DRAFT

El Paso Electric Company

Integrated Resource Plan
For the Period 2021-2040

El Paso Electric

September 16, 2021

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I. EXECUTIVE SUMMARY

EPE presents this Integrated Resource Plan ("IRP" or "Plan") pursuant to the requirements of the New Mexico Public Regulation Commission's ("Commission" or "NMPRC") IRP Rule, 17.7.3 NMAC ("IRP Rule"), the New Mexico Efficient Use of Energy Act, NMSA 1978, § 62-17-1 *et seq*. ("EUEA"), and the New Mexico Renewable Energy Act, NMSA 1978, §62-16-1 *et seq*. ("REA").[1] This IRP, like our 2009, 2012, 2015 and 2018 IRPs, discusses EPE's integrated resource planning process (the "Planning Process") and develops an integrated resource portfolio to safely, reliably and cost-effectively meet the electricity needs of EPE's customers for the next twenty years. Unlike past IRPs, this IRP addresses New Mexico's 2019 Renewable Energy Act amendments, including New Mexico's renewable portfolio standard ("RPS"), which includes the following targets for renewable and carbon-free energy:

- 80% of all retail sales of electricity in New Mexico from renewable energy by 2040; and
- 100% of all retail sales of electricity in New Mexico from zero carbon resources by 2045

EPE's carbon footprint is among the lowest one-third of the utility industry due to its ownership of Palo Verde nuclear generation and the fact EPE exited from coal generation in 2016. Table 1 shows a comparison of output emissions for EPE, US Power Sector, WECC, New Mexico, and Texas.

Table 1. Comparison of 2019 Output Emissions

2019 Output Emissions	CO_{2e} (lbs/MWh)
El Paso Electric	543
U.S. Power Sector	884
WECC Southwest	957
New Mexico	1327
Texas	913

U.S. EPA, 2021. Emissions & Generation Resource Integrated Database (eGRID) at https://www.epa.gov/egrid/summary-data

This IRP provides a pathway for EPE to reach New Mexico's 100 percent zero carbon requirements through a cost-effective integrated resource portfolio which safely and reliability serves EPE's New Mexico customers.

[1] In addition, this IRP is consistent with the Stipulation resolving protested issues in EPE's Commission-accepted 2015 IRP approved by Commission Final Order in Case No 15-00241-UT.

To assist with the development of a full system resource plan which meets EPE's multi-jurisdictional obligations, EPE engaged Energy+Environmental Economics ("E3") to provide modeling analyses, including assessment of its planning reserve margin ("PRM"). EPE also engaged Burns and McDonnell to provide life extension analyses for units planned for retirement through 2026. To assess impacts of decarbonization through 2040, EPE conducted a preliminary grid reliability study. EPE conducted additional modeling to address New Mexico REA requirements based on a New Mexico load and resource analyses.

The analyses resulted in four portfolios presented below: 1) Total System Least Cost; 2) Least Cost + NM Dedicated Resources; 3) Separate System Planning with Gas; and 4) Separate System Planning with no Gas.

These portfolios are described further below, and in E3's Report appended to this IRP and incorporated herein by reference.

IRP MODELING AND INITIAL TOTAL SYSTEM LEAST COST PORTFOLIO

The IRP develops an integrated resource portfolio to meet the energy needs of EPE customers for the next twenty years safely, reliably, and cost-effectively. Within the IRP, various types of renewable resource technology types are considered along with the integration of such resources with conventional energy resources to accomplish an optimal portfolio for EPE customers. Resource options modeled include solar photovoltaic ("PV"), wind, battery storage, conventional gas generation, biomass, geothermal, and demand side management ("DSM"). Conventional gas resources modeled are assumed to be hydrogen fuel capable. EPE utilized NREL renewable resource potential maps to identify geographical sites closest to EPE's system for potential wind and geothermal resources shown in Figure 1. Transmission upgrade costs between the resource locations and EPE's load pockets were then considered as costs associated with those resource options.

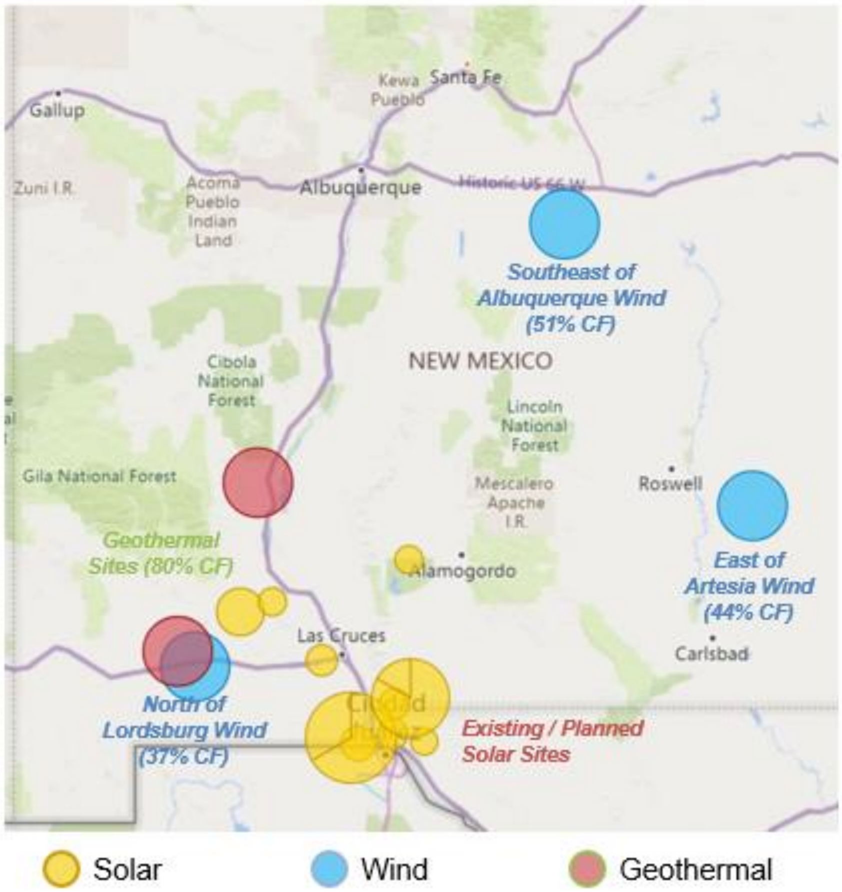


Figure 1. EPE Renewable Resource Geographical Locations

Two E3 proprietary models were utilized to carry out the IRP modeling analyses. First, E3's RECAP model was utilized for resource adequacy, reliability, and resource availability. The RECAP model estimates Effective Load Carrying Capability ("ELCC") values for the different resource types and also assesses the loss of load expectation ("LOLE") based on the statistical variability of load, variable energy resource availability, and the forced outages of all resources and import transmission lines. Through this process, EPE elected to implement the industry standard of one loss of load event every ten years (i.e., 0.1 LOLE) to maintain best practice in reliability planning for the system. EPE plans to shift to the 1 in 10 target over the twenty-year horizon in a phased approach.

Second, E3's RESOLVE capacity expansion planning model was used to determine the optimal integrated demand-side and supply-side portfolio for a utility system. RESOLVE is a linear program model which allows it to efficiently analyze resource options and combination of resource options to identify the most cost-effective portfolio. This includes the ability to evaluate the combination of storage with solar and wind as well as the synergies that exist between solar and wind resources. In addition, RESOLVE can assess the impacts of various scenarios and sensitivities based on total plan costs by imposing renewable energy targets, decarbonization targets or various sensitivities to inputs such as a carbon tax or fuel cost levels.

The resulting Total System Least Cost Portfolio resource additions by type for future years are shown in Table 2.

Table 2. Total System Least Cost Portfolio Incremental Resource Additions (MW)

Resource Category	**2025**	**2027**	**2031**	**2035**	**2040**	**2045**
Battery	*126*	*1*	*283*	*607*	*179*	*487*
Gas New	-	-	-	*141*	*134*	*108*
Gas 5-yr Extension	*74*	*313*	-	-	-	-
Geothermal	-	-	-	-	-	-
Nuclear	-	-	-	-	-	-
Solar	*159*	-	*251*	*689*	*306*	*624*
Wind	*203*	-	-	-	*28*	*69*

The Total System Least Cost Portfolio does not impose any constraints beyond reliability requirements. The selected resource additions result in the optimal cost-effective resource portfolio before considering REA requirements or jurisdictional allocation. The battery storage and conventional gas generation resources compliment the solar resources, which are intermittent in nature. The actual resource additions in the future will be determined by the 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. The resulting installed capacity by resource type for EPE's system, existing plus new resources, is shown in Table 3.

Table 3. Installed Existing Plus New Resource Capacity (MW)

Resource Category	**2025**	**2027**	**2031**	**2035**	**2040**	**2045**
Battery	*176*	*177*	*460*	*1,067*	*1,246*	*1,682*
BTM Solar	*80*	*108*	*166*	*221*	*289*	*368*
DR	*56*	*61*	*71*	*81*	*93*	*93*
Gas	*1,531*	*1,531*	*1,395*	*1,075*	*1,208*	*1,317*
Geothermal	-	-	-	-	-	-
Nuclear	*622*	*622*	*622*	*622*	*622*	*622*
Solar	*544*	*544*	*795*	*1,414*	*1,693*	*2,037*
Wind	*203*	*203*	*203*	*203*	*232*	*300*

TOTAL SYSTEM DECARBONATION SCENARIOS

To assess the options for reaching New Mexico's REA requirements, EPE expanded the IRP analysis to include portfolios that provided higher renewable energy integration and a higher carbon free energy mix for its total system energy needs. This was accomplished by imposing carbon free requirements in the modeling to match the RPS requirements. The IRP considered resource portfolio scenarios that included 100% carbon free energy by the year 2040. Table 4 summarizes the system decarbonization scenarios.

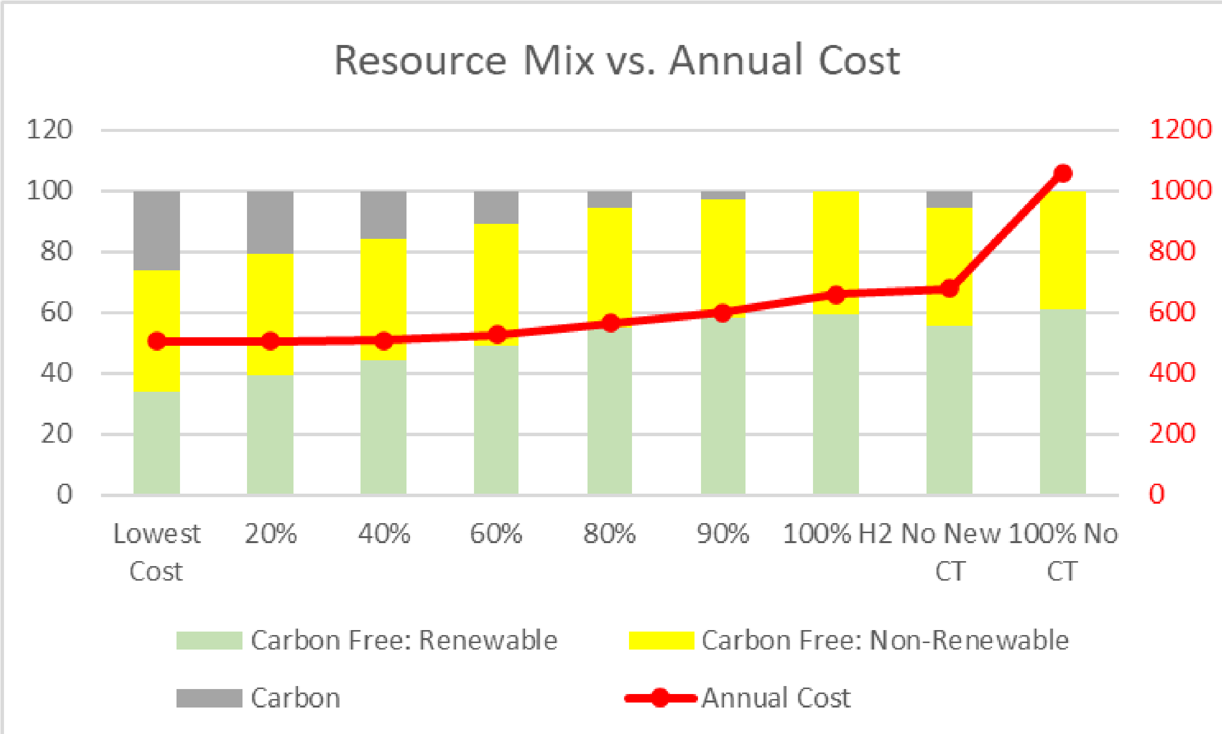
Table 4. System Decarbonization Scenarios

PORTFOLIO NAME	PORTFOLIO DESCRIPTION	CARBON FREE (%)	RENEWABLE (%)
Lowest Cost	Meets State RPS in Aggregate	74	34
20%	20% Carbon Emission Reduction by 2040	79	40
40%	40% Carbon Emission Reduction by 2040	84	44
60%	60% Carbon Emission Reduction by 2040	89	49
80%	80% Carbon Emission Reduction by 2040	94	55
90%	90% Carbon Emission Reduction by 2040	97	58
100% H2	100% Carbon Emission Reduction by 2040 with Hydrogen Fuel	100	59
No New CT	No New Combustion Turbines after 2024	94	55
100% No CT	100% Carbon Emission Reduction by 2040 with Only Renewables (Existing Nuclear)	100	61

The renewable integration on EPE's system is limited by two technical constraints, 1) transmission grid stability needs which require the use of dispatchable combustion generation for the last 10-15% of energy mix (which may be in the form of hydrogen fuel in the future); 2) EPE's existing carbon-free, clean Palo Verde Generating Station ("PVGS") energy which currently provides approximately 45-50% of customer energy needs system wide. As noted in Table 4, the decarbonization study results in a maximum renewable energy resource mix of approximately 50-60% by 2040.

The cost impact and customer affordability for greater renewable energy integration was also assessed by the technical study. The relationship between renewable energy integration and cost in year 2040 is illustrated in Figure 2. Cost increases are greater for the higher clean energy portfolios illustrated on the right. Specifically, the costs are greater above the 80% clean energy mix.

Figure 2. Annual Cost of Decarbonization Scenarios for 2040



The Total System Lease Cost Portfolio provides sufficient renewable resources to meet both New Mexico RPS and Texas renewable requirements in the aggregate but falls short of meeting New Mexico requirements when proportionally allocated between the Texas and New Mexico jurisdictions (~80/20). Additionally, given the significant cost increase for total system 100 percent carbon free attainment, and lack of Texas mandate, it became necessary to assess jurisdictional planning options for addressing the New Mexico REA requirements while separately meeting Texas' resource planning requirements. EPE and E3 developed three jurisdictional modeling options to evaluate the most cost-effective manner for EPE to comply with New Mexico REA requirements.

JURISDICTIONAL ANALYSIS AND LEAST COST PORTFOLIO

Because the initial model runs were performed on a total system basis, it was necessary to assess RPS impacts on a jurisdictional basis. EPE opted to evaluate the jurisdictional impacts by utilizing the Least Cost System Portfolio as the starting point. The jurisdictional analysis evaluated three different approaches to meeting New Mexico REA requirements, which resulted in three New Mexico specific resource portfolios. Table 5 summarizes the three jurisdictional scenarios that were evaluated.

Table 5. New Resource Jurisdictional Allocation Options

	Least Cost ("LC")	Least Cost + REA Resources ("LC+REA")	Separate System Planning ("SSP")
Portfolio optimization	Least-cost system optimization	Reoptimize Least Cost to add additional renewables & storage dedicated to NM to satisfy REA requirements	Optimize NM and TX systems independently without modeling interactions between them
NM zero-carbon generation balancing period	Annual	Annual	Hourly
NM and TX capacity pooling to ensure reliability	✓	✓	✗
Resource allocation	Resources allocated proportionally; more RECs allocated to NM	Incremental resources are allocated to New Mexico	Optimization identifies resources specifically for NM and TX jurisdictions
NM allocated new gas capacity	✓	✗	✗

1. **<u>Option-1.</u>** Least Cost Option - System Portfolio Allocated Proportionally (~80/20) and REC Transfer.

   Under this option, all new resources are allocated on a jurisdictional basis, inclusive of gas, and renewable energy. Once allocated, New Mexico's RPS is met through renewable energy delivered to EPE's system from: (1) renewable energy and RECs assigned to EPE's New Mexico jurisdiction; (2) existing dedicated New Mexico RPS resources and associated RECs; and (3) additional RECs assigned to EPE's New Mexico jurisdiction. This option assumes the transfer of stand-alone RECs from EPE's Texas jurisdiction to EPE's New Mexico jurisdiction, an allocation of new gas capacity to New Mexico, which could be converted to run on a higher share of hydrogen fuel in the future, and no allocation of PVGS Unit 3 to New Mexico.

2. **<u>Option 2.</u>** Least Cost Plus REA Resources - System Portfolio Allocated Proportionally plus New Mexico Dedicated Resources.

   Under this option, all new resources are allocated on a jurisdictional basis, except for new gas which is 100 percent allocated to Texas. Additionally, to meet New Mexico's RPS and capacity requirements, RESOLVE reoptimized and New Mexico dedicated renewable and capacity resources were selected to meet New Mexico's jurisdictional requirements. Importantly, this scenario allows capacity pooling and dispatch benefits for system dispatch optimization. Under this scenario, REA compliance is assessed based on annual retails sales, allowing system gas resources when required to supply New Mexico energy needs This scenario is most comparable with past practice except for the exclusion of new gas resources.

3. **Option 3.** Separate Systems for New Mexico and Texas.

   This approach is based on a separate New Mexico portfolio and a separate Texas portfolio. This scenario segregates EPE's system planning and identifies a New Mexico REA compliant portfolio with no allocations of new resources. Additionally, this approach assumes no capacity pooling between New Mexico and Texas, nor does it include joint system dispatch optimization. It also assesses New Mexico REA compliance on an hourly, as opposed to annual, basis. Therefore, there is no leveraging of cross-jurisdictional resources and as such the cost is higher for New Mexico because additional renewables and battery storage must be added to ensure hourly balancing and resource adequacy for New Mexico. This scenario was run both with and without the assumed use of hydrogen combustion generation. As indicated below, the scenario without hydrogen fuel options results in a higher cost. EPE's preliminary grid reliability study has only assessed the impacts of an 80 percent carbon free scenario through 2040, and exclusive reliance on inverter-based technologies has not yet been determined viable under a 100 percent carbon free scenario. This may be addressed in the future through continued technology advancements for both inverter-based resources and grid devices.

The resulting capacity, annual generation, and resource mix for each of the scenarios for Total System and New Mexico jurisdictional basis are shown in Figure 3a and Figure 3b.

Figure 3a. Total System & New Mexico Capacity Allocation Comparison

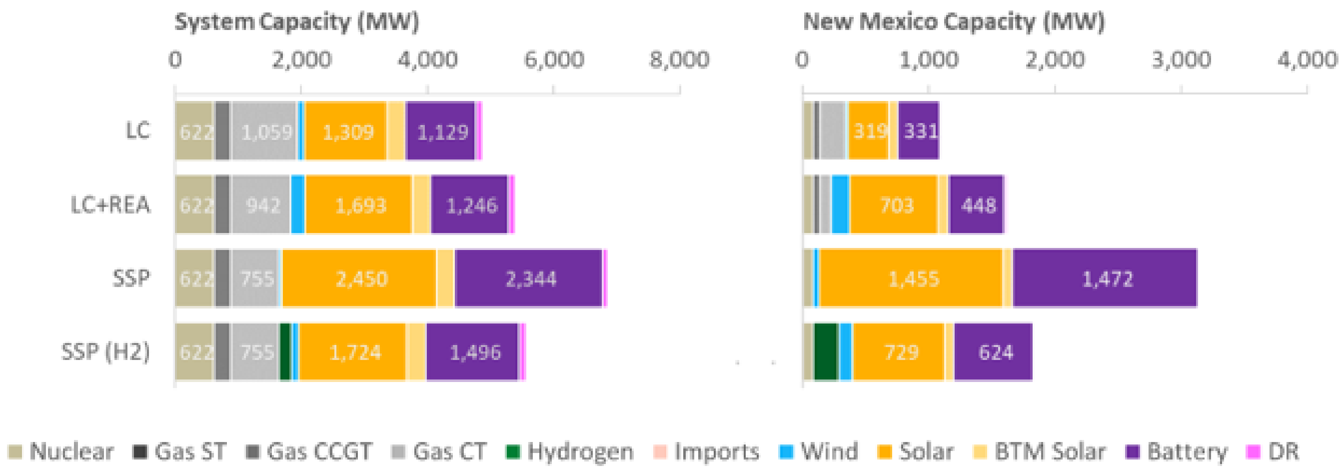
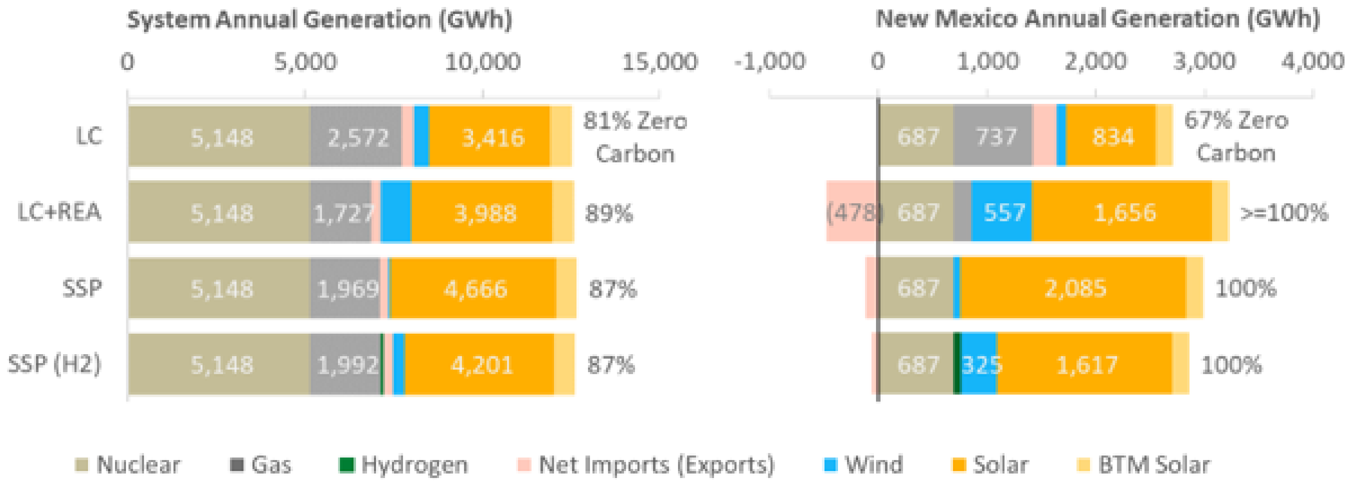
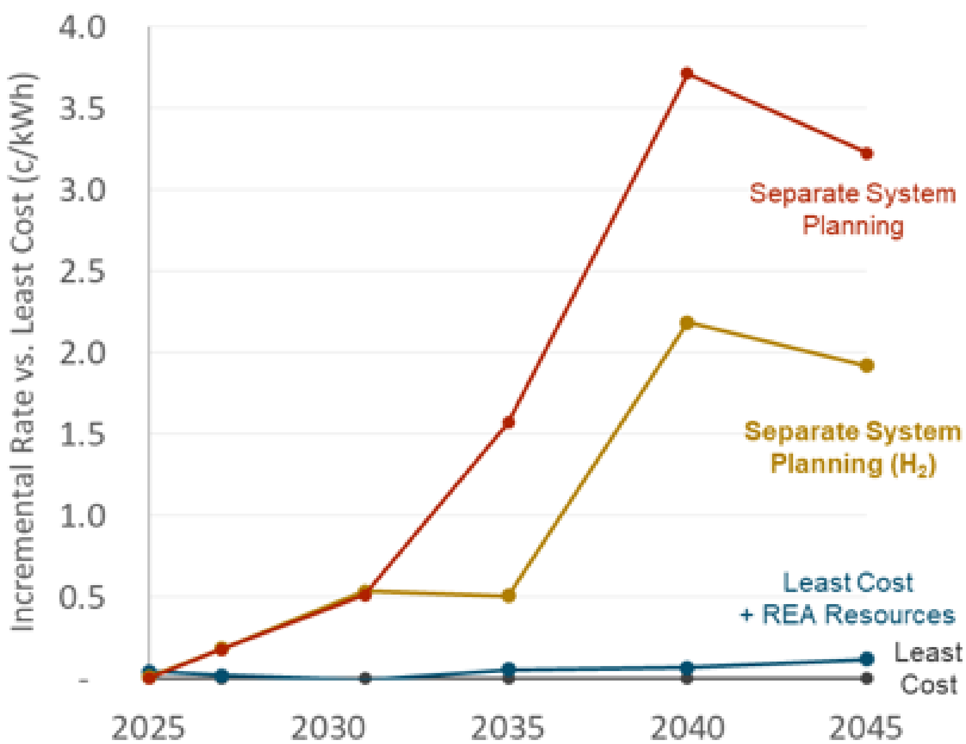


Figure 3b. Total System & New Mexico Annual Generation Allocation Comparison



The cost differential between the various jurisdictional approaches to REA compliance are illustrated over the planning horizon in Figure 4.

Figure 4. New Mexico Customer Rate Impact (Relative to Least Cost Case)



Option 1 presents challenges due to the required transfer of stand-alone RECs between EPE's jurisdictions and the requirement for new gas plant additions. Due to these challenges, EPE presents Options 2 and 3 as the most cost-effective resource options. Both address EPE's multi-jurisdictional planning requirements including the New Mexico RPS requirements and the Texas lowest cost portfolio requirements.

Option 2 assumes that system resources will be proportionally allocated to each jurisdiction. The cost benefits apparent in this scenario, as compare to the Separate System Planning scenario, result from capacity pooling and load diversity during optimal dispatch of both Texas and New Mexico resources while adhering to New Mexico REA requirements. It is important to note that this scenario still requires each jurisdiction, New Mexico and Texas, to acquire sufficient capacity to meet their respective demand and reliability needs. However, it also allows for total system dispatch to optimize both jurisdictional resources to the benefit for both states. As discussed above, this scenario assumes the ability to at times utilize system gas resources to serve New Mexico customers in the event of renewable or carbon free resource energy output unavailability.

Option 3 assumes separate resource planning to address jurisdictional planning requirements. This scenario provides New Mexico the most resource planning autonomy to meet New Mexico's renewable and clean energy standards. Option 3 costs more, however, because the cost benefits associated with capacity pooling and load diversity during optimal dispatch of system-wide resources would not be realized. In short, this approach best addresses the divergence between resource selection standards in Texas and New Mexico but comes at a greater cost to New Mexico.

RECOMMENDED PORTFOLIO

EPE presents as its recommended resource plan Option 2, the Least Cost plus REA resource portfolio. The resulting incremental portfolio additions for the total system are shown in Table 2. Table 6 shows the New Mexico incremental resource portfolio additions.

Table 6. Incremental Resources Portfolio Additions for New Mexico

Resource Category	2025	2027	2031	2035	2040	2045
Battery	*94*	*1*	*50*	*192*	*101*	*352*
Gas_CT	-	-	-	-	-	-
Gas 5-Yr Extension	*15*	*63*	-	-	-	-
Geothermal	-	-	-	-	-	-
Nuclear	-	-	-	-	-	-
Solar	-	-	*59*	*303*	*225*	*199*

Wind	*122*	-	-	-	*28*	-

EPE will pursue this portfolio by separate jurisdictional Requests for Proposals ("RFP") specific to New Mexico and Texas. This will allow EPE to pursue respective jurisdictional specific RPS requirements to meet demand. The separate RFP solicitations and resulting regulatory approval filings will also provide New Mexico with the autonomy it has demonstrated interest in. While the resources will be pursued via separate RFPs, the total system resource portfolio's capacity will be pooled and will be optimally dispatched at a system wide level to offer the cost benefits shown by the Least Cost plus REA analysis.

Under this IRP, REA compliance will be measured annually to ensure New Mexico assigned renewable resources and carbon free resources meet or exceed the New Mexico RPS. Including the 100 percent carbon free requirement. For example, there may be hours of the year that gas generation may serve New Mexico load; however, the total New Mexico assigned carbon free resources' output will equal or exceed the total annual New Mexico retail sales to ensure compliance with the 100 percent carbon free requirement.

The final EPE System and New Mexico L&R are presented in Figure 5a-5b and Figure 6a-6b respectively. Given that the RESOLVE analysis looks at five discrete build years, the L&R does distribute some of the resource additions to address preceding years due to retirements and associated deficiencies.

<u>LOADS AND RESOURCES</u>

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Figure 5a. EPE System Final L&R

System	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1.0 GENERATION RESOURCES[1]										
1.1 RIO GRANDE	244	202	202	202	202	202	202	202	202	202
1.2 NEWMAN	654	801	801	801	801	801	733	733	733	733
1.3 COPPER	65	65	65	65	65	65	65	65	65	0
1.4 MONTANA	331	331	331	331	331	331	331	331	331	331
1.5 PALO VERDE	585	585	585	585	585	585	585	585	585	585
1.6 RENEWABLES[2]	4	4	4	3	3	3	3	3	3	3
1.7 STORAGE	0	0	0	0	0	0	0	0	0	0
1.8 POSSIBLE EMERGING TECHNOLOGY EXPANSION[3]	0	0	0	0	0	0	0	0	0	0
1.9 INTERRUPTIBLE[4]	52	52	52	52	52	55	55	55	55	62
1.10 LINE LOSSES FROM OTHERS[5]	8	8	8	8	8	8	8	8	8	8
1.0 TOTAL GENERATION RESOURCES	**1943**	**2048**	**2047**	**2046**	**2046**	**2050**	**1982**	**1982**	**1982**	**1924**
2.0 RESOURCE PURCHASES										
2.1 RENEWABLE PURCHASE[6]	58	53	52	45	44	44	44	44	38	38
2.2 NEW RENEWABLE PURCHASE[7]	11	85	83	72	71	71	70	70	62	61
2.3 NEW RENEWABLE/ BATTERY PURCHASE[8]	54	49	49	42	42	41	41	41	36	36
2.4 NEW BATTERY PURCHASE[9]	50	50	50	50	50	50	50	50	46	46
2.5 EDDY TIE PURCHASE[10]	35	35	35	35	35	35	35	35	35	35
2.6 MARKET RESOURCE PURCHASE[11]	225	85	110	0	0	0	85	135	0	25
2.0 TOTAL RESOURCE PURCHASES	**433**	**357**	**379**	**243**	**242**	**241**	**325**	**374**	**217**	**241**
3.0 FUTURE RESOURCES[12]										
3.1 RENEWABLE	0	0	0	120	119	120	119	119	207	206
3.2 RENEWABLE/STORAGE	0	0	0	126	126	126	126	126	378	378
3.3 GAS GENERATION	0	0	0	0	0	0	0	0	0	0
3.0 TOTAL RESOURCE PURCHASES	**0**	**0**	**0**	**246**	**246**	**246**	**246**	**245**	**584**	**584**
4.0 TOTAL NET RESOURCES (1.0 + 2.0 + 3.0)	**2376**	**2404**	**2426**	**2535**	**2534**	**2537**	**2553**	**2602**	**2783**	**2748**
5.0 SYSTEM DEMAND[13]										
5.1 NATIVE SYSTEM DEMAND	**2188**	**2225**	**2252**	**2293**	**2331**	**2372**	**2408**	**2459**	**2506**	**2553**
5.2 DISTRIBUTED GENERATION	-19	-22	-22	-24	-24	-33	-33	-33	-33	-42
5.3 ENERGY EFFICIENCY	-15	-23	-31	-38	-46	-54	-62	-69	-77	-85
6.0 TOTAL SYSTEM DEMAND (5.1 - (5.2+5.3))	**2154**	**2180**	**2200**	**2230**	**2261**	**2285**	**2313**	**2357**	**2396**	**2426**
7.0 MARGIN OVER TOTAL DEMAND (4.0 - 6.0)	**222**	**224**	**227**	**305**	**274**	**252**	**240**	**245**	**387**	**322**
8.0 PLANNING RESERVE 10.1% thru 2029 then 12.9%	**219**	**222**	**224**	**228**	**231**	**234**	**237**	**241**	**313**	**318**
9.0 MARGIN OVER RESERVE (7.0 - 8.0)	**2**	**2**	**2**	**78**	**43**	**18**	**3**	**4**	**74**	**4**

1. Generation unit retirements are consistent with the 2021 IRP. Rio Grande 6 is classified as inactive reserve.
2. Existing EPE owned solar renewables (27% - 54% ELCC)
3. Emerging technologies may include customer or other distributed resources as well as additional community solar. None were used for the 2021 IRP.
4. Interruptible customer capacity shifted to the resource side of the L&R. Capacity MW contribution per 2021 Load Forecast.
5. Line losses from others shifted to resource side of the L&R and is the typical amount of repayment of transmission wheeling losses from transmission customers with in-kind energy during peak hours.
6. Existing renewable solar PPAs (27% - 54% ELCC)
7. New renewable solar PPAs (27% - 54% ELCC)
8. New solar and battery storage PPAs (27% - 54% ELCC)
9. 50 MW New Battery Purchase reflects the 50 MW battery that is coupled with the 100 MW solar PPA. (71% - 100% ELCC)
10. 35MW reliability purchase through the Eddy tie.
11. Denotes market purchase either spot market or short-term purchased power.
Amounts greater than 645 MW-PV output will need to come into EPE via exchange
(Freeport), through the acquisition of additional transmission or on a non-firm path.
Also, availability of such power is not guaranteed.
12. Future Resources from 2025 forward are to address both NM RPS and system capacity needs.
13. System demand is based on the 2021 Long-Term Forecast dated April 2021.
14. Effective Load Carrying Capability ("ELCC") is expressed as a percentage of the generators nameplate rating which is the contribution to reliably serve load and is listed here for the peak hour.

Figure 5b. EPE System Final L&R (continued)

System	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
1.0 GENERATION RESOURCES[1]										
1.1 RIO GRANDE	202	202	74	74	74	74	74	74	74	74
1.2 NEWMAN	452	452	452	452	452	452	452	452	452	452
1.3 COPPER	0	0	0	0	0	0	0	0	0	0
1.4 MONTANA	331	331	331	331	331	331	331	331	331	331
1.5 PALO VERDE	585	585	585	585	585	585	585	585	585	585
1.6 RENEWABLES[2]	2	2	2	2	2	2	2	2	2	2
1.7 STORAGE	0	0	0	0	0	0	0	0	0	0
1.8 POSSIBLE EMERGING TECHNOLOGY EXPANSION[3]	0	0	0	0	0	0	0	0	0	0
1.9 INTERRUPTIBLE[4]	62	62	62	69	69	69	69	69	78	78
1.10 LINE LOSSES FROM OTHERS[5]	8	8	8	8	8	8	8	8	8	8
1.0 TOTAL GENERATION RESOURCES	**1642**	**1642**	**1514**	**1521**	**1521**	**1521**	**1520**	**1520**	**1529**	**1529**
2.0 RESOURCE PURCHASES										
2.1 RENEWABLE PURCHASE[6]	24	24	24	10	10	9	2	2	2	2
2.2 NEW RENEWABLE PURCHASE[7]	48	48	48	48	47	47	42	42	42	42
2.3 NEW RENEWABLE/ BATTERY PURCHASE[8]	28	28	28	28	28	28	25	25	25	25
2.4 NEW BATTERY PURCHASE[9]	36	36	36	36	36	36	35	35	35	35
2.5 EDDY TIE PURCHASE[10]	35	35	35	35	35	35	35	35	35	35
2.6 MARKET RESOURCE PURCHASE[11]	15	75	0	25	70	140	50	120	30	85
2.0 TOTAL RESOURCE PURCHASES	**187**	**247**	**171**	**182**	**226**	**294**	**190**	**260**	**170**	**224**
3.0 FUTURE RESOURCES[12]										
3.1 RENEWABLE	304	303	378	376	374	373	394	393	427	425
3.2 RENEWABLE/STORAGE	567	567	729	729	729	729	796	796	847	847
3.3 GAS GENERATION	82	82	130	130	130	130	205	205	255	255
3.0 TOTAL RESOURCE PURCHASES	**952**	**951**	**1237**	**1235**	**1233**	**1232**	**1395**	**1393**	**1529**	**1527**
4.0 TOTAL NET RESOURCES (1.0 + 2.0 + 3.0)	**2781**	**2840**	**2921**	**2937**	**2980**	**3047**	**3106**	**3174**	**3228**	**3281**
5.0 SYSTEM DEMAND[13]										
5.1 NATIVE SYSTEM DEMAND	**2593**	**2650**	**2702**	**2756**	**2804**	**2869**	**2931**	**2996**	**3060**	**3125**
5.2 DISTRIBUTED GENERATION	-42	-42	-42	-48	-48	-48	-48	-48	-57	-68
5.3 ENERGY EFFICIENCY	-92	-100	-108	-115	-123	-131	-138	-146	-154	-162
6.0 TOTAL SYSTEM DEMAND (5.1 - (5.2+5.3))	**2458**	**2507**	**2552**	**2593**	**2633**	**2691**	**2745**	**2802**	**2849**	**2896**
7.0 MARGIN OVER TOTAL DEMAND (4.0 - 6.0)	**323**	**332**	**369**	**344**	**347**	**356**	**361**	**372**	**379**	**385**
8.0 PLANNING RESERVE 10.1% thru 2029 then 12.9%	**323**	**329**	**335**	**341**	**346**	**353**	**360**	**368**	**375**	**382**
9.0 MARGIN OVER RESERVE (7.0 - 8.0)	**0**	**3**	**35**	**4**	**1**	**2**	**1**	**4**	**4**	**3**

Figure 6a. EPE New Mexico Final L&R

New Mexico	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1.0 GENERATION RESOURCES										
1.1 RIO GRANDE	49	40	40	40	40	40	40	40	40	40
1.2 NEWMAN	130	118	118	118	118	118	104	104	104	104
1.3 COPPER	13	13	13	13	13	13	13	13	13	0
1.4 MONTANA	66	66	66	66	66	66	66	66	66	66
1.5 PALO VERDE	78	78	78	78	78	78	78	78	78	78
1.6 RENEWABLES	3	2	2	2	2	2	2	2	2	2
1.7 STORAGE	0	0	0	0	0	0	0	0	0	0
1.8 POSSIBLE EMERGING TECHNOLOGY EXPANSION	0	0	0	0	0	0	0	0	0	0
1.9 INTERRUPTIBLE	10	10	10	10	10	11	11	11	11	12
1.10 LINE LOSSES FROM OTHERS	2	2	2	2	2	2	2	2	2	2
1.0 TOTAL GENERATION RESOURCES	**350**	**329**	**329**	**329**	**329**	**329**	**316**	**316**	**316**	**304**
2.0 RESOURCE PURCHASES										
2.1 RENEWABLE PURCHASE	31	28	28	24	24	23	23	23	20	20
2.2 NEW RENEWABLE PURCHASE	11	45	44	38	38	37	37	37	33	32
2.3 NEW RENEWABLE/ BATTERY PURCHASE	11	10	10	8	8	8	8	8	7	7
2.4 NEW BATTERY PURCHASE	10	10	10	10	10	10	10	10	9	9
2.5 EDDY TIE PURCHASE	7	7	7	7	7	7	7	7	7	7
2.6 MARKET RESOURCE PURCHASE	55	50	60	0	0	0	0	0	0	0
2.0 TOTAL RESOURCE PURCHASES	**124**	**150**	**158**	**87**	**86**	**86**	**85**	**85**	**76**	**76**
3.0 FUTURE RESOURCES										
3.1 RENEWABLE	0	0	0	31	31	32	32	32	55	55
3.2 RENEWABLE/STORAGE	0	0	0	95	95	95	95	95	134	134
3.3 GAS GENERATION	0	0	0	0	0	0	0	0	0	0
3.0 TOTAL RESOURCE PURCHASES	**0**	**0**	**0**	**126**	**126**	**126**	**126**	**126**	**188**	**188**
4.0 TOTAL NET RESOURCES (1.0 + 2.0 + 3.0)	**475**	**479**	**487**	**541**	**541**	**542**	**528**	**527**	**580**	**568**
5.0 SYSTEM DEMAND										
5.1 NATIVE SYSTEM DEMAND	**437**	**444**	**450**	**458**	**465**	**474**	**481**	**491**	**500**	**510**
5.2 DISTRIBUTED GENERATION	-4	-4	-4	-5	-5	-7	-7	-7	-7	-8
5.3 ENERGY EFFICIENCY	-3	-5	-6	-8	-9	-11	-12	-14	-15	-17
6.0 TOTAL SYSTEM DEMAND (5.1 - (5.2+5.3))	**430**	**435**	**439**	**445**	**451**	**456**	**462**	**471**	**478**	**484**
7.0 MARGIN OVER TOTAL DEMAND (4.0 - 6.0)	**45**	**44**	**48**	**96**	**90**	**85**	**66**	**57**	**102**	**84**
8.0 PLANNING RESERVE 10.1% thru 2029 then 12.9%	**44**	**44**	**45**	**45**	**46**	**47**	**47**	**48**	**63**	**64**
9.0 MARGIN OVER RESERVE (7.0 - 8.0)	**1**	**-1**	**3**	**51**	**44**	**39**	**18**	**8**	**39**	**20**

Figure 6b. EPE New Mexico Final L&R (continued)

New Mexico	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
1.0 GENERATION RESOURCES										
1.1 RIO GRANDE	40	40	15	15	15	15	15	15	15	15
1.2 NEWMAN	48	48	48	48	48	48	48	48	48	48
1.3 COPPER	0	0	0	0	0	0	0	0	0	0
1.4 MONTANA	66	66	66	66	66	66	66	66	66	66
1.5 PALO VERDE	78	78	78	78	78	78	78	78	78	78
1.6 RENEWABLES	1	1	1	1	1	1	1	1	1	1
1.7 STORAGE	0	0	0	0	0	0	0	0	0	0
1.8 POSSIBLE EMERGING TECHNOLOGY EXPANSION	0	0	0	0	0	0	0	0	0	0
1.9 INTERRUPTIBLE	12	12	12	14	14	14	14	14	16	16
1.10 LINE LOSSES FROM OTHERS	2	2	2	2	2	2	2	2	2	2
1.0 TOTAL GENERATION RESOURCES	**248**	**248**	**222**	**223**	**223**	**223**	**223**	**223**	**225**	**225**
2.0 RESOURCE PURCHASES										
2.1 RENEWABLE PURCHASE	10	10	10	7	7	6	0	0	0	0
2.2 NEW RENEWABLE PURCHASE	26	25	25	25	25	25	22	22	22	22
2.3 NEW RENEWABLE/ BATTERY PURCHASE	6	6	6	6	6	6	5	5	5	5
2.4 NEW BATTERY PURCHASE	7	7	7	7	7	7	7	7	7	7
2.5 EDDY TIE PURCHASE	7	7	7	7	7	7	7	7	7	7
2.6 MARKET RESOURCE PURCHASE	0	0	0	0	0	0	0	0	0	0
2.0 TOTAL RESOURCE PURCHASES	**56**	**55**	**55**	**52**	**52**	**50**	**41**	**41**	**41**	**41**
3.0 FUTURE RESOURCES										
3.1 RENEWABLE	107	107	140	140	139	139	169	168	195	194
3.2 RENEWABLE/STORAGE	190	190	241	241	241	241	281	281	310	310
3.3 GAS GENERATION	0	0	0	0	0	0	0	0	0	0
3.0 TOTAL RESOURCE PURCHASES	**297**	**297**	**381**	**380**	**380**	**379**	**450**	**449**	**505**	**504**
4.0 TOTAL NET RESOURCES (1.0 + 2.0 + 3.0)	**600**	**600**	**658**	**656**	**655**	**653**	**715**	**714**	**771**	**770**
5.0 SYSTEM DEMAND										
5.1 NATIVE SYSTEM DEMAND	**518**	**529**	**539**	**550**	**560**	**573**	**585**	**598**	**611**	**624**
5.2 DISTRIBUTED GENERATION	-8	-8	-8	-9	-9	-9	-9	-9	-11	-14
5.3 ENERGY EFFICIENCY	-18	-20	-21	-23	-25	-26	-28	-29	-31	-32
6.0 TOTAL SYSTEM DEMAND (5.1 - (5.2+5.3))	**491**	**501**	**509**	**518**	**526**	**537**	**548**	**560**	**569**	**578**
7.0 MARGIN OVER TOTAL DEMAND (4.0 - 6.0)	**110**	**99**	**149**	**138**	**130**	**116**	**167**	**154**	**202**	**192**
8.0 PLANNING RESERVE 10.1% thru 2029 then 12.9%	**64**	**66**	**67**	**68**	**69**	**71**	**72**	**73**	**75**	**76**
9.0 MARGIN OVER RESERVE (7.0 - 8.0)	**45**	**34**	**82**	**70**	**61**	**45**	**95**	**81**	**128**	**116**

A. 2021 IRP Four-Year Action Plan

EPE's four-year action plan includes the following steps:

- EPE will continue moving forward with the selected resources previously approved by the Commission in Case Nos. 19-00099-UT and 19-00348-UT (Hecate I and II and Buena Vista I and II). These resources have an anticipated Commercial Operation Date ("COD") of 2022.
- EPE will complete the regulatory approval process for EPE's 2021 Annual Renewable Energy Plan filed May 5, 2021, and file subsequent annual reports and plans in 2022, 2023, 2024, and 2025 pursuant to 17.9.572 NMAC and the New Mexico REA.
- EPE will complete the regulatory approval process for the 2022-2024 Energy Efficiency and Load Management Plan filed July 16, 2021 and will file a subsequent 3-year plan pursuant to 17.7.2 NMAC and the EUEA.
- EPE will issue a New Mexico RFP in 2021 to address current capacity needs and RPS resource needs to meet the REA 2025 target of 40 percent.
- EPE will conduct a Demand Side Management potential study.
- EPE will continue to consider voluntary customer programs for renewable energy.
- EPE will file for abandonment of units that are past their useful lives.

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:

- identify the most cost-effective portfolio of resources that best meets customer needs for the next twenty years,

- consider various resource options, including supply-side and demand-side options, while taking into consideration statutory requirements, environmental sustainability, reliability, risk; and,

- partner up with customers via the Public Process to provide information to and receive inputs and recommendations throughout the Planning Process.

The Planning Process can be described as the method to develop the most cost-effective integrated resource portfolio 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 and load management goals and renewable energy standards are incorporated into the Planning Process. EPE evaluated renewable energy resources, energy efficiency, and demand side management resources to meet the REA and EUEA requirements through the Planning Process. For example, the EUEA establishes energy efficiency and load management programs that are approved by the Commission. EPE's statutory goal is five percent of the 2020 retail sales by 2025. In addition, the REA establishes a renewable portfolio standard ("RPS") for EPE's New Mexico jurisdiction, requiring a number of renewable resources based on a percentage of EPE's annual New Mexico retail energy sales.

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

While the IRP requirement is a three-year cycle, EPE continually evaluates its' Plan for resource adequacy and reliability. The ongoing Planning Process can be summarized in the following steps:

- determine a baseline for future capacity needs utilizing the latest load forecast that incorporates data for distributed generation ("DG"), energy efficiency and load management ("EE/LM"), and electric vehicle charging ("EV"), and comparing that to the most current information for existing supply-side resources and their expected retirement dates;
- identify possible demand-side and supply-side resources that may be utilized to serve load safely and reliably if a capacity need is determined. This 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 RFP results, along with publicly available information, is used to form resource assumptions
- analyze resource options to ensure reliability, adequacy, statutory compliance, and appropriate integration into EPE's system to select the most cost-effective portfolio of resources to best meet customer needs, safely and reliably (the "expansion portfolio"),
- incorporate applicable forecast data, existing resource information and expansion portfolio into the L&R, and
- update annually with latest forecast and resource data.

EPE follows the process as summarized above during its annual and continuous resource planning in the usual course of business. However, during years where the IRP Planning Process is occurring, additional key steps occur

- performance of sensitivity analyses of various factors, such as load forecast, fuel cost, carbon tax considerations at various rates, DG growth, EV growth, along with feasible supply side and demand side resource options as suggested by the Public Participants, 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 437,000 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. 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 major universities and a steel production facility. Figure 7 shows a geographical representation of EPE's total service territory.

Figure 7 – EPE Service Territory

B. Summary of the 2018 IRP Action Plan and Status

EPE has completed all required items set forth in its 2018 IRP four-year action plan. In summary, EPE:

- filed for regulatory approval with the NMPRC for resources selected from the Company's 2017 All Source RFP for Electric Power Supply and Load Management Resources;
- filed its 2018, 2019-2020, and 2021 Annual Renewable Energy Plan pursuant to 17.9.572 NMAC and the REA;
- filed its 2019-2021 Energy Efficiency and Load Management Plan in 2018 pursuant to 17.7.2 NMAC and the EUEA and its 2022-2024 Plan on July 16, 2021.
- Initiated an RFP to be issued in 2021 to address resource needs identified in 2024;
- evaluated the Demand Response Pilot Program results at the conclusion of the program; and,
- proposed a voluntary New Mexico Community Solar program and proposed and received approval for a New Mexico State University solar generation project.

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 facilities fueled by solar, natural gas, and uranium. EPE also purchases renewable energy through various long-term Purchased Power Agreements ("PPAs") and Qualifying Facilities (“QF”). In addition, EPE purchases varying amounts of firm and non-firm energy through the wholesale markets to meet the needs of its customers. Also, EPE is currently in the process of joining the Western Energy Imbalance Market which offers a real-time energy market that allows members to find low-cost energy across a wide geographic area to serve real-time customer electricity demand. These resources, in combination with future low-cost efficient options, will create a portfolio that results in the most cost-effective plan for EPE customers, considering reliability and risk.

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 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 expanded its renewable portfolio with the addition of its Texas Community Solar Facility and the Holloman Solar Facility in 2017 and 2018, respectively. The Texas Community Solar Facility is a 3 MW Solar PV system located on approximately 21 acres near the MPS, whose generation is dedicated to EPE's Texas Community Solar program which allows customers to voluntarily subscribe to utility-scale single-axis tracking PV based on their current usage. It allows customers to participate in supporting renewable energy generation without physically having to locate solar panels where they reside. It became commercially operational on May 31, 2017 and, to date, is fully subscribed. 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 generation from the 10 MW Newman Solar Facility. Therefore, the Texas Community Solar program consists of a total of 5 MW, i.e., 3 MW of EPE-owned generation and 2 MW from the Newman Solar Facility which is under a PPA.

The Holloman Solar Facility is a 5 MW EPE-owned solar resource dedicated to serve HAFB. It became commercially operational on October 18, 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 with fuel types, in-service dates, and currently planned retirement dates are listed in Table 7. Table 7 includes Rio Grande Unit 6 as required in the Final Order of Case No. 17-00317-UT. It is also important to note that the majority of EPE's generating facilities listed in Table 7 have been in service for a significant number of years. This is an important consideration for integrated resource planning because the 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") costs, is provided hereto in Attachment C-2.

Table 7. 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	622	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	352	Natural Gas	Fuel Oil	March 2015 March 2015 May 2016 September 2016	December 2060 December 2060 December 2061 December 2061	45 45 45 45
Rio Grande Unit 6 (1) Unit 7 Unit 8 Unit 9	Sunland Park, NM	323	Natural Gas	N/A	June 1957 June 1958 July 1972 May 2013	December 2021 December 2022 December 2033 December 2058	64 64 61 45
Newman Unit 1 Unit 2 Unit 3 Unit 4 Unit 5 – CTs Unit 5 – HRSG	El Paso, TX	729	Natural Gas	N/A	May 1960 June 1963 March 1966 June 1975 May 2009 April 2011	December 2022 December 2022 December 2026 December 2026 December 2061 December 2061	62 59 60 51 52 50
Copper Unit 1	El Paso, TX	63	Natural Gas	N/A	July 1980	December 2030	50
EPE-owned Solar Texas Community Solar Holloman Solar Small Solar Systems	EPE Service Territory	3 5 < 1	N/A	N/A	May 2017 Oct 2018 2009 – 2011	May 2047 Oct 2048 2029 – 2032	Various

(1) Rio Grande Unit 6 is subject to a pending abandonment proceeding in Case No. 20-00194-UT.

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 8.

Table 8. 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
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
Buena Vista Energy Center, LLC ("Buena Vista 1")	Otero County, NM	100	May 2022	20 years
Buena Vista Energy Center II, LLC ("Buena Vista 2")	Otero County, NM	20	May 2022	20 years
Hecate Energy Santa Teresa, LLC ("Hecate 1")	Santa Teresa, NM	100	December 2022	20 years
Hecate Energy Santa Teresa 2, LLC ("Hecate 2")	Santa Teresa, NM	50	December 2022	20 years

Additionally, interconnected to EPE's system is a biogas energy QF, the Camino Real Landfill Gas to Energy Facility or Four Peaks (3.2 MW) located in Sunland Park, New Mexico (at the Camino Real Landfill).[2] Furthermore, EPE offers net metering and REC programs for customer-owned solar PV and wind generation. The RECs obtained from New Mexico renewable resources are used to meet EPE's New Mexico RPS requirements.

On November 18, 2019, the Company filed for NMPRC approval of the PPAs selected from the Company's 2017 All Source RFP for Electric Power Supply and Load Management Resources. The two, NMPRC-approved PPAs include: (i) a 100 MW solar plant to be constructed in Santa Teresa, New Mexico; and (ii) a 100 MW solar plant combined with a 50 MW battery energy storage to be constructed in Otero County, New Mexico. On March 31, 2020 the Company filed for regulatory approval with the NMPRC for two additional solar resources to meet the New Mexico RPS.

[2] The $30/MWh renewable energy credit ("REC") premium for this facility approved by the Commission in Case No. 18-00099-UT, is subject to a Commission Stay Order issued in that docket, while pending a City of Las Cruces appeal of the Commission Final Order in that case to the New Mexico Supreme Court.

These two additional renewable resources were approved by the NMPRC on December 2, 2020 and include: (iii) a 50 MW solar plant to be constructed in Santa Teresa, New Mexico and (iv) a 20 MW solar plant to be constructed in Otero County, New Mexico.

In combination with existing and upcoming 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 IRP. Additionally, EPE utilizes short-term market purchases to mitigate the need for new resource additions and to allow for economical resource selections.

3. Approved Utility-owned Generation not In-service

Newman Unit 6 ("NM6"), also known as Newman GT5, is a 1x0 Mitsubishi M501GAC simple-cycle combustion turbine expected to provide a total net summer capacity of approximately 228MW. NM6 was selected as a result of EPE's 2017 All Source RFP. The Commission denied EPE's Certificate of Convenience and Necessity ("CCN") Application for NM6 by Final Order issued December 16, 2020. However, the PUCT approved a CCN for NM6 on October 16, 2020. Therefore, EPE is pursuing required permitting for NM6 and it is anticipated to be commercially operational May 1, 2023 as a Texas resource.

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 9. 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 9. Environmental Impacts of Existing Supply Side Resources

2020 Data: Based on Rolling Average							
Unit	NOx [3]	CO [3]	PM	SO_2 [4]	Hg[1]	CO_2 [5]	Water Consumption[6]
	(lbs/kWh)						(gal/kWh-site)
Montana 1	0.00010	0.00003	0.00006	0.00001	*	1.10	0.18
Montana 2	0.00011	0.00005	0.00006	0.00001	*	1.08	
Montana 3	0.00011	0.00003	0.00007	0.00001	*	1.15	
Montana 4	0.00011	0.00005	0.00006	0.00001	*	1.08	
Rio Grande 6	0.00000	0.00000	0.00000	0.00000	*	0.00	0.64
Rio Grande 7	0.00148	0.00013	0.00001	0.00000	*	1.43	
Rio Grande 8	0.00224	0.00015	0.00008	0.00000	*	1.28	
Rio Grande 9	0.00010	0.00011	0.00001	0.00000	*	1.16	
Newman 1	0.00250	0.00021	0.00001	0.00001	*	1.42	0.61
Newman 2	0.00208	0.00011	0.00001	0.00001	*	1.38	
Newman 3	0.00155	0.00005	0.00001	0.00001	*	1.29	
Newman 4 [2]	0.00163	0.00044	0.00001	0.00001	*	1.19	
Newman 5	0.00007	0.00006	0.00007	0.000005	*	0.97	
Copper 1	0.00576	0.00262	0.00013	0.00001	*	2.24	0.09
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	

[1] No oil burned in 2020; therefore, no Hg emissions were created

[2] Newman GT-1 and GT-2

[3] Rio Grande, Newman, Montana, and Copper NOx and CO emission data from continuous emissions monitoring system

[4] Rio Grande, Newman, Montana, and Copper SO_2 emission data calculated from natural gas sulfur content

[5] Rio Grande, Newman, and Montana CO_2 emission data calculated as per 40 CFR 75 Appendix G, Equation G-4; Copper as per 40 CFR 98 Subpart C

[6] EPE's water consumption at Palo Verde is estimated as 15.8 percent (percentage of ownership by EPE) of the total from 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, NOx, carbon monoxide ("CO"), ozone and SO2. NAAQS must be reviewed by the EPA at five-year intervals, and if necessary, revised. On October 1, 2015, the EPA released a final rule tightening the primary and secondary 8-hour 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 its precursors, NOx, and VOCs, in combination with sunlight. The EPA recently designated one of the areas in which we operate as nonattainment. Specifically, in December 2017, EPA proposed to designate southern Doña Ana County, New Mexico, as a nonattainment area. In June of 2018 the EPA provided public notice of this designation and later officially designated the area as nonattainment. In July 2020 the U.S. Court of Appeals for the D.C. Circuit remanded the attainment designation assigned to El Paso County back to the EPA for further consideration and explanation. On May 25, 2021, the EPA sent a 120-day notification letter to the State of Texas stating they intend to modify the El Paso ozone designation to nonattainment. States that contained any areas designated as nonattainment were required to complete development of State Implementation Plans in the 2020-2021 timeframe for marginal and moderate designations.

Nonattainment areas deemed marginal are expected to have until August 2021 to meet the primary (health) standard, while attainment in moderate areas needs to be obtained by August 2024. 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 and although the official withdrawal was finalized in November 2020, the US officially rejoined in February 2021 along with pledging to reduce GHG emissions by 50 percent from 2005 levels by 2030. The federal government signaled a “whole-of-government” approach expecting the private sector to partner in transforming many business sectors, amongst them the power industry.

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 led to the Supreme Court halting enforcement in 2016 and a failed attempt at replacing it with the Affordable Clean Energy (ACE) rule in 2017. Although it was ruled that the ACE violated the CAA in January 2021, the CPP was not reinstated leaving the door open to a new rule being proposed. The current Biden administration is pursuing climate initiatives which may result in funding, incentives or new requirements.

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 and/or recently promulgated GHG regulations. In accordance with the CAA 111(b), performance standards for newly constructed electric generating units, Newman 6 will be the first EPE unit to operate with a permitted GHG emission limit. This will aid in achieving EPE’s carbon reduction goals.

Climate change also has potential physical effects relevant to the Company's business. 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 three Commission ordered sensitivity scenarios with 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 9, and is a primary consideration in comparing generation technologies and evaluating resource portfolios. All the 5 relatively new GE LMS 100 turbines and the planned Newman 6 unit are not steam generating units, and the planned Newman 6 unit specifically will not include a cooling tower in its peripheral equipment, drastically reducing its water consumption rate when compared to older units. 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 cultural resources exist within a project's area of potential effect and whether 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 continuously measuring the sustainability of our businesses practices focusing specifically in the effects on environmental, social, and corporate governance (ESG) factors. 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

Demand side resources are a reduction to the overall forecasted native system demand.

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

1. New Mexico Energy Efficiency ("EE") Programs;
2. New Mexico Residential and Commercial Load Management ("LM") Programs;
3. Texas Energy Efficiency Programs; and,
4. Texas Residential and Commercial Load Management 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 New Mexico EE/LM programs and the Texas EE/LM programs are included below. EPE will continue to consider demand side resource options as part of its IRP as described in Section VI.

1. New Mexico Energy Efficiency Programs

The Commission's March 2019 Final Order in Case No 18-00116-UT approved EPE's 2019-2021 EE/LM Plan. Pursuant to the EE Rule, EPE continues to offer these programs. In EPE's Application for Approval of its proposed 2022-2024 EE/LM Plan filed July 15, 2021, EPE is proposing four new residential programs to help reach additional customers and to be better positioned to meet the increased savings requirements in EUEA.

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

Residential

- The Residential Comprehensive Program offers rebates for the installation of attic insulation, duct sealing, air infiltration, evaporative coolers, refrigerated A/C units, solar screens, pool pumps, cool roofs, windows, and smart thermostats.
- The New Mexico EnergySaver (Low Income) Program provides income-qualified customers a variety of EE measures for their homes at no cost, including evaporative cooler replacement, advanced power strips, LED lighting, smart thermostats, attic insulation, duct sealing, air infiltration, water heater pipe and tank insulation, high efficiency showerheads and kitchen and bathroom faucet aerators. 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 students and teachers are provided with a LivingWise® kit that contains educational materials and energy saving devices that students install in their homes.
- The Residential Lighting Program offers discounts at participating retail locations for customers to replace their existing light bulbs with more energy efficient Light Emitting Diodes ("LED") lighting.
- The ENERGY STAR® New Homes Program provides incentives for homebuilders to construct energy efficient homes that exceed the current building code.

Commercial

- The Commercial Comprehensive Program provides incentives and rebates to commercial customers whose average annual demand is up to and including 100 kW for installing eligible energy efficiency measures such as lighting, HVAC, controls, pool pumps, cool roofs, commercial food service equipment, refrigeration measures, and building envelope measures.
- The SCORE Plus Program provides incentives to large commercial customers with an average demand greater than 100 kW, as well as schools, city, county, and government customers for EE measures including lighting, HVAC, controls, pool pumps, cool roofs, commercial food service equipment, refrigeration measures, building envelope measures, and custom projects.

2. New Mexico Residential and Commercial Load Management Programs

The Commission's March 2019 Final Order in Case No 18-00116-UT approved EPE's Commercial Load Management Program, and the Commission's July 2020 Final Order in Case No 18-00116-UT approved EPE's Residential Load Management Program.

EPE's Residential and Commercial Load Management Programs engage utility customers to reduce their electricity use (load) during peak hours or under certain conditions, which in turn, can substantially reduce demand for electricity during EPE's peak hours, providing aggregate benefits for the electric grid and participants themselves. The load management season begins on June 1 and continues through September 30 each year.

- The Residential Load Management Program provides customers with rebates for enrolling an existing qualifying internet-enabled smart thermostat for load management events or for the purchase and enrollment of a new internet-enabled smart thermostat through EPE's online website. Participants who enroll, voluntarily allow EPE to control their smart thermostat to relieve peak load during the time of the event.

- The Commercial Load Management Program allows participating customers to provide on-call, voluntary curtailment of electric consumption during peak demand periods in return for incentive payments. This program is designed to target commercial participants from the educational, government, and private commercial sector with an average demand greater than 100 kW.

Table 10 shows EPE's New Mexico EE Portfolio of Programs and their Average Estimated Useful Life ("EUL").

Table 10. Current Portfolio New of Mexico EE/LM Programs and Program EUL

Program	**Estimated Useful Life[1]**
Residential Programs	
LivingWise®	9
Residential Comprehensive	15
Residential Lighting	12
ENERGY STAR® New Homes	21
Residential Load Management	10
NM EnergySaver (Low Income)	16
Commercial Programs	
Commercial Comprehensive	14
SCORE Plus	14
Commercial Load Management	1

1. EUL values as identified by the statewide Measurement and Verification Evaluator for program year 2020.

Table 11 provides the actual verified savings for EPE's New Mexico EE/LM programs for 2015 to 2020 and provides anticipated savings for 2021 to 2024. The projected savings are based on EPE's Plan approved by Final Order in NMPRC Case

No. 18-00116-UT. The gross megawatt ("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 11. New Mexico Verified and Projected Participation, Impacts, and Budget for EE/LM 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♦	165,050	2.501	12,729	$2,942,309	$1,508,575	$4,450,884
2018♦	163,177	3.664	17,217	$3,183,759	$1,882,557	$5,066,315
2019♦	210,695	4.892	16,549	$3,149,722	$1,966,960	$5,116,681
2020	66,303	7.032	22,166	$3,156,200	$1,765,885	$4,922,085
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. 50806, EPE's annual demand reduction goal for 2020 was 11.16 MW and its energy savings goal was 19,552 MWh. EPE achieved a demand reduction of 20.74 MW, which exceeded the demand goal by 85.84%, and an energy reduction of 30,670 MWh, which exceeded the energy goal by 56.86%. Currently, EPE offers five residential and three commercial EE programs in its Texas service territory.

Table 12 provides the actual verified demand and energy savings for EPE's Texas EE programs for 2015 through 2020 and provides the projections for 2021 and 2022. The 2021 and 2022 projections are based on the information provided in EPE's 2021 Energy Efficiency Plan and Report, PUCT Project No. 51672.

Table 12. 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♦	16.846	20,726
2019♦	14.181	21,054
2020♦	20.743	30,670
2021	16.691	23,479
2022	19.827	26,882

♦ Verified by Commission approved statewide EM&V contractor

4. Texas Residential and Commercial Load Management Programs

EPE's Residential and Commercial Load Management Programs engage utility customers to reduce their electricity use (load) during peak hours or under certain conditions, which in turn, can substantially reduce demand for electricity during EPE's peak hours, providing aggregate benefits for the electric grid and-participants themselves.

The load management season begins on June 1 and continues through September 30 each year.

D. Energy Storage Resources

The Commission Final Order in Case No. 19-00348-UT denied EPE’s requested approval of a stand-alone 50 MW battery selected pursuant the 2017 All-Source RFP; and EPE's resource portfolio does not contain any existing utility scale energy storage resources[3]. However, in 2022, EPE plans to install a 100 MW Solar facility coupled with 50 MW battery storage which was approved in that docket. The integrated solar/storage system will firm solar output during specified peak hours of operation. The planned battery storage system will charge during low load hours and discharge the stored energy during peak hours to provide firm energy during peak hours. Battery storage is a relatively new and emerging technology that is continually being integrated into utility scale applications to provide greater flexibility to the electrical system allowing for greater integration of solar and/or wind resources.

[3] EPE does own a 1 MW battery storage system coupled with the 3 MW Aggie Power project located at NMSU.

Besides “firming” solar generation, battery storage can also help to balance electricity loads to avoid energy “curtailment” by shifting excess energy from low load hours to peak hours. Further, battery storage provides greater resilience to the system by providing backup power during an electrical disruption due to a generation resource contingency or in the case of a solar PV facility, a brief generation disruption from an intermittent weather condition such as passing clouds. Battery storage is a resource that EPE modeled in this 2021 IRP and will continue to model for future resource needs. Other types of energy storage include pumped-storage, hydropower, electromechanical storage, thermal energy storage, flywheel storage, and compressed air storage. These other types of technologies were not modeled in EPE’s 2021 IRP because these storage technologies, as compared to battery storage, are not yet cost effective and/or may not be suitable for the desert southwest conditions.

E. Reserve Margin and Reliability Requirements

1. Reliability Requirements

EPE's resource planning efforts consider the reliability requirements of 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.[4] 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."

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."

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

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, 17.9.560.13 (C) NMAC 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 year-round resource adequacy to their firm customers with reasonable reliability. 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 planning reserve margin (“PRM”). 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, and EPE has been utilizing that reserve margin since then. As part of this IRP, EPE requested that E3 reassess its PRM requirements, and that analysis is described later in this report.

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

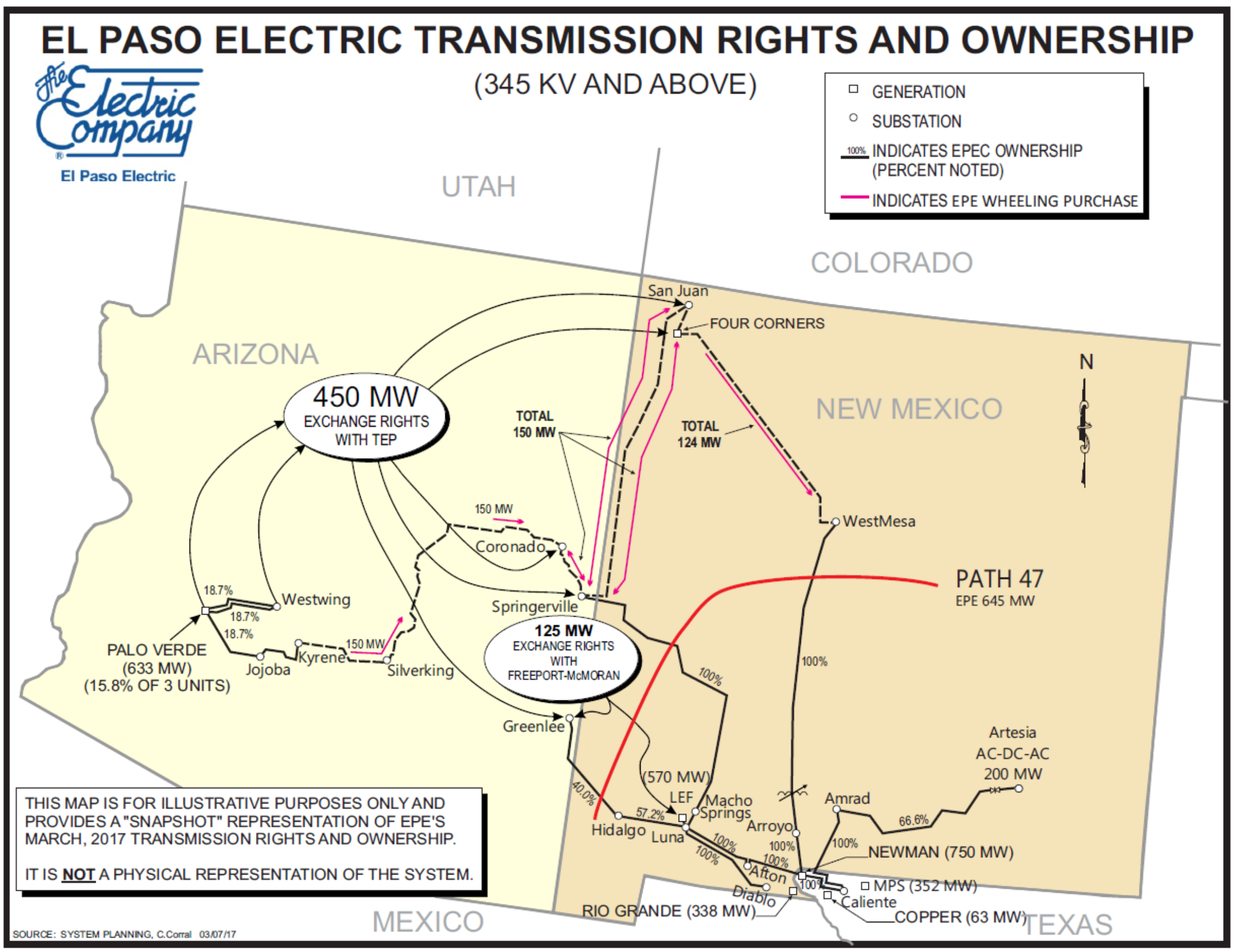
EPE connects with SPS at the Eddy County HVDC Terminal near Artesia, New Mexico and has a 67% ownership in the Terminal and accompanying 345 kV transmission line connecting to the EPE system along with the joint owner, PNM. Through this HVDC Terminal, EPE can access resources, when available, in the Southwest Power Pool ("SPP") for delivery to EPE loads. Additionally, Empire substation is a new 345kV substation built along the Amrad—Eddy line, approximately 1 mile west of the HVDC Eddy substation. The Empire substation was built to allow for the interconnection of the Oso Grande Wind Farm. Improvements on the Amrad-Empire 345kV and the Empire-Eddy 345 kV lines allowed for an increase in its transmission capacity rating. The new line ratings are 400 MVA.

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, and 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. Figure 8 shows a map of EPE's EHV Transmission system.

Figure 8 – EPE Transmission Rights and Ownership



Segments Which Comprise the EPE Extra High Voltage Transmission System

1. Energy Imbalance Market

EPE has elected to join the Western EIM with an implementation date of April 01, 2023. 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.

Therefore, EPE's decision to join the EIM still necessitates EPE, to continue with its Planning Process to plan for adequate resources to meet EPE's load requirements.

2. 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:

<u>Transmission Services Purchased by EPE from PNM</u>

EPE has a transmission service agreement under PNM's Open Access Transmission Tariff ("PNM OATT") for 104 MW firm, point-to-point transmission from Four Corners Power Plant ("FCPP") 345 kV Switchyard to West Mesa 345 kV Switching Station from July 1, 2017 to July 1, 2022 and is currently working on an extension agreement to roll over through July 1, 2027. 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, 2019 to May 31, 2024. 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.

3. 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 216 miles of 69 kV transmission lines, 522 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 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 OATT. A summary of this plan is posted on EPE's web site.

4. 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 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 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.

5. 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 using 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 allows 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.

6. 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.

7. 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 BPS Planning Roles Task Force ("BPSPRTF"), the Loads and Resources Task Force ("LRTF"), the Joint Synchronized Information Subcommittee ("JSIS"), the Modeling and Validation Subcommittee ("MVS"), the Production Cost Data Subcommittee ("PCDS"), the Production Cost Modeling Subcommittee ("PCMS"), the System Review Subcommittee ("SRS"), and the Studies Subcommittee ("StS"). In addition, EPE is a member of the General Electric Positive Sequence Load Flow ("PSLF") Users Group, the regional transmission planning group WestConnect, and the Southwest Area Transmission ("SWAT") Subregional Planning Group.

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 Arizona, part of California, Colorado, part of Montana, part of Nebraska, New Mexico, Nevada, part of South Dakota, and part of Wyoming.

8. 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 and EOP-011 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.

<u>Conclusion and Discussion</u>

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.

G. Back-Up Fuel Capabilities and Options

Presently EPE has three primary resource types, nuclear, gas, and solar energy resources. The Newman and Montana Power Stations have dual gas pipeline interconnections providing added reliability and mitigating the potential for gas fuel supply disruption. The four Montana Power Station units are also dual fuel capable with the ability to utilize diesel fuel oil in case of gas fuel supply disruption. In 2022, EPE will increase its solar energy capacity as well as introduce a 50 MW battery storage resource, further increasing its diversity. Table 7 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."

EPE’s resource diversity in terms of resource type, dual pipeline access, and alternate diesel fuel oil capabilities allowed EPE to meet customer demand needs during an unprecedented winter storm the week of February 14th, 2021. The winter storm plunged the state of Texas into subfreezing temperatures causing massive power outages overwhelming the state’s electricity infrastructure. The winter storm caused disruptions to the region’s natural gas fuel supply causing overlapping declaration of critical operation conditions to both its Interstate and Intrastate natural gas pipelines. To retain the integrity and reliability of its system after experiencing a loss of its natural gas supply, EPE switched all the Montana units to fuel oil during the week of the winter storm. EPE was also able to save customers millions of dollars in fuel costs by burning fuel oil instead of procuring additional natural gas supply in the day-ahead market.

IV. CURRENT LOAD FORECAST

A. Forecast Summary

The 2021 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 2021-2040 (see Attachment B-1). The 2021 expected (base) forecast predicts 10- and 20-year compound annual growth rates ("CAGR") of 1.1% and 1.5% for native system energy, respectively. The 2021 expected forecast predicts 10- and 20-year CAGR of 0.9% and 1.7%, 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 the17.7.3.9 (D) NMAC.

B. Load Forecast Methodology and Inputs

EPE's 2021 Load Forecast is developed from several 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, load management, light-duty electric vehicle adoption, saturation of refrigerated air conditioning, potential changes in customers, and changes in consumption patterns resulting from COVID-19.

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, gross metropolitan product (GMP), and weather are typical drivers of electricity sales; more customers and increased GMP, which represents an increased production of goods and services in the region, will typically result in higher electricity demand. The primary data sources for EPE's econometric models are IHS Markit, AccuWeather, and EPE's customers' historical usage/load data. IHS Markit provides the underlying assumptions of the economic and demographic data that are used in developing EPE's forecasted energy and peak demand. AccuWeather provides EPE with regional weather Cooling Degree Days (CDD) and Heating Degree Days (HDD) used in weather normalizing historical sales and producing "normal" weather values for the forecast period. AccuWeather's data comes from the National Oceanic and Atmospheric Administration (NOAA) sites in El Paso and Las Cruces and have been adjusted for missing values and other anomalies via AccuWeather. EPE also uses the historical usage/load data for each of its major customer classes.

The 2021 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.

Residential class sales are estimated using a use per customer ("UPC") methodology. The estimated UPC is then multiplied by the customer forecast to arrive at total kWh forecast for this customer class. The energy forecasts for small commercial & industrial, large commercial & industrial, street lighting, 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 conversion from traditional streetlights to more efficient LED lights that the cities of El Paso and Las Cruces undertook caused a significant change in the historical dataset for the Street Lighting classes which make econometric modeling of these classes difficult. As a result, the energy forecasts for the Texas and New Mexico Street Lighting class are calculated using forecasted growth for total households in each city.

Customer forecast equations are also estimated for each of the customer classes using econometric models, except for the large commercial & industrial and street lighting classes. The number of large commercial & industrial and street lighting 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 2020 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 2021 Load Forecast include changes in load for distributed solar generation, energy efficiency, and light-duty electric vehicles.

The econometric sales forecasts are adjusted to reflect the effects of energy efficiency, distributed solar generation, and light-duty electric vehicles that are otherwise not represented in the historical database. Energy efficiency effects include the results of EPE-sponsored energy efficiency and load management programs that are required in its Texas and New Mexico jurisdictions. The distributed generation effects accounts for customer owned solar generation in the residential, small commercial & industrial, and government customer classes. The light-duty electric vehicle adjustments include forecasted incremental load from electric vehicle adoption in EPE's service territory. The estimates for energy impacts from efficiency energy savings, distributed generation, and light-duty electric vehicle 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 prior to any adjustments, sales to RGEC, and company use, to calculate 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, distributed solar generation, and light-duty electric vehicle 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 2021 Load Forecast assumes that 10-year average weather conditions (2011-2020) exist throughout the forecast period (2021-2040). 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 using 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 EE/LM 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, using historical data, EPE's models and forecasted estimates of energy and demand do indirectly account for organic demand-side management.

E. Distributed Generation

EPE forecasts 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 (2021-2040) 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 include 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 49 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. Light-Duty Electric Vehicles

EPE light-duty electric vehicle projections for energy sales and demand impacts are calculated for a 20-year period by jurisdiction and only impact the residential customer class. Estimates indicate a single light-duty vehicle can consume an average of 3,870 kWh per year, equivalent to half of the average annual energy consumption of a residential household. Demand impact can vary widely depending on the type of charger, creating demand spikes between 1.2 and 19.2kW per vehicle. The forecast assumes an average demand impact of 7.2 kW per vehicle to estimate future demand impacts.

In addition to the light-duty electric vehicle forecast, EPE also forecasts load requirements for medium and heavy-duty electric vehicles, however, only the light-duty vehicle forecast was included in the current long-term forecast because their load is more present and growth trends are clearer than the other vehicle categories over the forecast period.

G. Load Forecast Scenarios

In addition to the expected (base) estimates, the 2021 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 B-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 2021 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 9 and 10 contain a graphical representation of the low and high forecast scenarios of native system energy and native system peak demand.

Figure 9 – Native System Energy Forecast Scenario Comparison

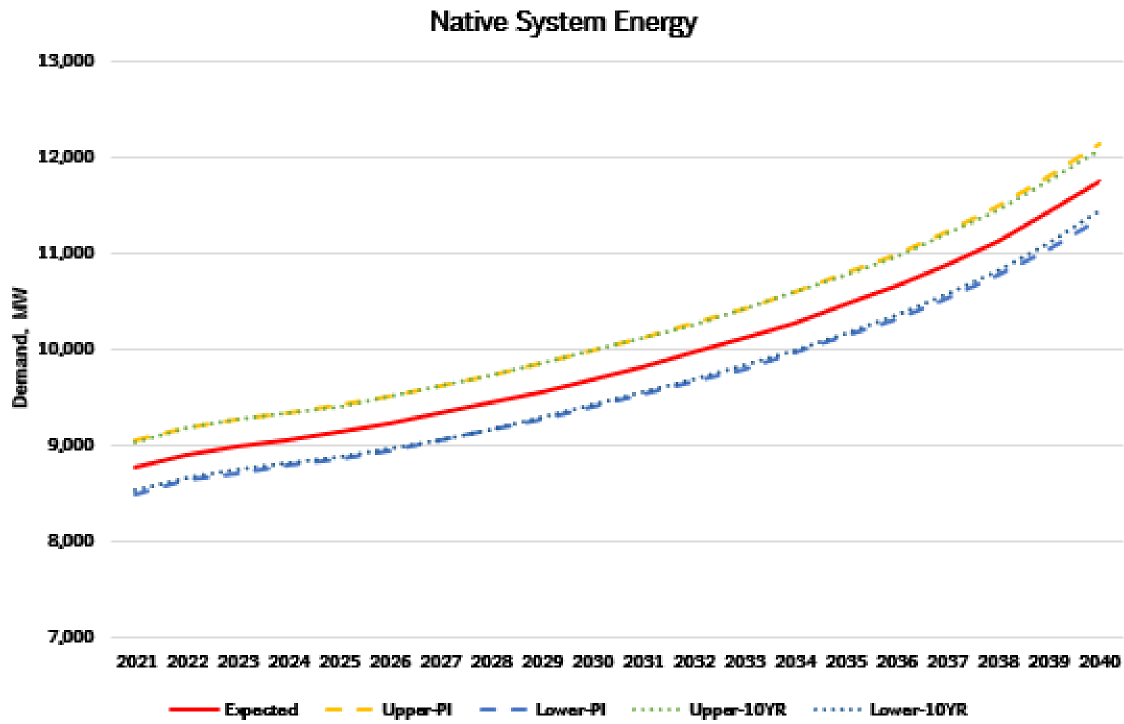
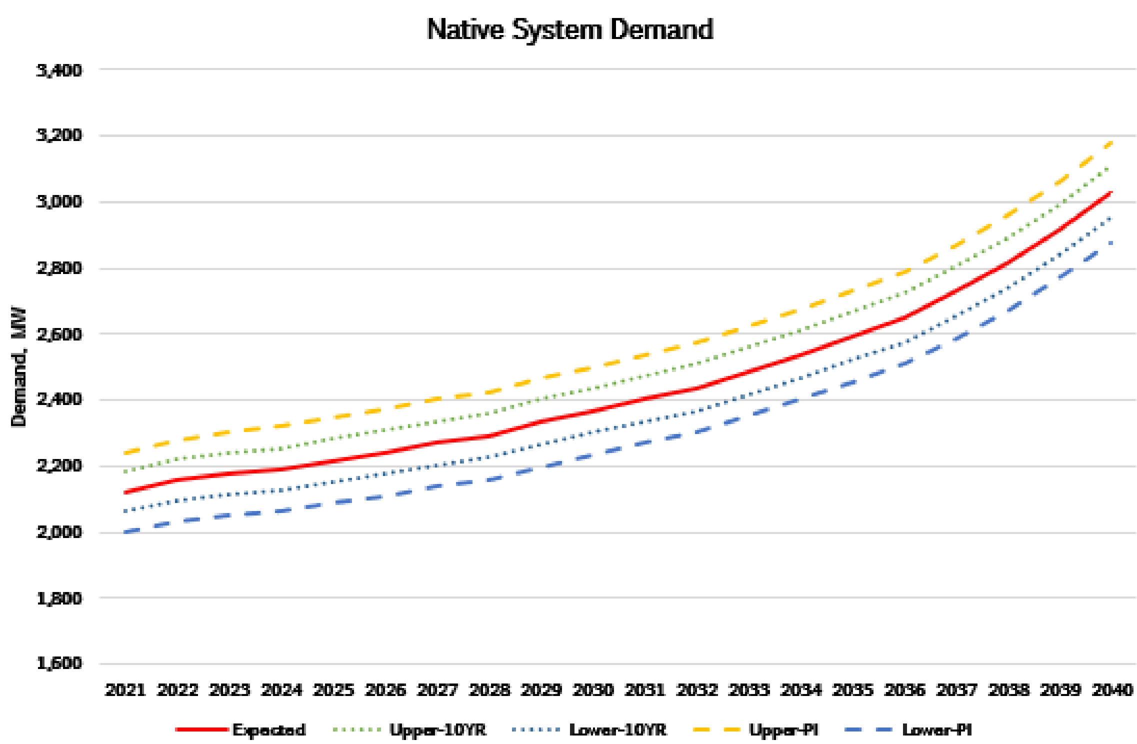


Figure 10– Native System Peak Demand Forecast Scenario Comparison



From Figures 9 and 10 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 1.1% and 1.5% for native system energy, respectively. The expected forecast also predicts 10- and 20-year CAGR of 0.9% and 1.7%, respectively, for native system peak demand. The upper forecast scenario predicts 10- and 20-year CAGR of 1.4% and 1.7% for native system energy, respectively. The upper forecast also predicts 10- and 20-year CAGR of 1.2% and 1.8%, respectively, for native system peak demand. The lower forecast scenario predicts 10- and 20-year CAGR of 0.8% and 1.4% for native system energy, respectively. The lower forecast scenario predicts 10- and 20-year CAGR 0.6% and 1.5%, respectively, for native system peak demand.

H. Historical Forecast Accuracy and Comparison

Tables 13 and 14 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 five years preceding 2021, (2015-2020). Please note that the energy data in Table 13 is total energy sales, which is composed of energy sales "at meter" for both retail and wholesale customers.

Table 13 - Total Sales (MWh) Historical Forecast Accuracy

Total Sales (MWH)						
	2015	**2016**	**2017**	**2018**	**2019**	**2020**
Actual	**7,867,229**	**7,874,577**	**7,906,846**	**8,093,667**	**8,063,475**	**8,162,678**
2016 Forecast		7,956,182	8,078,403	8,210,150	8,324,909	8,454,899
2017 Forecast			7,967,828	8,034,627	8,092,888	8,166,668
2018 Forecast				7,958,254	8,040,954	8,117,977
2019 Forecast					8,187,471	8,272,764
2020 Forecast						8,105,289

Percent Difference						
2016 Forecast		1.04%	2.17%	1.44%	3.24%	3.58%
2017 Forecast			0.77%	-0.73%	0.36%	0.05%
2018 Forecast				-1.67%	-0.28%	-0.55%
2019 Forecast					1.54%	1.35%
2020 Forecast						-0.70%

Table 14 - Native System Demand (MW) Historical Forecast Accuracy

Native System Demand (MW)						
	2015	**2016**	**2017**	**2018**	**2019**	**2020***
Actual	**1,794**	**1,892**	**1,935**	**1,929**	**1,985**	**2,173**
2016 Forecast		1,811	1,846	1,878	1,907	1,933
2017 Forecast			1,927	1,946	1,963	1,978
2018 Forecast				1,964	1,988	2,005
2019 Forecast					1,972	1,989
2020 Forecast						2,015

Percent Difference						
2016 Forecast		-4.29%	-4.60%	-2.63%	-3.93%	-11.04%
2017 Forecast			-0.43%	0.87%	-1.11%	-8.96%
2018 Forecast				1.82%	0.15%	-7.72%
2019 Forecast					-0.65%	-8.48%
2020 Forecast						-8.19%

* Note: The difference between the forecasted native system peak for 2020 and the actual 2020 native system peak are due to changes in consumption pattern resulting from COVID-19 and extreme summer weather, which led to a record native system demand growth of 188 MW.

Table 15 contains a comparison of the annual forecast of energy sales and system peak demand in EPE's most recently filed resource plan (2018) to the annual forecasts in the current resource plan (2021).

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Table 15. Annual Forecast Energy Sales Versus Peak Demand

Total Energy Sales Forecast Comparison (MWh)		
	2018 Forecast	2021 Forecast
2018	7,958,254	
2019	8,040,954	
2020	8,117,977	
2021	8,197,532	8,192,517
2022	8,293,704	8,316,878
2023	8,394,406	8,395,619
2024	8,492,212	8,460,016
2025	8,592,592	8,528,249
2026	8,699,571	8,611,976
2027	8,810,080	8,709,868
2028	8,920,613	8,812,014
2029	9,039,504	8,924,130
2030	9,169,955	9,046,082
2031	9,294,405	9,171,235
2032	9,428,932	9,299,848
2033	9,572,253	9,441,968
2034	9,722,605	9,598,635
2035	9,875,965	9,769,099
2036	10,035,608	9,953,933
2037	10,203,914	10,158,865
2038		10,390,825
2039		10,656,933
2040		10,974,528

Peak Demand Forecast Comparison (MW)		
	2018 Forecast	2021 Forecast
2018	1,964	
2019	1,988	
2020	2,005	
2021	2,034	2,121
2022	2,061	2,155
2023	2,090	2,177
2024	2,111	2,190
2025	2,146	2,216
2026	2,176	2,240
2027	2,206	2,269
2028	2,231	2,292
2029	2,270	2,331
2030	2,306	2,367
2031	2,340	2,404
2032	2,370	2,436
2033	2,416	2,488
2034	2,456	2,538
2035	2,498	2,593
2036	2,533	2,648
2037	2,586	2,728
2038		2,813
2039		2,913
2040		3,028

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 system load growth. The Forecasted loads are based on the 2021 Load Forecast for the L&R and is shown in Figure 11.

Figure 11. Initial L&R

El Paso Electric Company
Loads & Resources 2021-2040
Initial 2021 IRP

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1.0 GENERATION RESOURCES																				
1.1 RIO GRANDE	323	278	232	232	232	232	232	232	232	232	232	232	232	88	88	88	88	88	88	88
1.2 NEWMAN	729	729	811	811	811	811	494	494	494	494	494	494	494	494	494	494	494	494	494	494
1.3 COPPER	63	63	63	63	63	63	63	63	63	63	-	-	-	-	-	-	-	-	-	-
1.4 MONTANA	352	352	352	352	352	352	352	352	352	352	352	352	352	352	352	352	352	352	352	352
1.5 PALO VERDE	622	622	622	622	622	622	622	622	622	622	622	622	622	622	622	622	622	622	622	622
1.6 RENEWABLES	6	6	6	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
1.7 STORAGE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1.8 POSSIBLE EMERGING TECHNOLOGY EXPANSION	-	-	-	-	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
1.9 INTERRUPTIBLE	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56
1.10 LINE LOSSES FROM OTHERS	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
1.0 TOTAL GENERATION RESOURCES	**2,158**	**2,113**	**2,149**	**2,149**	**2,189**	**2,189**	**1,872**	**1,872**	**1,872**	**1,872**	**1,809**	**1,809**	**1,809**	**1,665**	**1,665**	**1,665**	**1,665**	**1,665**	**1,665**	**1,665**
2.0 RESOURCE PURCHASES																				
2.1 RENEWABLE PURCHASE	73	72	72	72	71	71	70	70	69	69	69	56	55	55	23	22	20	6	6	6
2.2 NEW RENEWABLE PURCHASE	-	43	42	42	42	42	41	41	41	41	41	40	40	40	40	40	39	39	39	39
2.3 NEW RENEWABLE/ BATTERY PURCHASE	-	75	75	74	74	74	73	73	72	72	72	71	71	71	70	70	70	69	69	69
2.4 NEW BATTERY PURCHASE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2.5 MARKET RESOURCE PURCHASE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2.0 TOTAL RESOURCE PURCHASES	**73**	**190**	**189**	**188**	**187**	**186**	**185**	**184**	**183**	**182**	**181**	**167**	**166**	**166**	**133**	**132**	**128**	**115**	**114**	**114**
3.0 FUTURE RESOURCES																				
3.1 RENEWABLE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3.2 RENEWABLE/STORAGE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3.3 GAS GENERATION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3.0 TOTAL RESOURCE PURCHASES	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
4.0 TOTAL NET RESOURCES (1.0 + 2.0 + 3.0)	**2,231**	**2,303**	**2,338**	**2,337**	**2,376**	**2,375**	**2,057**	**2,056**	**2,055**	**2,054**	**1,990**	**1,976**	**1,976**	**1,831**	**1,798**	**1,797**	**1,794**	**1,780**	**1,779**	**1,779**
5.0 SYSTEM DEMAND																				
5.1 NATIVE SYSTEM DEMAND	**2,139**	**2,190**	**2,228**	**2,256**	**2,297**	**2,337**	**2,380**	**2,418**	**2,473**	**2,524**	**2,576**	**2,623**	**2,690**	**2,754**	**2,825**	**2,895**	**2,990**	**3,089**	**3,204**	**3,334**
5.2 DISTRIBUTED GENERATION	(9)	(19)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)
5.3 ENERGY EFFICIENCY	(8)	(15)	(23)	(31)	(38)	(46)	(54)	(62)	(69)	(77)	(85)	(92)	(100)	(108)	(115)	(123)	(131)	(138)	(146)	(154)
6.0 TOTAL SYSTEM DEMAND (5.1 + 5.2 + 5.3)	**2,122**	**2,156**	**2,183**	**2,203**	**2,237**	**2,269**	**2,304**	**2,335**	**2,382**	**2,425**	**2,470**	**2,509**	**2,568**	**2,625**	**2,688**	**2,750**	**2,837**	**2,928**	**3,036**	**3,158**
7.0 MARGIN OVER TOTAL DEMAND (4.0 - 6.0)	**109**	**147**	**156**	**134**	**139**	**106**	**(247)**	**(279)**	**(326)**	**(371)**	**(479)**	**(533)**	**(592)**	**(794)**	**(890)**	**(953)**	**(1,043)**	**(1,149)**	**(1,257)**	**(1,379)**
8.0 PLANNING RESERVE 15% OF TOTAL DEMAND	**318**	**323**	**327**	**330**	**336**	**340**	**346**	**350**	**357**	**364**	**370**	**376**	**385**	**394**	**403**	**413**	**426**	**439**	**455**	**474**
9.0 MARGIN OVER RESERVE (7.0 - 8.0)	**(209)**	**(176)**	**(172)**	**(196)**	**(196)**	**(234)**	**(593)**	**(629)**	**(684)**	**(734)**	**(850)**	**(909)**	**(977)**	**(1,188)**	**(1,293)**	**(1,366)**	**(1,469)**	**(1,588)**	**(1,712)**	**(1,853)**

1. Generation unit retirements are consistent with the 2018 IRP.
2. Existing EPE owned solar renewables at 70 percent contribution to peak.
3. Emerging technologies may include customer or other distributed resources as well as additional community solar.
4. Interruptible customer capacity shifted to the resource side of the L&R. Capacity MW contribution per 2021 Load Forecast.
5. Line losses from others shifted to resource side of the L&R and is the typical amount of repayment of transmission wheeling losses from transmission customers with in-kind energy during peak hours.
6. Existing renewable solar PPAs at 70 percent contribution to peak.
7. New renewable solar PPAs at 25 percent contribution to peak.
8. New solar and battery storage PPAs with solar at 25 percent contribution to peak.
9. System demand is based on the 2020 Long-Term Forecast dated April 1, 2021.
10. Native System Demand includes EV load.

Unit Retirements

Rio Grande 6 (45MW) - December 2021 (2014)
Rio Grande 7 (46MW) - December 2022
Newman 1 (73MW) - December 2022
Newman 2 (73MW) - December 2022
Newman 3 (90MW) - December 2026
Newman 4 CC (227MW) - December 2026
Copper (63MW) - December 2030
Rio Grande 8 (144MW) - December 2033

Renewable Purchases

Line 2.1 includes SunEdison, NRG, Macho Springs, Juwi, and Hatch solar purchases (70% availability at Peak)

New Renewable Purchase

Line 2.2 includes system solar resource 100 MW Solar (25 at Peak) and NM RPS solar resource 70 MW in 2022 (18 MW 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

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. Supply side resources modeled in this 2021 IRP includes: Solar PV, Wind, Biomass, Geothermal, Battery, Combined Cycle and Gas Peaker. Gas-fired combustion turbines are assumed to be Hydrogen fuel capable. Given EPE's existing resource portfolio and clean energy targets, no coal generation and/or new nuclear generation was modeled. Additionally, given EPE's geographical location, hydro resources were also not considered in this IRP. The input assumptions for resource options are given in Appendix A with sources for the Technology Cost, Financing, and Transmission given in Appendix B.

1. Solar Photovoltaic Resource Option

EPE included utility scale solar PV resource option for model analysis. The amount of solar PV option that was selected by the model was based on minimizing cost while achieving clean energy targets and maintaining reliability. A generic hourly generation profile based on EPE's existing solar PV facilities was utilized to model the operational characteristics of the 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 create 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.

2. Wind Resource Options

EPE utilized an hourly generation profile from National Renewable Energy Laboratory (“NREL”) 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.

3. Biomass Resource

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. For the 2021 IRP EPE modeled a generic Biomass resource.

4. 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 generic geothermal resource for this IRP.

5. Gas- Fired Thermal Power Plant Option

Gas-Fired Thermal power plants have had widespread use since the 1940s. Gas-Fired Thermal power plants can include: Combustion Turbine ("CT"), Combined Cycle ("CC"), and Reciprocating Engine ("Recip") type power plants. Modern Gas-Fired power plants have advanced due to technology improvements resulting in lower capital cost, enhanced efficiency, lower water usage, and added capability to convert to hydrogen fuel to meet future statutory zero carbon goals and to provide firm dispatchable capacity. Also, modern CTs' and Recips' have flexible fast start ramping capabilities which increases the flexibility and resilience of the electrical system needed for greater integration of renewable resources. For this 2021 IRP, EPE modeled the CT and the Recip engine as a single generic hydrogen fuel capable Gas Peaker since both types of gas-fired units have similar characteristics.

6. Hydrogen Fuel in Gas Turbines

As the power utility sector shifts toward decarbonization, utilizing hydrogen fuel in gas turbines has become a potential option for utilities. Most gas turbines burn natural gas or methane to release energy which ultimately produces the electricity we use at home and for industry. An advantage of gas turbines is that they can operate on many other fuels besides natural gas. Some of these fuels, such as hydrogen, do not contain carbon in the first place, and will therefore not emit carbon dioxide when combusted. Furthermore, hydrogen can be introduced to new gas turbines and existing gas turbines alike, reinforcing the concept that solutions are available today to decarbonize assets already in the field and those waiting to be installed. Natural gas turbines can be fully converted or partially converted to utilize hydrogen as a fuel. Using 100% hydrogen fuel for a gas turbine will lead to a significant reduction in carbon dioxide emissions relative to operation on natural gas or other hydrocarbon fuels. As a near-term alternative, partial conversions are being considered rather than using 100% hydrogen fuel. For example, hydrogen blending with natural gas is being considered to reduce carbon dioxide emissions. In the case of hydrogen blending, the amount of carbon dioxide reduction will be a function of the percentage of hydrogen in the fuel.

Although hydrogen is a promising fuel alternative to reduce carbon dioxide, it is currently not the preferred choice for many utilities since needed storage and transportation infrastructure for the hydrogen fuel is not yet widely available. Furthermore, electrolysis and steam reforming from natural gas, which are the two main processes of hydrogen extraction, are relatively expensive and not yet cost effective. Another reason why hydrogen is not widely used today is due to its storage complications. Since hydrogen has a lower density, it must be compressed and stored at lower temperatures to guarantee its effectiveness and efficiency as an energy source. From a safety perspective, hydrogen gas at high concentrations is highly flammable and volatile and requires equipment upgrades to minimize risk.

B. Energy Storage

BATTERY RESOURCE OPTION

Energy Storage, specifically Lithium-Ion Battery Storage, is an accredited energy storage technology that allows for greater integration of renewable resources. 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 and wind, by charging during low load hours and firming up capacity during peak conditions offsetting the inherent variable and intermittent characteristics of renewable resources. The capital cost of batteries has continued to trend downward 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, MW, is the maximum amount of power the battery can discharge at a given moment. Secondly, battery duration is the length of time (typically in hours) that the storage system can provide output to the electrical grid system. Lastly, energy capacity, MWh, is the total amount of energy the battery can store and is typically the nameplate capacity times the hours of duration. For example, a 50 MW nameplate battery with a four-hour duration would have a total energy level available for dispatch of 200 MWh. The battery Storage resource modeled in the 2021 IRP is a generic battery.

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.

C. Demand Side Resources

ENERGY EFFICIENCY RESOURCE OPTION

In addition to EPE's current EE–programs, EPE opted to model a high EE case without identifying specific programs, but rather to assess portfolio impact. For the reference case, EPE modeled 6.5% of native system load in 2040 based on the EPE 2021 Energy and Demand Forecast. For the high EE sensitivity case, EPE doubled the incremental amount from the reference case resulting in 13% of native system load in 2040. These amounts are consistent with neighboring utility Arizona Public Service ("APS") 2020 IRP filing which includes approximately 15% EE on an energy basis.

DEMAND RESPONSE RESOURCE OPTION

EPE also includes Load Management ("LM") Programs as a resource option. When considering LM as a resource, it is important to understand that events are limited and subject to customer acceptance. When a LM 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 LM 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 reviewed the EPE 2019 Residential Appliance Saturation Survey ("RASS") for viable Demand Response programs based on appliance saturation rates and on benchmarking of neighboring utilities. EPE identified the Smart Thermostat Program as the option with greatest potential with a Refrigerated Air saturation rate of 50.9% within the EPE territory. For 2021 IRP, EPE modeled 50MW by 2040 for the reference case and 60 MW by 2040 for the high DR sensitivity case. These DR amounts are comparable to the regional utility, PNM, which in a 2017 potential study found that demand response potential in the range of 60 MW to 80 MW was available, (PNM 2017-2036 IRP Plan).

To identify future DSM programs, EPE is planning to work with a third party to conduct a Potential study as a follow up to the 2021 IRP. EPE will be looking to include the following three elements in the study:

- Potential – How much DSM is there within the EPE territory?
- Economic – What is economically feasible?
- Achievable- Given real world conditions, how much is achievable?

RATES AND TARIFFS THAT INCORPORATE LOAD MANAGEMENT CONCEPTS

17.7.3.9.F(3) NMAC 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 monthly, 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-day ("TOD") 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.

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. On April 19, 2021, EPE filed its Automated Metering System ("AMS") plan in Texas Docket No. 52040-*Application of El Paso Electric Company for Advanced Metering System (AMS) Deployment Plan, AMS Surcharge, and Non-Standard Metering Service Fees.* EPE plans to file its grid modernization plan this year that will include EPE's AMS for New Mexico.

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.

TOD Rates – In EPE's most recent rate case, Case No. 20-00104-UT, EPE proposed expanding the number of classes with available TOD rate options. Rate classes with a TOD rate options are the Residential Service, Small General Service, General Service, Irrigation Service, City County Service, and Water, Sewage and Storm Sewage Pumping Service Rates. The standard Large Power Service, Military Research & Development and State University Service rates are TOD rates. Additionally, TOD rates are mandatory for new customers requesting service under; (1) Water, Sewage and Storm Sewage Pumping Service class; and (2) the General Service class if a customer's maximum demand is expected to be 400 kW or greater. TOD 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. TOD 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 load management option for residential and large commercial customers through its EE/LM programs, which is discussed in more detail above.

EPE's current rates were implemented pursuant to the Final Order in NMPRC Case No. 20-00104-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.

Customer and System Benefits

TOD 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 TOD 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 TOD 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 TOD 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 TOD 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.

Table 16 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 16. Rate Structure Development

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

The solid black line indicates the point at which the mandatory rate structure for the class would include TOD energy charges (the TOD line). Generally, large industrial, military, and irrigation and pumping customers already have mandatory TOD 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 TOD and dynamic pricing options.

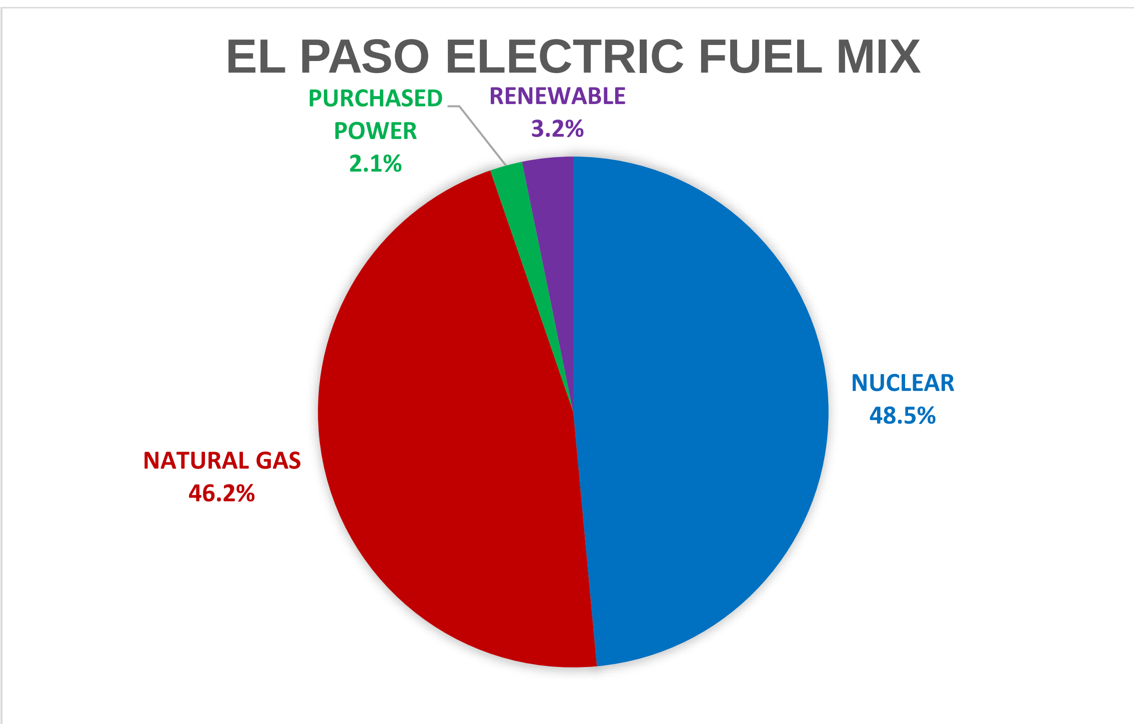
EPE's assessment of the impact of rate differentials and rate structures is that the net effect of rate structures changes, participation rates driven by mandatory requirements, and dynamic pricing following AMI implementation would not exceed the lower band confidence interval of future native system demand and energy (Figures 9 and 10). 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 is comparable to avoided cost of the relevant resource alternative.

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 2020, the most recently completed calendar year, is based on MWh generation as shown in Figure 12.

Figure 12. EPE 2020 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 its local Montana Power Station. 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

A. TRANSMISSION CONSTRAINTS FOR MOST COST-EFFECTIVE RESOURCE PORTFOLIO

Transmission considerations are an essential part of the task of identifying a cost-effective resource portfolio, especially when considering resources located beyond the areas in which EPE's load resides. First, it is important to identify the potential for EPE to import resources that can reach EPE's load. As documented in EPE's prior IRPs, available wind resource options are located in specific geographical areas. Such areas are not within the central core where the bulk of EPE's load resides. The same is true for potentially available geothermal resource options. Solar on the other hand, is somewhat different. EPE has identified a significant amount of potentially available solar resource capacity near the fringes of where the bulk of EPE's load resides on its system. Anticipated solar facilities in the capacities being considered as potentially available for future portfolios are expected to be located on the periphery of EPE's Las Cruces and El Paso load pockets. With respect to battery storage as well as gas generation resources, these types of resources are potentially available near to EPE's load. They tend to require less land and may be more readily sited closer to load. The central load pocket and peripheral areas to the local system are shown in Figure 13.

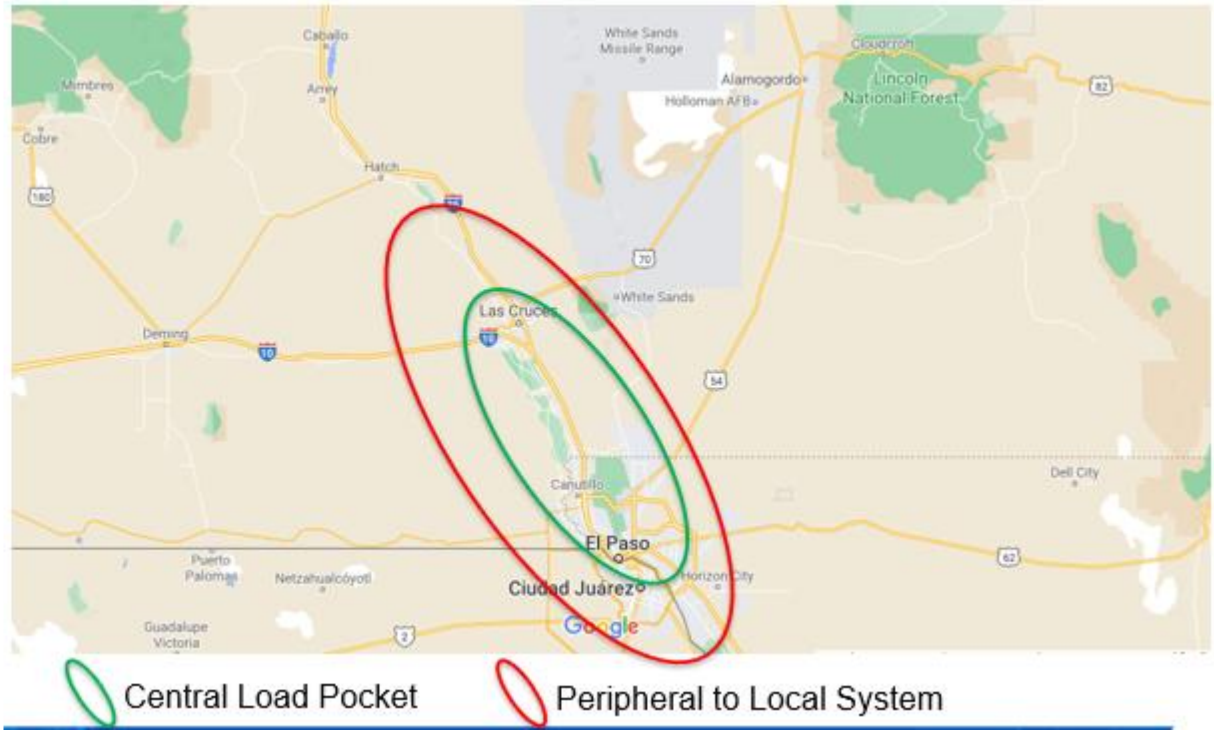
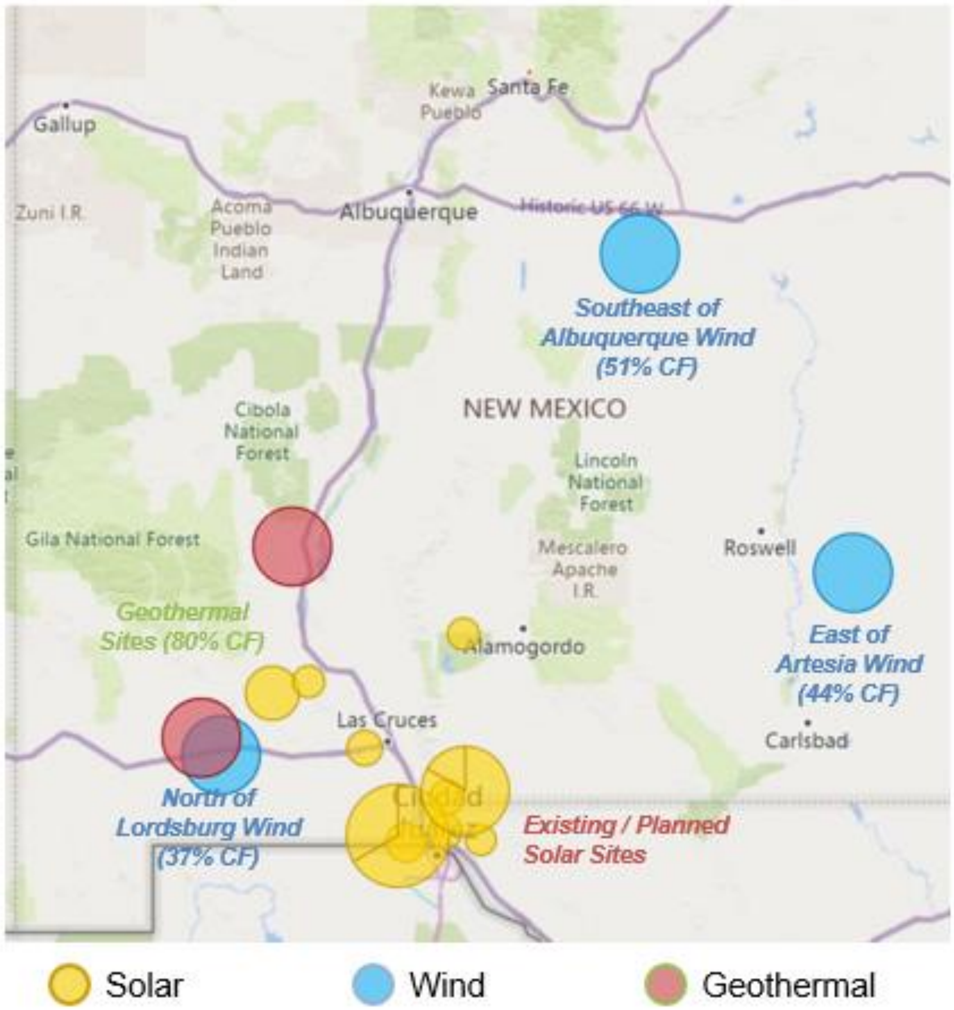


Figure 13. EPE Local and Peripheral Areas for New Renewable Resources

EPE utilized NREL renewable resource potential maps to identify geographical sites closest to EPE's system for potential wind and geothermal resources. The approximate location of the geographical sites was previously shown in Figure 1 above and for proper context, is shown here again as Figure 14. Transmission upgrade costs between the resource locations and EPE's load pockets were then considered as costs associated with those resource options.

Figure 14. EPE Renewable Resource Geographical Locations



Second, it is important to consider the impact on reliability of displacement of gas generation on its system by increased inverter-based renewable and storage resource options. EPE has evaluated and identified, for year 2030 and year 2038, system reliability impacts on EPE's service territory that would result from increased integration of renewable resources on EPE's system. Increased renewable generation was assumed to partially replace existing EPE-owned thermal generation as a percentage of EPE's overall resource mix. The assessment included steady state and transient stability analyses under various generation dispatch scenarios minimizing the dispatch of gas resources to identify voltage constraints and system stability after faulted conditions and line contingencies. EPE also conducted a short circuit ratio (SCR) analysis to identify the potential that breakers would exceed their duties resulting from the displacement of gas generation by increased integration of inverter-based and storage resource options on EPE's system. The analyses included steady state, transient stability, and reactive margin (V-Q) analyses to identify potential criteria violations for pre- and post-contingency conditions.

EPE's evaluation produced the following observations:

- Voltage stability was an issue. Voltage exceedances occurred on the higher voltage transmission lines in EPE's service territory in study year 2030, as well as in study year 2038. It is likely that reactive support devices, such as static VAR compensators (SVCs), static compensators (STATCOMs), synchronous condensers, and/or additional local generation could address this issue in study year 2030. Such measures, alone, are not expected to be able to fully remedy this issue in study year 2038.

- EPE's load is likely to experience greater load shedding during multiple contingencies. This is especially so in study year 2038. With the reduction in thermal generation (and a corresponding increase in renewable generation), there is a reduction in the level of dynamic voltage support that thermal generation would have provided. With less dynamic voltage support available, the risk of system instability increases. Load shedding is a way to mitigate the risk of system instability. While most of EPE's area can accommodate significant inverter-based resources (IBRs) for the 2038 study year (relying on activation of EPE's Under Voltage Load Shed (UVLS) program when necessary to maintain reliability when dynamic voltage support is insufficient), investment in transmission infrastructure may be necessary to mitigate this reliability risk on a long-term basis so that the EPE system can accommodate the projected growth in its load without substantial increases in the frequency and scope of load shedding events. The type and scope of effective mitigation in the form of transmission infrastructure will be dependent in part to the Western System Coordinating Council's ("WECC") system evolution. EPE's preliminary analysis was based on the WECC's current system and showed a system encroaching on threshold limitations for reliability due to short circuit. It is recommended that an assessment be performed every three years to capture WECC's system transformation from gas and coal units to inverter-based generation, and the impact this will have on inertia and short circuit. The reduction in turbine-based (thermal) generation will certainly impact EPE's short circuit capability beyond 2030; this is an area requiring continued evaluation.

Key Takeaways:

- The 2030 New Mexico REA requirement of 50 percent renewable is likely attainable on the EPE system with the implementation of additional known technologies such as SVCs, STATCOMs, and/or synchronous condensers.
- Additional technical solutions, including under-voltage load shedding and transmission infrastructure, could be pursued to address the system conditions that would arise under the 2040 New Mexico REA requirement of 80 percent renewable requirement.
- Attaining the 2045 goal of 100 percent carbon free resources (given known technology evolution through the next twenty years) is expected to require the utilization of combustion turbines (either gas or hydrogen fueled). Hydrogen fueled combustion turbines would be carbon free and their consideration is discussed further later in this report. Others in the industry are making similar observations on the continued role of combustion turbines in electric grid operations. One such example is the NREL study for Los Angeles attaining 100 percent carbon free requires combustion turbines with hydrogen fuel or renewable biofuels.[5]

B. RESOURCE ADEQUACY AND RESULTING RESERVE MARGIN

Due to the changing characteristics of a resource portfolio which will continue to integrate greater amounts of variable energy resources and storage capacity with finite capacity, EPE reassessed its resource adequacy as part of this IRP process with support from E3.

To do so, E3 evaluated EPE's resource adequacy needs via its RECAP modeling software evaluating resource adequacy across the full year. The RECAP model assesses the loss of load expectation ("LOLE") based on the statistical variability of load, variable energy resource availability, and the forced outages of all resources and import transmission lines. The RECAP model quantifies the availability of resources in terms of Effective Load Carrying Capability ("ELCC") which is representative of that resource's contribution to reliably serving load. The ELCC accounts for the statistical probability for the availability of a resource to serve load and addresses unavailability due to forced outages for all resources. Further, the ELCC accounts for variable energy resources such as solar and wind including the output variations due to weather variability. ELCC is also utilized to consider limitations for duration of storage resources and limitations for number of call events for demand side resources. The ELCC is a robust measure of a resource's contribution to a utility's reliability standard and is defined as the quantity of "perfect" capacity that could be replaced or avoided by a resource while providing equivalent system

[5] NREL. LA100: The Los Angeles 100% Renewable Energy Study – Executive Summary. pp. 29, 34. March 2021. https://www.nrel.gov/docs/fy21osti/79444-ES.pdf

reliability. The PRM was assessed with the Perfect Capacity ("PCAP") metric. The RECAP model can determine the PRM that is required to meet a specified LOLE.
EPE elected to implement a reliability target of one loss of load event every ten years (i.e., 0.1 Loss of Load Expectation, or LOLE), which is increasingly common industry practice. The "one in ten" target is a reasonable threshold given the importance of reliability expected by society, governmental agencies, and EPE's obligation to provide safe and reliable power. EPE's current PRM approximates the LOLE of 24 loss of load hours in ten years. EPE proposes to shift to the "one in 10" target over the twenty-year horizon in a phased approach. As such, for IRP years through 2029, EPE will utilize a "two in ten" LOLE target and will augment its PRM by maintaining retired units in mothball status prior to fully abandoning. In 2030, EPE will shift to the "one in ten" LOLE target.

The resulting PCAP PRM through 2029 will be 10.1% for a 2 in 10 LOLE. The 2030 PCAP PRM will increase to 12.9% for a 1 in 10 LOLE. A more detailed description of the modeling and results in provided in E3's EPE Report.

EPE has considered all feasible supply, energy storage, energy efficiency, and demand-side resource options on a consistent and comparable basis 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 in detail.

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.

RECAP Model

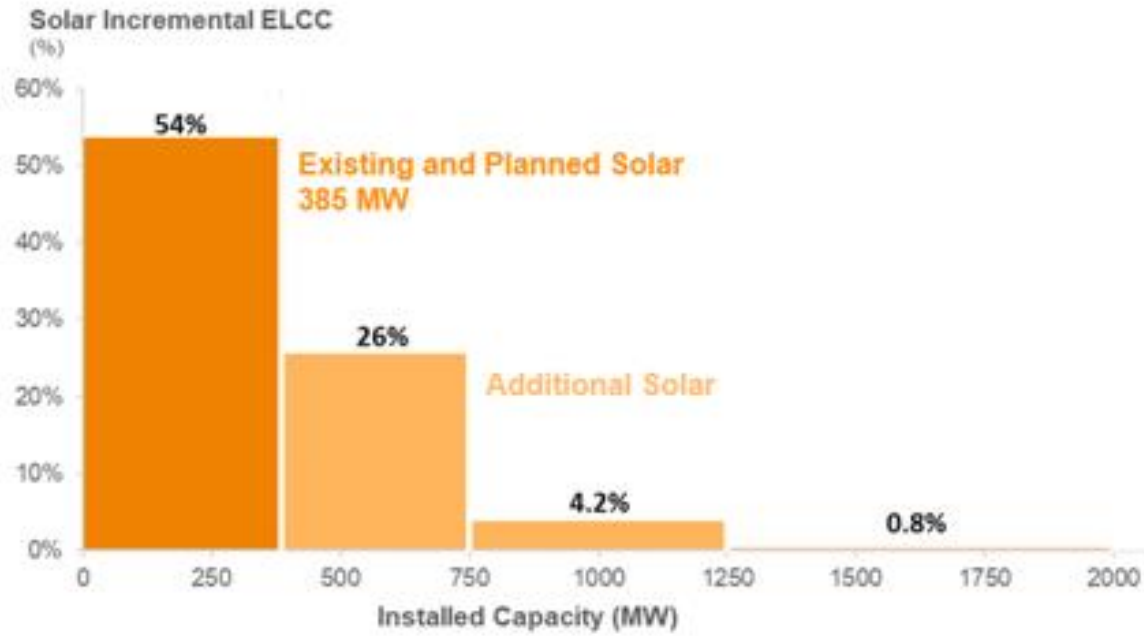
The first step in the resource planning process is to quantify the ELCC values for each resource type. This is necessary because as mentioned above, resources differ in their availability to serve load at different times of the day and year. Solar photovoltaic resources are only available during daytime hours. Wind resources have higher output profiles during nighttime hours and vary throughout the year. Geothermal resources also have seasonal output profiles that must be considered. Similarly, battery storage facilities have limited availability specific to their energy storage capacity. All resources, including gas and nuclear resources have unexpected, forced outage rates. As described earlier in the report and as described further in E3's EPE Report, RECAP utilizes statistical analysis to estimate ELCC values for the different resource types. The E3 report describes further the unique characteristics of the resource types and how the RECAP model assesses their contribution to serving load. Before describing the unique characteristics of the various resource types, it is re-iterated that the RECAP analysis considers forced outage rates for all types of resource types including gas generation and nuclear generation. Following is a brief description of key characteristics of the various resources.

Solar Resources

Solar power output has two main sources of variation: Diurnal: Solar energy is generated only when the sun is shining in the daytime and none is generated at night. Intermittent: 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. Prior to 2018, 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. In EPE's 2018 IRP as EPE planned to increase the amount of solar resources, it was necessary to consider the added variability risk and solar contribution to peak. In EPE's 2018, EPE assigned a 25% contribution for solar up through the next 400 MW of solar capacity. This was necessary to reliably meet peak demand as described in the following paragraphs. In the 2021 IRP EPE is shifting to assessing contribution to serving load via the ELCC methodology with the RECAP model. RECAP can assess both the diurnal and intermittency variability by way of the ELCC value. It is important to note that the diurnal solar output patterns result in 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. Simply put, since solar is only available during the daytime hours, at a certain point, a utility will have sufficient solar resources to meet daytime loads. However, regardless how much more solar is added above that point, it will not help serve the nighttime loads (unless coupled with battery storage – this will be discussed further in the RESOLVE section). At this point, the contribution to peak of additional solar falls to zero since it can no longer contribute to peak reduction.

The second step is to assess solar performance due to intermittency attributed to cloudy days or low solar irradiance days. The RECAP analysis utilizes historical solar generation data from EPE and simulated solar generation data from NREL to statistically quantify the variability. The RECAP model is then able to assess expected ELCC values at higher solar integration levels. The ELCC concept is illustrated in Figure 15. Furthermore, there is a resultant cumulative ELCC for solar combined with storage which is described in more detail within the E3 report in section 5.1.3.

Figure 15. ELCC for Standalone Solar



Wind Resources

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. Figure 16 illustrates NREL expected monthly output profiles for wind resource regions that are closest to EPE's service territory.

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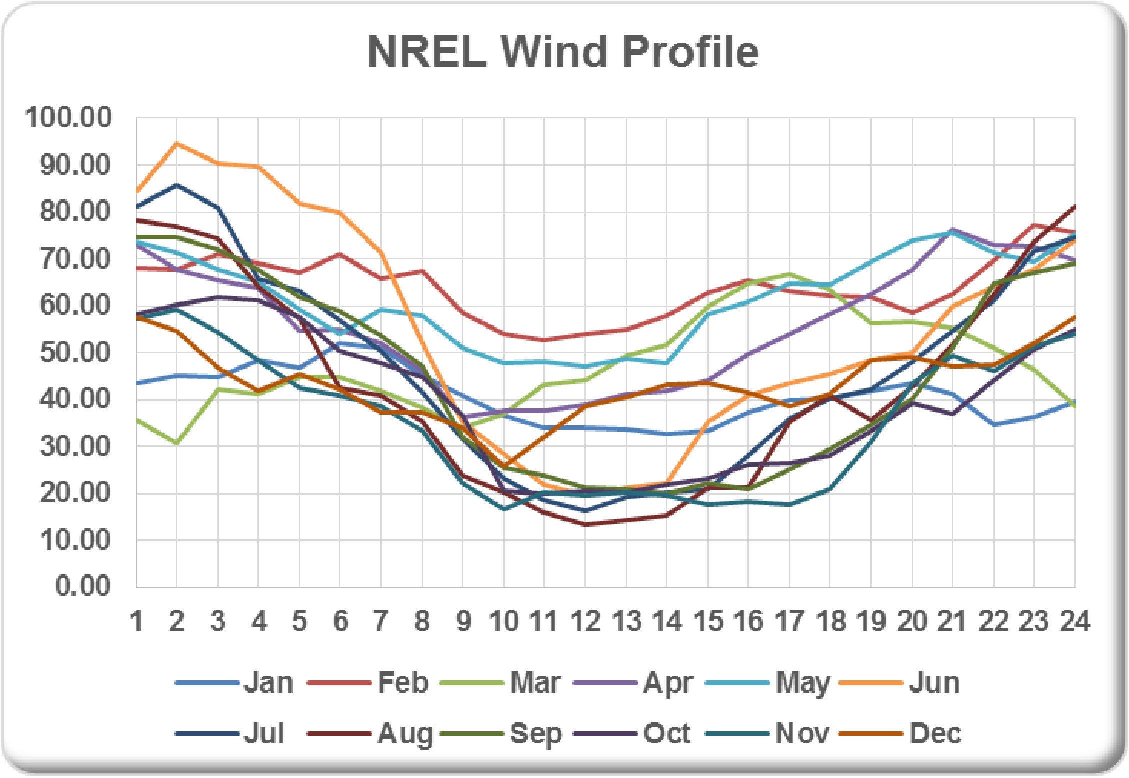
Figure 16. Monthly Wind Profiles



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. In a similar fashion to solar, the RECAP analysis utilizes simulated wind generation data from NREL to statistically quantify the diurnal, season, and intermittency variability to assess expected ELCC values at increasing wind integration levels. Figure 17 shows the incremental ELCC values for the Wind resource.

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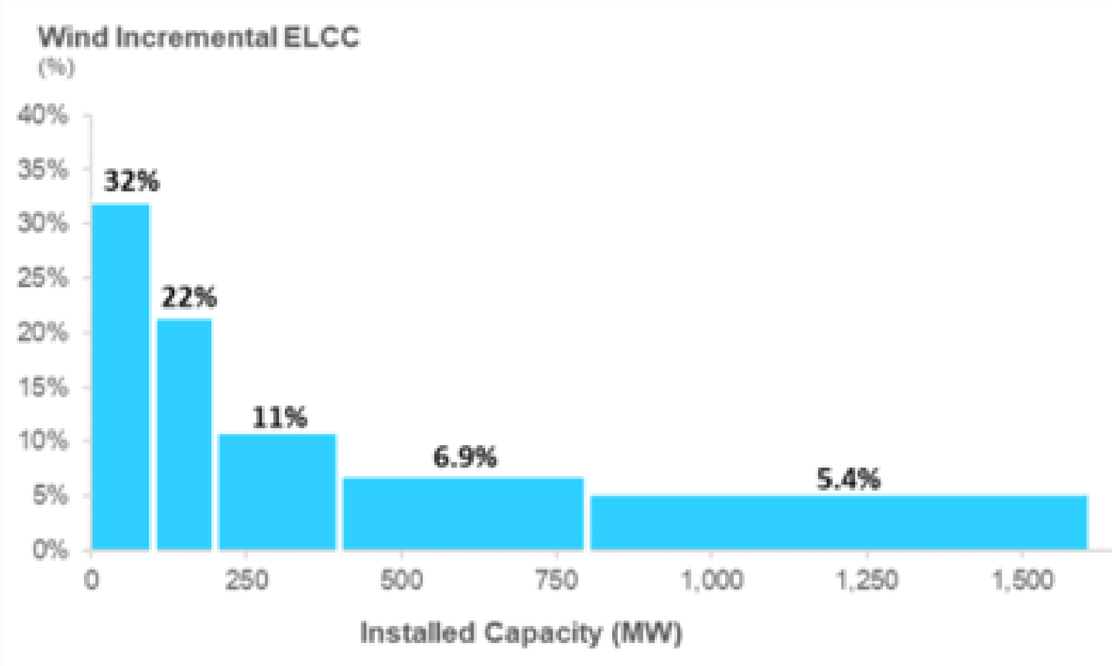
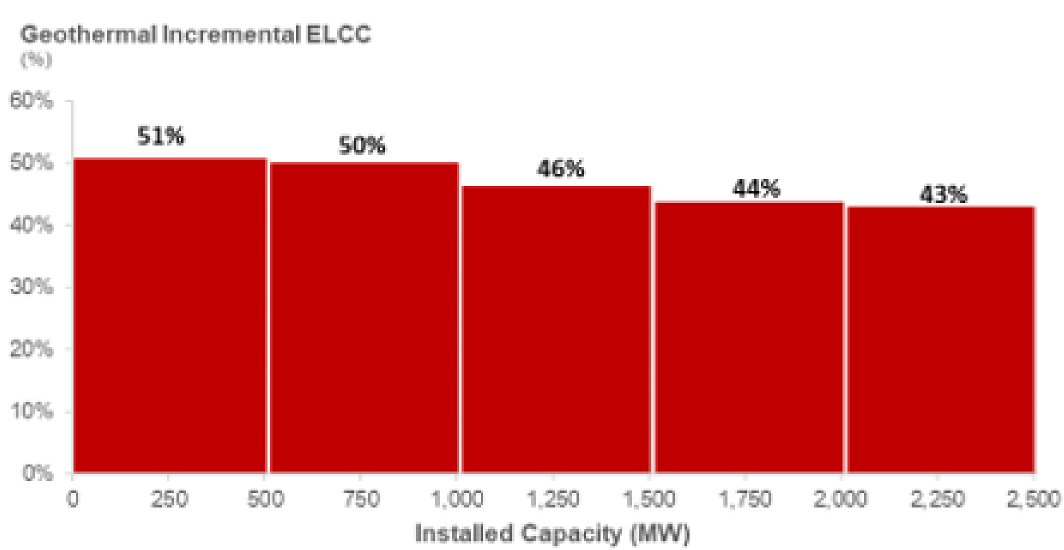
Figure 17. Incremental ELCC for Wind Resource



Geothermal Resources

Geothermal has at times been thought of as a resource available at 100% nameplate throughout the year and all of hours of the day. However, as more geothermal facilities have been constructed, it has been learned that geothermal resources also have diurnal and seasonal output patterns most likely attributed to ambient conditions. In a similar fashion, the RECAP analysis utilizes simulated generation profiles for potential geothermal resource projects to statistically quantify the diurnal and season variability to assess expected ELCC values for geothermal resources. Figure 18 shows the incremental ELCC for geothermal.

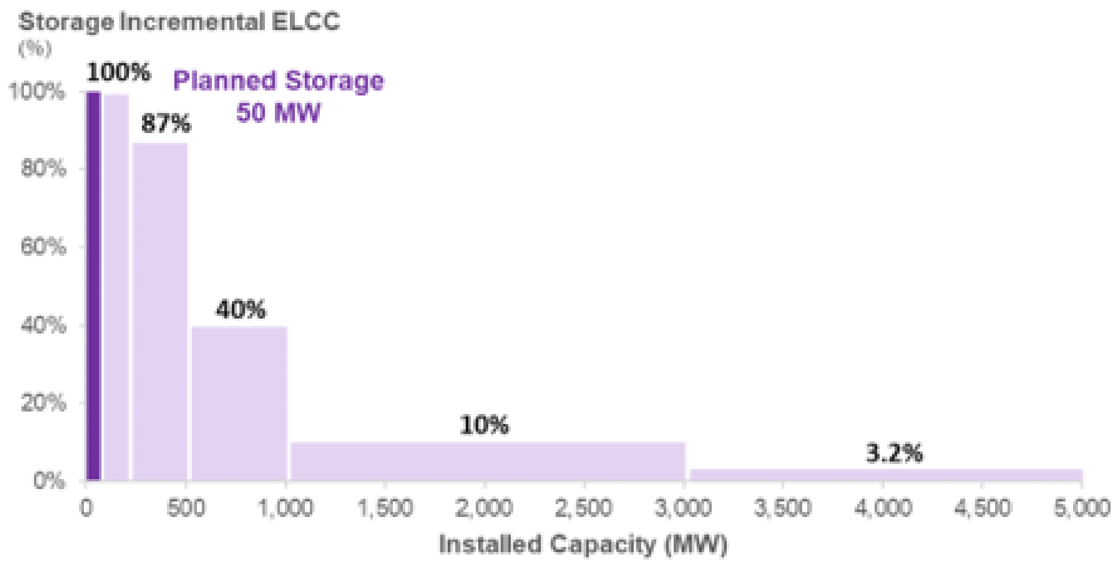
Figure 18. Incremental ELCC for Geothermal Resource



Storage

Storage is modeled as a four-hour duration lithium-ion battery storage system. The storage system is modeled to incorporate the 85% efficiency and furthermore evaluates the availability of a charging energy resource. Similarly, RECAP considers the benefits of coupling battery storage with solar or wind to shift outputs and assess an ELCC value for battery storage at greater integration levels. Figure 19 shows the ELCC for standalone 4-hour energy storage.

Figure 19. Incremental ELCC for Standalone 4-hour Energy Storage



RESOLVE MODELING

RESOLVE is a capacity expansion planning model that determines the optimal integrated demand-side and supply-side portfolio for a utility system under a prescribed set of inputs and assumptions. RESOLVE is a linear program model which allows it to efficiently analyze a multitude of resource options and combination of resource options to identify the most cost-effective portfolio. This includes the ability to evaluate the combination of storage with solar and wind as well as the synergies that exist between solar and wind resources. In addition, RESOLVE can assess the impacts of various scenarios and sensitivities based on total plan costs by imposing renewable energy targets, decarbonization targets or various sensitivities to inputs such as a carbon tax or fuel cost levels. RESOLVE 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 to develop a coordinated integrated plan which would be best suited for the EPE system. RESOLVE 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 demand side management options. The

E3 report provided in E3's EPE Report provides a more detailed description of the RESOLVE model, modeling inputs, and scenarios.

RESOLVE MODELING – PRELIMINARY DECARBONIZATION SCENARIOS

EPE initiated the RESOLVE modeling efforts by first running a range of decarbonization scenarios including up to 100 percent carbon free portfolios by 2040 utilizing the ELCC values determined by RECAP for each resource types. The two carbon free scenarios analyzed were: (1) 100 percent carbon emission reduction by 2040 with hydrogen fuel (100% H2); and (2) 100 percent carbon emission reduction by 2040 with only renewable and existing nuclear (100% No CT). Under the first carbon free scenario, all existing gas plant would be converted to hydrogen fuel and all new gas plant would be hydrogen fueled. Under the second carbon free scenario, all existing and planned gas plant would be used only for planning reserve margin and reliability. EPE also modeled a scenario with no new combustion turbines after the 2024 operations of Newman 6 (No New CTs). The purpose of this preliminary analysis was to evaluate on a total company basis the cost of increased renewables and decarbonization up to 100 percent carbon free portfolios by 2040. This analysis provides EPE information for total system decarbonization comparable to the New Mexico RPS requirements as well as inform EPE's City of El Paso Renewable Study. These modeling scenarios were performed for EPE's full system requirements inclusive of New Mexico and Texas load requirements in the following order.

- First, the RESOLVE model was allowed to select the lowest cost portfolio with no imposed renewable energy or carbon reduction requirements to establish a baseline portfolio for the preliminary decarbonization scenarios.
- Second, both the New Mexico RPS and Texas renewable requirements[6] were imposed, and the model optimized inclusive of the state requirements.
- Then RESOLVE was utilized to run further decarbonization scenarios in 20 percent increments.

The scenarios analyzed through these three steps and the resulting carbon free and renewable percentages are denoted in Table 17 below. Significantly, as discussed below, step 1 and step 2 of this preliminary decarbonization analysis, resulted in the same least cost baseline portfolio.

[6] Texas has a statewide goal for 10,000 mw of installed renewable generation located in Texas by 2025, with a target of 500 mw of it to be non-wind generation. The goal is to be met through a requirement for each load serving entity in the state to retire their share of Renewable Energy Credits (RECs) each year. El Paso Electric Company can obtain RECs for retirement either through producing such RECs from their own renewable generation located within Texas or purchasing them. PURA Section 39.904, Goal for Renewable Energy, and 16 Tex. Admin. Code §25.173.

Table 17. Decarbonization Scenarios Modeled in Resolve

PORTFOLIO NAME	PORTFOLIO DESCRIPTION	CARBON FREE (%)	RENEWABLE (%)
Lowest Cost	Meets State RPS	74	34
20%	20% Carbon Emission Reduction by 2040	79	40
40%	40% Carbon Emission Reduction by 2040	84	44
60%	60% Carbon Emission Reduction by 2040	89	49
80%	80% Carbon Emission Reduction by 2040	94	55
90%	90% Carbon Emission Reduction by 2040	97	58
100% H2	100% Carbon Emission Reduction by 2040 with Hydrogen Fuel	100	59
No New CT	No New Combustion Turbines after 2024	94	55
100% No CT	100% Carbon Emission Reduction by 2040 with Only Renewables (Existing Nuclear)	100	61

The specific scenario details are set forth in E3's EPE Report. Figure 20 shows the additional nameplate capacity in 2040 for each corresponding portfolio cost (excluding grid reliability costs) for each respective scenario analyzed.

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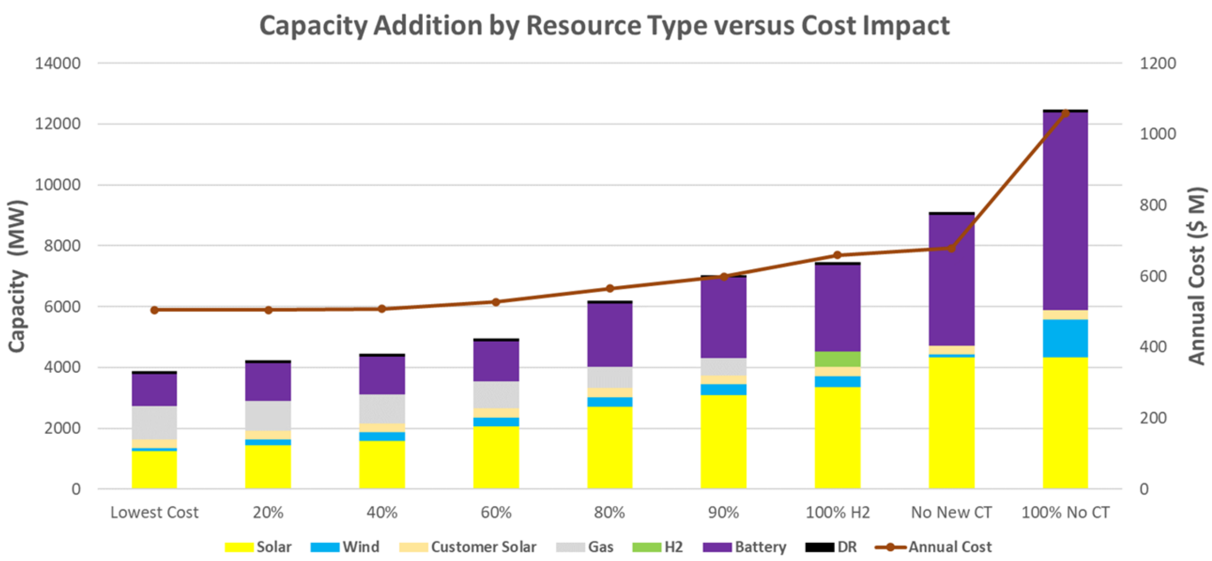
Figure 20. 2040 Capacity Addition by Resource Type with Cost Impact



As illustrated by Figure 20, increased decarbonization and renewable integration results in increased cost. More importantly, note the cost difference for the two 100 percent carbon free scenarios. The 100% No CT scenario which does not include combustion turbines, whether gas or hydrogen fueled, results in a significantly greater cost than the 100% H2 scenario. This is because significantly greater amounts of renewables and storage are required to eliminate the last 10 percent of carbon without a transition to hydrogen fueled CTs. This is an important finding in evaluating options for full decarbonization while considering customer affordability. Also, noteworthy, is the greater cost of the No New CT scenario that assumes no new combustion turbines after 2024 or after EPE's Newman Unit 6 planned for 2023. These findings are consistent with similar analyses for other regions that include combustion turbines as part of the transition to decarbonization because CTs provide needed firm capacity for resource adequacy and grid reliability, even if utilized at a very low-capacity factor. The units may then transition to hydrogen fuel options as the technology evolves, which is carbon free. It is important to note that EPE has not completed a grid reliability assessment for a 100 percent carbon free portfolio without combustion turbines. EPE has assessed an 80 percent carbon free portfolio equivalent and deemed it is viable with increased transmission infrastructure upgrades. However, that preliminary study addressed above in Section IX encroaches on the limits of grid reliability. Further, EPE does not currently see the grid technology to eliminate combustion turbines completely, but further technological advancements may provide future solutions.

The graphs in Figure 21a -21b more clearly illustrate the correlation of increased cost at increased renewable integration and decarbonization. These graphs illustrate the following three important points:

1. attaining 60 to 80 percent decarbonization is possible with marginal cost increase;
2. attaining the last 10 to 20 percent decarbonization is more reasonably attainable, based on cost, with the planned use of hydrogen fueled combustion turbines; and,
3. eliminating the use of hydrogen combustion turbines greatly increases the cost of the last 10 percent decarbonization.

Figure 21a. Percent Renewable and Decarbonization for Scenarios

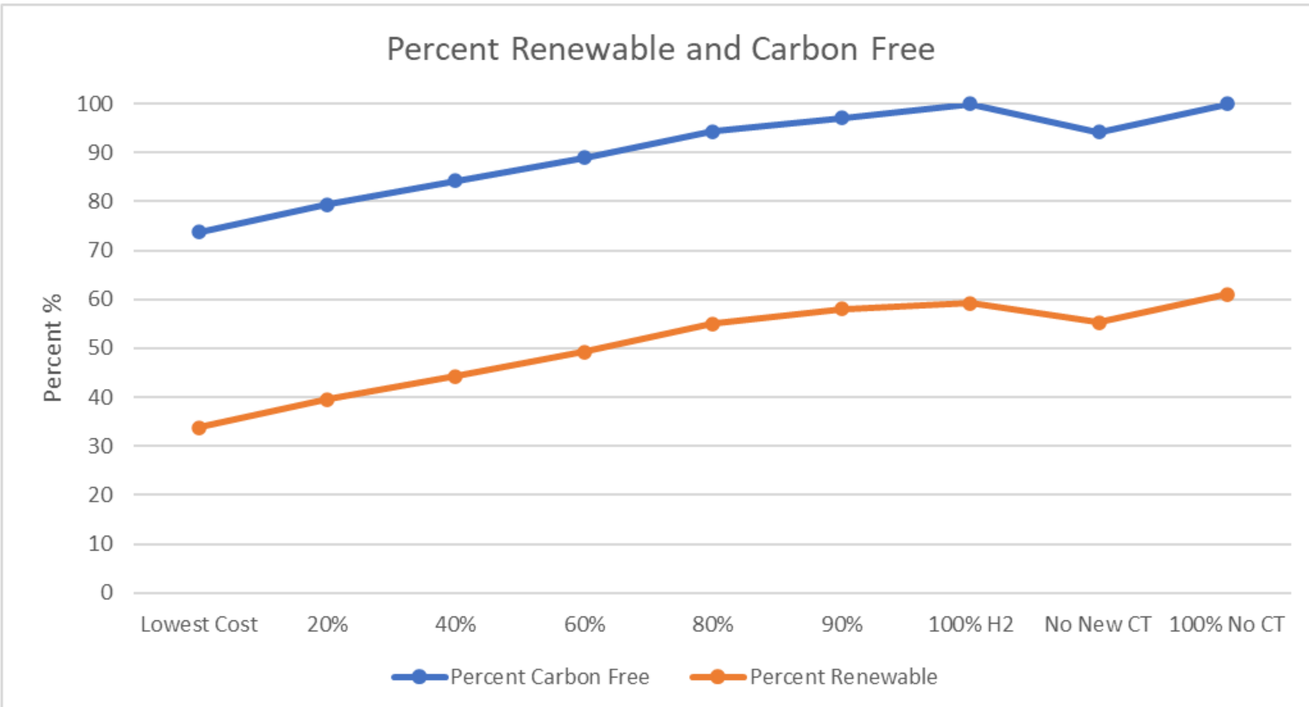
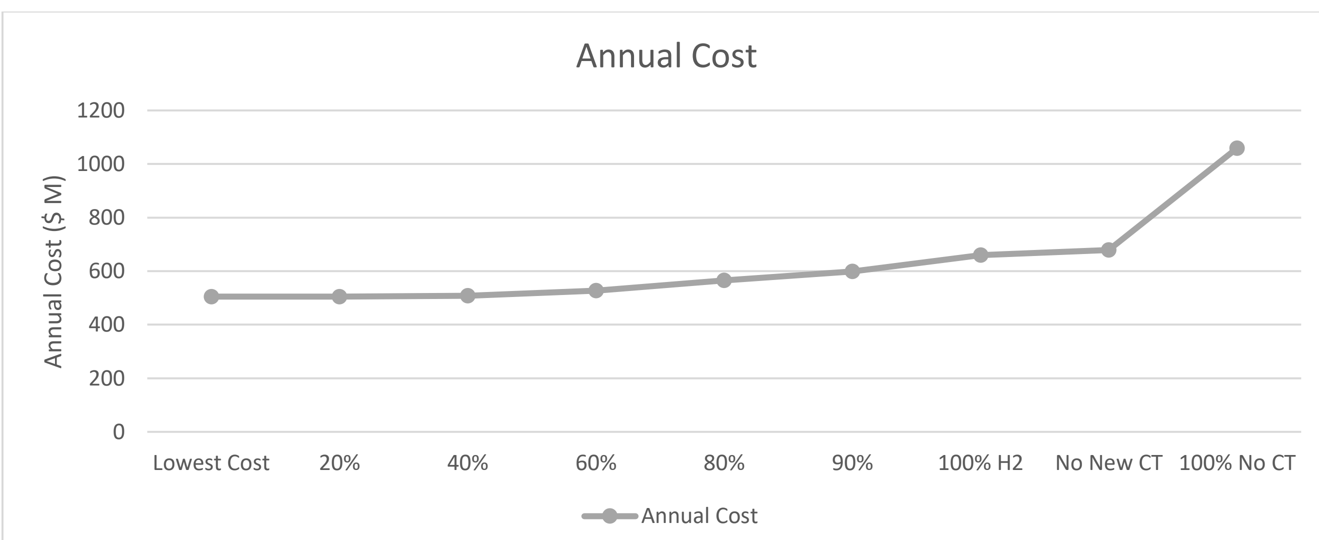
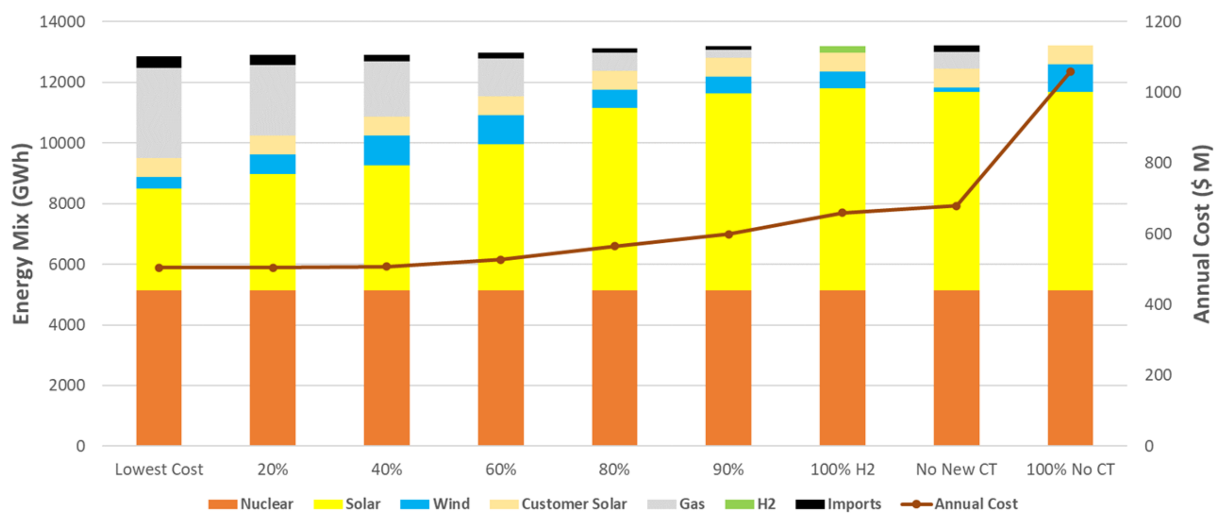


Figure 21b. Annual Cost for Decarbonization Scenarios



A positive finding is that the continued projected cost declines for renewable and storage costs results in continued increased renewable integration. The lowest cost portfolio selected sufficient renewable energy resources to comply with both New Mexico and Texas renewable requirements in an aggregate on a total system basis. Additionally, as depicted in the Figure 22 below, an 80 percent carbon free scenario is attainable with marginal cost impact to customers. The 80 percent carbon free scenario results in approximately 45 percent renewables for the total system (the presentation of New Mexico REA compliant scenarios is addressed in the following section of the IRP report).

Figure 22. 2040 Energy Mix of Carbon Scenarios with Cost Impact



<u>RESOLVE MODELING –IRP ANALYSIS</u>

<u>Key Assumptions:</u>

- **<u>Retirement Analysis</u>**

  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 7 and Newman Units 1-4 for this IRP. To best facilitate this evaluation, EPE hired the 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 the following extensions. The retirement options were considered in the base case RESOLVE model 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. Retirement extensions of 5 years were selected by the model for Newman

Unit 1, Newman Unit 3 and Newman Unit 4 based on current cost projections. The retirement extensions will be re-evaluated as part of any future Requests for Proposals ("RFP") evaluation.

- **<u>Newman 6</u>**

  The full Newman 6 capacity is included at full nameplate for any system resource portfolio analysis. However, Newman 6 is not allocated to New Mexico in any jurisdictional analysis.

- **<u>PV 3</u>**

  The full EPE owned PV3 capacity is included at full nameplate for any system resource portfolio analysis. However, PV3 is not allocated to New Mexico in any jurisdictional analysis.

<u>Least Cost System-Wide Portfolio Analysis</u>

EPE initiated the jurisdictional analysis for New Mexico RPS compliance by first establishing the Least Cost System-Wide Portfolio. The Least Cost System-Wide Portfolio capacity additions by year are depicted in Figure 23 below. The portfolio includes selection of retirement extensions for Newman 1, Newman 3 and Newman 4. Additional sensitivities for retirement analysis will be performed plus review of permitting and reliability considerations. Retirement of units are denoted below the x-axis line.

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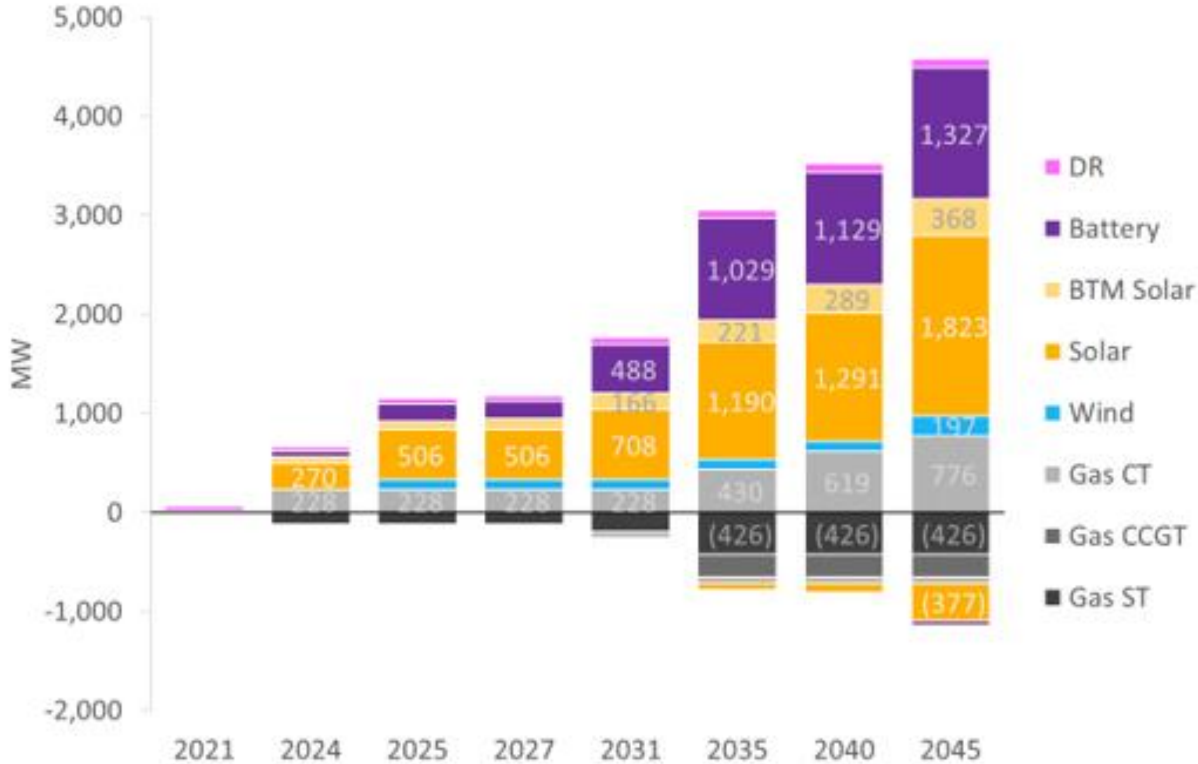
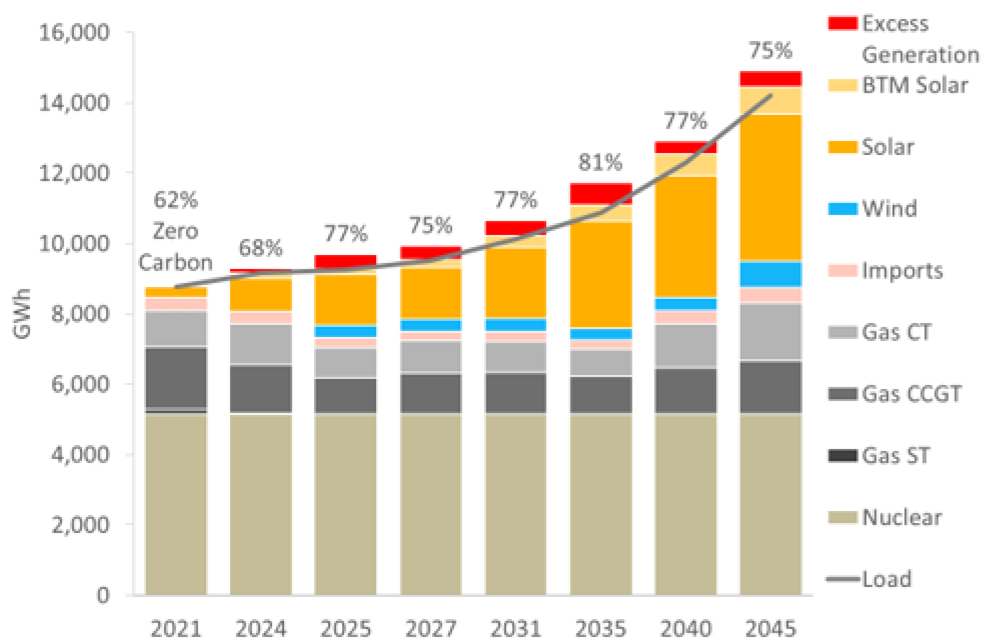
Figure 23. Least Cost System-Wide Portfolio by Year



The resulting resource energy mix of the Least Cost System-Wide portfolio are shown in Figure 24 below.

Figure 24. Least Cost System-Wide Portfolio by year Energy Mix



Jurisdictional Analysis

Because the initial model runs were performed on a total system basis, it was next necessary to assess RPS impacts on a jurisdictional basis. EPE opted to evaluate the jurisdictional impacts by utilizing the Least Cost System-Wide Portfolio as the starting point. The jurisdictional analysis evaluated three different approaches to meeting New Mexico REA requirements, which resulted in three New Mexico specific resource portfolios. The three jurisdictional scenarios are summarized in Table 18 below.

Table 18. New Resource Jurisdictional Allocation Options

	Least Cost ("LC")	**Least Cost + REA Resources** ("LC+REA")	**Separate System Planning** ("SSP")
Portfolio optimization	Least-cost system optimization	Reoptimize Least Cost to add additional renewables & storage dedicated to NM to satisfy REA requirements	Optimize NM and TX systems independently without modeling interactions between them
NM zero-carbon generation balancing period	Annual	Annual	Hourly
NM and TX capacity pooling to ensure reliability	✓	✓	✗
Resource allocation	Resources allocated proportionally; more RECs allocated to NM	Incremental resources are allocated to New Mexico	Optimization identifies resources specifically for NM and TX jurisdictions
NM allocated new gas capacity	✓	✗	✗

4. **<u>Option-1.</u>** Least Cost Option - System Portfolio Allocated Proportionally (~80/20) and REC Transfer.

   Under this option, all new resources are allocated on a jurisdictional basis, inclusive of gas, and renewable energy. Once allocated, New Mexico's RPS is met through renewable energy delivered to EPE's system from: (1) renewable energy and RECs assigned to EPE's New Mexico jurisdiction; (2) existing dedicated New Mexico RPS resources and associated RECs; and (3) additional RECs assigned to EPE's New Mexico jurisdiction. This option assumes the transfer of stand-alone RECs from EPE's Texas jurisdiction to EPE's New Mexico jurisdiction, an allocation of new gas capacity to New Mexico, which could be converted to run on a higher share of hydrogen fuel in the future, and no allocation of PVGS Unit 3 to New Mexico.

5. **<u>Option 2.</u>** Least Cost Plus REA Resources - System Portfolio Allocated Proportionally plus New Mexico Dedicated Resources.

   Under this option, all new resources are allocated on a jurisdictional basis, except for new gas which is 100 percent allocated to Texas. Additionally, to meet New Mexico's RPS and capacity requirements, New Mexico dedicated renewable and capacity resources were selected to meet New Mexico's jurisdictional requirements. Importantly, this scenario allows capacity pooling and dispatch benefits for system dispatch optimization. Under this scenario, REA compliance is assessed based on annual retails sales, allowing system gas resources when required to supply New Mexico energy needs This scenario is most comparable with past practice except for the exclusion of new gas resources.

6. **<u>Option 3.</u>** Separate Systems for New Mexico and Texas.

   This approach is based on a separate New Mexico portfolio and a separate Texas portfolio. This scenario segregates EPE's system planning and identifies a New Mexico REA compliant portfolio with no allocations of new resources. Additionally, this approach assumes no capacity pooling between New Mexico and Texas, nor does it include joint system dispatch optimization. It also assesses New Mexico REA compliance on an hourly, as opposed to annual, basis. Therefore, there is no leveraging of cross-jurisdictional resources and as such the cost is higher for New Mexico because additional renewables and battery storage must be added to ensure hourly balancing and resource adequacy for New Mexico. This scenario was run both with and without the assumed use of hydrogen combustion generation. As indicated below, the scenario without hydrogen fuel options results in a higher cost. EPE's preliminary grid reliability study has only assessed the impacts of an 80 percent carbon free scenario through 2040, and exclusive reliance on inverter-based technologies has not yet been determined viable under a 100 percent carbon free scenario. This may be addressed in the future through continued technology advancements for both inverter-based resources and grid devices.

The resulting capacity and resource mix for each of the scenarios including New Mexico jurisdictional basis is shown in Figure 25a-25b.

Figure 25a. Total System & New Mexico Allocation Comparison

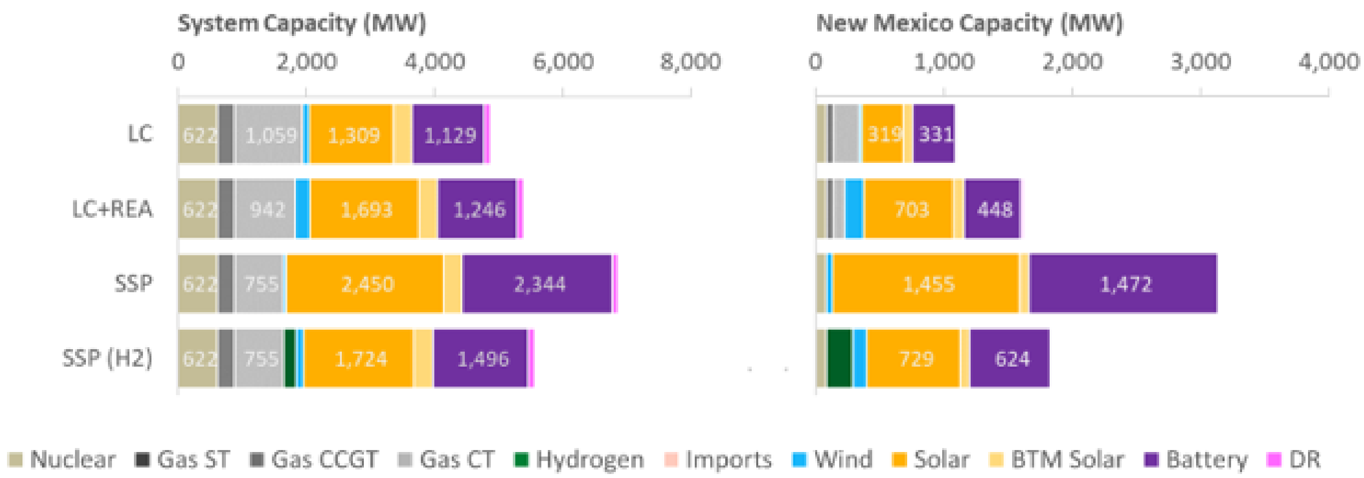
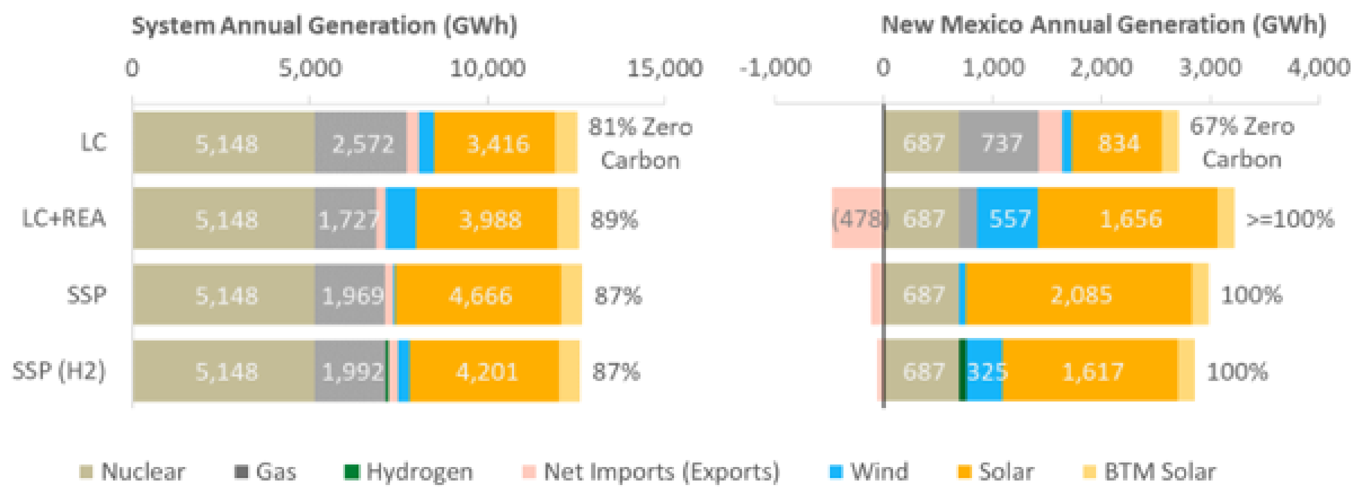
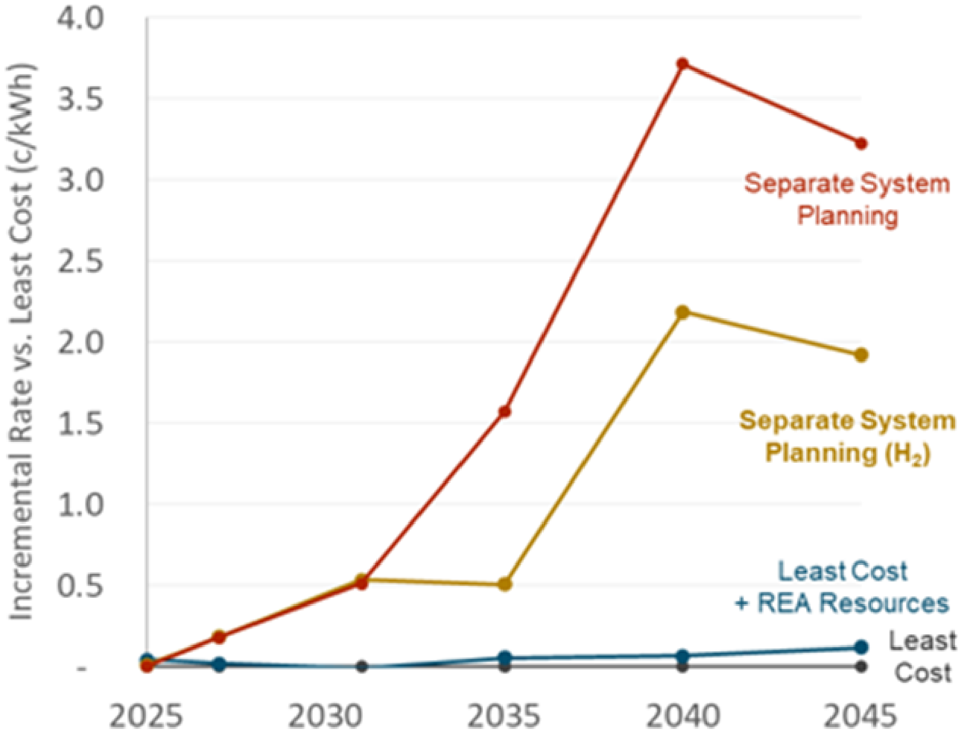


Figure 25b. Total System & New Mexico Allocation Comparison



The cost differential between the various jurisdictional approaches may be more easily compared over the planning horizon in Figure 26.

Figure 26. Cost Differential Between Jurisdictional Options



Option 1 presents challenges due to the required transfer of stand-alone RECs between EPE's jurisdictions and the requirement for new gas plant additions. Due to these challenges, EPE presents Options 2 and 3 as the most cost-effective resource options. Both address EPE's multi-jurisdictional planning requirements including the New Mexico RPS requirements and the Texas lowest cost portfolio requirements.

Option 2 assumes that system resources will be proportionally allocated to each jurisdiction. The cost benefits apparent in this scenario, as compare to the Separate System Planning scenario, result from capacity pooling and load diversity during optimal dispatch of both Texas and New Mexico resources while adhering to New Mexico REA requirements. It is important to note that this scenario still requires each jurisdiction, New Mexico and Texas, to acquire sufficient capacity to meet their respective demand and reliability needs. However, it also allows for total system dispatch to optimize both jurisdictional resources to the benefit for both states. As discussed above, this scenario assumes the ability to at times utilize system gas resources to serve New Mexico customers in the event of renewable or carbon free resource energy output unavailability.

Option 3 assumes separate resource planning to address jurisdictional planning requirements. This scenario provides New Mexico the most resource planning autonomy to meet New Mexico's renewable and clean energy standards. Option 3 costs more, however, because the cost benefits associated with capacity pooling and load diversity during optimal dispatch of system-wide resources would not be realized. In short, this approach best addresses the divergence between resource selection standards in Texas and New Mexico but comes at a greater cost to New Mexico.

The Least Cost System-Wide Portfolio Serves as the Base Case for Sensitivities

The Base Case Portfolio was developed utilizing the planned retirements as defined in Table 7. 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:

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.

A. 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.

Throughout the 2021 IRP, EPE accounted for transmission and reserve margin constraints 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 considered its geographical location and its transmission import limits when developing its optimal portfolio. The resulting portfolio ensures an adequate reserve margin to meet a 2 in 10-year LOLE through 2029 and then shifts to a 1 in 10-year LOLE from 2030 forward.

The recommended portfolio will have sufficient system resources and New Mexico dedicated resources to comply with the current 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, like 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.

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 renewable resources and the introduction of battery storage, the most cost-effective portfolio has a greater diversity of resources.

B. Alternative Portfolios (sensitivities, carbon tax)

Sensitivity Analysis

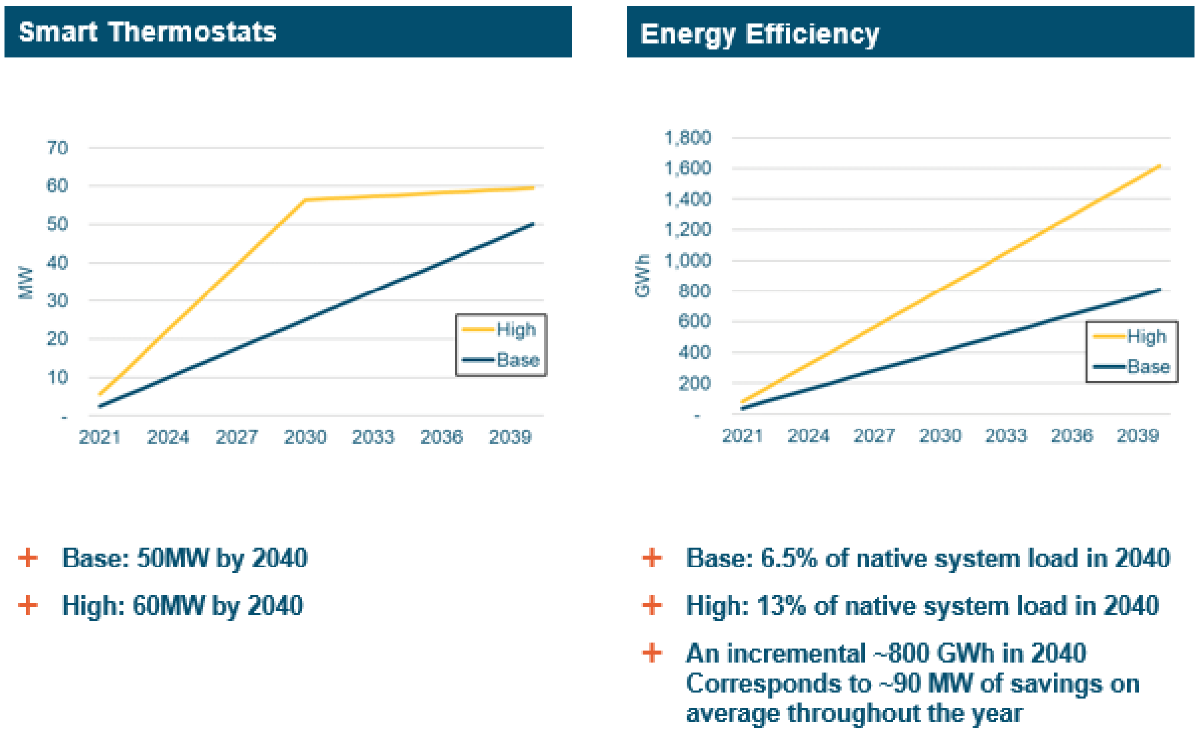
EPE analyzed various sensitivities to capture the cost differences and changes to the resource expansion plan. The sensitivities included variations to projected load, forecasted natural gas prices, and carbon tax costs at different price thresholds. Therefore, EPE modeled and analyzed high and low sensitivities 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.

High Demand Side Management Sensitivity Analysis

EPE opted to run a high Demand Side Management (DSM) sensitivity to assess portfolio impacts to the Least Cost System-Wide scenario. This approach was selected because EPE's current customer load characteristics do not provide a significant amount of load management options outside of thermostat control DSM options for refrigerated air systems. For example, only 8 percent of customers have pools and only 15 percent of customers have electric water heaters. This does not offer much in the form of substantive DSM options. However, EPE understands that this will change as greater electrification of load takes place. Therefore, EPE modeled a high DSM sensitivity case based on a high DSM and Energy

Efficiency adoption. It is noted, that in addition to the thermostat program expansion, EPE also assumed managed electric vehicle charging in the future which is also a form of DSM. Figure 27 describes the high DSM/EE scenario.

Figure 27. High DSM/EE Sensitivity Scenarios



Figures 28a-28b show the resulting portfolio impact denoted as a change in cumulative capacity addition reduction and change in annual generation by resource type and year vs. the reference case.

Figure 28a. High DSM/EE Resulting Change in Cumulative Capacity .vs Ref Case

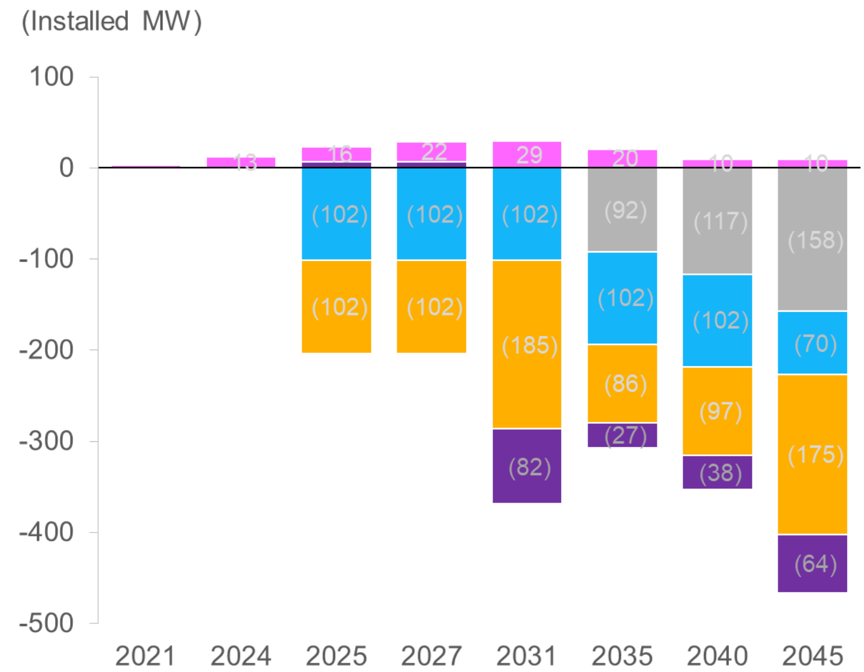
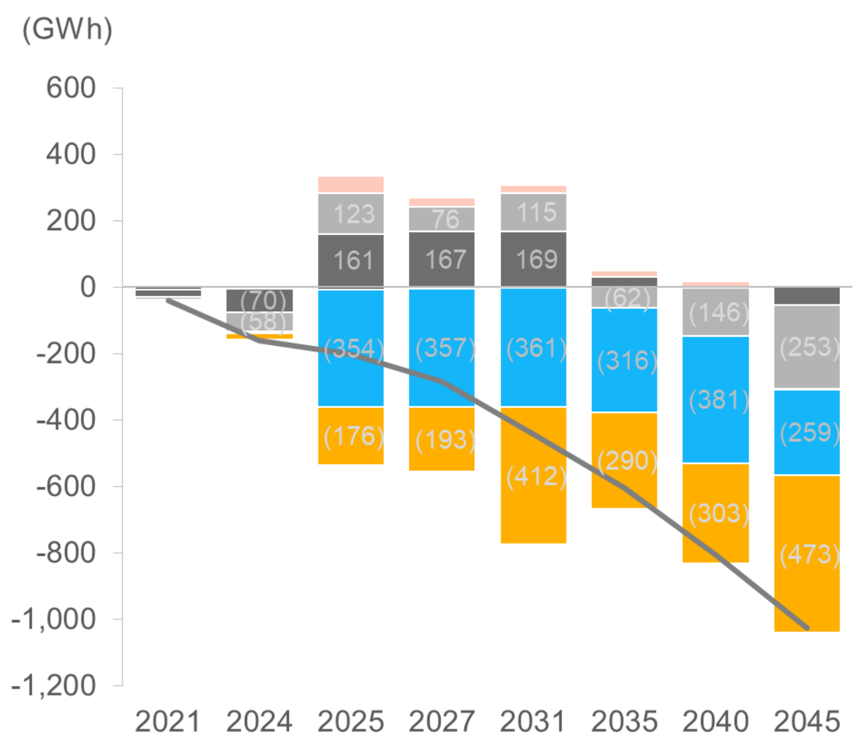


Figure 28b. High DSM/EE Resulting Change in Annual Generation vs. Ref Case



C. Recommended Portfolio

EPE presents as its recommended resource portfolio, the Least Cost-plus REA option, ("Option 2"). The resulting incremental resource additions for Option 2, for Total System, are shown in Table 19a. Similarly, the resulting incremental resource additions for Option 2, for New Mexico, are shown in Table 19b.

19a. Option 2 Incremental Resource Additions for Total System, (MW)

Resource Category	**2025**	**2027**	**2031**	**2035**	**2040**	**2045**
Battery	*126*	*1*	*283*	*607*	*179*	*487*
Gas New	-	-	-	*141*	*134*	*108*
Gas 5-yr Extension	*74*	*313*	-	-	-	-
Geothermal	-	-	-	-	-	-
Nuclear	-	-	-	-	-	-
Solar	*159*	-	*251*	*689*	*306*	*624*
Wind	*203*	-	-	-	*28*	*69*

Table 19b. Option 2 Incremental Resources Additions for New Mexico, (MW)

Resource Category	2025	2027	2031	2035	2040	2045
Battery	*94*	*1*	*50*	*192*	*101*	*352*
Gas_CT	-	-	-	-	-	-
Gas 5-Yr Extension	*15*	*63*	-	-	-	-
Geothermal	-	-	-	-	-	-
Nuclear	-	-	-	-	-	-
Solar	-	-	*59*	*303*	*225*	*199*
Wind	*122*	-	-	-	*28*	-

The actual resource additions will be determined via future RFP solicitations and dependent on actual proposals and pricing. EPE will pursue this portfolio by separate jurisdictional RFP specific to New Mexico and Texas. This will allow EPE to pursue respective jurisdictional specific RPS requirements to meet demand. The separate RFP solicitations and resulting regulatory approval filings will also provide New Mexico with the autonomy it has demonstrated interest in. While the resources will be pursued via separate RFPs, the total system resource portfolio's capacity will be pooled and optimally dispatched at a system wide level to offer the cost benefits shown by the Least Cost plus REA analysis. As stated above, the retirement extensions of the existing units will be re-evaluated as part of future RFP resource selection.

Under this IRP, REA compliance will be measured annually to ensure New Mexico assigned renewable resources and carbon free resources meet or exceed the New Mexico RPS. Including the 100 percent carbon free requirement. For example, there may be hours of the year that gas generation may serve New Mexico load; however, the total New Mexico assigned carbon free resources' output will equal or exceed the total annual New Mexico retail sales to ensure compliance with the 100 percent carbon free requirement.

LOADS AND RESOURCES

The final EPE System and New Mexico L&R are presented in Figure 29 and Figure 30 respectively. Given that the RESOLVE analysis looks at five discrete build years, the L&R does distribute some of the resource additions to address preceding years due to retirements and associated deficiencies.

Reference Figures 5a-5b and 6a-6b for the respective L&R tables.

D. 2021 IRP Four-Year Action Plan

EPE's four-year action plan includes the following steps:

- EPE will continue moving forward with the selected resources previously approved by the Commission in Case Nos. 19-00099-UT and 19-00348-UT (Hecate I and II and Buena Vista I and II). These resources have an anticipated Commercial Operation Date ("COD") of 2022.
- EPE will complete the regulatory approval process for EPE's 2021 Annual Renewable Energy Plan filed May 5, 2021, and file subsequent annual reports and plans in 2022, 2023, 2024, and 2025 pursuant to 17.9.572 NMAC and the New Mexico REA.
- EPE will complete the regulatory approval process for the 2022-2024 Energy Efficiency and Load Management Plan filed July 16, 2021 and will file a subsequent 3-year plan pursuant to 17.7.2 NMAC and the EUEA.
- EPE will issue a New Mexico RFP in 2021 to address current capacity needs and RPS resource needs to meet the REA 2025 target of 40 percent.
- EPE will complete a Demand Side Management potential study.

- EPE will continue to consider voluntary customer programs for renewable energy.
- EPE will file for abandonment of units that are past their useful lives.

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).

Curtis Hutcheson, Manager-Regulatory Case Management, chaired the public participation process. Mr. Hutcheson scheduled the original public meetings and then coordinated the development of the final meeting schedule and meeting agendas with input from the public participants. The public participants were encouraged to place items on the agenda for discussion at the public meetings. The result was three additional meetings. Due to the pandemic, the public meetings were all held online, using WebEx and Zoom platforms. EPE continues to use the NMIRP@epelectric.com email, consisting of EPE employees directly related to 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 nine public advisory meetings over the course of approximately 12 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. EPE structured the Public Process to be inclusive and interactive. The online meetings were set up so that the Participants could view presentation materials taking place during each meeting and hear audio. The remote Participants were able to submit questions through the Q&A or chat conversation panels.

EPE recorded some meetings, upon request, and posted these on EPE's IRP website.

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.

By attending any public meeting, the Participants were automatically enrolled in EPE's attendance invitation 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 Participants 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 July 10, 2020. EPE also included notice of the Participants 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/Load Management Plan case. The notice and certificates of service were filed with the Commission's Records Bureau.

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 E-1. The attachment also contains the Proof of Publication, Affidavit of notification to customers, and Certificate of Service filed with the Commission on May 13, 2021. 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 load management, 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

An average of 48 people attended EPE's public advisory meetings remotely as attendees over the course of the approximately 12-month Public Process. There was an average of 10 panelists during each meeting.

Public participation consisted of continuous attendance from the participants who were very active in the Q&A and chat panels and were engaged throughout the entire Public Process. There were also representatives from certain groups and companies, such as Coalition for Clean Affordable Energy, Western Resource Advocates, Solar Smart Living, Cypress Creek Renewables, 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 six meetings; but, with the addition of three meetings requested by public participants, the final schedule consisted of nine meetings. EPE modified its initial meeting schedule to accommodate several requests of the Participants. For example, EPE scheduled extra meetings to address topics to be covered in more detail as requested by the Participants. Attachment E-2 shows the original and final public advisory group meeting schedule.

Meetings were typically held on Friday'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. All meetings were held online.

The schedule was structured 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 meetings was presentation oriented. Typically, presentations were completed before answering questions submitted through the Q&A and chat panels, unless directly related to terms used in the presentation for clarification. Additionally, at the end of each meeting, submitted questions were answered as time permitted.

EPE presented topics required in the Rule for the Public Process, as well as more detailed information on those topics 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.

In response to public feedback, and to provide more information and explanation of the modeling process to the participants, EPE added three additional meetings to address specific topics; first on November 9, 2020, second on February 5, 2021, and the third on March 19, 2021.

During the November 9, 2020, meeting, the Public Participants provided a slide presentation, then there was a discussion by EPE regarding EPE's expectations as to its generation portfolio and power procurement in 2040 and 2045, consistent with REA requirements regarding renewable and non-carbon sources, EPE's expectations regarding "must-run" resources in a non-carbon world and implications for renewable resources, including the use of curtailments, EPE's expectations regarding the level of reliability appropriate for the system today and in 2040, and how EPE expects to analyze the provision and cost of defined levels of reliability, discussion by EPE of native load and system requirements in 2020, including how EPE met peak demand during the summer peak period, discussion of future meeting agendas, and additional scheduled meetings.

During the February 5, 2021, meeting, EPE presented the modeling update in a joint presentation with E3 and discussed dates of future meetings.

During the March 19, 2021, meeting, EPE presented an IRP modeling status summary, New Mexico Renewable Energy Act requirements, transmission for new resources discussion, an assumptions update, model updates and results, and next steps.

The last three meetings were on June 1, July 1, and September 2, 2021. For the June 1 meeting, EPE presented the load forecast and the preliminary modeling results. EPE emailed the draft IRP report to the participants on June 15, 2021 so they could review before the July 1 meeting. On July 1, EPE presented the jurisdictional analysis and received comments on the draft IRP report. On August 15, 2021, EPE emailed the final draft of the IRP report. Finally, at the September 2, 2021 meeting, EPE received feedback from the participants on the final report.

E. Public Input

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

- participate in the online public advisory meetings and give their input during the meetings,
- submit written requests for information through the Q&A and chat panels during the meetings,
- send EPE their written input or requests by email, during or after scheduled meeting,

EPE received and considered all views and opinions expressed during the Public Process.

F. Conclusion of Public Advisory Process

Due to the pandemic and New Mexico Governor Gresham's Executive Orders, EPE made a significant effort to provide the public as much access as possible to make it a more inclusive and interactive process. By providing the Participants with additional features such as increasing the number of meetings and public discussion time, and including a written request and response option, EPE made the public process as accessible and as effective as possible under the circumstances.

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.

Appendix A Resource Assumptions

Table 1. Resource Lifetime (years)

Resource	Lifetime
Solar	30
BTM Solar	30
Wind	30
Geothermal	25
Biomass	20
Standalone Batteries	20
Paired Batteries	20
Gas Peaker	40
Nuclear (SMR)	30

Table 2. Upfront Capital Cost ($/kW) (2021 $)

Resources	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Utility-Scale Solar	900	858	815	773	730	688	681	675	669	663	657	651	645	639	633	626	620	614	608	602	596
BTM Solar	1,693	1,607	1,521	1,435	1,350	1,264	1,249	1,234	1,220	1,205	1,190	1,175	1,161	1,146	1,131	1,117	1,102	1,087	1,072	1,058	1,043
Wind (Artesia/ABQ)	1,463	1,431	1,399	1,367	1,333	1,299	1,286	1,273	1,260	1,247	1,234	1,220	1,207	1,194	1,180	1,167	1,153	1,140	1,126	1,113	1,099
Wind (Lordsburg)	1,785	1,743	1,700	1,655	1,609	1,561	1,549	1,537	1,525	1,512	1,500	1,488	1,475	1,463	1,450	1,437	1,424	1,411	1,398	1,385	1,372
Geothermal	8,545	8,451	8,358	8,265	8,172	8,080	8,040	7,999	7,959	7,920	7,880	7,841	7,801	7,762	7,724	7,685	7,647	7,608	7,570	7,532	7,495
Biomass	4,499	4,482	4,464	4,447	4,429	4,407	4,385	4,363	4,339	4,321	4,301	4,275	4,255	4,234	4,209	4,184	4,166	4,142	4,121	4,100	4,081
Standalone Batteries	786	749	712	674	637	599	591	585	576	570	562	553	547	539	533	524	516	510	501	495	487
Paired Batteries	726	691	657	622	588	553	545	540	532	527	519	511	505	497	492	484	476	471	463	457	449
Gas Peaker	1,223	1,214	1,205	1,198	1,194	1,188	1,183	1,178	1,171	1,167	1,164	1,159	1,156	1,153	1,149	1,145	1,143	1,139	1,136	1,133	1,130
Nuclear (SMR)	7,339	7,301	7,257	7,217	7,176	7,126	7,079	7,030	6,979	6,936	6,891	6,836	6,791	6,744	6,691	6,637	6,595	6,544	6,497	6,450	6,406

Table 3. Fixed O&M ($/kW-yr) (2021 $)

Resources	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Utility-Scale Solar	13	13	12	11	11	10	10	10	10	10	10	10	9	9	9	9	9	9	9	9	9
BTM Solar	12	12	11	10	10	9	9	9	9	9	9	8	8	8	8	8	8	8	8	8	7
Wind	43	43	42	42	42	41	41	41	40	40	40	39	39	39	38	38	38	38	37	37	37
Geothermal	187	186	185	185	184	183	183	183	183	183	183	183	183	183	183	183	183	183	183	183	183
Biomass	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130
Standalone Batteries	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Paired Batteries	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Gas Peaker	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
Nuclear (SMR)	**126**	**126**	**126**	**126**	**126**	**126**	**126**	**126**	**126**	**126**	**126**	**126**	**126**	**126**	**126**	**126**	**126**	**126**	**126**	**126**	**126**

Table 4. Real Levelized Cost ($/kW-yr) (2021 $)[1]

Resources	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Utility-Scale Solar	48	58	57	55	53	51	51	50	50	50	49	49	48	48	48	47	47	47	46	46	45
BTM Solar	65	87	84	81	77	73	72	71	70	69	69	68	67	66	65	64	63	63	62	61	60
Wind (Artesia/ABQ)	98	133	132	131	130	128	127	126	125	124	123	122	121	120	118	117	116	115	114	113	112
Wind (Lordsburg)	129	150	150	148	146	144	143	142	141	140	139	138	137	136	135	134	133	131	130	129	128
Geothermal	663	672	680	680	680	679	677	675	672	670	667	665	663	660	658	656	653	651	649	646	644
Biomass	440	448	455	458	460	462	460	459	457	456	454	452	451	449	447	445	444	442	441	439	438
Standalone Batteries	90	86	82	77	73	69	68	67	66	66	65	64	63	63	62	61	61	60	59	59	58
Paired Batteries	63	71	68	64	60	56	55	55	54	54	53	52	52	51	51	50	50	49	49	48	47
Gas Peaker[2]	117	116	116	116	116	115	115	114	114	114	113	113	113	113	112	112	112	112	112	111	111
Nuclear (SMR)	652	654	657	660	662	664	661	657	653	650	647	642	639	636	632	628	624	621	617	613	610
Smart Thermostats	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29

[1] The levelized cost includes interconnection costs.
[2] The levelized cost for Gas Peaker includes gas pipeline reservation costs.

Table 5. Capacity Factor (%)

Resource	Capacity Factor
Solar[3]	32%
BTM Solar	24%
Wind (Artesia)	44%
Wind (ABQ)	50%
Wind (Lordsburg)	37%
Geothermal	80%

Table 6. Real Levelized Cost of Energy ($/MWh) (2021 $)[4]

Resources	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Solar	17	21	20	20	19	18	18	18	18	18	18	17	17	17	17	17	17	17	17	16	16
BTM Solar	31	42	41	39	37	35	35	34	34	33	33	33	32	32	31	31	31	30	30	29	29
Wind (Artesia)	25	34	34	34	34	33	33	33	32	32	32	32	31	31	31	30	30	30	30	29	29
Wind (ABQ)	22	30	30	30	30	29	29	29	29	28	28	28	28	27	27	27	27	26	26	26	26
Wind (Lordsburg)	40	46	46	46	45	44	44	44	44	43	43	43	42	42	42	41	41	41	40	40	40
Geothermal	95	96	97	97	97	97	97	96	96	96	95	95	95	94	94	94	93	93	93	92	92

Table 7. Thermal Resource Characteristics

Resource	Heat Rate (MMBtu/MWh)	Variable O&M (2021$/MWh)
Gas Peaker	10.1	$1
Biomass	13.5	$5
Nuclear (SMR)	10.0	$2

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[3] The capacity factor for solar PV differs slightly by location. This value is used for illustrative purposes for calculating the levelized cost of energy.
[4] The levelized cost of energy is not a direct model input. Also, the metric does not indicate the value of individual resources, which is determined dynamically through the capacity expansion model. Nevertheless, the metric can be useful for understanding the relative cost of resources.

Table 8. Lifetime Extension Costs ($/kW-yr) (2021 $)

Resource	Extension Period	Capital + Fixed O&M
Rio Grande 7	5 years	$114
Newman 1	5 years	$79
Newman 2	5 years	$80
Newman 3	5 years	$58
Newman 4	5 years	$47

Table 9. Hydrogen Retrofit Cost ($/kW-yr) (2021 $)

Resource	Additional Cost
Gas Plants[5]	$12

[5] This is the assumed cost of converting a natural gas-fired plant to burn hydrogen fuel.

Appendix B Resource Assumptions

Resource Input	Source of Data
Resource Potential • Technical potential (MW)	*Given the abundance of solar and wind resources relative to the size of EPE's system, no limits are applied for renewables*
Technology Cost • Capital cost ($/kW) • Fixed O&M ($/kW-yr) • Interconnection cost ($/kW)	**NREL Annual Technology Baseline (ATB) for Renewables/Thermal** *Supplemented with regional cost adjustments and interconnection costs from NREL ReEDS datasets* **Lazard Levelized Cost of Storage 6.0 / NREL ATB for Batteries** *Lazard's LCOS 6.0 costs are used for batteries in the near term and the long-term cost decline trajectory from the NREL ATB is applied*
Financing • Project capital structure • Tax credits	**E3 Pro Forma Financial Model** *Calculates price for a long-term cost-based power purchase agreement between a third-party developer and a credit-worthy utility*
Transmission • Existing headroom • Cost to expand transmission	**El Paso Electric System Planning team** *Provided a simplified representation of the transmission system for purposes of determining headroom on the transmission system and the cost of expansion*