El Paso Electric and the Public Interest

<u>What's the problem?</u>

As a regulated monopoly, El Paso Electric (EPE) operates on a cost plus basis. This means it receives reimbursement for all operating expenses plus a profit margin. For shareholders the return on equity is currently 9.48%[1] and is applied to all non-depreciated capital assets, including power plants still in service within the EPE system.[2]

Because of this reimbursement formula, EPE pursues its corporate goal of increased profit by steadily <u>maximizing capital assets</u>, even if these expenditures are unnecessary or if alternatives less costly to ratepayers are readily available.

New power plants are the biggest capital expenditures a utility makes. Unchecked by regulators, EPE has been on a power plant construction spree over the past several years, having built one new natural gas unit (Rio Grande 9) in 2013, two new gas units (Montana 1 & 2) in 2015 and two more (Montana 3 & 4) in 2016. The construction of additional new plants is proposed.[3]

In terms of benefit to EPE ratepayers, these new plants are largely unnecessary.

<u>What is the impact of the construction of unnecessary power plants on local ratepayers?</u>

The new plants cost approximately $95 million each to build.[4] These capital costs plus debt service are borne by EPE ratepayers. <u>If the utility's current and proposed capital expenditures are approved, local residents will pay hundreds of millions of dollars in unnecessary costs over the next forty years</u>.[5]

<u>How could this be happening? Isn't El Paso Electric required to get some kind of approval for new power plants?</u>

The New Mexico Public Regulation Commission (PRC) has the responsibility of approving new power plants requested by the utilities. In practice, the overworked Commission and its staff have generally accepted utility justifications for new power plants with little scrutiny.

Ultimately, the current regulatory process depends on interventions, protests and complaints by independent parties, including industrial users, to challenge EPE assertions. Historically, these parties have intervened at the last stage of the process, the formal rate case. Little attention has been paid to controlling overall costs, but rather to dividing costs among different classes of ratepayers.

This inattention to overall cost has been a grave disservice to area ratepayers, and it has led to an unnecessary and unconscionable transfer of economic resources from local residents to EPE's corporate stockholders.

EPE is a sophisticated, publicly traded corporation valued at more than 2 billion dollars.[6] It has enormous resources at its disposal and a shareholder expectation that corporate managers will maximize profits. This is what EPE is doing, relentlessly and without hesitation, in every position it takes throughout the regulatory process.

How does El Paso Electric justify building new generating capacity to the detriment of local ratepayers?

Utilities justify new capital investment by pointing to the need for sufficient capacity to serve ratepayers at times of peak demand. Unfortunately, given the incentives involved, EPE has consistently and deliberately chosen to address those capacity needs in the most expensive way possible – through the construction of new power plants – rather than utilizing a wide variety of strategies to lower peak capacity needs, or choosing other alternatives that are much less expensive for ratepayers.

What specific strategies has EPE used to justify unneeded capacity?

1. Once a power plant has been fully depreciated, it is in EPE's corporate interest to remove it from the available capacity calculations so that it can build a new plant that can be included in the rate base. The "retirement" of the fully functional Rio Grande 6 plant so that a new non-depreciated plant can be justified is an example of the kind of activity that builds corporate profits while costing ratepayers millions of dollars.[7] In addition to Rio Grande 6, EPE has plans to "retire" five additional plants between 2020 and 2024.[8]

2. EPE bases its projected capacity needs on peak demand: one hour of every year (usually in the afternoon of the hottest day of the summer) when the demand for electricity is highest.[9] This has meant that recently built EPE power plants are only needed a few hours a year for the benefit of local ratepayers,[10] but local ratepayers still bear the costs for plant construction and debt service.

Since the new power plants are only needed a few hours a year to meet peak demand, EPE uses the new plants to generate electricity for sales to utilities outside the EPE service area, at rates far below what is charged to EPE ratepayers.[11] The out-of-system rates are so low that EPE may not always recover costs,[12] but from a corporate standpoint that's fine, because EPE can claim that these new plants are used more than a few hours per year, thus justifying their addition to the rate base. The increased size of the rate base in turn justifies increased overall profits. In essence, this is a strategy to deliberately over-invest in unneeded capacity, with local ratepayers supporting the enterprise by paying for plants that provide them little benefit.[13]

3. EPE uses the few hours of peak demand to justify building new power plants when there are a wide variety of available techniques to lower peak demand in the first place, eliminating the need for new power plants.[14] These techniques for lowering peak demand include:

- providing effective demand response and time-of-use rates that allow consumers to use less electricity at peak hours in exchange for more favorable rates
- prioritizing energy efficiency as a way of lowering both peak and overall demand
- encouraging the addition of distributed rooftop solar by homeowners and businesses so that peak power needs (which always occur during daylight hours in summer) are supplemented by solar power that is producing at high capacity during that same time.

These and similar techniques have proven highly effective for utilities throughout the country that have chosen (or been forced by regulators) to put ratepayer needs ahead of a strategy of using unchecked peak demand to justify unneeded capacity.[15]

Since both peak and overall demand are lowered by solar panels installed by local homeowners and businesses, why does El Paso Electric do so much to discourage solar use by local residents?

The short answer is that EPE can't profit from generating facilities it doesn't own. Any capacity needs that are met by consumer investments can't be used to justify new company investments that would increase the rate base, company profits, and ratepayer costs.

El Paso Electric has:
Lobbied to eliminate tax incentives for distributed solar,
Lobbied for increased regulation of solar providers,
Requested demand charges for customers with solar,
Requested higher rates for customers with solar, and
Required increasingly difficult paper work for customers seeking to install solar.

Distributed solar generation – and improvements in energy efficiency – ultimately lower peak and overall demand, eliminating the need to build more capacity. Given that the profit-calculation formula is based on non-depreciated assets, EPE has consistently discouraged these capacity-lowering options. EPE's corporate priority is to build profit through capital expenditures, not save money for local ratepayers.

Besides the enormous cost to ratepayers, are there any other long-term consequences of EPE's strategy to over-invest in power plant generation capacity?

We are at a point in the history of energy generation that parallels where cell phone technology was a few years ago. The cost of renewable energy is plummeting. New storage technologies, which allow energy to be stored when there is an excess, for use when demand exceeds generation capacity, are being developed and brought into production daily. We have already reached the point where utility-scale solar plants in the Southwest cost significantly less to own and operate than new fossil fuel plants of the type EPE is planning to build.[16] Projected fuel costs alone for fossil fuel plants are higher than total construction and lifetime operating costs for a comparable utility scale solar generating facility.[17]

Any new conventional fossil-fueled plants that EPE builds would still have to be paid for by local ratepayers. Ratepayers would be chained to uncompetitive facilities, still transferring payment to corporate stockholders, for the two-to-five-decade life of the higher cost plants. This may explain some of the utility's haste in getting these plants built. But this is a recipe for continued impoverishment of our border region.

Fossil-fueled power plants add to air pollution with large quantities of green house gases.[18] And, significantly for our desert region, EPE's gas fired power plants use large quantities of water.[19]

An additional often-overlooked consequence occurs in the area of economic development. Investment in home and business solar installations, in energy efficiency, and in consumer demand-lowering technologies would create hundreds of good-paying local jobs,[20] while investment in large generating plants creates almost no local jobs at all. This should be an important consideration for local leaders and residents.

So what should we be doing instead?

EPE points to their high dollar investments as a good thing.[21] As we have seen, much of this investment, especially in new generating capacity, is more important for establishing an inflated profit base than it is for delivering inexpensive reliable power to local residents. A ratepayer-favorable strategy would be to keep capital costs as low as possible, with a goal of ever-lower rates for power users over time.

The good news is that community leaders have become aware of the underlying dynamics of EPE's corporate strategy as it affects its policies and proposals for our energy future. Public Regulation Commissioners and hearing officers have also begun to question utility assumptions and representations.[22]

Especially important have been decisions by the City of Las Cruces and Doña Ana County to intervene in the entire regulatory process, including in decision-making about new plant construction and other key factors in sound energy policy. Of equal significance is their decision to intervene on behalf of all residents, and not just relative to rates for streetlights or other narrow governmental interests. These decisions have already proven very important in the 2015 EPE rate case, in which the original EPE rate hike request of $8.6 million was, with vigorous city and county involvement, lowered to just $1.1 million.[23]

These interventions have the potential to save millions of dollars for local governmental entities and hundreds of millions of dollars for local residents in coming years. In the process, they will make clear the inconsistencies and structural constraints in the current rate making process. This, in turn, will hopefully lead toward changes in policy at the legislative level that better align utility goals with the economic futures of local individuals, businesses, families and our overall community.

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References in this report are available via endnotes to the online version, available at WWW.LifeIsGood2.com/EPE/report.pdf

[1] New Mexico Public Regulation Commission (PRC) case 15-00127-UT "Final Order Partially Adopting Recommended Decision (with Corrected Paragraph Numbering)" 8 June 2015 page 38 paragraph 77: "For the foregoing reasons, the Commission rejects EPE's Exceptions, and approves an ROE of 9.48% in this case." EPE's capital structure also includes debt (bonds) and the approved return on debt is 5.90%. The overall Rate of Return (RR) is: RR = RD * (D/T) + RE * (E/T)

Where:

RD = Return on Debt (bonds)

D = amount of Debt

RE = Return on Equity (stock)

E = amount of Equity

T = D + E (total capital)

[2] New Mexico uses traditional rate of return regulation for public utilities. The PRC determines which assets are allowed into rate base and sets the rate of return the utility is allowed to earn on those assets. The rate base assets are depreciated with the depreciation being charged to rate payers as an expense. A set overall rate of return is allowed on Rate Base (RB) - the remaining, non-depreciated assets. According to an NMSU Center for Public Utilities course on The Revenue Requirements Process by Bill Steele and Gary Duncan, Rate Base is calculated as:

RB = OC – D + WC + MS – CD – RT

Where:

OC = Original cost of physical assets

D = Accumulated Depreciation

WC = Working Capital

MS = Materials and Supplies

CD = Customer Deposits

RT = Reserve for deferred Taxes

And the formula for Revenue Requirements (RR) is:

RR = O + T + D + (R * RB)

where:

RR = Revenue Requirement

O = Operating expenses

T = Taxes

D = Depreciation

R = Overall Rate of Return

RB = Rate Base

[3] EPE's 2015 Integrated Resource Plan (page 79) lays out EPE's expansion plans for the next 20 years (through 2034). Of 1287 megawatts (MW) of planned additions more than 92% are fossil fueled. The first new fossil fuel plant is planned for 2022. EPE has issued a Request For Proposals (RFP) dated 30 June 2017.

[4] EPE's four most recent power plant purchases were LMS100 gas turbines. Montana 1 and 2, including the cost of common, switchyard, and transmission facilities had a combined cost of $213.1 million. See table ARR-1 in the direct testimony of A Ramirez, case 15-00127. Montana 3-4, including additional transmission facilities, do not yet have an approved cost, but in the Montana 3 & 4 CCN case were estimated to cost a combined $168 million. This calculates to an average cost of $95 million per plant or $1.08 million per MW of peak capacity.

[5] The fixed cost of Montana 1 – 4 over a 42 year timeframe beginning in 2012 is estimated to be $1.95 billion. ($1,951,524,000**).** This number is calculated by adding an additional calculation summing the revenue requirements of Montana 1 – 4 minus variable O&M and fuel costs (row 51 added in red) to a spreadsheet supplied by EPE during the Texas Montana 3&4 case. (Microsoft Excel is required to view this spreadsheet).

[6] As of December, 2016, EPE claims total assets of $3.38 billion. Market capitalization as of 19 March 2018 is $2.01 billion. See EPE's investor page.

[7] The decision to "retire" Rio Grande 6 for planning purposes was challenged by ratepayer Allen Downs in a formal complaint against EPE, PRC case# 16-00017-UT, and is currently being challenged by Merrie Lee Soules' petition for declaratory order in case# 17-00317-UT.

[8] When applying for permission to build Montana 3 and 4 (CCN case 13-00297-UT), EPE witness R. Acosta testified to these anticipated "retirements":

Rio Grande 6	2014
Rio Grande 7	2020
Newman 5 (phased out)	2021-2023
Newman 1	2022
Newman 2	2023
Newman 3	2024

[9] EPE forecasts peak load by estimating the amount of energy (kilowatt hours) that they expect to sell in a given year. They then divide that number by the previous year's load factor. See the direct testimony of G. Novela page 7 and his oral testimony at page 825 of the transcript in rate case 15-00127-UT. Load factor is average load divided by maximum load over a given time period.

EPE measures peak load by averaging maximum Megawatt load over a one hour period as required by the Federal Energy Regulatory Commission (FERC) Form 1 (Annual Report of Major Electric Utilities). For 2016, EPE's maximum load was 1915MW which occurred on 14 July during the 4PM hour. EPE's FERC Form 1 can be found at https://www.epelectric.com/investor-relations/regulatory-filings under the "FERC" tab. Peak load will be found at page 401b.

EPE targets its generation capacity at 115% of peak load. According to EPE, the 15% planning reserve margin is set higher than for neighboring utilities because EPE's territory is located at the edge of the Western Electricity Coordinating Council (WECC). See EPE's 2015 IRP, page 56.

[10] Between 2011 and 2014 EPE native load was within 10% of peak less than 150 hours per year, and was within 5% of peak less than 30 hours per year. See Downs direct testimony page 16 in rate case 15-00127-UT.

[11] EPE's 2014 FERC report page 311 shows that 3,322,053 MWh were sold off system for $97,398,726 for an average price of 2.932 cents per kWh.
EPE's 2014 FERC report page 304.2 shows that 7,625,640 MWh were sold on-system for $785,060,830 for an average price of 10.30 cents per kWh.
Power sold off-system was 30.345% of total power sold in 2014: 3,322,053MWh / (3,322,053MWh + 7,625,640MWh). The 2014 FERC Form 1 report was an exhibit in the 2015 rate case.

[12] According to EPE's 2014 FERC Form 1 report the plants with the lowest fuel costs are:

Plant	Fuel Cost/kWh	MW Capacity	FERC Page	
Palo Verde	$0.01	633	402.1	
Four Corners	$0.02	108	403	(Abandoned in 2016)
Rio Grande 9	$0.043	89	402	
And the least efficient plant (highest fuel cost) is:				
Copper	$0.086	64	403	

Since off-system sales in 2014 were at an average price of 2.932 cents per kWh (FERC Page 311 shows 3,322,053 MWh sold for $97,398,726), and since the Palo Verde and Four Corners plants totaled 741MW, any time during 2014 when the on-system load exceeded 741 MW, the marginal cost of fuel (4.3 cents per kWh or higher) would be higher than the 2.932 cent average off-system sale price, and off system sales could be at a loss. Marginal fuel cost at peak in 2014 was as high as 8.6 cents per kWh – the approximate fuel cost for the Copper generation plant. Of course the fuel cost/ kWh for Rio Grande 9, Copper, and all gas fired generation will vary with the price of gas.

[13] This write up by Mr. Fischmann explains that when off-system customers pay less than the full cost of power, ratepayers must pay more than full cost.

[14] EPE's unwillingness to consider alternatives to new plant construction provides the basis for Merrie Lee Soules' Protest to EPE's Integrated Resource Plan (PRC Case #15-00241-UT).

[15] See Northwest Power and Conservation Council's Seventh Northwest Power Plan with special attention to its Executive Summary and to Chapter 14, which addresses Demand Response resources. For an example of an existing Time of Use consumer rate structure

see Pacific Power's Time of Use Hours and Pricing and for a discussion of how solar generation can lower peak demand, see Reducing Peak Demand with Solar Energy and Distributed Solar Helps Lower Demand Electricity Prices.

[16] According to a 2015 Berkeley Lab study of Utility-Scale Solar, most solar PPA's are priced at or below $50/MWh, with some as low as ~$30/MWh, levelized in real 2015 dollars. EPE's 2015 IRP places the cost of a combined cycle gas plant at $82/MWh and Montana 1-4 type generators (LMS100's) at $111/MWh.

[17] Looking at fuel costs for the combined cycle gas plant that EPE proposes to build in 2022, the average of fuel prices as given in EPE's 2015 IRP beginning in 2022 is $5.76/MMBtu. Multiply fuel cost by the heat rate for a combined cycle plant of 6800 BTU per KWH and the fuel cost averages more than $39.00 per MWh.

[18] The US Environmental Protection Agency (EPA) states that carbon dioxide is the primary greenhouse gas pollutant, and the electric power industry is responsible for 32% of US greenhouse gas emissions. EPE's 2015 IRP says that the type of power plant used in EPE's Montana Power Station (LMS100's) generate over 1000 pounds of carbon dioxide for each Megawatt-hour of electricity.

[19] EPE's Montana power plants are GE LMS100's which use evaporative coolers to cool the combustion air on hot days. In a siting study for the Montana Power Station, conducted by Black & Veatch water usage was estimated at 2,500 gallons per minute or 3,600,000 gallons per day under "Hot Day" conditions for generic power plants.

[20] According to CNBC, one in fifty new jobs in 2016 was in the solar industry. An article on Energy.gov says in 2015 the solar workforce grew at a rate 12 times faster than the overall economy.

[21] In a June, 2016 "Marketing Tour" presentation aimed at investors, EPE claimed "Consistently increasing peak load growth and customer base" and "Sizeable capital expenditures plan and resulting rate base growth for the next several years".

[22] For example, the PRC hearing examiner in IRP case 15-00241 objected to EPE's removal of Rio Grande 6 from its list of utility owned generation and required that it be relisted.

[23] EPE requested a New Mexico revenue increase of $8,591,997 in the 2015 rate case 15-00127-UT. See the rate case executive summary page 2. EPE received a $1,096,144 revenue increase. See rate case exhibit JS-3 (GC revised) page 2 of 2. EPE will be asking for additional rate increases in another rate case expected to be filed in Spring of 2019 (delayed from Spring, 2017). See Sun-News editorial.