov/cleanpowerplan/clean-power-plan-final-rule-technical-documents_.html.

[xv] EPE's response to Template 15: "EPE has agreed to model EE programs in excess of the goal if they are viable and result in a least cost option. EPE reviewed the most recent IRP filed by Arizona Public Service (APS) in relation to their Energy Efficiency programs and forecasts. Based on this review, there are several key considerations to keep in mind when comparing to EPE's Energy Efficiency forecasts. The Arizona Corporation Commission (ACC) Energy Efficiency Standard (EES) requires a 22% cumulative energy savings by 2020. This varies greatly to New Mexico's goal which is 8% by 2020. This difference, which is driven by regulatory initiatives is a cause of the higher EE penetration forecast from APS. APS is forecasting its energy efficiency to grow to 534MW to meet the 22% goal based on the ACC regulations. EPE has already met its 2020 EE goal of 8% for New Mexico.

[xvi] NMPRC Case No. 15-00241-UT, Stipulated Terms, 4.h "EPE will evaluate rate design in IRP analyses, such evaluation to include analysis of the impact of rate differentials on peak

demand and energy consumption, and comparison to supply-side and other demand-side measures on cost-effectiveness."

Attachment I-2: E3 Reserve Margin Study Report

Estimating the Economically Optimal Planning Reserve Margin

Prepared on behalf of El Paso Electric Co.

May 2015

Energy+Environmental Economics

Estimating the Economically Optimal Planning Reserve Margin

Prepared on behalf of El Paso Electric Co.

May 2015

Energy and Environmental Economics, Inc.
101 Montgomery Street, Suite 1600
San Francisco, CA 94104
415.391.5100
www.ethree.com

Table of Contents

1 Executive Summary

Target Planning Reserve Margin (tPRM)[7] is a common metric used in generation planning to determine an electric utility's resource need above typical annual peak load. As a proxy for system reliability, the tPRM is useful in informing resource decisions between detailed reliability studies.

The need for generation resources above peak load is driven by several factors. First, the tPRM is most commonly defined by using median annual peak load; thus additional generating capacity is needed to cover years in which demand eclipses this level such as during an extremely hot summer. Second, generation resources are subject to forced and planned outages and may be unavailable during some hours of the year when needed. Finally, the North American Electric Reliability Council (NERC) mandates that utilities hold operating reserves[8] for interconnection reliability purposes which must be accounted for through planning reserves.

El Paso Electric Co. (EPE) has been using a 15% tPRM standard—in line with most jurisdictions across the west and the Western Electricity Coordinating Council's (WECC) reliability assessment processes.[9] Energy and Environmental Economics (E3) was retained to investigate the tPRM standard for EPE and to make recommendations pertaining to its application. Our analysis **determined the societally optimal tPRM to be 15.2%** based on EPE system characteristics, NERC operating reserve requirements,[10] customer outage costs, and the cost of building and installing new capacity. We therefore do not recommend adjustments to the historical tPRM standard.

The study has also pointed to several additional conclusions:

+ Our analysis shows that deviating from the 15% tPRM by 2-3% does not substantially affect total societal cost. A PRM as low as 13% or as high as 18% will result in only a $1MM/year increase in societal costs, or 0.1% of EPE's annual revenue requirement. This is an important conclusion

[7] In this report we distinguish between the actual observed reserve margin and tPRM, which is the target planning reserve margin. In either case, it is defined as [(Resource Capacity/Median Peak Load) - 1] and expressed as a percentage.
[8] Operating reserves are defined as available generation resources above instantaneous system demand.
[9] http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2014SRA.pdf
[10] http://www.nerc.com/files/bal-std-002-0.pdf

because it points to the need to emphasize factors in addition to PRM in making least cost resource decisions.

+ While our analysis shows that a PRM of 13% has the same expected societal costs as a PRM of 18%, the variability in annual costs is much higher at the lower PRM. This is because customer outages are infrequent but extremely costly, whereas the carrying cost of additional capacity is modest but incurred each year. Given the choice between these two scenarios, a higher PRM, and therefore less variability, is considered preferable.
+ For purposes of determining tPRM, we have not assumed imports beyond contracted external resources; however, depending on external conditions, it is possible that non-firm imports would be available to serve EPE load. Allowing for the possibility of non-firm imports, EPE system reliability would be higher than our model indicates, lowering the tPRM. This said, for resource planning purposes, leaning on neighboring balancing authorities for non-firm capacity is not common practice and is not recommended in this report.
+ Planning reserve margin calculations typically use nameplate or summer rated capacity. For renewable resources, nameplate capacity is no longer a good approximation for resource adequacy contribution due to resource variability. Established metrics such as the effective load carrying capability (ELCC) are well suited to calculating values that can be used in the PRM calculation and is something for EPE to consider going forward.

The following report sections give background on calculating tPRM, give details specific to calculations for EPE's system, and discuss the above conclusions in greater detail.

2 Background

2.1 Planning Reserve Margin

The planning reserve margin (PRM) is defined as the percentage by which the total capacity of system resources exceeds the median peak load.[11] Surplus capacity is necessary to ensure that the supply of resources is sufficient to meet load under a variety of system conditions such as warmer than average weather (increase in load) or an unexpected generator failure (decrease in system resources). Typical PRMs can range from 10%-20% as shown in the table below.

Table 27: Planning Reserve Margins in Use by Other Jurisdictions

	PRM
PJM	15.6%[6]
NYISO	16.1%[6]
Southern Company	15.0%[6]
CAISO	15.0%[12]
FPL	20.0%[13]
ERCOT	10.2%[14]
MISO	14.8%[15]
SPP	13.6%[16]

A tPRM is typically determined with one of two common approaches. The first is through benchmarking to a particular engineering metric for customer reliability and the second is through economic analysis to find the point at which the marginal benefits of additional capacity matches the marginal cost of a new

[11] Different jurisdictions often use slight variations on this calculation, such as whether total capacity is measured as installed capacity (ICAP) or unforced capacity (UCAP), as well as whether the median (1-in-2) peak load is used or a higher percentile (1-in-10). When expressed as 1-in-X, peak load refers to the frequency that the annual peak exceeds some value.
[12] http://www.ferc.gov/legal/staff-reports/2014/02-07-14-consultant-report.pdf
[13] http://www.fpl.com/about/ten_year/pdf/2014TYP_text.pdf
[14] ERCOT does not have an official planning reserve margin as it functions as a de-regulated market with no explicit capacity market.
[15] https://www.misoenergy.org/Library/Repository/Study/Seasonal%20Assessments/2014%20Summer%20Resource%20Assessment.pdf
[16] http://www.occeweb.com/News/2014/2014-08-21%20Intro%20to%20SPP%20OCC.ppt

unit. This section provides an overview of these two approaches and explains the choice of economic analysis for the EPE system.

2.2 Engineering Approach

The tPRM can be determined by benchmarking to reliability metrics such as the expected number of outage hours per year, or the expected number of outage events per year. Many utilities across the United States use a 1-in-10 standard; though in the industry, no broad agreement exists regarding the precise definition of this metric or calculation methodology.

Common interpretations of the 1-in-10 standard includes 0.1 hour of lost load per year, 2.4 hours of lost load per year, or one loss of load event per 10 years (independent of severity or duration). We believe part of this confusion has arisen from changes in modeling methodologies enabled by increased computing capabilities.[17] In addition, recent focus on resource flexibility as a new dimension to the planning problem has raised question about the level of operational detail appropriate to stay constant with the original metrics.[18]

Due to these difficulties with engineering standards, we have elected to focus on the economic approach, which has less ambiguity associated with the tPRM criterion. The economic approach also has other advantages, which are detailed below.

2.3 Economic Approach

The economic approach for determining tPRM finds the level of reserves such that total system costs are minimized. System costs include both the cost of installing and maintaining a particular planning reserve margin as well as the customer outage and reliability costs associated with that planning reserve margin. In other words, an economically efficient target planning reserve margin is determined by directly comparing the cost of new capacity to the customer outage and reliability costs that are avoided by that capacity. Figure 8 illustrates this concept and how the economic tPRM is the point at which total system costs are minimized.

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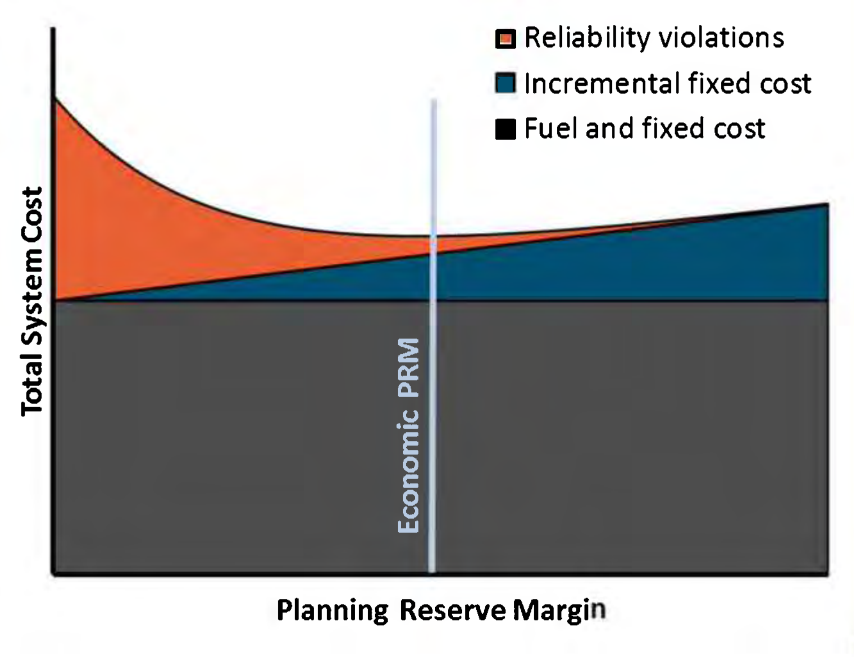
[17] Many models initially did not perform hourly analysis when the 1-in-10 metric was established and the transition has resulted in fragmentation.

[18] Operational reserves are not traditionally included in loss of load probability modeling nor are any constraints regarding generator flexibility

Figure 8: Economically Optimal Reserve Margin at Lowest System Cost



This economic approach is well established in the literature[19,20,21] and is being increasingly utilized across the U.S.[22] A recent report prepared by Brattle for the Federal Energy Regulatory Commission (FERC) details much of the theory in determining an economically efficient planning reserve margin.[23] For purposes of this report, we note below the primary advantages that led to our focus on the economic method in studying El Paso Electric:

+ The basic premise of the economic method, which is to plan the system to minimize cost and maximize benefits, is universally understood among stakeholders.
+ The economic method avoids difficult-to-interpret metrics and instead reframes the conversation around the cost of new capacity and the value of customer service.

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[19] http://energy.ece.illinois.edu/GROSS/papers/1990%20Aug.pdf

[20] Sanghvi, A.P. *Measurement and Application of Customer Interruption Costs/Value of Service for Cost-Benefit Reliability Evaluation: Some Commonly Raised Issues.* Power Systems, IEEE. Vol 5, Issue 4. 1990.

[21] Afshar K., M. Ehsan, M Fotuhi-Firuzabad, N. Amjady. *Cost-Benefit Analysis and MILP for Optimal Reserve Capacity Determination in Power System*. Applied Mathematics and Computation. Vol 196, Issue 2. 2008.

[22] http://brattle.com/system/publications/pdfs/000/004/978/original/Estimating_the_Economically_Optimal_Reserve_Margin_in_ERCOT_Revised.pdf?1395159117

[23] http://www.ferc.gov/legal/staff-reports/2014/02-07-14-consultant-report.pdf

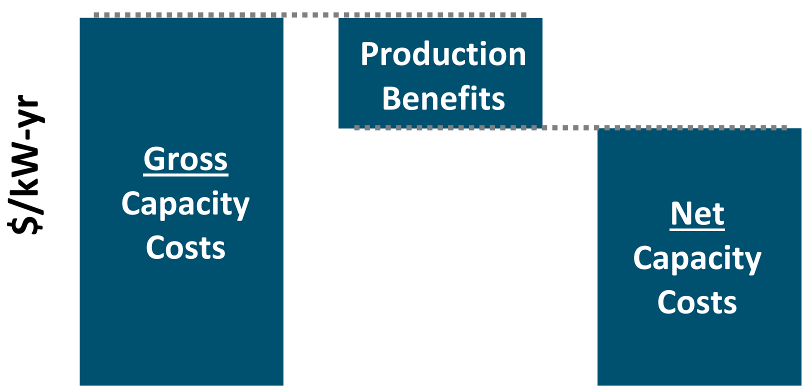
+ Regional differences in risk preferences, new generation costs, or operational practices can be incorporated with intuitive results.
+ The cost minimizing framework for planning can be extended to encompass power system flexibility or other constraints in an internally consistent way (not analyzed in this report).

2.3.1 Calculation Steps

2.3.1.1 Cost of new capacity

The addition of capacity to an electric system has numerous economic impacts. In general, the largest impacts are the gross capacity and operations & maintenance costs as well as any system production cost savings (e.g. reduced expenditures on energy). The difference between these two values yields the net capacity cost which is the relevant input in determining the economically optimal target planning reserve margin. Figure 9 illustrates this below.

Figure 9: Net Capacity Cost Calculation



2.3.1.2 Reliability costs

Customer outage and reliability costs are a function of two drivers: the total quantity of outages and the value that a customer ascribes to service. The total quantity of outages is measured as 'expected unserved energy' in MWh. The value that a customer ascribes to service is the value of lost load (VOLL) measured in $/MWh. Multiplying these two values together yields total customer outage and reliability costs.

The amount of expected unserved energy (EUE) associated with a particular planning reserve margin is a function of a power system's loads and resources. Specific EPE inputs used in this analysis are listed in

Section 4. Stochastically analyzing a utility's potential loads over a wide range of system conditions and combining that with a stochastic analysis of the availability of resources to meet these loads is the foundation of the EUE calculation. We have developed the Renewable Energy Capacity Planning Model (RECAP), an open-source, loss-of-load-probability model that calculates system reliability as a function of detailed inputs on load and resource. Details about RECAP methodology are available in the Technical Appendix of this report.

Expected unserved energy is also a function of many assumptions related to the protocols that system operators use in times of system stress. For instance, many systems have certain emergency procedures that they can take, such as decreasing system voltage, which can help avoid the curtailment of firm load. Additionally, expected unserved energy is sensitive to how operating reserves are utilized to meet load. Operating reserves are defined as generation that is online and ready to use in addition to resources that are being utilized to serve load. When operating reserves dip below a certain threshold, system operators are forced to curtail loads in accordance with their own protocols or NERC regulations.

The second component that feeds into customer outage and reliability costs is the value of lost load (VOLL). This metric defines how much a customer is willing to pay to avoid power outages. This value can vary substantially by customer type, season, and geographical location. For example, a small business that loses power may incur large economic losses by having to temporarily shut down, whereas a residential customer that loses power may not incur any economic losses but rather the discomfort from a lack of air conditioning or lighting. Discussion of the VOLL for EPE is taken up in Section 3.3.

3 El Paso Electric Planning Reserve Margin

Our analysis shows that the economically optimal target planning reserve margin for EPE is 15.2%. We also find that a planning reserve margin that deviates slightly from this target (2-3%) does not substantially impact total system costs due to the tradeoff between the cost of capacity and cost of customer outages. This section details the specific inputs and assumptions used to characterize the EPE system as well the economically optimal planning reserve margin results.

3.1 EPE System Characteristics

This section describes the EPE system characteristics that we used in the analysis. As noted in the background section, customer outage and reliability costs are driven by the value of lost load and by expected unserved energy, which is a function of EPE system resources, transmission availability, and loads.

The following table describes the EPE system resources that we used in the analysis. Capacity, average forced outage rates, and average maintenance down times were also used to stochastically characterize these resources' ability to serve load.

Table 28: EPE System Resources in 2020

El Paso Electric Utility Plants	Capacity (MW)	Average Equivalent Forced Outage Rate (EFORd)[24]	Average Maintenance Down Time
Copper Unit 1	62	1.08%	2.18%
Montana Unit 1	88	1.50%	3.90%
Montana Unit 2	88	1.50%	3.90%
Montana Unit 3	88	1.50%	3.90%
Montana Unit 4	88	1.50%	3.90%
Newman 4GT1	72	4.14%	5.56%
Newman 4GT2	72	4.14%	4.72%
Newman 4ST	83	4.14%	3.70%
Newman 5GT3	70	1.02%	3.24%
Newman 5GT4	70	1.02%	2.50%
Newman 5ST	148	1.02%	6.25%
Newman Unit 1	74	1.69%	4.44%
Newman Unit 2	76	6.63%	3.52%
Newman Unit 3	97	2.15%	6.06%
Palo Verde Unit 1	211	2.20%	5.69%
Palo Verde Unit 2	211	2.20%	5.28%
Palo Verde Unit 3	211	2.20%	4.44%
Rio Grande Unit 7	46	1.29%	4.17%
Rio Grande Unit 8	142	8.21%	8.52%
Rio Grande Unit 9	87	2.57%	0.42%

Of these resources, we assumed that Palo Verde units were located behind two transmission resources (Path 47 and El Paso Import Capability [EPIC]), which further constrained its ability to serve load. The simultaneous transmission import capability of the two lines was limited to the maximum capacity of EPIC. The capacity and forced outage rates shown in the following table for both Path 47 and EPIC are based on

[24] Based on historical outages at these locations as opposed to theoretical idealized forced outage rates

conversations with EPE engineers and an analysis of historical transmission availability during high load hours.

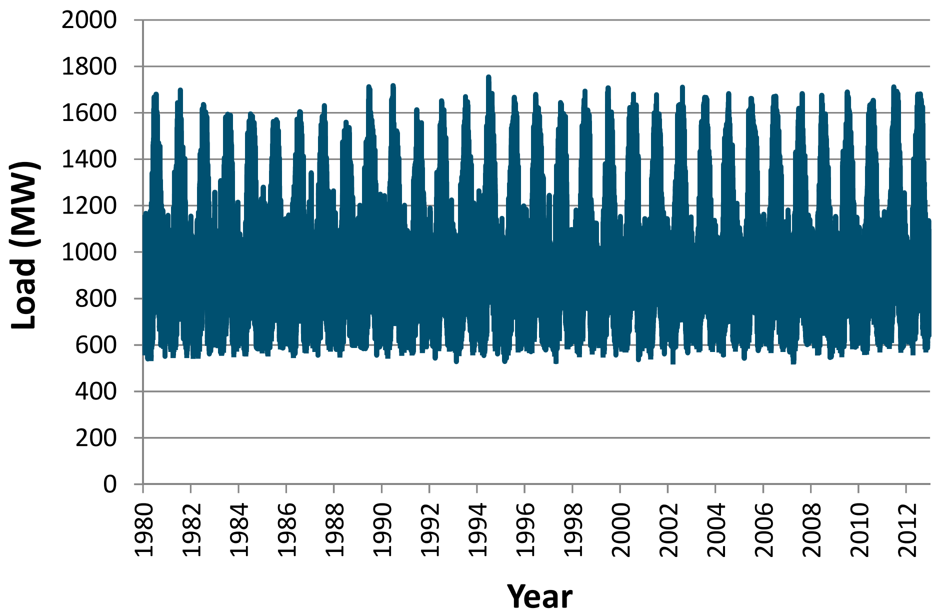
Table 29: EPE Transmission Resources

Transmission Line	Capacity (MW)	Average Equivalent Forced Outage Rate (EFORd)
Path 47	645	0.87%
EPIC	1166	4.91%

The calculation of expected unserved energy is also very dependent upon utility loads under various system conditions. The single largest factor that can affect utility load is weather. In order to capture all types of weather that might affect the El Paso area, we acquired daily temperature data from 1980 – 2012. Using a neural network regression model that matched this weather data and other factors to actual EPE loads from 2006-2012, we were able to synthetically create hourly loads for EPE for the weather years 1980 – 2012 as they would have manifested under 2012 system conditions. This rich, 33 year dataset,[25] shown below, provided the wide variety in system load conditions necessary to accurately calculate expected unserved energy.

[25] The effort to gather a large quantity of historical data was due to the specific application. A longer dataset is needed to insure robustness of results when studying power system reliability relative to other utility applications. The study team also explored the possibility of using weather data before 1980, but the data was excluded as likely underrepresenting the frequency of high load events faced by EPE in the future due to an observed upward trend in extreme weather events since 1950.

Figure 10: EPE Historical Loads (2012 Economic System Conditions)



3.2 EPE Cost of Capacity

EPE capacity costs were based on the new Montana Power Station in east El Paso. These four 88 MW simple-cycle aero-derivative combustion turbines began construction in 2014 which will continue for the next two years. EPE financial models estimate the gross capacity costs plus operations and maintenance expenses for these plants to be \$77.52/kW-yr, levelized in constant real dollars.[26]

Additionally, production cost modeling conducted by EPE estimates that these plants will provide \$4.68/kW-yr in annual benefits due to fuel savings and market sales; subtracting the annual benefits from the levelized capacity cost results in a net capacity cost of \$72.84/kW-yr.

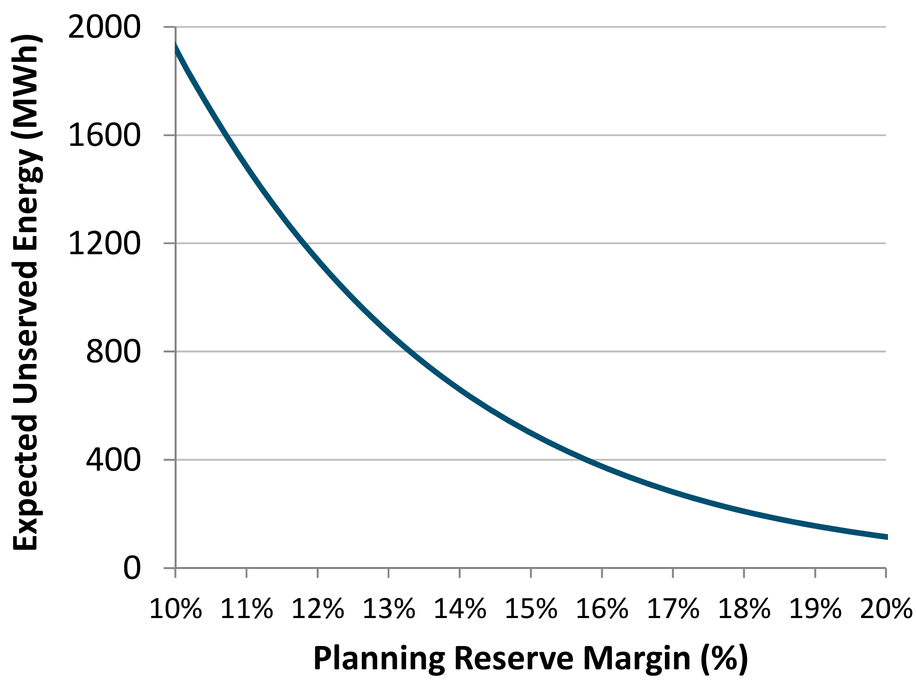
[26] This assumes a 7.35% nominal discount rate, 2% inflation, 40 year economic life. A levelization in constant real dollars was used for comparability with the customer outage costs, also assumed to be in real dollars. Both costs are assumed to escalate with inflation, but to stay equivalent relative to each other. Levelization in constant nominal dollars is common in other applications, yielding \$99.01/kW-yr, but is not appropriate in this case.

3.3 EPE Customer Outage and Reliability Costs

We calculate customer outage and reliability costs as the product between the expected unserved energy at a given planning reserve margin and the value of lost load.

Combining the probability distributions of the historical, weather-driven EPE loads and power plant and transmission line availability, we were able to calculate an output of expected unserved energy under various planning reserve margins. We have also assumed that EPE must hold 6% of load as contingency reserves in all hours due to NERC requirements, administered by WECC. Because of this, EPE is assumed to take load mitigation action such as load-shedding and/or voltage reductions as soon as available resources dip below 106% of load. The graph below shows annual expected unserved energy at various levels of planning reserve margins.

Figure 11: Expected Unserved Energy



Estimating the value of lost load is difficult due to wide variability between customers along with other factors such as curtailment protocols. Literature suggests that appropriate values for VOLL may range between $1,000/MWh to over $2,000,000/MWh. A meta-analysis conducted by Lawrence Berkeley

National Laboratory[27] on nationwide utility survey results yields the following table. Note that the dollar values are in $/MWh, thus while the marginal cost of outage decreases with duration, the overall event cost always increases with duration.

Table 30: Value of Lost Load Estimates – LBNL

	Cost per Unserved MWh ($2014) - Summer Weekday				
Customer Type	Momentary	30 min	1 hour	4 hours	8 hours
Medium and Large C&I	$ 200,743	$ 44,648	$ 28,992	$ 21,106	$ 16,700
Small C&I	$ 2,784,424	$ 645,137	$ 432,682	$ 356,374	$ 315,089
Residential	$ 25,049	$ 5,103	$ 3,015	$ 1,508	$ 1,044

We represented the value of lost load to EPE customers at $9,000/MWh. Because this value falls in the lower end of the spectrum of LBNL's meta-analysis, we believe this to be a conservative assumption. The $9,000/MWh value is also consistent with the assumption used by The Brattle Group in its 2014 study for the Public Utility Commission of Texas (PUCT) to estimate the economically optimal reserve margin in ERCOT.[28]

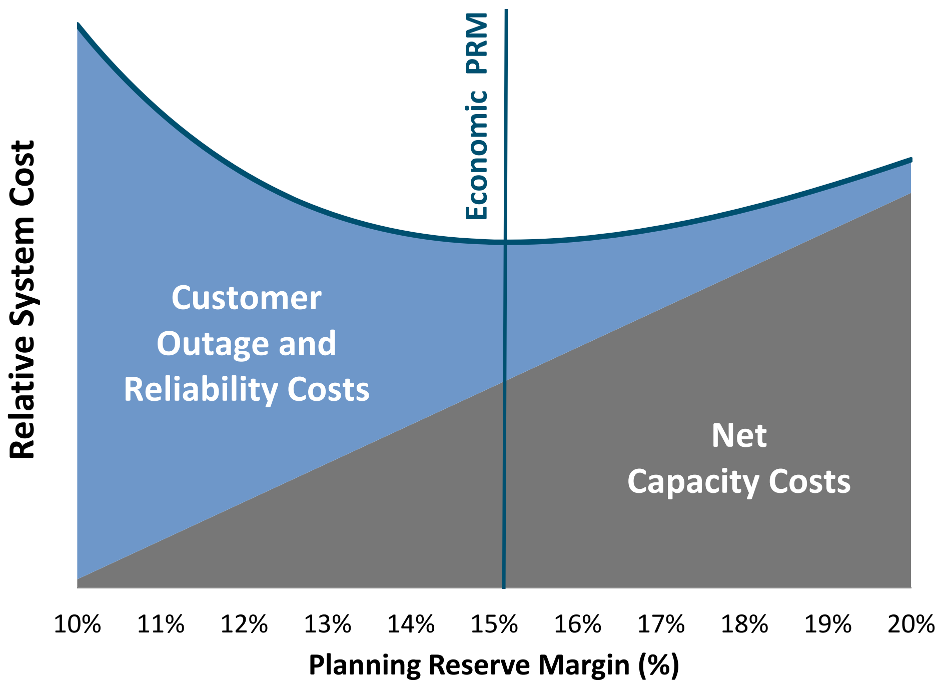
3.4 EPE Optimal Target Planning Reserve Margin

Combining customer outage and reliability costs with net capacity costs at different planning reserve margins, we were able to calculate an economically optimal target planning reserve margin of 15.2%. Figure 12 illustrates that a 15.2% PRM is economically optimal because this is the point at which total system costs are minimized.

[27] http://certs.lbl.gov/pdf/lbnl-2132e.pdf

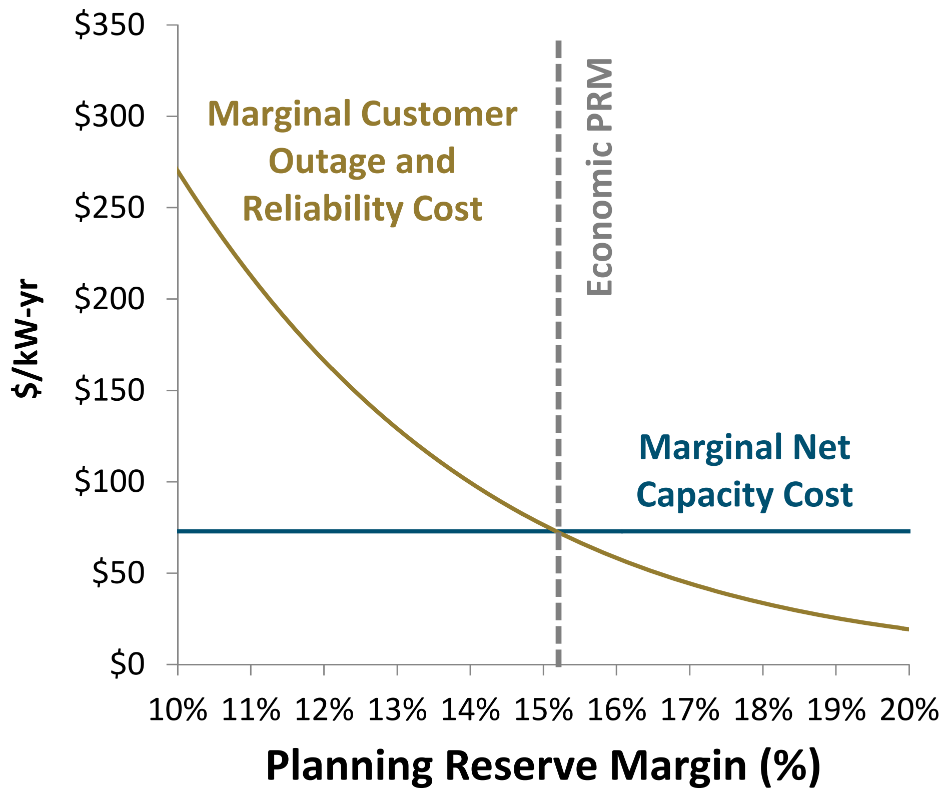
[28] http://brattle.com/system/publications/pdfs/000/004/978/original/Estimating_the_Economically_Optimal_Reserve_Margin_in_ERCOT_Revised.pdf?1395159117

Figure 12: Economically Efficient Planning Reserve Margin – Total Cost



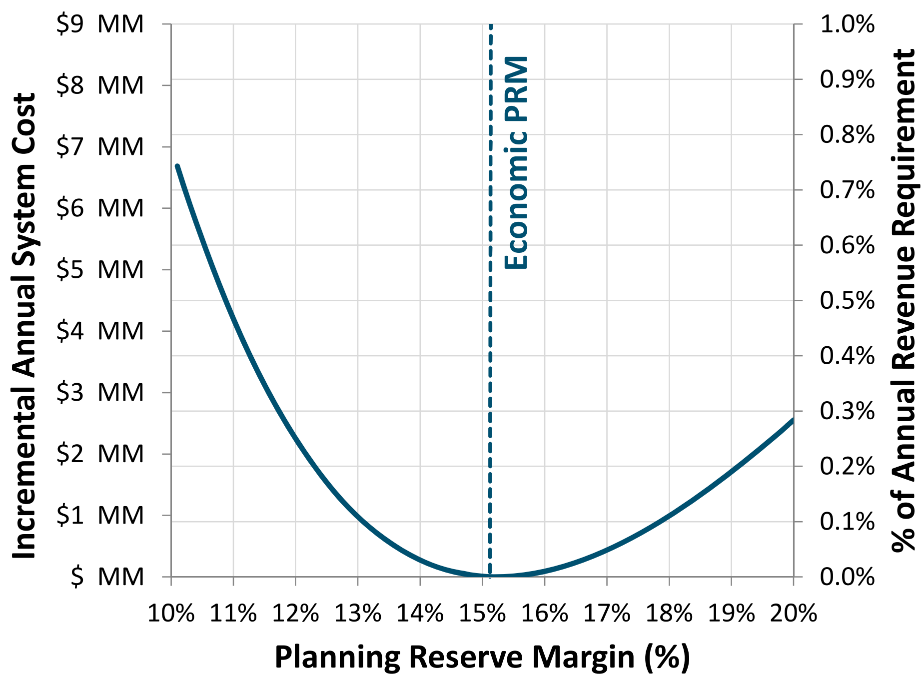
Alternatively, one can think of this optimal PRM as the point at which the *marginal* value of incremental capacity (measured as the decrease in customer outages) equals the *marginal* cost of adding additional capacity to the system. This concept is illustrated below in Figure 13. Note that this chart simply shows the slope or derivative of customer outage costs and net capacity costs shown in Figure 12.

Figure 13: Economically Efficient Planning Reserve Margin – Marginal Cost



In reality, it is not feasible for a 15.2% planning reserve margin to be realized year after year. The underlying drivers for peak load are not static and are subject to forecast error; in addition, resource expansion is subject to additional constraints and cannot be expected to match annual changes in peak load. Despite this, deviations from the 15.2% tPRM by 2-3% are shown to have a small impact on total system costs. Figure 14 shows the increase in total system cost as a function of PRM. From this graph it is clear that due to the relatively flat nature of the curve near its minimum, small deviations in planning reserve margin have a relatively small effect on total annual system cost. Although these costs are also shown as a percentage of annual revenue requirement in order to put them into context, it is important to note that the costs shown here include customer outage and reliability costs and thus are not directly comparable to costs associated with a utility revenue requirement.

Figure 14: System Cost by Planning Reserve Margin



Based on this analysis, we recommend that EPE maintain their 15% tPRM. This standard should be revisited in the future if the inflation adjusted cost of new generation or estimated customer outage costs change significantly. Additionally, with any large increase in wind or solar on the EPE system, care must be taken that this generation's contribution to resource adequacy is accurately characterized in the PRM framework.

3.4.1 Comparison to Other Jurisdictions

Our analysis for the EPE economically optimal tPRM (15.2%) is higher than the results of a recent Brattle Study for ERCOT that estimates the same value at 10.2%. However, given the relative sizes of EPE and ERCOT, we believe these results to be consistent with one another. Smaller systems result in higher tPRM standards for several reasons. When ERCOT unexpectedly loses a generator, that generator comprises a much smaller fraction of total resources as compared to EPE. Therefore, EPE needs to hold a higher level of reserves in order to provide the same level of reliability. Additionally, the larger number of total generators in ERCOT provides diversity on the system and reduces the likelihood the system will face extreme generator outage events.

Many other jurisdictions around the U.S. set a tPRM based not on economics but rather using an engineering approach. Despite this, the 15.2% tPRM for El Paso fits well within the bounds of the jurisdictional tPRMs shown in Table 27 in Section 2.1.

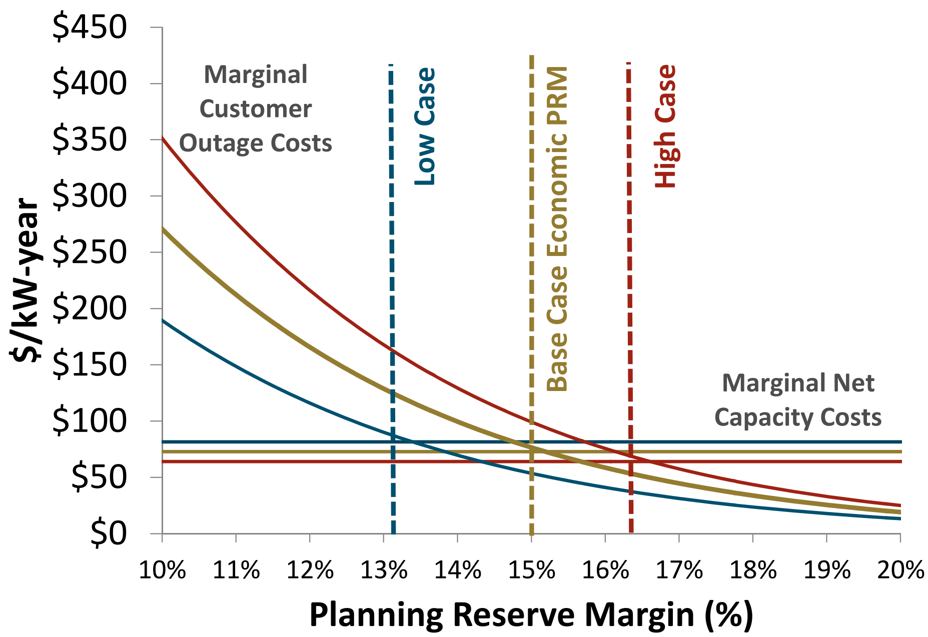
3.4.2 Sensitivity Case Results

The economically optimal planning reserve margin found in our analysis is sensitive to several key input assumptions. For instance, if customers actually face higher outage costs (value of lost load) than we have assumed, it would be prudent to increase the tPRM. Conversely, if net capacity costs are actually higher than assumed, the tPRM should be decreased. We analyzed the economically optimal PRM associated with each of the following set of sensitivity assumptions as compared to the base case.

- High tPRM Case
    - Gross Capacity Cost x 110%
    - Production Cost Benefits x 80%
    - Value of Lost Load x 130%
- Low tPRM Case
    - Gross Capacity Cost x 90%
    - Production Cost Benefits x 120%
    - Value of Lost Load x 70%

Using these sensitivity assumptions, the low tPRM case yielded a tPRM of 13.2% and the high case 16.4%, as shown in the figure below.

Figure 15: Economic PRM Sensitivity Cases



The purpose of the low and high tPRM cases was to show sensitivity to input assumptions. The adjustments themselves are arbitrary and do not reflect analysis or particular input uncertainties.

3.4.3 Risk and Variance

While our analysis shows that a PRM of 13% has the same expected societal costs as a PRM of 18%, the variability in annual costs is much higher at the lower PRM. This is because customer outages are infrequent but extremely costly, whereas the carrying cost of additional capacity is modest but incurred each year. Through time, both result in equivalent average costs, but the difference in costs for a specific year can be dramatically different, depending on whether a reliability event occurred. To the extent that utility customers are risk-averse, they will seek less variance in total annual costs and should prefer a higher PRM to a lower PRM given that the incremental annual systems costs are equal. This concept of risk aversion is well-established in the literature, although it is difficult to quantify.[29] The inherent planning difficulties associated with maintaining a tPRM will mean that EPE is often slightly over or under the target. In these cases, we recommend that EPE maintain an over-reliable system rather than under-reliable, all

[29] http://www2.econ.iastate.edu/classes/econ642/Babcock/pratt.pdf

else being equal.

In the same vein, it is possible that risk-averse utility customers may prefer a tPRM that is higher than 15.2% to mitigate variance in annual costs, even at the expense of higher average annual system costs. However, calculating a risk-conscious economically optimal tPRM was beyond the scope of this study.

4 Conclusions

This study of EPE used system specific data and a standard loss of load probability model to determine the economically efficient tPRM. The optimal reserve margin was found to be 15.2%, consistent with the existing EPE target of 15%. Thus, we do not recommend changes to existing planning criterion.

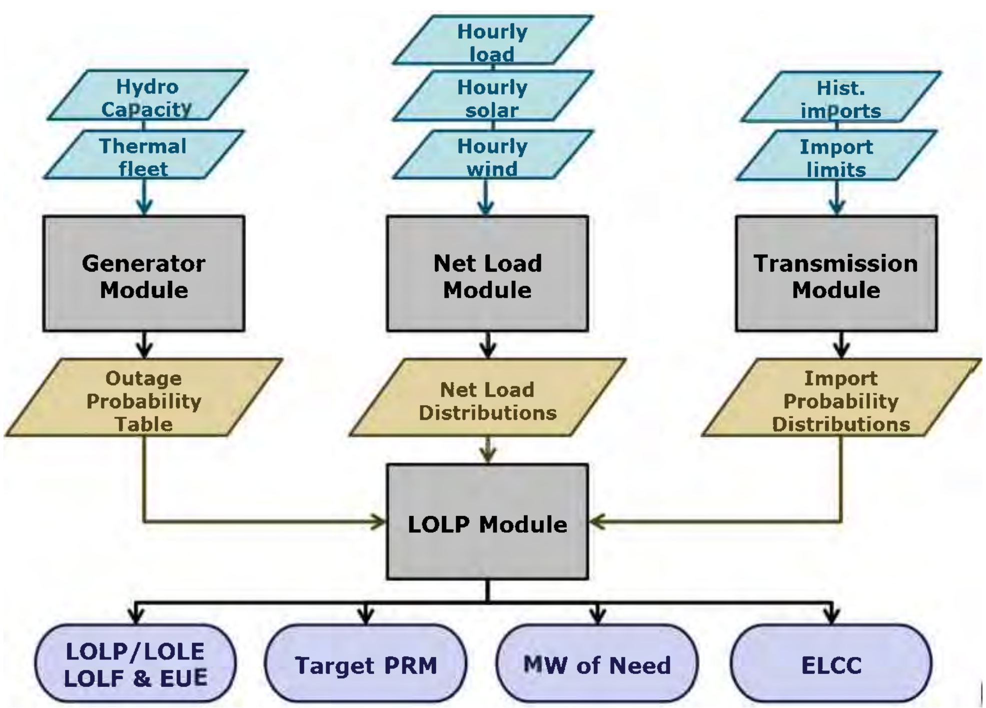
However, it is also recommended that the planning reserve margin be revisited again if 1.) The set of supply side resources changes significantly 2.) The inflation adjusted value of lost load is estimated in the future to be different than $9,000/MWh 3.) The cost of new system capacity changes significantly 4.) NERC operating rules increase or decrease operating reserve requirements during time of system emergency. In addition, if the amount of wind and solar on the EPE system increases significantly, we recommend using effective load carrying capability (ELCC) as the preferred method for measuring resource adequacy contribution within the PRM framework.

5 Technical Appendix

5.1 RECAP Methodology

The Renewable Energy Capacity Planning Model (RECAP) works by comparing probability distribution functions (PDFs) for supply and demand by month, hour, and day type (weekend, weekday) in order to find the probability that load will be greater than supply in the pertinent time slice. Relevant correlation between variables is enforced using conditional probability distributions. The model is organized into three modules, shown in
Figure 16, the methods of which are summarized below.

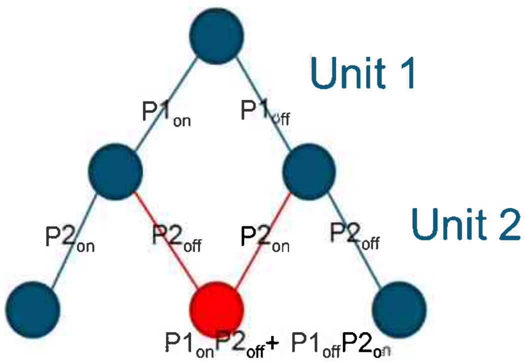
Figure 16: RECAP model flowchart



The generator module uses forced outage rates for a fleet of generators to calculate the probability of different total amounts of capacity outage. The output from this module is a capacity outage probability table, a standard output from resource adequacy models[30] illustrated in Figure 17.

[30] Billinton, R. and G. Yi (2008). "Multistate Wind Energy Conversion System Models for Adequacy Assessment of Generating Systems Incorporating Wind Energy." Energy Conversion, IEEE Transactions on 23(1): 163-170.

Figure 17: Process to create a capacity outage probability table

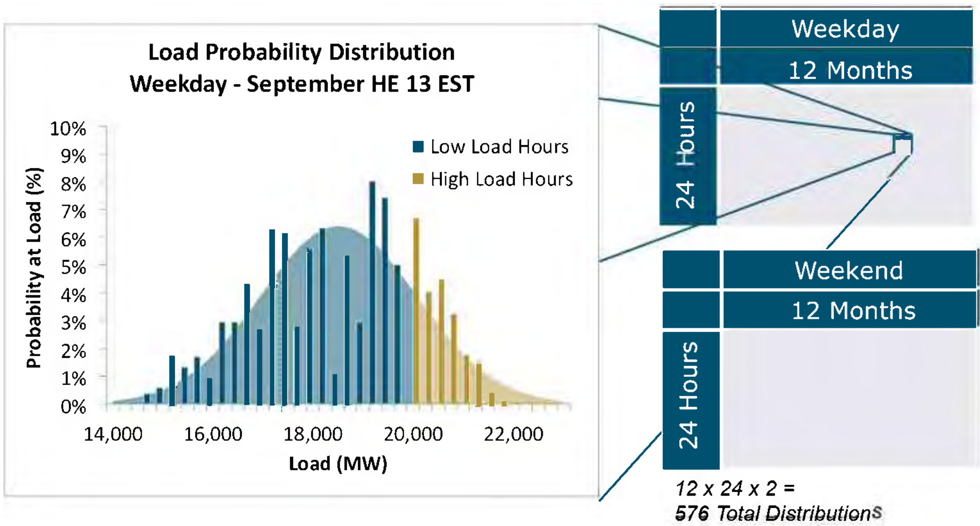


The transmission module creates import probability distributions using historical transmission outage distributions. Together with the capacity outage probability table, the import probability distributions give the probability of having different amounts of supply side resources available to a system operator.

The net load module creates a probability distribution function for net load[31]. The design was driven by the goal of making full statistical use of historical data, recognizing that often such data is not aligned through time. Gross load distributions are specific to a single month-hour-day type combination, as shown in Figure 18.

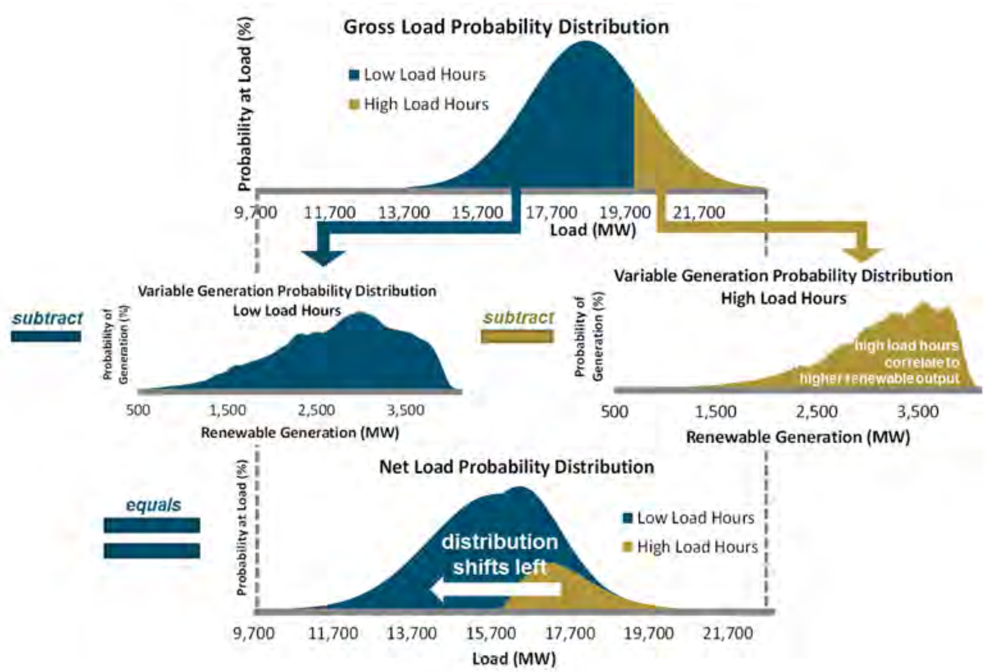
[31] Net load is gross load minus renewables, imports, run-of-river hydro, and other time sequential or energy limited variables (dispatchable hydro is modeled in the generator module). Demand response is split between the generator module and net load modules depending on the nature of the demand response program.

Figure 18: Gross load distribution



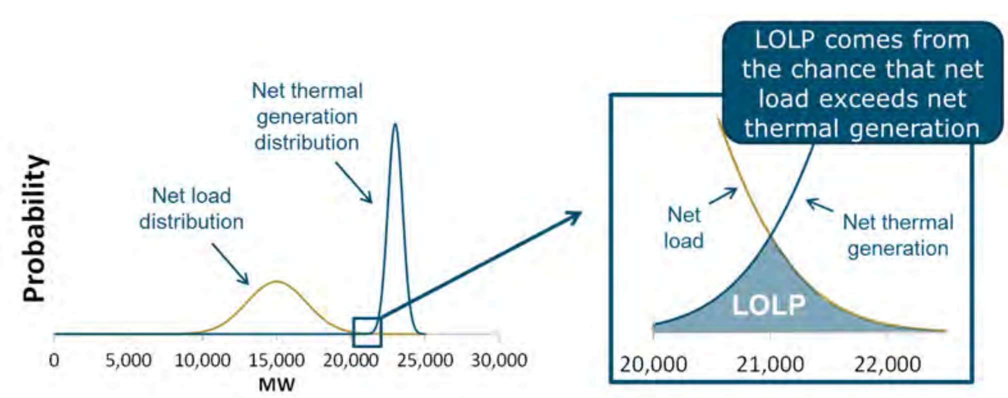
Relevant correlations between load, wind, and solar are enforced, where significant, using conditional probability distributions. Mathematically, the net load distribution function is a convolution of each of the constituent distributions. Within the RECAP Model the convolution is done a fast Fourier transform convolution algorithm. The convolution process is shown in Figure 19. The resulting net load probability distribution function is then fed into the LOLP module.

Figure 19 Net load distributions



The LOLP module combines the outputs from the net load module and generator module. Figure 20 demonstrates how this process works. The overlapping area between the generation curve and the net load demand curve is the probability of lost load for each day in that month/hour/day-type. Multiplying by the appropriate number of month/hour/day-type observations in one year and then summing across the year gives loss of load expectation, measured in hours of lost load per year. Expected Unserved Energy (EUE) is calculated by weighing each loss of load probability with the severity of each deficiency.

Figure 20 Loss of load probability module



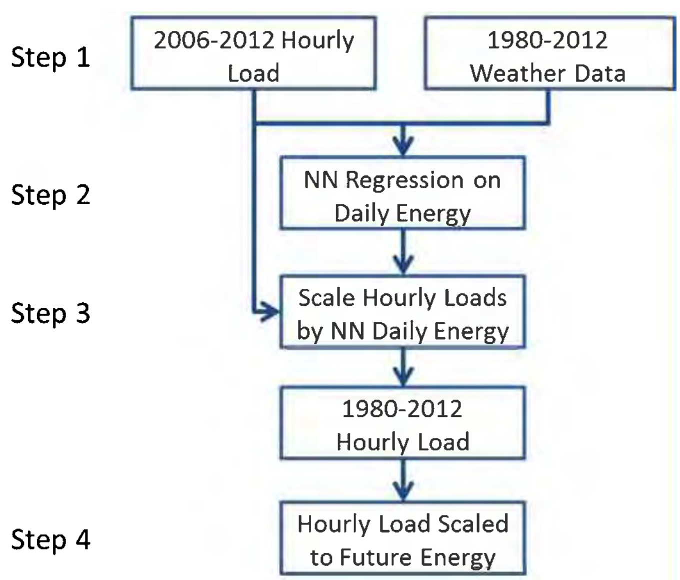
The resources are added or subtracted from the simulated power system and the resulting outage

metrics are recorded, shown in
Figure 11 on page 16. This result can be used directly to determine an economic target planning reserve margin. Alternatively, the outputs can be used to benchmark to engineering standards or calculate the effective load carrying capability (ELCC) for variable generation resources.

5.2 Load Regression Methodology

We use a neural network regression to take recent (2006-2012) hourly load data and extrapolate back to 1980 using historical weather data. The approach is shown in Figure 21 and each step (1-4) is described in more detail below.

Figure 21: Methodology for creating load profiles



Step 1: Hourly load data and daily weather data was gathered for the regression period.

Step 2: A neural network was trained using the following explanatory variables:

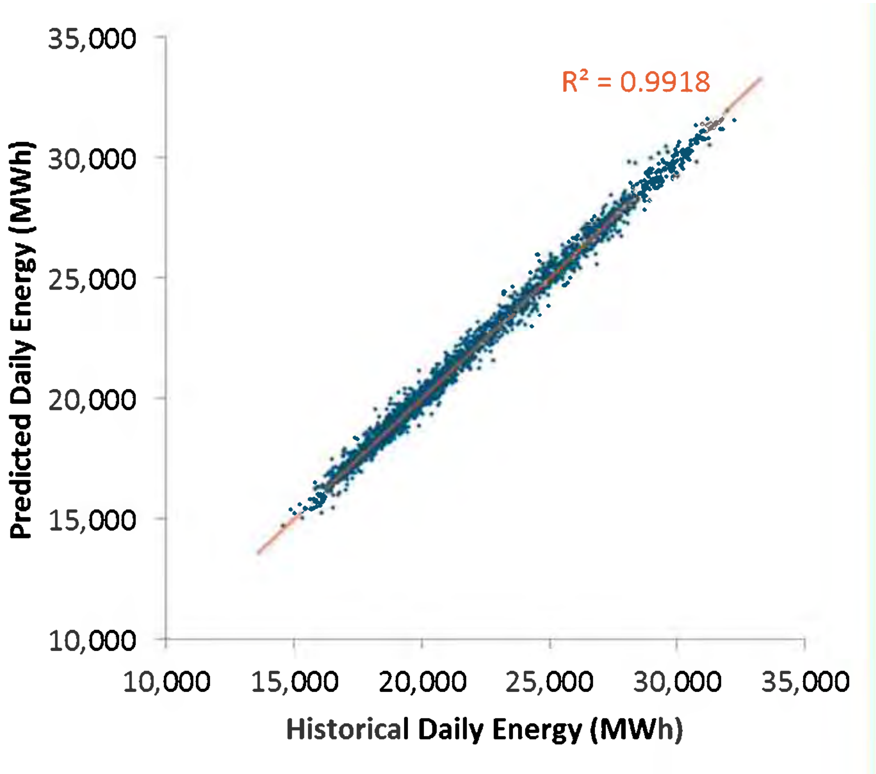
Table 31: Independent variables used in regression analysis

Variable	Data Source
Daily min, max, mean temperatures with temperature lag for EPE locations	www.weathersource.com
Maximum solar azimuth	Simulated based on dates

Indicator variables including: day of week, holiday, season, economic normalization	Various

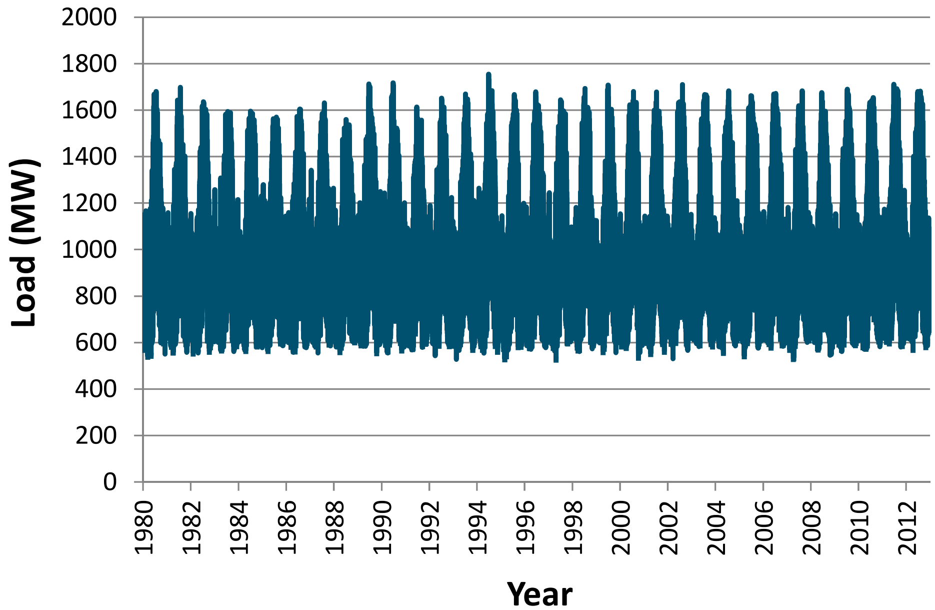
The neural network had 2 hidden layers, each with 29 nodes. Figure 22 shows a scatter plot with predicted vs. actual daily energy from 2006-2012 after the neural network had been trained.

Figure 22: Comparison of actual vs. predicted daily energy 2006-2012 from the neural network regression



Step 3: A daily energy matching function is used to produce hourly load data back to 1980 from the regressed daily energy data. In the matching algorithm, years without hourly data (1980-2005) is paired with a normalized daily load shape from those years where hourly data is available (2004-2012) based on the closest match of total daily energy. Matched days are within 15 calendar days of each other so that seasonally specific diurnal trends are preserved. In addition, weekdays and weekends are matched separately. The resulting output is shown in
Figure 10.

Copy of Figure 3: EPE Historical Loads (2012 Economic System Conditions)



Step 4: The resulting 32 years of hourly load profiles are scaled to forecasted future energy and median peak load. Behind-the-meter PV is introduced as a separate profile.

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF EL PASO ELECTRIC COMPANY'S INTERGRATED RESOURCE PLAN FOR THE PERIOD 2018-2037	)))))	**Case No. 18-00293-UT**

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of **El Paso Electric Company's Amended Integrated Resource Plan for the Period 2018-2037,** was emailed on January 3, 2019, to each of the following:

Nancy B. Burns	nancy.burns@epelectric.com;
Patricia Griego	patricia.griego@epelectric.com;
Curtis Hutcheson	curtis.hutcheson@epelectric.com;
Joan E. Drake	jdrake@modrall.com;
Joseph Yar	jyar@nmag.gov;
Elaine Heltman	eheltman@nmag.gov;
Dan Neidlinger	dneid@cox.net;
J. Cotton/Andrea Crane	ctcolumbia@aol.com;
Charles Noble	noble.ccae@gmail.com;
Noel J. Schaefer	schaefno@gmail.com;
Dahl Harris	dahlharris@hotmail.com;
Steve Michel	smichel@westernresources.org;
David Van Winkle	david@vw77.com;
Anastasia Stevens	astevens.law@gmail.com;
Jennifer Vega Brown	jvega-brown@las-cruces.org;
Marcia B. Driggers	marcyd@las-cruces.org;
Daniel Avila	davila@las-cruces.org;
Jose F. Provencio	joprovencio@las-cruces.org;
Jorge A. Garcia	JAG@las-cruces.org;
Harry S. Connelly	hconnelly@las-cruces.org;
Rick Gilliam	rick@votesolar.org;
Tom Solomon	tasolomon6@gmail.com;
Don Hancock	sricdon@earthlink.net;
Nann M. Winter	nwinter@stelznerlaw.com;
Rebekah Gallegos	rgallegos@stelznerlaw.com;
David Dollahon	ddollahon@las-cruces.org;
Tom Figart	tomf@donaanacounty.org;
Jason Marks	lawoffice@jasonmarks.com;
Rocky Bacchus	rockybacchus@gmail.com;

Allen Downs	ecomaxac@lifeisgood2.com;
Merrie Lee Soules	mlsoules@hotmail.com;
Lizbeth Ellis	lellis@nmsu.edu;
Glen Haubold	ghaubold@ad.nmsu.edu;
Doug Gegax	dgegax@nmsu.edu;
Robert Ganton	robert.a.ganton.civ@mail.mil;
Kyle J. Smith	kyle.j.smith124.civ@mail.mil;
Stephen Fischmann	stephen.fischmann@gmail.com;
Jack Sidler	jack.sidler@state.nm.us;
Judith Amer	judith.amer@state.nm.us;
Michael C. Smith	michaelc.smith@state.nm.us;
Bradford Borman	bradford.borman@state.nm.us;
Cydney Beadles	cydney.beadles@state.nm.us
Anthony Sisneros	anthony.sisneros@state.nm.us;
Elisha Leyba-Tercero	elisha.leyba-tercero@state.nm.us;
Philip B. Simpson	philipbsimpson@comcast.net;

Dated this 3rd day of January, 2019.

Trish Griego

Trish Griego
Legal Assistant