November 30, 2017

Integrated Resource Plan
Public Advisory Group: Public Input and Requests
Meeting Date: October 26, 2017

Questions received in notecards during PAG meeting

PAG Q1:

Is there a list of who EPE is getting power from other companies…also is there a list of companies that EPE sells to?

EPE Response:

A listing of companies that EPE transacts with for sales and purchases of wholesale power are found in EPE's annual FERC Form 1. The latest FERC Form 1 filing may be found in the FERC e-Library at the following link.

https://www.ferc.gov/docs-filing/elibrary.asp

PAG Q2:

Are 440 found on your website?

EPE Response:

Not on the EPE public website, but all EPE 440 filings are available through the NMPRC website, Case Lookup Edocket.

PAG Q3:

What is the process for determining what companies look at for power plants and their condition of the plant? How are they hired to do a look at these plant - what are the requirements?

EPE Response:

EPE utilizes firms that have a business segment for power generation and have established experience in the industry of power generation. EPE also leverages the use of firms that may already have experience directly with EPE power plants as they would already be familiar with the equipment and history given past work for EPE.

PAG Q4: Is there a coincident peak output and/or capacity factor for each resource. Is there a "factor for other peak" such as a 4CP? Call it contribution factor at peak.

EPE Response:

EPE estimates a capacity factor for each generation resource which indicates the expected capacity available from that resource at the anticipated time of system peak demand. EPE does not estimate a combined factor for capacity availability over a wider range of hours, but it would be assumed to be comparable.

PAG Q5:

Please model a TOU programs that will

1. Reduce peak 300 MW for 15% of peak hours
2. Reduce peak 150 MW "
3. Reduce peak 50 MW "

This should be TOU for residential, small commercial and general rates. Please show what the rates are to accomplish this.

EPE Response:

Voluntary and mandatory rate structures impact the magnitude and timing of customer demand and consumption. EPE plans to reflect the impact of expanded TOU participation in demand forecast sensitivities used in Strategist modeling. The model will reflect estimated customer usage impacts across rate classes and for specific rate differentials.

PAG Q6:

Please provide the backup information for the 440 filing for the transmission line from Rio Grande to Sunset ~$16M. It is important for EPE and ratepayers to determine the study and justification is adequate before it is built. If the expenditure will not be sufficiently justified it was stated that it is solely EPE's risk (Schichtl). The information in the 440 filing is insufficient for inclusion in rate base. If the information remains insufficient for inclusion in rate base, will EPE cancel the project? Are all T&D projects individually justified? If so, is that information available? If so, where?

EPE Response:

EPE's NMPRC Notice of Filing No. 67 "Upgrades to Transmission Lines from Rio Grande Substation to Sunset Substation and Sunset North Substation" provides the information required under Rule 17.5.440 NMAC. Rule 17.5.440.9(B) provides, in part, "(t)he report required to be filed under Subsection A of 17.5.440.9 NMAC is for informational purposes and shall not constitute nor be deemed to constitute an application by the utility for authority to engage in the reported undertaking, but the filing of a report under Subsection A of 17.5.440.9 NMAC shall not preclude the commission from taking any action which it deems appropriate with respect to the reported matter."

Capital expenditures are reviewed by the Commission in general rate case proceedings, where EPE has the burden of proving that the expenditures were just and reasonable, and that the facilities are used and useful and necessary for providing service. Cost data supporting T&D projects approved by the NM PRC for recovery in base rates in EPE's most recent rate case proceeding is provided in EPE's filed application in Case No. 15-00127-UT. In Texas, all T&D projects included in rates were supported by information filed in PUCT Docket No. 46831.

PAG Q7:

Please have Burns & McDonald analyze the power plants for extended life.

Hrs. per year	A	B	C	D
1. 3 years	50	100	150	300
2. 5 years	50	100	150	300
3. 7 years	50	100	150	300

Please also analyze Rio Grande 6 as well as the 3 plants listed. Please confirm the resource lead time is 5 years or some other time frame from decision to do an RFP to Plant in service.

EPE Response:

EPE will take this request into consideration in determining if there are viable intervals for evaluation. However, the conceptual approach requested is for the most part not conducive to requirements given the type of units that are being evaluated for retirement. The units being evaluated for retirement are conventional steam units that are not intended to be used for daily cycling or quick start-up.

Approximate lead time may be from 5 to 6 years from RFP to commercial operation.

PAG Q8:

What amount of DG other than solar is included in the DG projections? In MW.

EPE Response:

EPE's present projection for DG only includes solar as no other significant DG resources have been interconnected.

PAG Q9:

In the last 7 years, has there ever been a customer reported problem due to interruptible sales interruption requests? If so, what was the problem(s)?

EPE Response:

Assuming this question refers to customer non-compliance with requests for interruption by EPE – there have been instances of non-compliance by customers in the last 7 years. Noticed interruptible rate schedules in Texas and New Mexico include non-compliance provisions which require rebilling at firm rates of customers failing to comply with requested interruptions. Customers are not required and typically do not indicate specific reasons for non-compliance.

PAG Q10:

Please provide the complete justification and calculation of interruptible rates for the ~2015 NM rate case and the 2017 Texas rate case. Rate 38 TX and Rate 29 NM. Please show the value used for the peak MW and each 4CP. Please provide the complete justification and calculation from the most recent rate case for separately (Texas & NM).

1. All residential rates – both DG and non DG
2. Large Power Service – Rate 25 TX, Rate 9 NM
3. EVC – electric vehicle

Please show the value for the peak MW and each 4CP hour.

EPE Response:

All of the requested information supporting rates filed in the 2017 Texas rate case is available on the Public Utility Commission of Texas website for Docket No. 46831. All of the requested information supporting rates filed and approved in the 2015 New Mexico rate case is available on the New Mexico Public Regulation Commission website for Case No. 15-00127-UT.

Email 10/29/17

Questions from the October 26, 2017 Public Advisory Group meeting:

PAG Q11:

I have understood EPE to say that the Energy Efficiency forecast in the Loads & Resources Table had been revised from the previous Energy Efficiency forecast. When I compare the Energy Efficiency forecasts in each of the past four L&R Tables, it appears as if every year they are reduced to the point that the latest L&R Table has the value of Energy Efficiency smaller than any previous forecast. I thought I understood Ms. Susanne Stone to say that the Energy Efficiency programs were exceeding expectations. Please explain.

	2015	2016	2017	2018	2019	2020	2021	2022	2023
Energy Efficiency (Line 4.3 in the L&R)									
2013 Forecast (May 14, 2014)	14	20	27	34	41	40	40	40	40
2015 Forecast (May 29, 2015)		11	17	22	28	34	39	45	50
2016 Forecast (May 25, 2016)			11	16	21	27	32	38	43
2017 Forecast (May 12, 2017)				10	14	19	24	29	34

EPE Response:

The EE forecast amounts shown in the L&R represent additional EE in each year over and above the amount of energy efficiency savings reflected in the native system demand for the first year of the L&R. The forecasts as denoted in the L&R and in the table do indicate relatively consistent growth from year to year in the range of 5 to 6 MW. The appearance of it being lower is due to the fact that the first year in each row resets to the projected value for that year.

PAG Q12:

Attached please find documents representing circumstances at peak demand periods for both 2015 and 2016 showing EPE Off-System Purchases at Native and Total System Peaks. Please confirm that the difference of 198 MW in 2015 at peak and 135 MW in 2015 at peak is due to off-system sales. If not due to off-system sales, please clarify what was taking place in each year at peak. Also, please confirm that EPE was purchasing supplemental power at this total system peak as represented by the purchases identified as “Delivery”. If this is not correct, please clarify. On the premise that EPE was purchasing power at the same time it was making off system sales, please provide the price charged for those off-system sales at that time. Please provide comparable information for the 2017 peak, both native system peak and total system peak.

EPE Response:

The Native Peak Hour and Total System Peak for 2017 are 1,935 MW and 1,982 MW respectively.

The differences of 198 MW and 135 MW in 2015 and 2016 are due to the net inclusion of firm sales and losses payback. It was previously confirmed that during the 2015 and 2016 peaks those sales were all coupled with corresponding equivalent MW purchases.

The same is true for the 2017 peak values. The prices of the coupled purchases and sales are not relevant to the IRP process.

PAG Q13:

Please provide definitions for the terms "Availability Factor" and "Capacity Factor" and an equation and example for calculating each.

EPE Response:

Availability Factor: Percent number of hours a resource is available for generation. This is net of both planned and unplanned outage expectations.

Availability Factor = (Available Hours)/(Number of Hours in Period) x 100%
= (8,000 / 8,760) x 100% = 91% annual AF

Capacity Factor: Percent of energy generation versus nameplate capacity for the hours in the period.

Capacity Factor = [Net Energy Generation/(Net Nameplate Capacity x Hours in Period)] x 100%
= [1,000,000 MWh / (150 MW x 8,760 hours)] x 100% = 76% annual CF

PAG Q14:

Please provide a definition for the term "Contribution at Peak" and clarification of any instance where this is used in the L&R Tables, in Strategist, or in other planning scenarios.

EPE Response:

Contribution at Peak is utilized as a descriptor of how much a resource that is non-dispatchable and intermittent will generate coincident at peak hour. Contribution at Peak is utilized for solar in the L&R and the planning process.

Wind would also be a resource that also has a Contribution at Peak consideration.

PAG Q15:

Please clarify what historical information was used to create the distributed generation forecast, the detailed rationale for the forecast, and specifically whether it is based on the information included on page 35 of Mr. Paul Garcia's presentation from August 8, 2017. If other information was used for the forecast, please provide that information.

EPE Response:

EPE's distributed generation (DG) forecast is primarily driven by DG customer count growth. EPE is currently using the previous two (2) calendar years (2015 and 2016) of annual DG customer growth to estimate future growth. Using 2 years of data helps reduce the volatility that a one (1) year data set would provide while at the same time still using a current data set. EPE's DG forecast does not use the same DG customer counts that were on page 35 of Mr. Paul Garcia's presentation. Mr. Garcia presented the amount of DG customers that have interconnected on EPE's system. The DG forecast uses a similar count; however that forecast is not based on the date of interconnection; rather, the DG forecast customer count is based on when the DG customer received their first bill. Please see the table below, for the DG customer counts that were used as inputs to the DG forecast.

	2014	2015	2016
TEXAS	465	1,120	2,195
NM	1,759	2,056	2,403
TOTAL	2,224	3,176	4,598

PAG Q16:

Please confirm that Rio Grande 6 was used for generation in 2015, 2016, and 2017. Please confirm that Rio Grande 6 is considered inactive reserve.

EPE Response:

Rio Grande 6 was utilized in 2015, 2016 and 2017. Rio Grande 6 is designated as Inactive Reserves at 60 days past its last operating date.

PAQ Q17:

Please include Rio Grande 6 in the retirement analysis that EPE has requested of Burns and McDonnell for the purpose of evaluating retirement dates via the Capacity Expansion model, as per Joint Stipulation Case No. 15-00241-UT, as footnoted on page 36 of Mr. Gallegos presentation dated September 7, 2017.

EPE Response:

The reference to Joint Stipulation 15-00241-UT is for units planned for retirement in the first five years of the next IRP planning horizon. Retirement of Rio Grande 6 is not included in this period.

PAG Q18:

Please provide the exact request that EPE has made of Burns and McDonnell regarding the analysis of generation resources being considered for retirement.

EPE Response:

EPE requested an analysis of Rio Grande 7, Newman 1, and Newman 2 to assess the condition of the units and estimate costs of repairing, retrofitting, maintaining and operating the units to extend their useful life to 2037 (the end of the 20 year planning window).

PAG Q19:

Please adjust the L&R Table to remove any presumption of retirements for generation resources that are not included in the Burns and McDonnell analysis.

EPE Response:

This request is contrary to the planning process requirement of considering retirements as denoted by the rule. The 2015 IRP stipulation agreement did not state that retirements would not be planned within the 20 year window, rather, it stated EPE would evaluate retirements within Strategists (or comparable model) for any planned retirement within a 5 year horizon. EPE's base case assumption in the L&R for purposes of the IRP include unit retirements on the expected retirement dates, pursuant to 17.7.3.9(C)(5).

PAG Q20:

Please correct the interpretation that generation resources should be analyzed as not retired for the entire 20 year planning period. This interpretation has been credited to me (Merrie Lee Soules) on behalf of the PAG participants and that is not the intent. Please assure that Burns and McDonnell will evaluate retirement potential on an incremental basis, such as every three years.

EPE Response:

The scope of the analysis is to extend Rio Grande 7, Newman 1 and Newman 2 to 2037. As stated in EPE's response to PAG Q7 in this document, EPE will assess what shorter interval, if any, is viable for evaluation. As EPE shared on slide 17 of the October 26, 2017 presentation, these three units are at the highest end of unit age in the industry for units in operation. Units reach a point where any further life extension requires certain retrofits/repairs regardless of the interval being considered.

PAG Q21:

Please clarify what is meant on page 16 of Mr. Gallegos presentation of October 26, 2017, by the last bullet – "Additional system reliability will be considered for the portfolio (e.g. regulating reserve capability considering amount intermittent generation selected)

EPE Response:

EPE's July 6, 2017 presentation provided material on operational and reliability requirements related to serving load reliably. Many of the items focused on the ability to balance resources and loads. This included the impacts of intermittent generation resources on the ability to balance load and resources. EPE's October 5, 2017 presentation included several slides and discussion on the impacts and consideration of intermittent resources. As such, the ability to reliably balance is a result of the total portfolio of resources. If the resulting IRP portfolio were to result in a greater amount of intermittent generation, then corresponding complimenting resources would be required that provide dispatch flexibility to address the variability of intermittent generation and load variability.

Email 11-13-17

PAG Q22:

I have a question concerning the "Generic Hourly Solar Profile" given on page 51 of the 5 October Meeting 7 presentation.
It is my understanding that the numbers in yellow represent the hourly output in MW of the Macho Springs 50MW solar installation. I also understand that the data in the blocks with dashed outline (May to Sept, 11AM to 4PM) represent peak hours.
You have said previously that in preparing a loads & resources document, you use 70% of rated output as the expected contribution from solar at peak.
But using the data in the "Generic Hourly Solar Profile", I calculate an average solar output of 87% at peak. By peak month, May is highest
(91%) and Aug is lowest (79%). By peak hour, 12-13 is highest (93%) and
15-16 is lowest (76%). All of these numbers are above the 70% number that you use in L&Rs.

If "Generic Hourly Solar Profile" presents real data from Macho Springs, and the blocks with dashed outline represent the period you use when calculating output at peak, why aren't you using 87% of rated solar output (or some other value between 76% and 91%) as the expected contribution from solar at peak?

EPE Response:

The 70% contribution at peak that EPE has utilized is based on the coincident output from EPE's utility scale solar facilities at peak hour during the peak months. For example, this is typically hour ending 5 pm for the months of June to September.