July 28, 2017

Integrated Resource Plan
Public Advisory Group: Public Input and Requests
Meeting Date: July 6, 2017

I. Questions submitted in writing at the 7/6/17 meeting to be responded in writing by EPE

PAG Q1:
If all of Dona Ana capacity was replaced by solar DG,
a. What cost impact will it have on EPE system?
b. Will additional transmission lines be required?

EPE Response:
The scenario presented may seem simple and direct at first; however, there are many complex implications as it relates to load balancing, system regulation, back-up capacity and operational impacts to equipment utilization. In addition there are numerous assumptions that need to be made to respond to the question. For example, does "all of Dona Ana capacity" include night time load?

There are several variations of this hypothetical, two being –

<u>Hypothetical No. 1</u>
Distributed generation ("DG") is installed throughout a region of EPE's service territory (e.g. Dona Ana County) such that the peak capacity of the installation equals the peak capacity of the region on a non-coincident basis - the peak demand of the region occurs outside the peak of the distributed generation profile.
<u>Hypothetical No. 2</u>
Distributed generation is installed throughout a region of EPE's service territory (e.g. Dona Ana County) such that the peak capacity of the installation equals the peak capacity of the region on a coincident basis - the peak demand of the distributed generation profile is equal to the region demand at the time of the DG peak..

Under each scenario, there will be the following impacts on cost and transmission lines:

a. Potential cost impacts
   i. Variable cost ($) reduction (fuel and O&M) resulting from reduced operation of existing system resources, reduced losses
   ii. Cost impact on variable O&M rate ($/MWh) (unit) on a per unit basis resulting from modified dispatch of existing resources, heat rate penalty, etc.
   iii. Cost impact on of maintaining local generation for voltage support, backup, firming and shaping
   iv. Cost Impact of excess generation on off-system sales
   v. No impact on existing capacity costs (distribution, transmission, production)
   vi. Cost impact associated with DG energy/capacity valuation

b. Transmission impacts
   i. No additional / reduced transmission requirement
   ii. Unknown impact to distribution and substation equipment requirements due to potential for increased regulation requirements

PAG Q2:
Same as #1 except assume the solar DG is combined with Demand Response that adjusts for all solar production variation.

An additional cost impact would be the cost associated with demand response/storage needed to adjust for all solar production variation.

EPE Response:
Please see EPE's response to PAG Question #1

PAG Q3:
Is there any substation impact if DG is on a community basis such as every 3rd house w/ 3x capacity instead of an exact amount 1:1 for each house?

EPE Response:
In order to respond to this question, additional assumptions need to be made. It is assumed this question implies that "3x capacity" implies to a capacity that equals 3 times the home's peak load. If this is the case, there would be potential impacts on the distribution system prior to the substation. The reverse power flows from the home into the distribution system may require to upgrade the service drop and/or transformers feeding the homes. A similar effect may occur in the substation where the potential exists to impact equipment due to the reverse flows. Additionally, any such high amounts of solar DG on a feeder have the potential to cause voltage fluctuations due to the intermittent nature of solar which would need to be mitigated by substation equipment. It should also be noted that the protection and control systems would need to be modified to consider the reverse flows.

PAG Q4:
What is required for AMR to be used for TOU instead of just quantity?

EPE Response:
EPE's existing Automatic Meter Reading ("AMR") meters cannot be used or reconfigured to serve as Time of Use ("TOU") meters to deliver the time interval, granular, meter data that is required to support a robust TOU tariff. So, the current AMR meters would have to be replaced with a different meter capable of recording and remitting time interval data. The presently deployed AMR (Itron model #C3SR) meters do not have recording and remote data reading/access capability. Furthermore, these replacement TOU capable meters (with recording and data reading/access capability) would only work in conjunction with installation of a supporting communication system by which the meter data could be collected and processed for tariff application.

PAG Q5:
Why was Mr. Townsend able to get detailed data from his Itron meter? Will EPE agree to ask Itron to allow customers to electronically read the ERT meters EPE has?

EPE Response:
Mr. Townsend has installed, at his expense, an after-market device that functions in conjunction with EPE's AMR meter. It is from this installed device that Mr. Townsend gets detailed usage data for his personal residence.

EPE would not have a problem with the customer having the ability to electronically read their own meter so long as the customer paid for the reading device and the reading device could be programmed, or wired, to assure that the customer could only read his/her meter. It is important to note that the AMR meter only, and continually (every several seconds), transmits two data points: a meter identification number and the current kWh total.

PAG Q6:
[Original text]: Por que cuando instalan una instalacion electrica en una casa regular no le exigen a los inspectores a que le pongan atencion a los contratistas de instalaciones de alambrado. Con la diferencia en los codigos de alambrado se supone que tienen que usar #12 en las toma Corrientes, 14 en los focos de la lus, 12 toma Corrientes por breiker.
[Translation]: Why don't you require inspectors to pay attention to the contractors when it comes to wiring installations? The codes are supposed to require #12 [gauge] in the outlets, 14 in the light bulbs, and 12 outlets per breaker.

EPE Response:
This question should be addressed to EPE's New Service department. The EPE contact number is (915) 543-2028.

PAG Q7:
Please explain in detail the differences between the Loads and Resources table provided to the PRC in case 17-00090-UT dated May 12, 2017 and the one provided to PAG participants at the July 6, 2017 meeting.

EPE Response:
Both Load and Resource ("L&R") documents are based on the L&R document contained in EPE's 2015 IRP and both are updated with the same load forecast (2017) and same planned retirements

The L&R document dated May 12, 2017 includes an expansion plan, which identifies planned resource additions to address resource deficiencies. The L&R document dated July 6, 2017 does not include an expansion plan, but rather is the starting point of the 2018 IRP process. The 2018 IRP process will identify the planned resources in the L&R document included in the 2018 IRP.

PAG Q8:
Please provide the Transmission Expansion Plan that was referenced in the presentation.

EPE Response:
This study is available on EPE's website on the following link:
https://www.epelectric.com/files/html_pages_content1049.pdf

PAG Q9:
Please direct me to EPE's 440 filings at the NMPRC since the last rate case filing in 2015.

EPE Response:
EPE's 440 filings are publically filed with the NMPRC. The following link contains more information on documents filed with the PRC http://www.nmprc.state.nm.us/general-counsel/case-lookup.html

PAG Q10:
Please provide the Loss of Load Study that was referenced in the meeting.

EPE Response:
The referenced study has been posted on the IRP webpage:
https://www.epelectric.com/community/2017-18-public-advisory-group-meetings

PAG Q11:
What is included in the Native System load? Is Rio Grande Electric Co-op included? Is Holloman included? Is Ft. Bliss included? Is WSMR included? Is NASA included?

EPE Response:
Native System Load is a system value that includes retail customers in both Texas and New Mexico jurisdictions, and one full requirements wholesale customer in Texas. Yes, all listed customers are included in native system load.

PAG Q12:
Please provide ramp rate characteristics for all of EPE's generating units.

EPE Response:
Palo Verde is a nuclear, baseload unit and is excluded from the below listing.

Unit	MW/Minute
Montana 1	50
Montana 2	50
Montana 3	50
Montana 4	50
Newman 1	3
Newman 2	3
Newman 3	4
Newman 4	8
Newman 5	14
Rio Grande 6	2
Rio Grande 7	2
Rio Grande 8	5
Rio Grande 9	50
Copper	6

PAG Q13:
Please include in each agenda an opportunity to address responses to written questions from participants.

EPE Response:
We will schedule time during each meeting to discuss EPE's responses to PAG's written input and requests.

PAG Q14:
Please clarify the implications of the statement included in the presentation materials "EPE Proprietary Material". As this is a public process, how can material possibly be EPE proprietary?

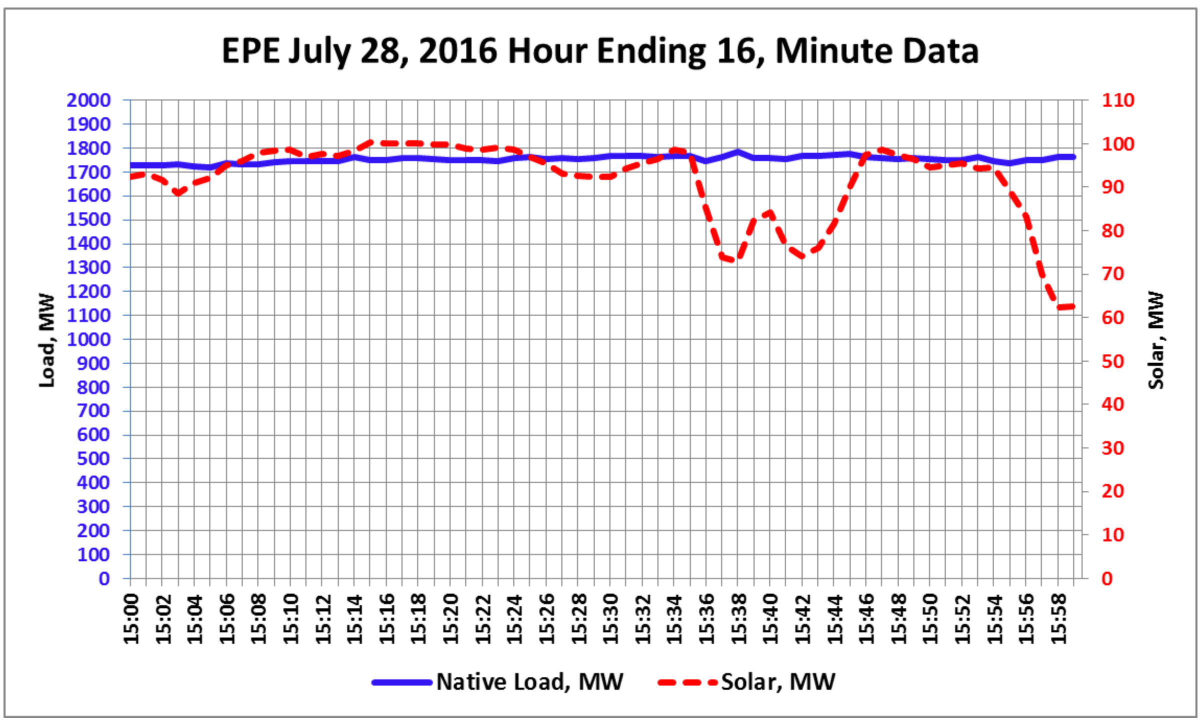
EPE Response:
Proprietary means that the material presented is the intellectual property of EPE. A third party cannot sell that information for profit or represent that the information is the result of its own analysis.

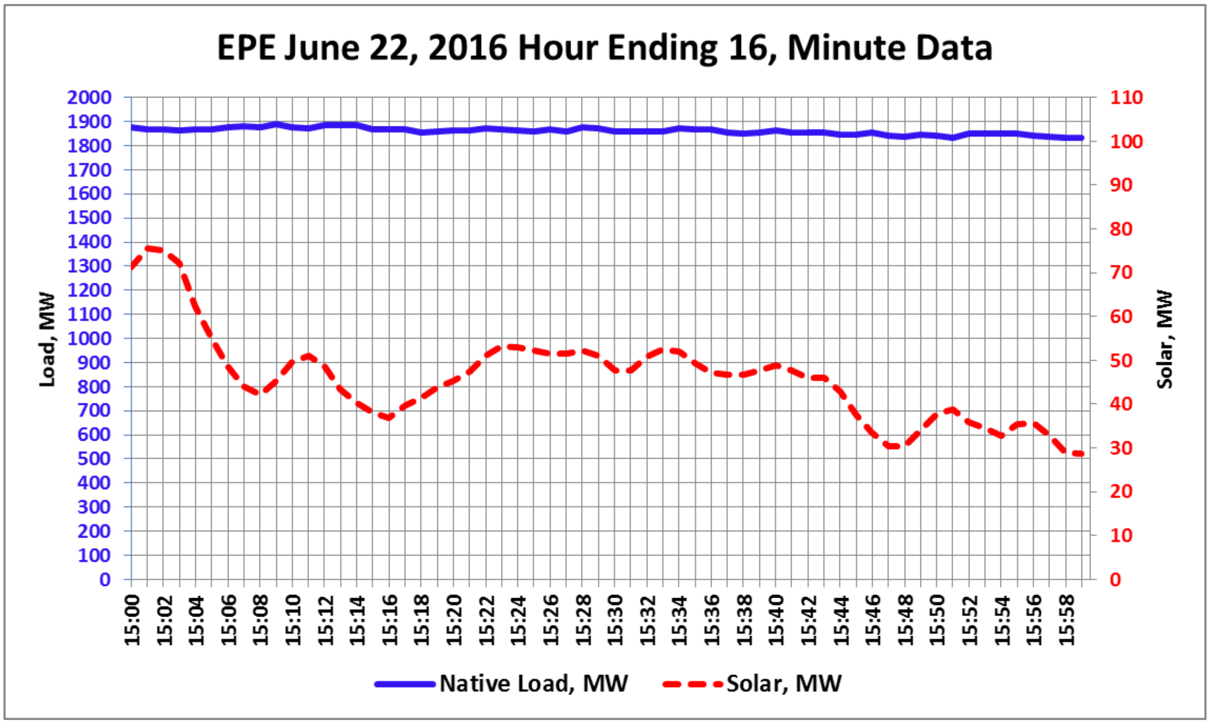
PAG Q15:
What are the transmission constraints that will be modeled?

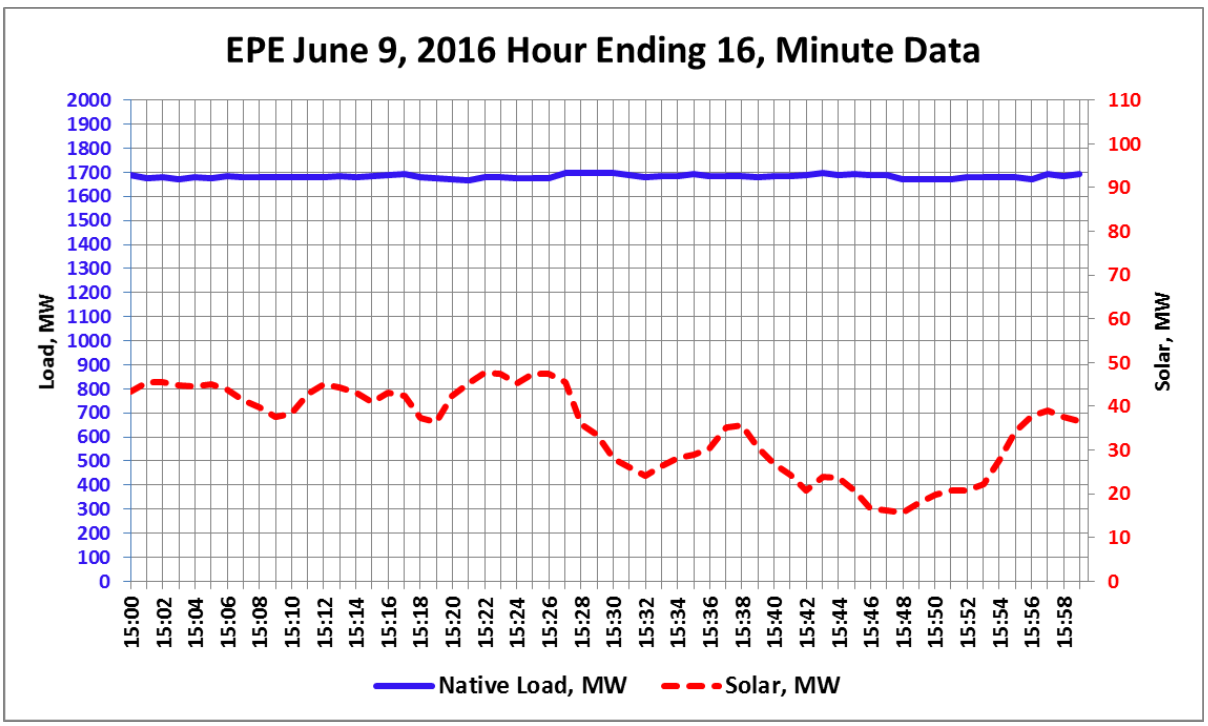
EPE Response:
Transmission constraints will be discussed during the 10/5/17 meeting.

PAG Q16:
Regarding pages 31-33 – why did you pick June 23, 2016 to represent this concept? Is this the worst case, typical case or best case? Please provide slides representing all 3 cases.

EPE Response:
June 23, 2016 happened to come to our attention because it was the first time we set a new peak in 2016. Given the high peak load day, there was attention to the day and it was noted that solar had a reduced output. It was interesting in that many believe that cloud cover will simultaneously result in lower solar output and as well as lower load. The data from this day indicated it is possible for conditions to result in lower solar output while load remains high. While this phenomenon may not be the norm all the time, it has occurred on multiple occasions. Attached are some additional charts, however, best or worst case is relative to other variables. The slides are not titled as best or worst, but rather with descriptors.







PAG Q17:
Please provide detailed information regarding the evaluation and determination of unit retirements.

EPE Response:
Retirement assumptions will be discussed during the 10/5/17 meeting. In addition, we plan to use a portion of the 2/16/18 meeting to discuss retirements in more detail.

PAG Q18:
Please provide the detailed parameters that will be used to evaluate unit retirements in the resource modeling.

EPE Response:
Please see EPE's response to PAG Question #17.

II. Written Input and Requests submitted through email

Email sent 7/10/17 from Allen Downs, a complete copy of Mr. Downs' email and EPE's initial response is attached as Attachment A.

EPE Response:
Conventional generating unit capacities are many times referenced in different contexts. There is "gross" output which is the total output of the unit versus "net" output which is the net energy delivered to the grid net of any station service (station service is the energy utilized by the unit/plant as part of its operation). Outputs may also be referenced to be at sea level versus actual site elevation which impacts ambient air conditions which impact combustion. Additionally, as you stated, air temperature may also impact unit output. While it is not uncommon for outputs to be referenced to in varying contexts during conversations, EPE's Resource Planning process does work to maintain a consistent baseline of "net output at EPE's site elevation during summer peak ambient conditions."

EPE's Resource Planning department works with the plants to obtain the units' gross and net output during EPE's summer peak conditions. These are the values presented in the May IRP meeting and coincide with the numbers utilized in the L&R as well as in the planning studies that will be performed later in the IRP process. The current values are utilized as a constant to the remainder of the units planned life.

Memo sent by email on 7/5/17 from ML Soules, K. Sherrouse, D. Kurtz, A. Downs, a complete copy of the email and EPE's initial response is attached as Attachment B:

EPE Response:
The following topics will be addressed on the following meeting dates:
- Loads and Resources Table and the assumptions that it represents: 10/5/2017
- Retirements and how they will be evaluated: 10/5/2017
- Planning Reserve assumptions and impact: 10/5/2017
- Fuel Cost assumptions: 10/5/2017
- Solar Cost and other assumptions related to solar: 10/5/2017
- Wind Cost and other assumptions related to wind: 10/5/2017
- Energy Storage assumptions: 10/5/2017
- Demand Management assumptions: 10/5/2017
- Energy Efficiency assumptions: 10/5/2017
- Off system sales: 10/5/2017
- Purchased Power assumptions: 10/5/2017

- The Burns and McDonnell studies from 2012*: 10/5/2017
- How will sensitivity analyses be done: 10/5/2017
- Levelized Costs: 10/5/17
- Smart Meters: 7/6/2017

*The referenced studies correspond to retirements.

Due to interest from the PAG regarding the subject of retirements, EPE will schedule time during the 2/16/18 meeting to discuss retirements. We will evaluate possible resource scenarios during the 10/5/17 meeting.

Memo sent 7/5/17 from Steve Fischmann, a complete copy of the email memo and EPE's initial response is attached as Attachment C.

EPE Response:
The memo requests that EPE's 2018 IRP PAG include the topics listed below. EPE has identified below the meeting in which it will address these topics.

1. A thorough review of demand management and energy efficiency options to address the continued increase in peak loads: 8/8/2017
2. Thorough evaluation of in front of the meter energy storage: 10/5/2017
3. Specific analysis of Solar costs in the southwest: 10/5/2017
4. Evaluation of any presumed plant decommissioning and replacement plans vs the relative costs of extended maintenance or upgrades: 7/6/17 and 2/16/18
5. Evaluation of early plant closings in favor of lower cost renewables: 7/6/17 and 2/16/18
6. Listing of all strategist modeling parameters and data inputs used for each resource in each scenario. Include capacity parameters, peak hour contributions, costs broken down into generating, regulatory, and integration expenses, any caps on total use of a particular resource.. 10/5/2017
7. Calculation of the levelized cost of each resource as modeled in the scenarios that are presented. 10/5/2017
8. Analysis of purchased power as a resource. 10/5/2017
9. Analysis of spot purchases and sales of power, firm power sale and power purchase agreements, and non-spot power purchase and sale agreements and their impact on total system costs. 10/5/2017
10. Various timing scenarios of resource additions/deletions to take advantage of federal tax incentives for renewables. 10/5/2017
11. Palo Verde levelized costs including future nuke capital investment. 10/5/2017

We will evaluate possible resource scenarios during the 10/5/17 meeting.

From:	Perez, Maritza
To:	"A Downs One Hour"; NMIRP
Cc:	"Myra Segal"
Subject:	RE: IRP PAG Question on generation plant capacities
Date:	Monday, July 10, 2017 5:55:25 PM

Good afternoon Mr. Downs,

Thank you for your email. I will make sure we address your questions. Please expect a response at least 10 days before the next meeting.

Best regards,

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Regulatory Case Manager
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Maritza.Perez@epelectric.com

-----Original Message-----
From: A Downs One Hour [mailto:ecomaxac@lifeisgood2.com]
Sent: Monday, July 10, 2017 11:33 AM
To: Perez, Maritza <Maritza.Perez@epelectric.com>; NMIRP <NMIRP@epelectric.com>
Subject: IRP PAG Question on generation plant capacities

Maritza:

My question concerns how generation unit capacities are determined. I have assumed when an unqualified unit capacity is given, it is the net capacity available from that generation unit under the conditions of temperature, humidity, and other relevant factors expected to prevail on the hottest summer afternoons (at the time of annual peak load).
The "Existing Conventional Generation" table on page 22 of the slides for the 1st meeting labels the capacities shown as "Summer Net Capacity"
and the values given are consistent with the undated Loads and Resources Table covering 2018 to 2027 which was handed out with the slide package for the 6 July meeting, but some of them vary from the values given in the last rate case.
The values given by Mr. Ramirez entitled "EPE Local Generation" at the 6 July meeting on slide package page 42 are also different. When asked why his RG6 and RG7 values were higher than the capacities generally given in the past, he explained that the values in his slide were "gross"
values - output before allowing for generation plant loads.
This makes perfect sense for RG6 and 7; comparing his numbers to the "Summer Net Capacity" numbers, RG6&7 each have 4MW generation plant loads (GPL). But it does not seem to make sense for some of the others.
Montana1&2 have 1MW GPL but Montana3&4 have zero GPL and Newman 4 has a negative 7MW GPL - the gross output is less than the net output.
Is there a set of "Correct" gross output values and Summer Net Capacity values for EPE's generation, or are these numbers changing over time as equipment ages or undergoes maintenance?
If values do change, where would one find the correct current value of "Net Summer Capacity" as it changes over

time. How does EPE account for these changes over time in its future planning, for example, in Loads and Resources documents?

Thank you,
Allen Downs

From:	Merrie Lee Soules
To:	Gallegos, Omar A; Myra Segal; Perez, Maritza
Cc:	Don Kurtz; Karen Sherrouse; Allen
Subject:	Request for Tomorrow''s PAG meeting
Date:	Wednesday, July 05, 2017 12:54:38 PM
Attachments:	Memo to EPE for 7-6 meeting.docx

Attached please find a request to add items to tomorrow's agenda, clarify where certain topics will be addressed in the Public Advisory Group process, and a formal request that certain options be evaluated. I am making this request on behalf of myself and other participants to the Public Advisory Process as indicated by our names on the request. I believe others would also support this request. Thank you for your consideration,

Merrie Lee Soules

Date: July 5, 2017

To: El Paso Electric,

For the Public Advisory Group meeting this Thursday, July 6, please add two items to the beginning of the agenda:

- Review and discussion of written responses to questions
- Clarification of the Schedule and agenda topics

This is to request that El Paso Electric address the following topics and clarify in which Public Advisory Group meeting the topic will be included:

- Loads and Resources Table and the assumptions that it represents
- Retirements and how they will be evaluated
- Planning Reserve assumptions and impact
- Fuel Cost assumptions
- Solar Cost and other assumptions related to solar
- Wind Cost and other assumptions related to wind
- Energy Storage assumptions
- Demand Management assumptions
- Energy Efficiency assumptions
- Off system sales
- Purchased Power assumptions
- The Burns and McDonnell studies from 2012
- How will sensitivity analyses be done
- Levelized costs
- Smart Meters

In addition, this is a formal request that the following options be evaluated:

- A scenario with no new fossil fuel generating resources
- A scenario with no increase in demand
- A scenario without nuclear fuel generation
- A scenario with no retirements
- A scenario without stranded investment cost

Sincerely,

Merrie Lee Soules
Karen Sherrouse
Don Kurtz
Allen Downs

From:	Schichtl, James
To:	mlsoules@hotmail.com; donkurtz7@gmail.com; ksherrouse@sbcglobal.net; ecomaxac@lifeisgood2.com
Cc:	myra.segal7@gmail.com; Perez, Maritza; Gallegos, Omar A
Subject:	FW: Request for Tomorrow"s PAG meeting
Date:	Wednesday, July 05, 2017 4:16:18 PM

Ms. Soules,

Thanks for your e-mail. We plan to address any follow-up to the first set of questions and answers in the meeting tomorrow, although we may need to limit that discussion to any clarification of responses because we have such a full agenda. If any of the questions require fuller consideration we will plan to respond in writing to those before the August meeting.

Regarding the list of topics you provided and the PAG meetings, we will respond in writing to indicate exactly where in the agenda those topics will be addressed.

Finally, with regards to the suggested scenarios, I think it will be helpful to wait to discuss potential expansion plans until after we have completed the informational meetings. I think this will allow for a full discussion within the entire group on the process and scenarios to be evaluated going forward.

Regards,

James Schichtl | **El Paso Electric Company**
Vice President, Regulatory Affairs
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James.Schichtl@epelectric.com

From:	Stephen Fischmann
To:	Perez, Maritza; Gallegos, Omar A; Gonzales, Ricardo
Cc:	Allen Downs; Merrie Lee Soules; Rocky Bacchus; Mariel Nanasi; Sandy Katayanagi
Subject:	Re: IRP Meeting Tomorrow
Date:	Wednesday, July 05, 2017 10:23:03 PM
Attachments:	Required IRP Analysis.docx

Maritza, Omar and Rico,

See my attached requests for today's IRP meeting and for ongoing conduct of the IRP process.

See there's lots of good background being covered on the agenda. Should be interesting tomorrow.

Best,
Steve

On Wed, Jul 5, 2017 at 6:34 PM, Perez, Maritza <Maritza.Perez@epelectric.com> wrote:

> Good afternoon,
>
> The presentation for tomorrow’s IRP Public Advisory Group meeting is now available on the IRP webpage.
>
> The 2017 Loads and Resources Table has also been uploaded. Please remember that the Loads and Resources Table will be discussed during the October 5th meeting, but is being provided early at your request.
>
> We have also posted a Feedback Form. For those attending the meeting in person, it will be available to fill in as a hard copy. You may also fill out and email the form to NMIRP@epelectric.com
>
> Best regards,
>
> **Maritza Perez** | **El Paso Electric Company**
> Regulatory Case Manager
> P.O. Box 982 | El Paso Texas, 79960
> T: (915) 543-2057 | C: (915) 478-5863

El Paso Electric

Maritza.Perez@epelectric.com

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Steve Fischmann
Co-Chair, NM Fair Lending Coalition
PO Box 2580
Mesilla Park, NM 88047
505-273-4956
stephen.fischmann@gmail.com

To: Omar Gallegos, Maritza Perez, Myra Segal, Public Input Participants
Fm: Steve Fischmann
Re: EPE IRP Public Input process
Date: July 5, 2017

Listed below are minimum components that I believe should be included in the IRP.

As part of the agenda for July 6, please include a discussion confirming when each of these components will be discussed in future meetings. That will better enable public participants to do their own research on each topic prior to the public meetings with EPE.

Also, please provide agenda a week ahead of time to allow public input on what should be included. If EPE is sole arbiter of agendas, input is likely to be influenced to support its preconceptions about where the IRP should go. Encouraging public input into upcoming agendas will better facilitate thoughtful alternate perspectives from IRP participants.

EPE IRP – Required Analysis for a thorough Least Cost Portfolio Study

1. **A thorough review of demand management and energy efficiency options to address the continued increase in peak loads.**

   Demand Management resources were flat in the prior IRPs even though demand projections show peak demand growing far faster than total demand. This peakiness is enormously expensive. Five peak demand plants representing 25% of EPE's capacity are needed to serve native customer demand just 2% of the time, yet native customers bear 100% of the expensive capital and holding costs of those plants – about $10 million per plant per year.

   Study of potential peak pricing and curtailment programs for the residential and small commercial customers that represent the majority of EPE's New Mexico load is needed, along with study of more robust energy efficiency measures.

   Potential pilots for residential and small commercial based on what other utilities are doing:

   Residential & Small Commercial Peak Pricing
   Residential & small commercial Curtailment Rates
   Behind the meter energy storage (Vermont – GMP- has a $15 per month plan)

Demand Response smart thermostat programs
Demand response smart electric water heater programs (GIWH)
Integration software for all the above as well as distributed renewables.

2. **Thorough in front of the meter energy storage evaluation.**

   Battery energy storage is experiencing a cost reduction curve similar to what happened with wind and solar. Tucson Electric has contracted for 100MW solar generation with a 30MW/120MWH battery storage system at under $45 per MWH to go into operation in 2019. Tucson Electric enjoys a full 30% tax credit on the storage portion by directly linking it to solar power. New combined cycle gas generation is generally pegged at closer to $70 per MWH.

   No storage was included in EPE's last IRP, and no analysis was done to show when storage becomes economically viable or how it could be most effectively used. (As a centralized resource, or at critical distribution and transmission points where storage can serve multiple functions regulating frequency, voltage, peak etc.). Evaluation of storage should take into consideration the reductions in additional generation and transmission investments it can create.

3. **Specific analysis of Solar costs in the southwest.**

   Tucson Electric's 100 MW facility is a $30 per MWH, 20 year purchase power deal. Many solar PPA deals reported in the trades are well under $40 per MWH. Self- build solar comes in as low as 2.5 cents kWh. Currently at 3% solar through direct PPA's. 2015's IRP appears to use nationwide solar costs as opposed to more favorable solar costs experienced in the sunny Southwest.

4. **Evaluation of any presumed plant decommissioning and replacement plans vs the relative costs of extended maintenance or upgrades.**

5. **Evaluation of early plant closings in favor of lower cost renewables.**

   Strategist modelling defaults assume all existing resources stay in place. It does not evaluate the economics of replacing an existing facility with a lower cost resource unless the modeler specifically decides to run that scenario.

6. **A comparison of the following scenarios in the published IRP:**

   a. high renewables option

b. High storage option
c. no nukes option
d. high demand response option
e. high purchased power option
f. an extended plant life option through upgrades.

7. **Listing of all strategist modeling parameters and data inputs used for each resource in each scenario. Include capacity parameters, peak hour contributions, costs broken down into generating, regulatory, and integration expenses, any caps on total use of a particular resource,……**

8. **Calculation of the levelized cost of each resource as modeled in the scenarios that are presented.**

   This can provide a useful cross check on how reasonable a strategist or another modeled scenario is.

9. **Analysis of purchased power as a resource.**

   Purchased power was used as a resource in the 2012 IRP but EPE did not use it in the 2015 IRP even though it can be far cheaper than new plant construction and a potential bridge to future low-cost renewables that avoids investment in fossil fuel facilities that could face early obsolescence. For the last several years, purchased power costs have been low due to low gas prices and an apparent glut of generation on the market. Include transmission issues in this analysis.

10. **Analysis of spot purchases and sales of power, firm power sale and power purchase agreements, and non-spot power purchase and sale agreements and their impact on total system costs.**

    2014 FERC reports show wholesale electricity sales of 3.4 million megawatts from EPE to other power companies generating $101 million in revenues. At 2.9 cents per KWH, this would not cover fuel costs on marginal production from EPE's less efficient gas plants. Are there other factors that make these sales worthwhile? The same year, EPE purchased 2.1 million megawatts of energy at a cost of $65 million or about 3.1 cents per KWH. EPE estimated in the 2015 IRP that off system sales would continue to represent over 30% of its total energy sales through 2034. In recent years sales of power ranging from 100-200 MW have occurred even during peak summer hours. Examination of this practices' impact on peak capacity requirements is needed.

11. **Various timing scenarios of resource additions/deletions to take advantage of federal tax incentives for renewables.**

Incentives phase out, dropping from 30% to 0% by 2023.

12. **Palo Verde levelized costs including future nuke capital investment.**

    Merchant nuclear plants are having a difficult time competing on price in open power markets across the nation. Most are asking for subsidies or shutting their doors. A clear picture of how nuclear stacks up in EPE's IOU monopoly environment is required.

From: Schichtl, James
To: stephen.fischmann@gmail.com
Cc: ecomaxac@lifeisgood2.com; mlsoules@hotmail.com; RockyBacchus@gmail.com; mariel@seedsbeneaththesnow.com; stkataya@yahoo.com; Gallegos, Omar A; Perez, Maritza; Gonzales, Ricardo; myra.segal7@gmail.com
Subject: EOE IRP Public Input Process
Date: Thursday, July 06, 2017 9:53:28 AM

Mr. Fischmann,

Thanks for your e-mail. We won't be modifying the agenda for this afternoon, we already probably have more material to cover than can be managed in 3 hours. But we can discuss managing agendas going forward and PAG input on the content. The agenda provides broad topics, based on the IRP rule, which we should be able to manage to include specific items.

Regarding the list of topics you provided and the PAG meetings, we will respond in writing to indicate exactly where in the agenda those topics will be addressed.

Regards,

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