Questions from Phil Simpson email.

1. In III., DESCRIPTION OF EXISTING RESOURCES, C., Demand Side Resources, 2. New Mexico Energy Efficiency programs, Table 6 lists the New Mexico Annual MW Demand Savings (at Meter) in 2019 as 8.732 MW, and 3. Texas Energy Efficiency Programs, Table 7 lists the Texas Annual MW Demand Savings (at Meter) in 2019 as 14.181 MW. Why do the Loads and Resources Tables 11 and 25 both show only 9 MW of Energy Efficiency in 2019 rather than the combined NM and TX EE savings of 23 MW?

EPE Response: The Energy Efficiency (EE) demand savings listed in the referenced tables are total demand savings summed for each program. The Loads and Resources tables reflect the actual demand savings at time of peak. EPE does this by applying a coincidence factor to the demand savings that result in the demand savings at the time of peak. Additionally, the Texas Load Management savings, 7 MW, is removed from the forecasted EE savings. The load management program is a year to year program with no commitment by the customer for participation in future years. While EPE's interruptible rate requires the customer to give a year's advance notice of termination, there is no such requirement for customers in the load management program. It is a voluntary program and customers may opt out of the interruption or the program itself with minimal consequences; however, no incentive is paid if they do not comply so there is financial motivation to interrupt when called upon.,

2. Regarding the Native System Peak Demand Forecast Scenarios in the IRP Section IV., Current Load Forecast, Figure 4, EPE modeled a big uncertainty in 2018 Peak Demand, and uncertainties in future loads similar to 2018, but no uncertainty in future growth. In reality the 2018 Peak Demand is relatively well-known, but the future growth is more difficult to predict. Please adjust the methodology to reflect the fact that uncertainty in demand is much larger for 5, 10, or 20 years in the future than for 2018. If EPE does not change the growth curves to reflect that growth in uncertainty, please explain why. Essentially, why doesn't the uncertainty in load increase over time due to uncertainty in load growth?

EPE Response: In general, EPE produced both upper and lower (high and low) scenarios for both native system energy and native system peak demand to account for future uncertainty. The figure that was shown at the Integrated Resource Plan on July 19, 2018 had two types of upper and lower scenarios. One type was based on extreme weather and the other was created using confidence intervals.

These weather based scenarios pulled 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.

The confidence intervals scenarios are built using 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. These confidence intervals scenarios do get wider over time.

3. No Load Management is apparent in the L&R Table (Draft IRP, page 62, Table 11 – Initial L & R) other than the constant 54 MW of Interruptible Sales. There seems to be no load shifting due to the advances described at the end of IRP Section IV, IDENTIFICATION OF RESOURCE OPTIONS (EXISTING CHARACTERISTICS AND INTERACTIONS). Multiple changes to rate structures are listed that EPE says "can, over the long term, impact the system profile sufficient to impact resource planning". Time of Use (TOU) rates incentivize customers to shift energy usage from peak to non-peak times, thus shifting load to non-peak times and reducing peak demand. Table 15, Rate Structure Development, shows the Advanced Metering Initiative (AMI) to be implemented in 3 to 5 years, which will enable TOU as well as dynamic pricing (Critical Peak Pricing and Peak Time Rebate) to "provide incremental reductions in

on-peak usage already reduced in response to TOU pricing differentials." Why do these planned reductions in demand not have an impact on load growth, or at the very least show up as alternate, lower growth curves with decreased growth in load?

EPE Response: Load reductions based on the items listed in Section IV may be correlated to the low load forecast shown on Figure 4 and Attachment B-1.

4. Regarding Interruptible Sales in the L&R Table, the constant 54 MW level does not seem appropriate. Why don't the Interruptible Sales grow as AMI enables Interruptible Rates to be applied to residential and small commercial customers, as well as the larger commercial, industrial and irrigation customers now able to participate? (Draft IRP page 77, Rate Structures Incorporating Load Management or Load Shifting Concepts).

EPE Response: The interruptible rate is closed to new customers, so the 54 MW is considered a constant in the L&R. Demand Response was modeled as a Demand Response Pilot Program.

5. How did EPE calculate that 25% is the portion of nameplate solar capacity that can be relied upon at peak load with a 95% confidence level? (Section IX., page 89). A comprehensive description of the methodology is needed to justify this severe de-rating of solar capacity. Some specific aspects of this question include:

a. Does the 25% solar contribution at peak account for single axis tracking used in utility scale solar? (7/19/18 presentation page 11) (I think Omar said yes, verbally, but would like to confirm).

b. What day of the year was assumed for peak load?

c. How much of the degradation down to 25% was due to geometry (angle of incidence), and how much was due to weather (clouds)?

d. Regarding cloud cover, how many solar sites were used, and how far apart were they? Geographic diversity improves solar reliability since cloud cover is less likely to impact all solar generation sites simultaneously.

e. Possibly a typo, but where did the number "230 MW" come from on page 89 when the related discussion was about a 400 MW number?

EPE Response: Recognize that the 25% contribution to peak seems severe; however, EPE took the approach of attempting to maintain the same 15% planning reserve margin. There various ways that utilities have addressed the variability of solar in their planning. Some utilities will credit solar with a higher expected contribution to peak, but then they also increase their reserve margin to provide a back-up to solar. The end results of both approaches end up with added capacity being added due to the solar variability. We will continue to explore this topic of solar contribution to peak as part of on-going efforts and do welcome your input and feedback.

Looking at some of the past presentations on renewables that were part of the IRP, an example was shared for a June 2016 day when solar output dropped to the low 30% range on a high load day. So while 25% seems drastic, an actual occurrence where output dropped to a value that was close to the 25% supports the consideration.

a. Yes, it is in part based on the existing facilities EPE has which all but one are single-axis tracking (either single-axis or azimuth tracking, only our Hatch facility is dual-axis tracking).
b. It considered the top 100 load hours throughout the peak months.
c. The variability is attributed to weather variability (cloud cover) that would reduce production.
d. This value was based on six facilities anddispersion based on EPE's utility-scale solar facilities located within EPE's system from Deming, NM to east El Paso, TX.
e. This was a typo. It is corrected in the updated report. It should be "400 MW".

6. In IX., DETERMINATION OF THE MOST COST EFFECTIVE RESOURCE PORTFOLIO AND ALTERNATIVE PORTFOLIOS, page 90, regarding wind resources, the IRP states "its output profile is a lot less consistent and highly variable than solar." This seems contradictory or at least ambiguous; does this mean less consistent and more highly variable?

EPE Response: This was a typo. It is corrected in the updated report. "its output profile is a lot less consistent and highly variable when compared to solar."

7. In IX., page 92, regarding Retirement Analysis, the IRP states "The retirement analysis was performed in Strategist where the unit extensions were introduced as options competing against the IRP resource options as part of the Base Case. The respective capital and project O&M expenditures were utilized for each option". What were those prices? Will that analysis be provided as part of the IRP?

EPE Response: EPE will add a summary table for these costs.

8. In IX., page 92, regarding Retirement Analysis, the IRP states "This analysis applies to Rio Grande Unit 6, Rio Grande Unit 7, Newman Unit 1, and Newman Unit 2 for this IRP, as they are planned to retire in 2022." However, the L&R table indicates Rio Grande 6 retires at the end of 2018. Please clarify this discrepancy.

EPE Response: This was a typo. It is corrected in the updated report. "This analysis applies to Rio Grande Unit 6, which has a planned retirement of 2018, as well as, Rio Grande Unit 7, Newman Unit 1, and Newman Unit 2 for this IRP, as they are planned to retire in 2022. "

9. In IX., Table 12 – IRP Resource Options Input Assumptions, the Capital Costs ($/kW) for Demand Response is listed as $15.25, and the Fixed O&M ($/kW-yr) is $444.30. These numbers are very different from those presented by EPE in the October 5, 2017 presentation. Can EPE please explain the difference or how those prices were calculated? A notation states that Demand Response O&M costs include customer incentives. Does this line refer to the Demand Response Pilot Program, with costs of $125 per customer enrollment, and $25/year incentives, or to some enhanced demand response program?

EPE Response: The differences are due to some of the costs being shifted out of capital expenditures into O&M to capture the dollar amounts required for maintenance of the program.