additions and improvements for the local generation fleet that entered service from April 2015 through September 2016, which covers the period that starts with the first month after the test-year end in EPE's last rate proceeding, Docket No. 44941, through the end of the Test Year in this case.

In addition, I address the operations and maintenance ("O&M") expenses and practices that EPE employs to manage its local generation fleet, together with the level of O&M expenses that should be included in rates.

Last, I also support the reasonableness of the capital additions placed in service at Palo Verde from April 2015 through September 2016, together with the reasonableness of the Palo Verde Test Year O&M expenses.

I discuss total Company local generation fleet capital investments and operating costs in my testimony. EPE witness Rene F. Gonzalez discusses the allocation of total Company costs to the Texas jurisdiction in his testimony.

Q. WHAT DOES YOUR TESTIMONY DEMONSTRATE?

A. My testimony demonstrates that the capital additions to EPE's local generation fleet added from April 1, 2015, through the September 30, 2016, Test Year-end were prudent and reasonable and are used and useful in providing safe, reliable, and efficient power to meet customers' needs. The costs to add the new MPS Units 3 and 4 were lower than the estimated costs reflected in the final order in Docket No. 41763, which was the MPS Units 3 and 4 Certificate of Convenience and Necessity ("CCN") proceeding.

I also demonstrate that EPE maintains effective cost controls at its local generating facilities. The O&M practices that EPE employs to manage its local generation fleet are reasonable, and the Test Year O&M costs, as adjusted, are reasonable and should be included in rates.

Last, my testimony also demonstrates that the O&M and capital cost processes at Palo Verde are prudent. The resulting requested level of Palo Verde O&M expenses included in rates is reasonable and necessary, and the resulting capital additions are prudent and reasonable and used and useful in serving customers.

Q. WHAT RATE CASE SCHEDULES DO YOU SPONSOR OR CO-SPONSOR?

A. The schedules that I sponsor or co-sponsor are listed in Exhibit ARR-1.

Q. WERE THE SCHEDULES AND EXHIBITS YOU ARE SPONSORING OR CO-SPONSORING PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION?

A. Yes, they were.

III. EPE'S GENERATING FACILITIES

Q. WHAT ARE EPE'S GENERATING FACILITIES?

A. EPE meets the bulk of its customers' electrical requirements with power produced at its generating stations, which are fueled by a mix of natural gas, uranium, and renewable resources. Table ARR-1 identifies EPE's generating stations, with nominal capacities and fuel types, as of the September 30, 2016, end of the Test Year. These reflect the capacity resources EPE includes in its planning reserve margin analyses.

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Table ARR-1

Generating Station	Net Peak Capacity (MW)	Primary Fuel Type	Secondary Fuel Type	Duty
Palo Verde (Units 1, 2, and 3)	633	Uranium	N/A	Base load
Rio Grande (Units 7, 8, 9)	276	Natural Gas	N/A	Peaking and Load-following
Newman (Units 1, 2, 3, 4, and 5)	752	Natural Gas	Fuel Oil (Units 1-3 only)	Peaking and Load-following; for Unit 5, load following and base load in combined cycle mode
Copper (Unit 1)	64	Natural Gas	N/A	Peaking
MPS (Units 1, 2, 3, and 4)	354	Natural Gas	Fuel Oil	Peaking and load-following
Total	2,079			

EPE also owns several small solar facilities with a combined capacity of less than 1 Mega-Watt ("MW").

The Newman and Copper power plants are located in EPE's Texas service area within the City of El Paso, Texas. The Rio Grande power plant is located in EPE's southern New Mexico service area, and adjacent to the City of El Paso. The Montana Power Station or MPS is located in EPE's Texas service territory just east of the City of El Paso, in unincorporated El Paso County. The Copper, Newman, Rio Grande, and MPS generating stations are considered EPE's "local" generation. Exhibit ARR-2A and ARR-2B are maps depicting the location of EPE's local generating stations.

PVNGS, which is located in Arizona, is considered EPE's "remote" generation. I, as well as EPE witness John Cadogan, address the costs and operations of PVNGS.

Q. DOES THE RIO GRANDE POWER PLANT HAVE ANY GENERATION NOT REFLECTED IN THE TABLE ABOVE?

A. Yes, it does. Rio Grande Unit 6 entered inactive reserve status on November 17, 2015; it is no longer considered available capacity for planning reserve margin purposes. However, Rio Grande Unit 6 was temporarily reactivated during the 2016 summer peak period due to system constraints.

Q. IS THE COMPANY SEEKING TO RECOVER ANY COSTS ASSOCIATED WITH THE RIO GRANDE UNIT 6?

A. No. As EPE witness Jennifer I. Borden describes, EPE is not seeking to include any Rio Grande Unit 6 costs in rate base or in cost of service.

Q. DID EPE ADD ANY NEW GENERATION UNITS FROM MARCH 31, 2015 (THE END OF THE TEST YEAR IN EPE'S LAST BASE RATE CASE IN DOCKET NO. 44941) THROUGH SEPTEMBER 30, 2016 (THE END OF THE TEST YEAR IN THIS DOCKET)?

A. Yes, as I mentioned above, EPE added two new generation units at the MPS. MPS Unit 3 entered service on May 4, 2016, and MPS Unit 4 entered service on September 15, 2016. MPS Units 3 and 4 are gas-fired, nominally rated 89 MW General Electric LMS100 simple cycle aero derivative combustion turbines that provide peaking and load following capability, just like MPS Units 1 and 2. MPS Units 3 and 4 are included in the generation Table ARR-1 above.

Q. DID EPE DIVEST ITSELF OF ANY GENERATION UNITS SINCE ITS LAST BASE RATE CASE?

A. Yes, it did. For decades EPE had been a minority owner of Units 4 and 5 of the coal-fired Four Corners Power Plant located in northwestern New Mexico. EPE's interest equated to 108 MW. In July 2016, when the controlling project agreements were scheduled to expire, EPE sold all of its ownership interest in Units 4 and 5 and common facilities. As a result, Four Corners is excluded from the generation Table ARR-1 above.

Q. IS THE COMPANY SEEKING TO INCLUDE FOUR CORNERS IN BASE RATES?

A. It is my understanding that EPE is not seeking to include any Four Corners' investment and operating expenses in base rates. EPE witnesses James Schichtl and Russell G. Gibson explain EPE's Four Corners rate proposal in their testimony.

IV. EPE'S LOCAL GENERATION FLEET—CAPITAL ADDITIONS

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. The purpose of this section of my testimony is to describe and support cost recovery of the capital additions to EPE's local generation fleet that EPE requests in this case. The scope of this request is those capital additions placed in service from April 1, 2015, through the Test Year ending September 30, 2016. First, I will address the two most significant additions, which are MPS Units 3 and 4. With the completion of these two units, EPE no longer has any generating units under construction. Then I will address the other capital additions.

Q. IS THERE A LIST OF THE MAJOR PRODUCTION PLANT CAPITAL ADDITIONS TO THE LOCAL GENERATION FLEET THAT EPE SEEKS TO INCLUDE IN RATE BASE?

A. Yes, EPE witness Larry J. Hancock includes a list of all plant additions that EPE has made from April 2015 through September 2016 for local generation. The local generation capital additions fall under the "Steam & Other Production" category in his exhibit. I sponsor the reasonableness of the construction expenditures.

A. MPS Units 3 and 4

Q. DO MPS UNITS 3 AND 4 MARK THE COMPLETION OF RECENT SIGNIFICANT ADDITIONS TO EPE'S LOCAL GENERATION FLEET?

A. Yes, they do. Beginning in 2009 and continuing through September 2016, EPE added six new generation units to its local fleet. These new units are: Newman Unit 5 (Phases I and II); Rio Grande Unit 9; and MPS Units 1, 2, 3, and 4. The total capacity of all these units is 720 MW. The addition of these new generation units is consistent with the plans outlined in the filings for and approval of CCNs for all of these units. No additional generating units are currently under construction or the subject of a CCN request.

Newman Unit 5, Rio Grande Unit 9, and MPS Units 1 and 2 have already been included in rate base. In this current rate proceeding, EPE is requesting that the last two new generation units (MPS Units 3 and 4) be included in rate base. I support the reasonableness and prudence of the costs of these two units and show that they are used and useful in serving EPE's customers. EPE witness Hancock addresses the Company's Allowance for Funds Used During Construction ("AFUDC") practices, and his list of capital additions includes these two units.

Q. PLEASE BRIEFLY DESCRIBE MPS UNITS 3 AND 4.

A. The MPS site was a greenfield (i.e., undeveloped) site before the four MPS units were built. MPS Units 3 and 4 were built after Units 1 and 2, which entered service in March 2015. MPS Units 3 and 4, like Units 1 and 2, consist of General Electric LMS100 simple cycle aero derivative combustion turbines fueled by natural gas, with fuel oil as an emergency backup. Although each unit has a nameplate rating of 100 MW at International Organization for Standardization ("ISO") conditions, MPS

Units 1 and 2 are rated at 88 MW under summer conditions and MPS Units 3 and 4 are rated at 89 MW under summer conditions, owing to the high summer temperatures and the high elevation of the MPS. Compared to EPE's older local units, MPS Units 3 and 4 can be started quickly and are designed to be ramped up and down to meet load fluctuations. Their heat rates are also more efficient than those of the older units. CCN authorization for Units 3 and 4 occurred in Docket No. 41763, as EPE witness David C. Hawkins explains.

Q. DOES EPE HAVE ANY OTHER GENERAL ELECTRIC LMS100 SIMPLE CYCLE AERO DERIVATIVE COMBUSTION TURBINES?

A. Yes, Rio Grande Unit 9, which entered service in 2013, is also a General Electric LMS100 simple-cycle aero-derivative combustion turbine.

Q. WHAT ARE THE COMMON FACILITIES AT THE MONTANA POWER STATION?

A. The common facilities at the MPS are those facilities that support all of the units at the plant. The common facilities fall into several major categories or plant functions including:

1. Land and security,
2. Water supply and treatment,
3. Gas delivery and distribution,
4. Compressed air system,
5. Fire protection,
6. Power distribution, and
7. Administrative and support activities.

Land and security includes the cost of the land, fencing, and other security facilities at the plant. These facilities are not distinguishable between units at the plant. Water supply and treatment includes the water delivery (piping) from the City of El Paso water system, water treatment system, circulating pumps, raw water tank, demineralization storage tank, ammonia system, water evaporation pond, and related facilities. The water supply and treatment facilities serve all four units at MPS.

Like the water supply and treatment facilities, the gas delivery and distribution facilities serve all of the MPS units and include the gas pipeline connection, gas compressors, and gas delivery facilities. Similarly, the compressed air system supplies air to instrumentation and turbine J3 bearings (a third bearing in the turbine that needs compressed air to seal against oil leaks) at all MPS units. The fire protection system consists of a pump house to pressurize the water for distribution in case of fire on the site. The power distribution facilities include the connections to the electric grid and facilities to distribute electricity throughout the plant, including other common plant. Administrative and support activities include the administration building, fire protection equipment, environmental testing facilities and equipment, telecommunications equipment, information technology equipment and software, and other costs associated with the construction of the plant not specific to any Unit.

Q. WHAT COMMON FACILITIES FOR MPS ARE ALREADY IN RATE BASE?

A. All of the common facilities that were required to be completed and in service in order to operate MPS Units 1 and 2 were included in rate base in Docket No. 44941. This includes almost all of the items listed above, since land, water supply and treatment, gas distribution and delivery, compressed air system, fire protection, power distribution, and administrative facilities were all required to operate MPS Units 1 and 2.

Q. WHAT ADDITIONAL COMMON FACILITIES FOR MPS IS EPE REQUESTING IN THIS CASE?

A. The Company is requesting that additions to common facilities since the completion of MPS 1 and 2 be included in rate base in this case. These facilities include the costs of connecting water supply and treatment facilities to MPS 3 and 4; costs of connecting gas distribution facilities to MPS Units 3 and 4; the cost of an additional air compressor; the cost of connecting power distribution facilities to MPS 3 and 4; and costs for other common facilities that were incurred after the end of the Test Year in Docket No. 44941. In addition, a third gas compressor was added to common plant to support all the MPS units.

Q. DO YOU HAVE PHOTOGRAPHS OF MPS UNITS 3 AND 4?

A. Yes. Exhibits ARR-3 and ARR-4 are photographs of the MPS Units 3 and 4.

Q. WHAT WAS THE ESTIMATED COST OF MPS UNITS 3 AND 4 AS STATED IN CCN DOCKET NO. 41763?

A. The order granting the CCN authorization for MPS Units 3 and 4 gave the cost estimates as $151.2 million in cash capital costs and $17.9 million in AFUDC, for total of $169.1 million. (See Findings of Fact Nos. 44 and 45 in the MPS Unit 3 and 4 CCN Final Order included with EPE witness Hawkins' testimony). For the individual units, the estimated cash capital costs were $77.6 million for Unit 3 and $73.6 million for Unit 4.

Q. WHAT WAS THE ACTUAL COST OF MPS UNITS 3 AND 4 AND COMMON?

A. The actual cash capital cost of MPS Units 3 and 4 and Common was $140,587,677. In addition, actual AFUDC was $10,673,283. Thus, total costs equaled

$151,260,960. For the individual units, the actual cash capital costs were $70,189,240 for Unit 3 and $70,398,437 for Unit 4. These values are summarized in Table ARR-2.

Table ARR-2

	CCN Docket No. 41763 Estimated Costs (millions)	MPS Units 3 and 4 Actual Costs (millions)	Difference (millions)
Cash Costs	$151.2	$140.6	($10.6)
AFUDC	$17.9	$10.7	($7.2)
Total	$169.1	$151.3	($17.8)

Q. WHAT DO YOU CONCLUDE FROM THIS COST INFORMATION?

A. The actual costs for MPS Units 3 and 4 were $17.8 million less than the CCN estimate. From this fact and from my own experience planning for and building these units, I conclude that EPE successfully followed procurement and management oversight processes in the construction of MPS Units 3 and 4. Costs were successfully controlled, and the plan approved in the CCN order was successfully implemented.

Q. DID THE COMPANY INCUR ANY ADDITIONAL COSTS FOR MPS UNITS 1 AND 2 DURING THE PERIOD FROM APRIL 2015 THROUGH SEPTEMBER 2016?

A. Yes. Like most major construction projects, the Company incurred some trailing costs for MPS Units 1 and 2. These costs included some wrap up activities following the in-service date such as the distribution control center, protective relay study and settings, and some billings that were not accrued as of the end of March 2015, such as gas compressor commissioning, and water supply system late billing. In total, these additional capital costs were $2,804,313.

Q. WERE THESE COSTS REASONABLE?

A. Yes. In fact, when you add the final costs for MPS Units 1 and 2 to the costs for MPS Units 3 and 4, the total cost of MPS was $5.3 million under the projected CCN cost as shown in the table below.

Table ARR-3

	Total MPS 1-4 Estimated Costs (millions)	Total MPS 1-4 Actual Costs (millions)	Difference (millions)
Cash Costs	$326.7	$330.9	$4.2
AFUDC	$38.6	$29.1	($9.5)
Total	$365.3	$360.0	($5.3)

Q. YOU REFERRED TO THE PROCUREMENT PROCESS FOR MPS UNITS 3 AND 4. WHAT PROCUREMENT PROCESS DOES EPE USE TO OBTAIN MAJOR SERVICES, GOODS, AND EQUIPMENT?

A. EPE uses competitive bidding to secure all major contracts and for major equipment, services, and material. This policy is a critical component in securing these items at a reasonable market price. EPE's competitive bidding process is in accordance with the Company's purchasing policies and procedures as follows:

- EPE's project team and the design engineer create a Scope of Work;
- A bidder list is created based on the design engineer's recommendation of vendors, including EPE's past working experience with the vendors at a power plant;
- Then EPE goes out for bid to at least three of the vendors with specifications and Scope of Work ;
- When bids are submitted by vendors, they are evaluated by the EPE project team and design engineer for technical and commercial conformance, e.g., conformance

to design specifications, terms and conditions, price, warranty, delivery, availability, etc., which is illustrated in the procurement flowchart included as Exhibit ARR-5;

- The EPE project team then makes a final decision based on the above criteria and past work experience, if applicable, with each bidder; and
- Upon completion of contract, a purchase order is issued.

Q. DID EPE FOLLOW THIS COMPETITIVE PROCUREMENT PROCESS FOR MPS UNITS 3 AND 4?

A. Yes, it did.

Q. WHAT WAS THE NATURE OF EXECUTIVE OVERSIGHT FOR THE PLANNING AND CONSTRUCTION OF MPS UNITS 3 AND 4?

A. As the Vice President of Power Generation, I provided executive oversight for the planning and construction of MPS Units 3 and 4.

EPE's Capital Planning Committee ("CPC") also played a role in oversight for these projects. The CPC was composed of not less than six members, appointed by the senior executive management team, and included corporate officers or directors from the various business units.

The project team reported to the CPC and met with it regularly to review the project and its costs. The CPC also reviewed the status of the project, any outstanding issues (for example, any change orders), actual costs and projected costs, the project timeline, and risks to both the timeline and costs. The CPC also considered whether any changed circumstances affected the need for, or timing of, MPS Units 3 and 4.

Q. WHY ARE THE PROCUREMENT PROCESS AND MANAGEMENT OVERSIGHT IMPORTANT?

A. These are important because MPS Units 3 and 4 were subject to the procurement and management oversight processes I described above. These processes, in turn, helped ensure that the projects were constructed at a reasonable cost, that they were prudently planned and managed, and that they were consistent with the plans laid out in the CCN case.

Q. DID THE CONSTRUCTION OF MPS UNITS 3 AND 4 PROCEED ACCORDING TO SCHEDULE?

A. Yes, it did. MPS Units 3 and 4 were originally scheduled to be completed by the summer peak needs in 2016 and 2017, respectively. Unit 3 entered service in May 2016 and Unit 4 in September 2016. The units were built in sequence to save costs, including avoiding setup time and mobilization of the contractor a second time for Unit 4, and combining common construction activities. An example of this cost saving approach is pouring the foundations for Units 3 and 4 turbines sequentially, saving the need for re-mobilization of contractor resources at a later date. In addition, AFUDC was reduced, since the costs were not carried as long as assumed in the CCN estimate.

Q. ARE MPS UNITS 3 AND 4 USED AND USEFUL IN SERVING CUSTOMERS?

A. Yes, they are. MPS Units 3 and 4 have been placed in service to help meet the needs of EPE's customers. Through November 2016, MPS Unit 3 produced 179,845 MegaWatt-hours ("MWh"), and MPS Unit 4 produced 55,506 MWh.

Q. WAS THE CONSTRUCTION OF MPS UNITS 3 AND 4 PLANNED AND MANAGED PRUDENTLY AND ARE THEIR COSTS NECESSARY AND REASONABLE?

A. Yes, EPE prudently planned and managed the construction of MPS Units 3 and 4, and the resulting costs, which were $17.8 million below the estimated CCN costs, were necessary and reasonable.

B. Other Capital Additions to Local Generation Fleet

Q. EXCLUSIVE OF THE NEW MPS UNITS 3 AND 4, WHAT IS EPE'S APPROACH FOR CAPITAL ADDITIONS TO ITS LOCAL GENERATING FLEET?

A. EPE strives to maintain efficient and reliable power plant operations. This requires capital projects that maintain or improve performance, availability, and reliability. In addition, some projects will be required to comply with laws or regulations, including environmental requirements.

Q. FOR THESE TYPES OF OTHER PROJECTS AT ITS EXISTING LOCAL GENERATION UNITS, DOES EPE USE COMPETITIVE BIDDING?

A. Yes, EPE uses the same competitive procurement process for capital additions that I described previously for the new generation units.

Q. BESIDES EPE'S NEW MPS UNITS 3 AND 4, WHAT ARE SOME OF THE LARGER CAPITAL ADDITIONS THAT EPE SEEKS TO INCLUDE IN RATE BASE?

A. Referring to the "Steam & Other Production" items in the capital additions exhibit to EPE witness Hancock's testimony, there are three items with a cost of $4 million or more. These are the Montana Supercore Capital Spare, the Fuel Oil Storage and Delivery System (labeled Montana Liquid Fuel Forwarding System in EPE witness

Hancock's capital additions exhibit), and the Four Corners Steam Production Capital Improvements.

Q. TURNING TO THE FIRST PROJECT, WHAT IS A SUPERCORE?

A. A supercore is an important part of an LMS100 generation unit, of which EPE has five (Rio Grande Unit 9, MPS Unit 1, MPS Unit 2, MPS Unit 3, and MPS Unit 4). The supercore contains the front frame, high pressure compressor, combustor, high pressure turbine, intermediate pressure turbine, and turbine mid frame. A diagram and photo of a supercore is shown in Exhibit ARR-6.

Q. IS IT NORMAL OR EXPECTED PRACTICE TO REPLACE THE SUPERCORE AFTER A CERTAIN PERIOD OF TIME?

A. Yes. Per General Electric, the original equipment manufacturer, the supercore, if maintained according to specifications, should last approximately 25,000 run hours before needing to be removed and sent into the shop for a refurbishment. Based on the current average of about 3,000 to 3,500 run hours per year, this is about seven or eight years. Of course, this depends on the actual run hours per year.

Q. WHY DID EPE PURCHASE THE SPARE SUPERCORE?

A. The spare supercore was purchased for increased reliability. The events that accelerated the purchase occurred in June and July 2016, during which the EPE service area was entering a prolonged heat wave and the EPE system was experiencing high demand.

On Tuesday, June 28, 2016, the supercore at MPS Unit 1 had to be removed from service and sent back to General Electric for repairs after a boroscope exam revealed a blade had broken off. A simple repair is expected to last at least ten weeks. However, in light of the boroscope exam results that revealed collateral damage to the supercore, the delay in the repair was estimated to be up to six or seven months. In evaluating this situation, EPE management knew: (1) triple digit temperatures were expected to last into the following week and thereafter; (2) EPE had recently experienced record native peak loads that had not been expected until two years later, in 2018; and (3) a forced outage had occurred at Newman Unit 4. Newman Unit 4 Gas Turbine ("GT")1 and GT2 each had a 40 MW derate due to the loss of Unit 4 steam turbine, which was a loss of 87 MW, for a total loss of 167 MW. During this time, EPE also had a 22 MW derate on Rio Grande Unit 8, due to a preheater issue, and a 55 MW derate on Rio Grande Unit 9, due to generator vibration issues. These combined for a system resource loss of 244 MW. The combination of these factors meant that operating margins were very thin.

The Company evaluated its options.

- The do-nothing option meant relying on purchased power until the damaged supercore would be repaired, an estimated six to seven month period. In addition, I understand that EPE upper management deemed that this alternative was too risky.
- The Company could move the supercore from MPS Unit 4 (which was still being constructed) to MPS Unit 1. The supercore from Unit 1 would be sent for repairs and upon return, would be installed in Unit 4. However, the MPS Unit 4 supercore was already fully installed. The costs and risks of this option (including a delay in completing MPS Unit 4 and costs of $250,000 to $300,000 to remove the supercore from Unit 4 and install it in Unit 1) outweighed its benefit (not having to rent or purchase another supercore).
- The Company explored renting a supercore from General Electric but none was available.

- Last, the Company could accept General Electric's offer to sell EPE another supercore with an extended warranty and at a price $2.2 million below recent quoted prices for new supercores. Buying a spare supercore would be consistent with General Electric's recommendation that companies with four or more LMS100 units should own a spare supercore. Having a spare supercore would significantly improve reliability by reducing future LMS100 outage times and providing savings though reduced reliance on purchased power.

The Company decided to purchase the spare supercore on Friday, July 1, 2016. The following week, the new supercore was installed in MPS Unit 1, which returned to service on Thursday July 7, 2016. The Company's decision proved to be prudent because on July 10, 2016, Newman Unit 5 steam turbine experienced a failure and the EPE system lost another 138 MW.

Q. HOW DO YOU EXPECT TO UTILIZE THE SPARE SUPERCORE IN THE FUTURE?

A. The spare supercore will be used to reduce outage times. It will be used to rotate out of service the first unit to reach the 25,000 service hour interval. Having the spare supercore turns a three month planned outage into a 48 hour outage. EPE will place the supercore that was rotated out of service into the shop during periods when the shop is less busy, thereby getting favorable pricing. Once that supercore is refurbished, it will go into the next unit to reach the 25,000 service hour interval the following year, as the utilization of our fleet is staggered out to overhaul one LMS100 supercore per year. This will continue until all the units are done. This process will be repeated with each LMS100 overhaul cycle. It also provides a level of reliability in case of any unexpected unit failure, which could take six to seven months to repair without the spare supercore.

Q. WERE THE COSTS FOR THIS SPARE SUPERCORE NECESSARY AND PRUDENT?

A. Yes, they were. The price EPE paid for the supercore was favorable compared to market prices. But more fundamentally, EPE thoroughly evaluated its alternatives and chose the one that best promoted reliability. All five of EPE's LMS100 generation units will benefit from EPE having the one spare supercore, which can be used in any of them as needed.

Q. WHAT WAS THE MONTANA FUEL OIL STORAGE AND DELIVERY SYSTEM PROJECT AND WHY WAS IT UNDERTAKEN?

A. This project promotes reliability by allowing all four gas-fired MPS units to use fuel oil as a backup fuel.

The main components of the Montana liquid fuel forwarding system include an off-loading skid, a fuel oil tank, forwarding pumps, fuel filters, control system and piping. The project was built to provide the MPS units an alternative fuel source if gas supplies are disrupted.

Q. WAS THE DUAL-FUEL CAPABILITY FOR THE MONTANA UNITS MENTIONED IN THE PLANS LAID OUT IN THE CCN CASES?

A. Yes, it was. The Commission's order in both CCN cases specified that the MPS Units will be "fueled by natural gas, with the capability to burn fuel oil as their secondary fuel source." (See Finding of Fact No. 41 in the Docket No. 40301 CCN order for MPS Units 1 and 2, and Finding of Fact No. 29 in the Docket No. 41763 CCN order for Units 3 and 4, which is an exhibit to EPE witness Hawkins' testimony.)

Q. WERE THE $6.8 MILLION COSTS FOR THIS FUEL OIL PROJECT REASONABLE AND PRUDENT?

A. Yes, they were. This project, like the spare supercore, will strengthen the reliability of EPE's local generation fleet. If gas supplies are disrupted, the MPS Units can utilize the fuel oil to continue service to customers.

Q. THE NEXT ITEM ON EPE WITNESS HANCOCK'S CAPITAL ADDITIONS EXHIBIT IS $4.4 MILLION FOR FOUR CORNERS STEAM PRODUCTION CAPITAL IMPROVEMENTS. DOES EPE SEEK TO INCLUDE THAT ITEM IN RATE BASE?

A. No, it does not. That item is on the list simply because it was a generation capital addition in the period from April 2015 through September 2016. As discussed by EPE witness Hancock, all of EPE's investment in Four Corners was retired when the plant was sold.

Q. PLEASE DESCRIBE THE REMAINDER OF THE LOCAL FLEET STEAM PRODUCTION AND OTHER PRODUCTION PROJECTS LISTED ON EPE WITNESS HANCOCK'S CAPITAL ADDITIONS EXHIBIT.

A. The remaining local fleet Steam Production and Other Production projects, excluding the new generation additions I discussed previously and projects less than $100,000, can be grouped into four of the ten categories (i.e., Plant Efficiency Improvement, Productivity Improvement, Reliability, and Habitability) specified in the instructions for Rate Filing package Schedule H-5.2b, which I shall use in describing these projects.

a. Plant Efficiency Improvement

These are projects that primarily replace components that have reached the end of their useful life or are no longer operable. These can also be projects that improve a plant's heat rate. Projects in this category include Newman 5 GT4 Stage 2 Buckets and Shrouds and the Newman gas metering upgrade. The total for this category is $878,753.

b. Productivity Improvement

These are general plant improvement items. The largest projects in this category are the blanket accounts for Newman, Rio Grande, and Copper. The blankets include items such as a reverse osmosis system for Copper, a fence for Copper, Newman 3 burners shutoff valves, Newman Unit 3 voltage regulator, Newman Unit 3 forced draft fan motor, GT-3 and GT-2 gas turbine parts, Newman Units 1 and 2 Foxboro upgrades, Rio Grande Unit 7 exciter repair, and Rio Grande Unit 7 boiler feed pump parts. The total for this category is $8,984,467.

c. Reliability

Since the local units must be available to start and run when called on to assure service to customers, EPE must make reliability improvements to assure adequate generation resources are available to serve load. For the most part these costs were incurred for general plant improvement projects, such as turbine parts, boiler tube repairs, and critical spares. The main project is the Newman Unit 5 GT4 hot gas path parts. The total for this category is $14,293,558.

d. Habitability

These projects were to improve the working conditions at the Newman and Rio Grande Stations. These projects include Newman Unit 4 Control Room improvements, Rio Grande maintenance shop improvements, a Newman outage trailer, and Rio Grande main sewer line replacement. The total for this category is $960,162.

Q. WERE ALL OF EPE CAPITAL ADDITIONS PROJECTS ADDED FROM APRIL 2015 THROUGH SEPTEMBER 2016 NECESSARY, BENEFICIAL AND USED AND USEFUL TO THE LOCAL GENERATION FLEET?

A. Yes, they were. All of these additions were necessary or helpful or both in maintaining the local generation fleet. In addition, they were the product of sound management decisions and were developed with strong budget controls. They were also subject to a competitive bidding process.

V. EPE'S LOCAL GENERATION FLEET- OPERATION AND MAINTENANCE

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. The purpose of this section of my testimony is to describe how EPE's local fleet of power plants is operated and the measures used to analyze the power plants' performance (for example, heat rate), together with EPE's O&M practices and rate recovery request.

A. Local Unit-General

Q. PLEASE BRIEFLY DESCRIBE THE TYPICAL USAGE OF EPE'S LOCAL GENERATION.

A. EPE's local fleet is dispatched by EPE's System Operations group. As a whole, EPE's local units are used to follow load and support the import of low-cost remote generation, although Newman Unit 5 also operates as a base load unit at times. For the most part, each of the local units can be used interchangeably to satisfy these functions. EPE's load demands are such that, under normal conditions, the local units typically operate at low loads during the night (off-peak periods) and high loads during the day (on-peak periods), particularly during the summer, except for Rio Grande Unit 9 and MPS Units 1 through 4, which are cycled daily.

Q. HOW DOES EPE MATCH ITS LOCAL UNITS TO LOAD REQUIREMENTS TO ENSURE THAT UNITS ARE AVAILABLE TO MEET DEMAND?

A. For daily operations, the Company's load demand profile requires that the Newman Units 1, 2, 3, and 4 and Rio Grande Units 7, 8, and 9 be used primarily as load-following units. Rio Grande Unit 8 is also used for voltage and reactive support for the system. Rio Grande Unit 9 and MPS Units 1 through 4 are fast-start units that are primarily used for peaking but can also be used for load following. Copper Station is a simple-cycle combustion turbine generator that is typically used as a daily peaking unit. Copper is subject to start-stop cycles, but it is also used for load following and to meet spinning reserve requirements. Newman Unit 5, when operating in combined cycle mode, is mostly base loaded during the day and reduced to minimum load during the night. It also has the ability to return to simple cycle peaking mode, if needed.

Q. DOES THE OPERATION OF EPE'S LOCAL GENERATION FOR PRIMARILY LOAD FOLLOWING AND VOLTAGE SUPPORT PURPOSES AFFECT THE UNIT EFFICIENCY LEVELS?

A. Yes. Units that are cycled or dispatched to follow daily load are subjected to increased stress due to the constant changes in thermal gradients. These thermal cycles increase the level of normal wear and tear experienced by the generating unit, which, in turn, cause losses in efficiency and availability. Also, reducing output to lower loads during off-peak hours will cause the unit to operate less efficiently. It is important to note that most units in EPE's local fleet (Rio Grande Units 7 and 8 and Newman Units 1, 2, 3, and 4) were originally designed and built to serve as base load units. EPE's resource mix has changed over time, as has the cost of fuels, and these local units are now called upon to serve in a role different than their original design. However, Rio Grande Unit 9 and MPS Units 1 through 4 are designed to be ramped up and down as needed and therefore allow EPE to meet load fluctuations more efficiently.

Q. IS THE AGE OF EPE'S LOCAL GENERATING FLEET AN IMPORTANT CONSIDERATION WHEN EVALUATING UNIT PERFORMANCE?

A. Yes. In broad terms, EPE's local generation is composed of both very new units and very old units. Four of EPE's local units (not counting Rio Grande Unit 6) are over 50 years old (Rio Grande Unit 7 and Newman Units 1, 2, and 3). As power plants of that vintage grow older, they become less efficient, have inflexible operating characteristics, and are more costly to run than newer units. Unless reliability must-run conditions exist, unit commitment will be based on lowest heat rate first, thus having the effect of dispatching older units last.

B. <u>Local Unit Maintenance</u>

Q. WHAT STEPS DOES EPE TAKE TO MAINTAIN THE EFFICIENCY AND AVAILABILITY OF ITS LOCAL GENERATING FLEET?

A. EPE conducts a comprehensive maintenance program that is designed to maximize the efficiency and availability of those units. The cornerstones of EPE's maintenance practices are regularly scheduled maintenance, and preventive and predictive maintenance programs.

Q. CAN YOU DESCRIBE EPE'S SCHEDULED MAINTENANCE ACTIVITIES?

A. Yes, I can. EPE's power generation operations, maintenance, system operations, and power marketing personnel collaborate to plan the timing of the outages to minimize the economic impact of planned maintenance, subject to system reliability. EPE's scheduled maintenance activities include periodic inspections and major unit overhauls, other planned maintenance intended to maximize unit availability and efficiency, and capital projects.

A major unit overhaul is a comprehensive tune-up where EPE takes a unit out of service to inspect for degradation of component parts, primarily in the turbine and generator, and repairs or replaces those component parts as necessary to maintain or improve efficiency and reliability.

Between major overhauls, EPE also conducts scheduled maintenance on a variety of unit components (e.g., boiler, turbine control valves, and auxiliary equipment) when unit efficiency or availability is likely to be impacted by the failure or potential failure of component parts.

Q. CAN YOU DESCRIBE EPE'S PREVENTIVE MAINTENANCE PROGRAM?

A. Yes. EPE's preventive maintenance program is the practice of performing routine, proactive equipment maintenance. This preventive maintenance is conducted not only during maintenance outages, but also throughout the year while the units are under normal operation. Preventive maintenance includes systematic inspection and routine tasks designed to keep equipment in sound operating condition and minimize degradation of equipment. EPE evaluates original equipment manufacturers' data, equipment operating history, and operating experience in conjunction with the relative significance of a generating unit's components and the associated risk of failure to determine the type of preventive maintenance required. If necessary, EPE then schedules a maintenance outage to inspect equipment and undertake maintenance work prior to the time the equipment is expected to fail. EPE's preventive maintenance program ensures greater control over the scheduling of maintenance activities, which can minimize the duration and cost of outages.

Q. DOES EPE ALSO FOLLOW PREDICTIVE MAINTENANCE PROCEDURES?

A. Yes. EPE monitors equipment operations through various inspection techniques, and utilizes statistical control measures in conjunction with actual equipment operating history to predict when to perform maintenance on a unit or component part prior to failure. The data gathered assists with work planning and allows EPE to predict the parts that will be required during an actual outage or repair phase. Predicting when a component part is expected to fail also provides EPE more control over scheduling maintenance and thus minimizes costs.

Q. WHAT ARE SOME OF THE PROCESSES EPE FOLLOWS IN ITS PREDICTIVE MAINTENANCE PROGRAM?

A. EPE conducts continuous unit performance monitoring, pre- and post-overhaul unit performance testing, steam path inspections during overhauls, critical equipment vibration monitoring, and lubricant oil analysis. EPE also uses thermography, ultrasonic sensing, and a variety of other analyses to identify, analyze, and resolve potential maintenance concerns. These predictive maintenance processes give EPE's maintenance and operations teams more options in planning and scheduling maintenance and minimizing costs. The alternative would be to wait for equipment to fail, which would create downtime since there would be no option but to repair.

Q. ARE EPE'S PREDICTIVE AND PREVENTIVE MAINTENANCE PROGRAMS IMPLEMENTED IN ALL ASPECTS OF UNIT OPERATIONS?

A. No. Many of the technologies available are not readily adaptable to all systems. EPE's preventive and predictive maintenance practices focus on rotating equipment and are being expanded to other critical areas of the plant. During operation of a plant, these practices cannot be applied to internal components such as boiler tubes or within the condenser. However, during plant outages, ultrasound equipment is used to check, test, and/or find tube leaks. In addition, EPE's maintenance department also conducts eddy current testing and non-destructive evaluation analysis of boiler and condenser tubes and main steam lines.

Q. EPE'S LMS100 UNITS EMPLOY A MORE MODERN TECHNOLOGY THAN THE OLDER UNITS. DOES EPE HAVE A MORE ADVANCED MONITORING CAPABILITY FOR THESE UNITS?

A. Yes. Through General Electric, EPE has a Remote Monitoring and Diagnostic program. General Electric has a 24/7 team, staffed by former field service and controls experts, who continually monitor the performance of all five of our LMS100 units. The team provides early warning alerts, and in case of more severe issues, the team notifies EPE via a phone call and supports the Company on resolution of the issue. The team is used for predictive maintenance, as the team analyzes data-logs, trends, and alarm history.

C. Local Unit Performance

Q. HOW DOES THE COMPANY MONITOR THE PERFORMANCE OF ITS LOCAL GENERATING UNITS?

A. EPE monitors the performance of these units using two key indicators or measurements: (1) net heat rate and (2) equivalent availability factor ("EAF"). Both net heat rate and EAF are industry-accepted measurements of generating unit performance. Net heat rate is used to monitor unit thermal efficiency, while EAF is used to measure unit availability, based on the percentage of time within a given period that a unit is available to generate electricity.

Q. HOW DOES NET HEAT RATE REFLECT UNIT EFFICIENCY?

A. A unit's net heat rate is defined as the amount of fuel energy (measured in British thermal units ("Btu") used to produce one kilowatt-hour ("kWh") of electricity delivered to the transmission system. Efficient power generation equates to less fuel consumed to produce a kWh and therefore lower fuel costs. A lower net heat rate means the turbine generator is more efficient than a unit with a higher net heat rate. The goal is to maintain a reasonable level of efficiency.

Q. DO EPE'S LOCAL GENERATING UNITS MAINTAIN CONSISTENT NET HEAT RATES, AND ARE THEY REASONABLE HEAT RATES?

A. Yes. The annual variances for EPE's local generating fleet efficiency are minimal and are within a range of reasonable operations, based on historical performance. As shown in Schedule H-12.3a, the annual average composite net heat rates for EPE's local generating fleet demonstrate that EPE maintained consistent and reasonable levels of efficiency during the Test Year. The Test Year did experience an anomaly such that unanticipated outages on several low heat rate units caused higher heat rate units to be used instead, but the heat rates for those units were still reasonable.

Q. WHAT HAS EPE BEEN DOING TO IMPROVE THE OVERALL EFFICIENCY OF THE GENERATING FLEET?

A. Most significantly, EPE has added more efficient generation facilities, as I described above. Newman Unit 5 entered service as a combined cycle facility in April 2011. This unit is the most efficient gas-fired facility in EPE's fleet. During the Test Year, this unit had a net heat rate of approximately 9,937 Btu/kWh running mostly in simple cycle mode due to the steamer outage. This compares to an average net heat rate of 11,883 Btu/kWh for the older Rio Grande Units 6 through 8 and Newman Units 1 through 4.

Rio Grande Unit 9, which entered service in May 2013, and MPS Units 1 through 4, which entered service in 2015 and 2016, have helped improve the efficiency of EPE's fleet and have provided other advantages, such as quick-start capability. During the Test Year, Rio Grande Unit 9 had a net heat rate of 9,590 Btu/kWh. MPS Units 1 and 2 had heat rates of 9,302 Btu/kWh and 9,292 Btu/kWh, respectively, during the Test Year. MPS Units 3 and 4 had heat rates of 9,216 Btu/kWh and 8,818 Btu/kWh, respectively.

The average net heat rate of these four MPS units is 9,270 Btu/kWh. This is significantly less than the average net heat rate of all units, 10,269 Btu/kWh, in 2015.

Q. WHY DOES EPE USE EAF AS AN INDICATOR OF PERFORMANCE?

A. As an indicator of performance, EAF takes into account all events that affect availability, rather than focusing on a single type of event. EAF represents the net maximum generation that can be provided by a unit after taking into account outages and derates. EPE uses EAF to measure performance of EPE's local generating units because it provides a clear indication of overall unit availability for a given period. For EPE, that period is May through September, because EPE is a summer peaking utility.

Q. HOW HAVE EPE'S LOCAL GENERATING UNITS PERFORMED RECENTLY WITH RESPECT TO AVAILABILITY?

A. For the years 2011 through 2015, EPE achieved consistently high levels of availability during the summer peak periods (May through September), when availability matters most to EPE and its customers. For the Test Year, the average EAF for all units, during the summer peak months of May through September 2016, was 77.5 percent. Table ARR-4 below summarizes this information.

Table ARR-4	
Year **(May through September)**	**Total Peak EAF Average (%)**
2012	90.5
2013	95.4
2014	91.6
2015	90.5
Test Year	77.5

Q. WHY WAS THE EAF FOR THE SUMMER MONTHS IN THE TEST YEAR LOWER THAN HISTORICAL PERFORMANCE?

A. During the summer of 2016, EPE's generation fleet experienced several major outages that contributed to the lower EAF in 2016. These include the following:

- Newman Unit 4 Steamer outage on June 4, 2016. This also caused a 40 MW derate each, on GT1 and GT2, and 87 MW on the steamer.

- Rio Unit 9 outage – beginning June 8, 2016, this unit was derated by 40 MW. On July 22, 2016, the Unit was taken offline for repairs, causing an extended outage. This event was a loss of 88 MW.
- MPS Unit 1 Supercore outage from June 29, 2016 until July 7, 2016. This event was a loss of 88 MW.
- Newman Unit 5 Steamer outage, which began on July 10, 2016. This event was a loss of 138 MW.

As shown in Table ARR-4 above, the summer of 2016 was an anomaly compared to recent history.

Q. DID THE HIGHER NUMBER OF OUTAGES DURING THE SUMMER OF 2016 LEAD TO A SPIKE IN TEST YEAR O&M COSTS?

A. No, it did not, as I explain later in my testimony.

Q. ARE THE COMPANY'S OPERATION AND MAINTENANCE PROGRAMS AND PRACTICES NECESSARY AND REASONABLE?

A. Yes, EPE's local generation fleet requires operation and maintenance programs, as any generation unit does. EPE's operation and maintenance programs are methodical and tailored to EPE's fleet, and they are based on engineering data gathered to set the intervals between inspections. EPE's practices conform to industry-wide standards. Over the past several years, they have led to good results, although the summer peak of 2016 was an anomaly.

D. <u>Local Generation Fleet Non-Fuel O&M Costs and Rate Request</u>

Q. WHAT IS THE AMOUNT OF NON-FUEL O&M COSTS FOR EPE'S LOCAL GENERATION FLEET?

A. During the Test Year, the unadjusted non-fuel O&M costs for the local generation fleet were $37,723,416. With adjustments, as addressed by EPE witness Borden, EPE's total Company Test Year non-fuel O&M costs are $38,120,341 for its local generation fleet.

Q. EARLIER YOU STATED THAT THE FORCED OUTAGES DURING THE SUMMER PEAK OF 2016 DID NOT CAUSE TEST YEAR NON-FUEL O&M COSTS TO SPIKE. PLEASE EXPLAIN.

Q. The simplest way to understand that no such spike occurred is to compare the Test Year local fleet O&M costs with historical amounts. The following table gives such information for the years 2011 through 2015:

TABLE ARR-5

Year	**Non-Fuel O&M** **(excluding Four Corners O&M, millions)**
2011	$ 32.9
2012	$ 34.7
2013	$ 32.2
2014	$ 34.7
2015	$ 35.7
Test Year	$ 37.7

Q. DID INSURANCE PROCEEDS HELP DEFRAY OR REDUCE O&M COSTS RESULTING FROM THE 2016 PEAK SEASON OUTAGES?

A. Yes, the Test Year O&M costs are net of those insurance proceeds.

Q. DID EPE MAKE ANY TEST YEAR ADJUSTMENTS FOR NON-FUEL O&M COSTS FOR EPE'S LOCAL GENERATING UNITS?

A. Yes, EPE witness Borden presents four specific adjustments to non-fuel O&M costs for the local units. The first adjustment is to employee payroll, part of which is for generation employees.

The second adjustment of approximately $420,097 is to include the annualized incremental cost of O&M for the MPS Units 3 and 4. This adjustment is necessary because MPS Units 3 and 4 did not operate throughout the entire Test Year. These costs for MPS Units 3 and 4 were calculated by using historical data from MPS Units 1 and 2, which had already been in operation for more than a year, since March 2015. EPE's experience with MPS 1 and 2 O&M facilitated the analysis because those two units are identical to, and on the same site as, MPS Units 3 and 4. The historical data from MPS 1 and 2 included such things as expected minor parts and repairs that would be needed. To that was also added any O&M recommended inspections and outages. The costs of required resources, such as water usage, were based on actual usage for MPS 1 and 2. Additionally, an O&M Tech was added to the staff at the MPS site. The adjustment annualized the MPS 3 and 4 costs to reflect a full 12 months of O&M expenses, as shown in Workpaper Adjustment No. 13 to Schedule A-3 and an incremental cost was added for Units 3 and 4.

The third adjustment eliminates the non-payroll O&M for the Hueco Mountain wind turbines of $193,784. The Hueco Mountain wind turbines were decommissioned in 2016.

Finally, EPE removed approximately $63,686 of costs related to Rio Grande Unit 6 non-labor maintenance expenses that occurred during the Test Year. As I mentioned previously, Rio Grande Unit 6 entered inactive reserve status on November 17, 2015; it is no longer considered available capacity for planning reserve margin purposes.

Q. ARE THE ADJUSTED TEST YEAR NON-FUEL O&M COSTS FOR LOCAL GENERATION REASONABLE AND NECESSARY?

A. Yes. The Test Year costs (with the four adjustments identified previously) are reasonable and necessary to operate and maintain the local generation units. As I described previously, EPE uses a preventive maintenance program and a predictive maintenance program to maintain its local generation fleet. These programs have led to very good performance of the local fleet. EPE uses its engineering data to determine maintenance intervals. In addition, although an abnormal level of forced outages occurred during the peak season of the Test Year, the O&M costs for the Test Year are well within the line of historical costs.

VI. PALO VERDE

Q. PLEASE DESCRIBE PVNGS.

A. PVNGS is a nuclear generating station, located on an approximately 4,000 acre site approximately 50 miles west of Phoenix, Arizona. The facility consists of three separate, virtually identical generating units and a variety of common support facilities. The Design Electrical ratings of the facilities are 1,333 MW for Unit 1; 1,336 MW for Unit 2; and 1,334 MW for Unit 3. EPE's share of the total PVNGS design capacity is 633 MW. PVNGS also has a switchyard that operates at 500 kV. EPE witness Cadogan also provides a detailed description of PVNGS in his direct testimony.

Q. PLEASE SUMMARIZE EPE'S COST OF SERVICE AND RATE BASE ADDITIONS REQUEST FOR PVNGS.

A. EPE is requesting rate base capital additions of $59.4 million on a total Company basis for PVNGS. EPE also is requesting $97.5 million in total unadjusted Company Test

Year, non-fuel O&M for PVNGS, along with the two adjustments that I summarize below.

Q. ARE ANY ARIZONA PUBLIC SERVICE COMPANY ("APS") EMPLOYEES TESTIFYING ON EPE'S BEHALF IN THIS CASE?

A. Yes, EPE witness Cadogan is an employee of APS, and he discusses PVNGS O&M and capital additions, from the plant wide perspective, from April 2015 through September 2016, in detail in his testimony.

Q. WHAT CONTROL DOES EPE HAVE OVER PVNGS?

A. EPE is a minority, non-operating owner of PVNGS. However, as a co-owner, EPE exercises its ownership and oversight rights provided to the Company by the PVNGS operating agreement. The Company's oversight activities are discussed later in my testimony.

A. Overview of Palo Verde

Q. IS PVNGS A RELIABLE AND ECONOMIC RESOURCE FOR THE COMPANY'S CUSTOMERS?

A. Yes, it is. PVNGS has long been a source of base load power at low fuel prices for EPE's customers. PVNGS diversifies EPE's portfolio of generation resources that provides long-term security to customers.

Q. HOW IS PVNGS OWNED AND OPERATED?

A. The ownership of PVNGS is divided among seven southwestern utilities ("Owners"): APS owns 29.10 percent; EPE owns 15.80 percent; Salt River Project Agricultural Improvement and Power District owns 17.49 percent; Southern California Edison

Company owns 15.80 percent; Public Service Company of New Mexico owns 10.20 percent; Southern California Public Power Authority owns 5.91 percent; and Los Angeles Department of Water and Power owns 5.70 percent.

APS operates PVNGS pursuant to a contract among the Owners, entitled the Arizona Nuclear Power Project Participation Agreement, which became effective August 23, 1973, and has been amended sixteen times. The agreement calls for several Owner committees: Administrative Committee, Engineering & Operations Committee, Audit Committee, Fuel Committee, Switchyard and Termination Funding Committee. I represent EPE as its designated representative on two of these committees as either a member or member alternate. The Termination Funding, Audit, Fuel, and Switchyard Committees are represented by other people from EPE.

B. PVNGS Performance During the Test Year

Q. HAS PVNGS OPERATED EFFICIENTLY?

A. Yes. For example, in 2015, PVNGS achieved a record capacity factor of 94.3 percent. As a comparison, the Nuclear Energy Institute reported the United States nuclear fleet averaged a 92.2 percent in 2015. I should add that PVNGS is subject to performance standards wherein it receives penalties, rewards, or neither in fuel reconciliation cases depending on the level of performance based on achieved capacity factor.

PVNGS continues to work to improve performance at the plant and will continue to incur costs related to its efforts to achieve excellent performance.

C. PVNGS Capital Monitoring and Approval Process of Capital Costs

Q. HOW DOES EPE MONITOR PVNGS CAPITAL ACTIVITIES AND COSTS?

A. EPE monitors PVNGS capital activities and costs primarily through the PVNGS E&O Committee's Capital Improvement Budget and Capital Project Approval process ("Capital Budget Procedure"). EPE participated in development of this procedure, which provides a process for all Owners to review, approve, and control PVNGS capital improvement costs. The PVNGS Owners must unanimously approve all capital improvements. A unanimous vote is likewise required for the capital budget each year. Once the budget is approved, APS can proceed with construction only on those projects for which E&O Committee approval has been received.

Q. WHAT IS EPE'S REVIEW PROCESS FOR THE PVNGS CAPITAL BUDGET?

A. EPE reviews the annual PVNGS Capital Budget as part of the overall budget package, to ensure that budget items and levels match the requirements determined necessary for safe and efficient operation by the E&O Committee. EPE analyzes the line items for consistency with activities from prior years and with ongoing repair, replacement, and improvement efforts. EPE regularly attends and participates in plant meetings to better understand and evaluate capital budget needs.

EPE reviews budget submittals to ensure that projects are identified and accounted for in the correct budget (capital versus O&M), that they are in the correct budget category, and that carryover work from the current budget year is accurately represented. EPE also scrutinizes individual projects to ensure the projected total costs do not exceed the capital improvement work authorization variance limits contained in the Capital Budget Procedure. In addition, EPE reviews projected indirect PVNGS capital improvement overhead costs, and distributable costs, and compares them to costs incurred in prior years. EPE also reviews capital project justifications.

Q. ARE THERE FURTHER REVIEWS OF THE CAPITAL BUDGET BY PROJECT?

A. Yes. Capital budget approval only indicates Owner concurrence to fund the capital project program at a certain level for a budget year. Projects are presented individually to the E&O Committee throughout the year using Work Authorization packages that include a business case and financial analysis for the proposed project. Non-regulatory projects above $500,000 must be approved by both the E&O and the executive-level Administrative Committees. Except for emergent issues that must be addressed immediately, APS may not spend money or otherwise proceed with project implementation until the project has been reviewed and approved by the applicable Owner Committee(s). This process allows owners the opportunity to review and ask questions about proposed projects to help ensure that these investment expenditures serve customer interests and allow the site to adapt to changing conditions as needed.

Q. DOES EPE COMPARE ACTUAL PVNGS CAPITAL COSTS TO BUDGET AMOUNTS?

A. Yes. EPE monitors variance explanations for budgeted amounts on a monthly basis. This monthly analysis allows comparison of individual projects against budget, and against the amount approved, in total, for the individual project. EPE can further investigate any material variances and communicate with APS to address any concerns.

Q. WHAT DO YOU CONCLUDE ABOUT THIS PROCESS FOR THE REVIEW AND APPROVAL OF CAPITAL EXPENDITURES?

A. The process of review and approval of capital expenditures is designed to ensure that proposed projects undergo several layers of scrutiny and review to demonstrate they are necessary and reasonable. Review and approval is required by PVNGS management and also requires unanimous approval of the Owners. The approval process ensures that capital improvements at PVNGS are consistent with the needs of all the Owners and in the interest of their customers.

D. PVNGS Capital Additions to Rate Base

Q. WHAT AMOUNT OF PVNGS CAPITAL ADDITIONS TO RATE BASE DOES EPE REQUEST?

A. The Company is seeking to include $59.4 million in PVNGS total Company capital additions to rate base, which were placed in service during the period April 2015 through September 2016, the end of the current Test Year.

Q. WHERE IS INFORMATION ABOUT THE CAPITAL PROJECTS THAT WERE ADDED AT PVNGS FROM APRIL 2015 THROUGH SEPTEMBER 2016?

A. There are three sources of this information. EPE witness Hancock's capital additions exhibit, which I discussed above, lists Palo Verde plant additions during the period April 2015 through September 2016. Schedule H-5.2a includes a list of all Palo Verde capitalized projects being requested in rate base with actual costs of $100,000 or more (EPE share). Lastly, the testimony of EPE witness Cadogan describes PVNGS major capital additions that support PVNGS's philosophy to replace aging plant components from a plant wide perspective, utilizing categorization specific to PVNGS.

Q. ARE THE PVNGS CAPITAL EXPENDITURES INCLUDED IN EPE'S REQUEST REASONABLE AND NECESSARY?

A. Yes. The capital projects represented by these costs have undergone the budget and project review processes discussed above. EPE, as well as all other PVNGS owners, have concurred that the projects and related costs are reasonable and necessary for safe, reliable, cost-effective service to our customers.

E. PVNGS O&M Expense

General Discussion

Q. DOES EPE MONITOR AND REVIEW PVNGS O&M COSTS?

A. Yes. EPE reviews the annual O&M budget package, including budget assumptions and O&M budget. EPE reviews the package to ensure that the budget is reasonable based upon expected plant performance and the refueling and maintenance outage schedules, and is consistent with the budgeted staffing levels and needs (*e.g.,* loads, insurance premiums, and U. S. Nuclear Regulatory Commission fees). In addition to a total budget, APS provides separate refueling and maintenance outage budgets that EPE reviews to verify that the amounts and scope are both reasonable and consistent with planned outage dates. The views and questions submitted by other Owners on the proposed O&M budget are also reviewed and considered by EPE prior to EPE participating in the budget approval process. Unanimous approval of the O&M Budget by the Owners is required under the Arizona Nuclear Power Project Participation Agreement.

Test Year Costs

Q. WHAT AMOUNT OF PVNGS O&M EXPENSE DID EPE INCLUDE IN THE TEST YEAR COST OF SERVICE?

A. EPE included the unadjusted Test Year costs, in the amount of $97.5 million for non-fuel O&M expense. The PVNGS O&M cost information is included in Schedule G-15 sponsored by EPE witness Borden, who also presents adjustments.

Q. WHAT DOES THIS TEST YEAR AMOUNT REPRESENT?

A. This amount represents EPE's Test Year share of the costs to perform the day-to-day operational activities and maintenance tasks on Units 1, 2, 3, and common plant at PVNGS.

Q. ARE THE TEST YEAR EXPENDITURES REASONABLE?

A. Yes. These costs are reasonable and necessary to provide safe, reliable energy to customers and reflect unadjusted Test Year costs. Processes and procedures are in place that allows owners to closely scrutinize the O&M budget before it is adopted. Efficiency of a plant, measured by O&M/MWh, can be affected by prudent spending on O&M as well as capital. As discussed in the testimony of EPE witness Cadogan, the combination of higher capacity factors and lower costs has put PVNGS below the industry average on a cost per MWh basis.

Q. HOW DOES EPE DETERMINE IF O&M COSTS ARE REASONABLE?

A. As described previously, EPE participates in the review and approval of the reasonableness of the PVNGS O&M budget. EPE monitors the PVNGS O&M variance explanations, and identifies issues throughout the year. EPE makes informal and formal recommendations for corrective action as is necessary. Furthermore, EPE monitors public policy issues such as Arizona property taxes, operational issues affecting plant capacity factor enhancements, and maintenance efficiencies. These steps help to ensure that costs remain reasonable not only when looking at operational budgets but also when costs are measured on a cents per kWh basis.

Q. DOES APS PROVIDE EXPLANATIONS OF ANY PVNGS O&M BUDGET VARIANCES?

A. Yes. APS and PVNGS personnel provide monthly variance reports and explain variances at E&O Committee meetings. Where necessary, EPE and other Owners seek clarifications in order to make budget recommendations.

Q. FOR ITS BASE RATE REQUEST, IS THE COMPANY PROPOSING ANY ADJUSTMENTS TO THE TEST YEAR PVNGS O&M EXPENSES?

A. Yes. As discussed in the testimony of EPE witness Borden, two adjustments have been made. The first adjustment removes the out of period amount of the true-up reversal for 2015 Palo Verde charges recorded in the Test Year. Another adjustment was made to reflect current premium costs for Property Insurance and Injuries & Damages. The net effect of these two adjustments is to reduce the cost of service by $2.1 million.

VII. CONCLUSION

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

DOCKET NO. _____

APPLICATION OF EL PASO ELECTRIC	§	PUBLIC UTILITY COMMISSION
	§	
COMPANY TO RECONCILE FUEL COSTS	§	OF TEXAS

DIRECT TESTIMONY OF

DAVID C. HAWKINS

FOR

EL PASO ELECTRIC COMPANY

SEPTEMBER 2019

EXECUTIVE SUMMARY

David C. Hawkins is the Vice President–Power Generation, System Planning and Dispatch for El Paso Electric Company ("EPE"). He is responsible for all activities of EPE's System Operations department, which is responsible for the reliable, real time operation of EPE's electric grid; Resource Planning and Management, in which he is responsible for daily and long-term wholesale power transactions, contract negotiation, and scheduling; and running PROMOD cases for financial planning, along with the long-term planning of new generation resources; Power Generation, in which he is responsible for the operations and maintenance ("O&M"), engineering, and capital projects for EPE's local generation fleet.

Mr. Hawkins discusses EPE's generation fleet, the operation and maintenance practices EPE follows, and the performance of the generation fleet during the period April 1, 2016 through March 31, 2019 (the "Reconciliation Period"). He also discusses how the rate treatment and jurisdictional allocation of two solar power purchase agreements follows the treatment that was specified in the settlement of EPE's last base rate case in Docket No. 46831.

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EXHIBITS

I. Introduction and Qualifications

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is David C. Hawkins, and my business address is 100 N. Stanton Street, El Paso, Texas 79901-1341.

Q. HOW ARE YOU EMPLOYED?

A. I am employed by El Paso Electric Company ("EPE" or the "Company") as Vice President–Power Generation and System Planning and Dispatch.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL AND BUSINESS BACKGROUND.

A. I graduated from New Mexico State University with a Bachelor of Science degree in Electrical Engineering in 1993 and a Master of Science degree in Electrical Engineering in 1994. Upon graduation, I was employed by West Texas Utilities Company in Abilene, Texas, as a Power Marketing Engineer until July 1996. In August 1996, I began working for Public Service Company of New Mexico as a Power Marketing Analyst where my job duties included analysis of the wholesale power market, and economic evaluation of wholesale transactions.

In April 2002, I began working for EPE as a Pre-scheduler, where my duties included optimization of EPE's generation dispatch through wholesale power transactions, daily and monthly natural gas procurement estimates, and regulatory compliance. In October 2004, I was promoted to Supervisor of Resource Management. Resource Management is responsible for daily and long-term wholesale power transactions, contract negotiation, scheduling and accounting, and running PROMOD cases for financial planning. In March 2006, the responsibility of fuels planning and procurement for EPE's generating units was incorporated into Resource Management. In November 2007, I was promoted to Manager of Long-Term Trading and Fuels. The section responsibilities include wholesale power transactions, fuel supply planning and procurement, and development of PROMOD for financial planning and regulatory filings. In February 2010, I was promoted to Director of Energy Trading, where my additional responsibilities included oversight of the Company's real-time marketing operation.

In October 2011, I moved laterally to Power Generation as Director-Generation Operations, where I supervised EPE's local generating plant operations and maintenance. In April 2013, I was promoted to Vice President–Power Marketing & Fuels and Resource Delivery Planning where I oversaw the long-term planning of new generation resources as well as the optimization of EPE's generation dispatch, the fuel supply planning and procurement, and wholesale power transactions. In June 2014, I was promoted to Vice President–System Operations, Resource Planning and Management where I have retained the job functions of my previous position, and, in addition, I oversee the System Operations department which is responsible for the reliable, real time operation of EPE's electric grid. In February 2018, my title became Vice President – Power Generation and System Planning and Dispatch, where in addition to my previous responsibilities, I assumed responsibility for EPE's Power Generation fleet in which I oversee the O&M, engineering, and projects for EPE's local generation fleet and oversight of EPE's remote generation.

Q. HAVE YOU PREVIOUSLY PRESENTED TESTIMONY BEFORE UTILITY REGULATORY BODIES?

A. Yes. I have previously presented testimony before the Public Utility Commission of Texas ("PUCT" or "Commission") and the New Mexico Public Regulation Commission ("NMPRC").

II. Purpose of Testimony

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I discuss EPE's generation fleet, the operation and maintenance practices EPE follows, and the performance of the generation fleet during the period April 1, 2016 through March 31, 2019 (the "Reconciliation Period"). I discuss how the rate treatment and jurisdictional allocation of two solar power purchase agreements follows the treatment that was specified in the settlement of EPE's last base rate case in Docket No. 46831.

Q. WHAT SCHEDULES AND EXHIBITS DO YOU SPONSOR?

A. The schedules that I sponsor, or co-sponsor, are identified in Exhibit DCH-1. The exhibits that I sponsor are identified in the Table of Contents of this testimony.

Q. WERE THE SCHEDULES AND EXHIBITS THAT YOU SPONSOR OR CO-SPONSOR PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes, they were.

Q. HAVE YOU READ THE EXECUTIVE SUMMARY THAT IS INCLUDED WITH THE COMPANY'S FILING IN THIS PROCEEDING?

A Yes, I have.

Q. IS THAT EXECUTIVE SUMMARY TRUE AND CORRECT FOR THOSE MATTERS THAT FALL WITHIN THE SUBJECTS OF YOUR DIRECT TESTIMONY?

A. Yes, it is.

III. Fuel Mix

Q. DURING THE FUEL RECONCILIATION PERIOD, DID EPE HAVE A DIVERSE GENERATION PORTFOLIO?

A. Yes, it did. EPE's generation portfolio included both gas-fired generating capacity and generating capacity that used nuclear fuel. For a very brief time at the beginning of the Reconciliation Period, EPE also owned an interest in coal-fired generating capacity, as I describe below.

Q. WHAT WAS EPE'S ENERGY MIX DURING THE RECONCILIATION PERIOD?

A. EPE's energy mix for the 36-month Reconciliation Period was as follows:

Resource Type	% of Energy
Nuclear	47.3%
Natural Gas	39.7%
Coal	0.3%
Renewable	1.7%
Purchased Power	11.0%
Total	100.0%

Q. WHAT DOES THE ENERGY MIX REFLECT?

A. EPE's energy mix reflects its diverse resource base, with an emphasis on its ownership interest in Palo Verde with its relatively stable production and low fuel costs. EPE's ownership interest in Palo Verde Generating Station ("Palo Verde") provided substantial base-load generation that was imported into the El Paso area from its location west of Phoenix, Arizona over long-distance transmission lines and EPE's interconnection to the western United States. The import of remote power from Palo Verde served to lower EPE's total fuel and purchased power costs and helped mitigate price volatility in the gas and purchased power market during the Reconciliation Period. In his direct testimony, EPE witness Victor Martinez establishes that EPE responded effectively within the relevant markets for EPE's procurement of natural gas and purchased power. EPE's off-system sales efforts served to reduce total reconcilable fuel and purchased power expenses for Texas customers during the Reconciliation Period.

Q. YOU MENTIONED ABOVE THAT DURING A BRIEF PART OF THE RECONCILIATION PERIOD, EPE OWNED AN INTEREST IN COAL-FIRED GENERATING CAPACITY. PLEASE EXPLAIN.

A. When the Reconciliation Period began, EPE owned seven percent or 108 Megawatts ("MW") of coal-fired generating capacity in the Four Corners Power Plant ("Four Corners") Units 4 and 5, which is a mine-mouth facility located near Farmington, New Mexico. On July 6, 2016, EPE sold its interest in Four Corners to an affiliate of Arizona Public Service Company, which was the plant operator. EPE received public interest and related findings for this sale in Docket No. 44805. Consequently, EPE owned part of Four Corners for only a few months of the Reconciliation Period (April 1, 2016 through July 5, 2016), and because of that I will only briefly address Four Corners later in my testimony.

IV. EPE's Actions During the Fuel Reconciliation Period to Reduce Fuel Costs

Q. DURING THE RECONCILIATION PERIOD, WHAT STEPS DID EPE TAKE TO IMPROVE THE EFFICIENCY OF ITS USE OF FUEL?

A. In addition to the measures that I describe below, EPE took a significant step to improve the efficiency of its local generation fleet by adding new, efficient generation with the addition of Montana Power Station ("MPS" or "Montana") Unit 3, which entered service in May 2016, and MPS Unit 4, which entered service in September 2016.

These significant investments in new facilities will help EPE not only meet growing customer demand but also increase the efficiency of its local generation fleet. MPS Units 3 and 4 have heat rates of approximately 9,200 Btu/net kWh, which are lower than the heat rate of EPE's older local units. This heat rate differential means that less fuel is consumed to produce the same amount of electricity. In addition, MPS Units 3 and 4 were designed to be able to ramp up and down more efficiently and rapidly than EPE's other older local units.

V. EPE'S Generation Fleet—Its Operation and Maintenance

A. EPE'S Generating Facilities

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. The purpose of this section of my testimony is to describe the Company's fleet of power plants. I also generally describe how the fleet is operated and the measures used to analyze the power plants' performance (for example, heat rate), together with EPE's O&M practices. In addition, I give an overview of Palo Verde, of which EPE is a minority owner.

Q. BRIEFLY DESCRIBE EPE'S GENERATING FACILITIES.

A. EPE meets the bulk of its customers' electrical requirements with power produced at its generating stations, which are fueled by a mix of natural gas, coal (only briefly in the Reconciliation Period), uranium, and renewable resources. Table DCH-1 below identifies EPE's generating stations, with net peak capacities and fuel types, as of March 31, 2019, the end of the Reconciliation Period:

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Table DCH-1

Generating Station	Net Peak Capacity (MW)	Primary Fuel Type	Secondary Fuel Type	Duty
Palo Verde (Units 1, 2 & 3)	633	Uranium	N/A	Base load
Rio Grande (Units 7, 8, 9)	278	Natural Gas	N/A	Peaking and Load-following
Newman (Units 1, 2, 3, 4 and 5)	736	Natural Gas	Fuel Oil (Units 1 – 3 only)	Peaking and Load-following and, for Unit 5, load following and base load in combined cycle mode.
Copper (Unit 1)	63	Natural Gas	N/A	Peaking
MPS (Units 1, 2, 3 and 4)	352	Natural Gas	Fuel Oil	Peaking and load-following
Total	2,062			

EPE also owns several small solar facilities with a combined capacity of approximately 8 MW.

The Newman and Copper power plants are located in EPE's Texas service area within the City of El Paso, Texas. The Rio Grande power plant is located in EPE's southern New Mexico service area, adjacent to the City of El Paso. Rio Grande Unit 6 is currently classified as inactive reserve; however, this unit was called upon during the Reconciliation Period. The Montana Power Station is located just east of the City of El Paso, in unincorporated El Paso County. These generating stations are considered EPE's "local" generation.

Palo Verde, located in Arizona, and Four Corners, located in New Mexico, were considered EPE's "remote" generation during the Reconciliation Period.

Exhibit DCH-2 is a map depicting the location of EPE's generating stations.

Q. WHAT IS THE GENERAL FUNCTION OF EPE'S LOCAL FLEET?

A. Because EPE is not able to meet all of its customers' demands with remote generation from Palo Verde, EPE's system relies on its local generation fleet to provide reliable electric power. EPE's local generation is necessary for three primary reasons. First, generation from EPE's local fleet provides load support necessary to meet customer power needs and to follow load as customer demand changes. Second, local generation provides load-serving reliability in the event that transmission constraints affect EPE's ability to import remote generation. Third, EPE's local generating fleet provides voltage/reactive support throughout EPE's system in conjunction with the import of low-cost remote generation.

Q. HOW IS EPE'S TRANSMISSION SYSTEM INTERCONNECTED WITH OTHER UTILITIES?

A. EPE's transmission network is interconnected at various points within the Western Electricity Coordinating Council (of which EPE is a member) and with the electrical systems of the Southwest Power Pool and the Mexican national utility (Comisión Federal de Electricidad) on an asynchronous basis. EPE also owns or has rights to transmission across the southwest United States that are used to import the Company's low-cost remote generation to EPE's service area.

Q. DO EPE'S TRANSMISSION RIGHTS AND INTERCONNECTIONS WITH OTHER UTILITIES PROVIDE BENEFITS TO EPE'S CUSTOMER?

A. Yes. These transmission rights and interconnections provide EPE the capability to exchange power with other utilities to lower overall energy costs and improve system reliability. EPE operated its mix of generating stations, transmission lines, and interconnections under a variety of changing conditions to provide a reliable supply of power to its customers at a reasonable cost during the Reconciliation Period.

B. Local Unit Operation and Performance

Q. PLEASE BRIEFLY DESCRIBE THE TYPICAL USAGE OF EPE'S LOCAL GENERATION.

A. Generally, EPE's local units are used to follow load and compensate for the variable output of renewable resources, provide grid stability and serve EPE's load obligations that are over what is met through the import of its low-cost remote generation. For the most part, each of the local units can be used interchangeably to satisfy these functions. EPE's load demands are such that, under normal conditions, the older steam units (Newman 1, 2 and 3, Rio Grande 7 and 8) and combined cycle units (Newman 4 and 5) are typically backed down to their minimums during the low loads hours during the night (off-peak periods) and allowed to be economically dispatched during the higher load periods during the day (on-peak periods), particularly during the summer. Rio Grande Unit 9 and MPS Units 1 through 4 are designed to be cycled and are routinely cycled to meet the varying load demands or to displace less efficient generation.

Q. HOW DOES EPE MATCH ITS LOCAL UNITS TO LOAD REQUIREMENTS TO ENSURE UNITS ARE AVAILABLE TO MEET DEMAND?

A. EPE develops a security-constrained economic dispatch on a daily basis and adjusts the dispatch as needed for changes in real-time conditions. As part of this dispatch EPE must have adequate generation on line to respond to any contingency that could impact the Company's ability to meet its load obligations. Because Newman Units 1, 2, 3, 4 and 5 and Rio Grande Units 7 and 8 are not designed to be cycled, the season will largely determine which of these units are on-line. During the peak months, these units are typically required to reliably meet peak load and as such are dispatched during those months. In the non-peak months, the dispatch of those units depends on generation and transmission maintenance outages. Rio Grande Unit 9 and MPS Units 1 through 4 are fast-start units that can be cycled and dispatched for meeting load obligations and to rapidly changing load conditions. Copper is a simple-cycle combustion turbine generator that is typically used as a daily peaking unit during the peak season. Copper is subject to start-stop cycles, but it is also used for load following and to meet spinning reserve requirements.

Q. WHY IS PLANT AVAILABILITY IMPORTANT FOR EPE?

A. Plant availability is important because it provides EPE with more options to reliably and economically meet customer demand. For example, EPE strives for a high level of availability at Palo Verde and, formerly, at Four Corners throughout the year because both of these remote stations reflect lower-cost fuel resources.

During the summer peak period (May to September), local unit availability becomes more important because customer demand is higher, there are fewer alternatives available on EPE's system (e.g., most or all units are fully committed), and wholesale power supplies are more limited. For this reason, EPE's goal is to maintain a higher degree of availability for its local generating fleet during the summer peak period. As discussed below, scheduled maintenance is performed during off-peak months when possible.

Q. DOES OPERATION OF EPE's LOCAL GENERATION FOR PRIMARILY LOAD FOLLOWING AND VOLTAGE SUPPORT PURPOSES AFFECT THE UNIT EFFICIENCY LEVELS?

A. Yes. Units that are cycled or dispatched to follow daily load are subjected to increased stress due to the constant changes in thermal gradients. These thermal cycles increase the level of normal wear and tear experienced by the generating unit, which, in turn, causes losses in efficiency and availability. Also, reducing output to lower loads during off-peak hours will cause the unit to operate less efficiently. It is important to note that most units in EPE's local fleet (Rio Grande Units 7 and 8 and Newman Units 1, 2, 3, and 4) were originally designed and built to serve as base load units. EPE's resource mix has changed over time, as has the cost of fuels, and these local units are now called upon to serve in a role different than their original design. However, Rio Grande Unit 9 and MPS Units 1, 2, 3 and 4 are designed to be ramped up and down as needed and therefore allow EPE to meet load and renewable resource fluctuations more efficiently.

Q. IS THE AGE OF EPE'S LOCAL GENERATING FLEET AN IMPORTANT CONSIDERATION WHEN EVALUATING UNIT PERFORMANCE?

A. Yes. In broad terms, EPE's local generation comprises both very new units and very old units. Four of EPE's local units are over 53 years old (Rio Grande Unit 7 and Newman Units 1, 2, and 3). As power plants of that generation age, they become less efficient, have less flexible operating characteristics, and are costlier to run than newer units. After reliability must-run conditions are met, unit commitment will be based on lowest heat rate first, thus having the effect of dispatching older units last.

Q. HOW DOES THE COMPANY MONITOR THE PERFORMANCE OF ITS LOCAL GENERATING UNITS?

A. EPE monitors the performance of these units using two key indicators or measurements: (1) net heat rate and (2) equivalent availability factor ("EAF"). Both net heat rate and EAF are industry-accepted measurements of generating unit performance. Net heat rate is used to monitor unit thermal efficiency, while EAF is used to measure unit availability, based on the percentage of time, within a given period, that a unit is available to generate electricity.

Q. HOW DOES NET HEAT RATE REFLECT UNIT EFFICIENCY?

A. A unit's net heat rate is defined as the amount of fuel energy (measured in British thermal units) used to produce one kilowatt-hour ("kWh") of electricity delivered to the transmission system. Efficient power generation equates to less fuel consumed to produce a kWh and therefore lower fuel costs. A lower net heat rate means the turbine generator is more efficient than a unit with a higher net heat rate. The goal is to maintain a reasonable level of efficiency while satisfying the system reliability requirements.

Q. DO EPE'S LOCAL GENERATING UNITS MAINTAIN REASONABLY CONSISTENT HEAT RATES?

A. Yes. The annual net variances for EPE's local generating fleet efficiency are minimal and are within a range of reasonable operations, based on historical performance. As shown in Schedule FR-4.2a, the annual average composite net heat rates for EPE's local generating fleet demonstrate that EPE maintained consistent and reasonable levels of efficiency during the Reconciliation Period. However, the unavailability of units can have an impact on the aggregated generation fleet heat rate, as I discuss below.

Q. PLEASE EXPLAIN WHY THE LOCAL GENERATING UNITS EXPERIENCE SOME VARIATION IN NET HEAT RATES OVER TIME.

A. Annual average net heat rate measurements can vary from year to year as a result of: (1) changes in unit dispatch; (2) variations in ambient conditions; and (3) time elapsed since the last major unit overhaul. Dispatch affects unit heat rate similar to the manner in which the type of driving (*e.g.*, city or highway) affects the gas mileage for an automobile. Typically, units operate more efficiently when running at a constant, nominal load over a longer period of time (*e.g.*, highway driving). Load following requires the units to constantly cycle up and down (*e.g.*, city driving), which causes the unit to operate less efficiently and results in greater variation in heat rate. As loads vary from period to period, so will the heat rate for units that perform load-following duty.

Variations in ambient conditions (*i.e.*, outdoor temperatures, humidity) will also affect unit dispatch and cause fluctuation in heat rates. For example, ambient conditions impact the effectiveness of a unit's cooling towers. A unit's thermal efficiency increases as the temperature of the cooling water decreases, and the temperature of the cooling water is affected by ambient conditions.

Heat rates also tend to trend upward over time as normal wear and tear deteriorates component parts, resulting in efficiency degradation. A unit is typically most efficient after a major overhaul, and efficiency is reduced over time due to the normal wear and tear that occurs subsequent to a major overhaul.

Because heat rates vary over time, the appropriate standard for efficiency is a range of reasonable operations that recognizes that efficiency will fluctuate over time. The average level of annual variance for EPE's local generating units' heat rate was minimal and falls within a range of reasonable operations. The annual variance of generating fleet heat rate was reflective of the inability of Newman Block 4 and 5 to operate in combined cycle mode at times during the Reconciliation Period due to the steam turbines being unavailable as discussed later in my testimony.

Q. WHY DOES EPE USE EAF AS AN INDICATOR OF PERFORMANCE?

A. As an indicator of performance, EAF takes into account all events that affect availability, rather than focusing on a single type of event. EAF represents the net maximum generation that can be provided by a unit after taking into account planned and forced outages and derates (reduction of rated capacity). EPE uses EAF to measure performance of EPE's local generating units because it provides a clear indication of overall unit availability for a given period.

Q. WHAT OTHER MEASURES OR INDICATORS ARE UTILIZED TO EVALUATE THE PERFORMANCE OF GENERATION UNITS?

A. Other performance measures or indicators are forced outage rate, scheduled outage factor, and capacity factor.

Q. WHAT IS CAPACITY FACTOR?

A. Capacity factor represents the ratio of the actual electrical energy produced by a generating unit over a period of time, compared to the electrical energy that could have been produced at continuous full power operation during the same period. Capacity factor is a standard industry measure, as are other measures such as forced outage rate, scheduled outage factor, and EAF. For base load resources such as Palo Verde and Four Corners, capacity factor is a more comprehensive measure of both performance and availability than other metrics because it takes into account the overall generation production in addition to all events that affect availability.

Q. LATER IN YOUR TESTIMONY, YOU DISCUSS THE CAPACITY FACTORS OF PALO VERDE AND THE FOUR CORNERS UNITS IN EVALUATING THEIR PERFORMANCE. IS CAPACITY FACTOR AN APPROPRIATE CRITERION BY WHICH TO EVALUATE EPE'S LOCAL GENERATION?

A. No, it is not. Unlike EPE's remote generation at Palo Verde and Four Corners, EPE's local generation is not base loaded, but rather is used to follow load as I described previously. As EPE's load increases or decreases, the local generation is ramped up and down to meet changing generation requirements. During low load levels, local generation units are ramped down, sometimes to minimum operating levels, or are shut down. Thus, a capacity factor measurement is not a reliable performance measure for these local units, since the units are technically available for service but may not be needed to meet load. A capacity factor measurement would not capture the availability of the local units. A capacity factor measurement is more applicable for base load units like Palo Verde and Four Corners that are not used to follow load changes.

Q. HAVE YOU PROVIDED OPERATING STATISTICS FOR MEASURES OF UNIT PERFORMANCE?

A. Yes. Schedule FR-4.2a of EPE's Rate Filing Package presents the EAF, forced outage rate, scheduled outage factor, net capacity factor, and net heat rate for each local generating unit on a monthly basis for the Reconciliation Period.

Again, I use EAF to measure performance both in this case and in actual operations because it provides a comprehensive picture of availability. The other operating statistics are certainly useful but do not fit with EPE’s system situation as well as EAF.

Q. ARE THERE TYPICAL TRANSMISSION LINE CONSTRAINTS, UNIT OPERATIONAL CONSTRAINTS, OR SYSTEM RELIABILITY CONSTRAINTS THAT LIMIT THE ECONOMIC DISPATCH OF EPE’S GENERATING UNITS?

A. Yes. The economic dispatch of EPE’s generating units is conditional upon satisfying the transmission line loading, the operating condition of generating units, system voltage and operating reserve requirements. All of these can vary over time. This conditional economic dispatch is referred to as security constrained economic dispatch.

Q. DURING THE RECONCILIATION PERIOD, DID EPE EXPERIENCE SUCH CONSTRAINTS TO A SIGNIFICANT DEGREE?

A. Yes. System voltage and operating reserve requirements define must run generation requirements and are monitored in real-time to evaluate the reliability of EPE’s system. Planned and unplanned outages of transmission lines and generating units limit economic dispatch and are not unusual in the operation of the bulk power system. EPE experienced limits on economic dispatch to a significant degree due to the outages of the steam turbines that are part Newman Block 4 and 5 facilities. The term “Block” is typically referred to in discussing combined cycle facilities, where multiple generators (gas turbines, steam turbine) associated with one facility are referred to as a “Block”. These outages are addressed later in my testimony.

C. Operation and Maintenance of Local Generation

Q. WHAT STEPS DOES EPE TAKE TO MAINTAIN THE EFFICIENCY AND AVAILABILITY OF ITS LOCAL GENERATING FLEET?

A. EPE maintains a comprehensive maintenance program that is designed to maximize the efficiency and availability of those units. The cornerstones of EPE's maintenance practices are regularly scheduled maintenance, and preventive and predictive maintenance programs.

Q. CAN YOU DESCRIBE EPE'S SCHEDULED MAINTENANCE ACTIVITIES?

A. Yes, I can. EPE's power generation operations, maintenance, system operations, and power marketing personnel collaborate to plan the timing of the outages to minimize the economic impact of planned maintenance, subject to system reliability. EPE's scheduled maintenance activities include periodic inspections and major unit overhauls, other planned maintenance intended to maximize unit availability and efficiency, and capital projects.

A major unit overhaul is a comprehensive tune-up where EPE takes a unit out of service to inspect for degradation of component parts, primarily in the turbine and generator, and repairs or replaces those component parts as necessary to maintain or improve efficiency and reliability.

Between major overhauls, EPE also conducts scheduled maintenance on a variety of unit components (e.g., boiler, turbine control valves, and auxiliary equipment) when unit efficiency or availability is likely to be impacted by the failure or potential failure of component parts.

Q. CAN YOU DESCRIBE EPE'S PREVENTIVE MAINTENANCE PROGRAM?

A. Yes. EPE's preventive maintenance program is the practice of performing routine, proactive equipment maintenance. This preventive maintenance is conducted not only during maintenance outages, but also throughout the year while the units are under normal operation. Preventive maintenance includes systematic inspection and routine tasks designed to keep equipment in sound operating condition and minimize degradation of equipment. EPE evaluates original equipment manufacturers' data, equipment operating history, and operating experience in conjunction with the relative significance of a generating unit's component and its associated risk of failure to determine the type of preventive maintenance required. If necessary, EPE then schedules a maintenance outage to inspect equipment and undertake maintenance work prior to the time the equipment is expected to fail. EPE's preventive maintenance program ensures greater control over the scheduling of maintenance activities, which can minimize the duration and cost of outages.

Q. DOES EPE ALSO FOLLOW PREDICTIVE MAINTENANCE PROCEDURES?

A. Yes. EPE monitors equipment operations through various inspection techniques and utilizes statistical control measures in conjunction with actual equipment operating history to predict when to perform maintenance on a unit or component part prior to failure. The data gathered assists with work planning and allows EPE to predict what parts will be required during an actual outage or repair phase. Predicting when a component part is expected to fail also provides EPE more control over scheduling maintenance and thus minimizes costs.

Q. WHAT ARE SOME OF THE PROCESSES EPE FOLLOWS IN ITS PREDICTIVE MAINTENANCE PROGRAM?

A. EPE conducts continuous unit performance monitoring, pre- and post-overhaul unit performance testing, steam path inspections during overhauls, critical equipment vibration monitoring, and lubricant oil analysis. EPE also uses thermography, ultrasonic sensing, and a variety of other analyses to identify, analyze, and resolve potential maintenance concerns. These predictive maintenance processes give EPE's maintenance and operations teams more options in planning and scheduling maintenance and minimizing costs. The alternative would be to wait for equipment to fail, creating downtime, with no options but to repair.

Q. ARE EPE'S PREDICTIVE AND PREVENTIVE MAINTENANCE PROGRAMS IMPLEMENTED IN ALL ASPECTS OF UNIT OPERATIONS?

A. No. Many of the technologies available are not readily adaptable to all systems. EPE's preventive and predictive maintenance practices focus on critical components of various systems on EPE's generating facilities. During operation of a plant, these practices cannot be applied to internal components such as boiler tubes or within the condenser. However, during plant outages, ultrasound equipment is used to check, test and/or find tube leaks. In addition, EPE's maintenance department also conducts eddy current testing and non-destructive evaluation analysis of boiler and condenser tubes and main steam lines.

Q. DESCRIBE EPE'S SCHEDULED MAINTENANCE ACTIVITIES DURING THE RECONCILIATION PERIOD.

A. EPE's scheduled maintenance activities include periodic scheduled major unit overhauls, a variety of other planned maintenance activities intended to maximize unit availability and efficiency, and capital projects. A summary of EPE's fossil unit scheduled maintenance activities is found in Schedule FR-3.2b.

As noted earlier, a major unit overhaul is a comprehensive inspection where EPE takes a unit out of service to inspect for degradation of component parts, primarily in the boiler, turbine and generator, and repair or replace those component parts as necessary to maintain or improve efficiency and reliability. Between major overhauls, EPE also conducts scheduled maintenance on a variety of unit components (*e.g.*, boiler, turbine control valves, and auxiliary equipment) when unit efficiency or availability are impacted by the failure or potential failure of component parts. EPE also plans and carries out various capital projects in conjunction with scheduled maintenance that are designed to support plant operations or maintain or enhance unit availability and efficiency.

Q. PLEASE SUMMARIZE THE COMPANY'S OPERATION PRACTICE AT ITS LOCAL FLEET?

A. EPE's operation practices follow industry standard practices, which include procedures and check list usage, operator rounds, standard routes, and both classroom and on the job training. EPE operations staff continuously monitor and checks plant equipment to ensure effective operation. This monitoring is performed, both in person and by a computerized control and monitoring system.

Q. DURING THE RECONCILIATION PERIOD, WERE THE COMPANY'S OPERATION AND MAINTENANCE PROGRAMS AND PRACTICES PRUDENT AND REASONABLE?

A. Yes, the operation and maintenance programs followed industry standard practices. They were based on engineering data gathered to set the intervals between inspections, and this particular practice conforms to industry-wide standards.

1. Overview of Palo Verde Nuclear Generating Station

Q. PLEASE DESCRIBE PALO VERDE.

A. Palo Verde is a nuclear generating station located on a 4,286-acre site approximately 50 miles west of Phoenix, Arizona. The facility consists of three separate, virtually identical, generating units, as well as a variety of common support facilities. The maximum design electric (capacity) ratings of the facilities are 1,333 MW for Unit 1; 1,336 MW for Unit 2; and 1,334 MW for Unit 3. EPE's share of the total Palo Verde design electric rating (capacity) is 633 MW. Palo Verde also has a switchyard that operates at 500 kV.

The major physical elements can be classified into two categories: buildings and structures comprising each generation unit, and buildings and structures comprising the common areas of the plant. Each unit consists of 1) the following structures: main steam support structure, three cooling towers, and two essential spray ponds; and 2) the following buildings: containment, turbine, corridor, auxiliary, control, radwaste, emergency diesel generator, fuel, and operations support. The major common area plant consists of a three-building administrative complex, a three-building training facility, maintenance and warehouse facilities, a low-level radwaste processing and storage facility, security and emergency response facilities, three evaporation ponds and the water reclamation facility, steam generator storage facilities, reactor head storage facilities, and a dry cask fuel storage facility.

Q. HOW IS PALO VERDE OWNED AND OPERATED?

A. The ownership of Palo Verde is divided among seven southwestern utilities ("Owners"): Arizona Public Service Electric Company ("APS") owns 29.10 percent; EPE owns 15.80 percent; the Salt River Project Agricultural Improvement and Power District owns

17.49 percent; Southern California Edison Company owns 15.80 percent, Public Service Company of New Mexico owns 10.20 percent; Southern California Public Power Authority owns 5.91 percent; and Los Angeles Department of Water and Power owns 5.70 percent.

APS operates Palo Verde pursuant to a contract among the Owners, entitled the Arizona Nuclear Power Project Participation Agreement ("Palo Verde-PA"), which became effective August 23, 1973, and which has been amended sixteen times. The Palo Verde-PA calls for several Owner committees: Administrative Committee, Engineering & Operations Committee, Audit Committee, Fuel Committee, Switchyard Committee, and Termination Funding Committee. A member of EPE's management/executive team represents the interests of EPE on each of these member committees.

VI. Generation Fleet Performance

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. The purpose of this section of my testimony is to support the fuel-related costs for EPE's generation fleet during the April 2016 through March 2019 Reconciliation Period. Specifically, I describe how the Company's generation fleet operated. In doing so, I use the principles and criteria discussed above in Section V.

A. Performance and Maintenance of Local Generation During the Reconciliation Period

1. Net Heat Rate

Q. HOW DID EPE'S LOCAL GENERATING FLEET PERFORM FROM AN EFFICIENCY STANDPOINT DURING THE RECONCILIATION PERIOD?

A. Table DCH-2 below depicts the net heat rate of the local fleet for the years 2016 through 2018. The average net heat rate for the years in the Reconciliation Period was 10,478 Btu/kWh.

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Table DCH-2

LOCAL FLEET EFFICIENCY	Net Heat Rate Btu/kWh	Deviation From Reconciliation Period Average
2016	10,765	2.74%
2017	10,791	2.99%
2018	10,012	-4.45%
Reconciliation Period Average	10,478	N/A

As the Company's performance indicates, the forced outages on the steam turbines of Newman Blocks 4 and 5, which I discuss below, impacted the overall efficiency of the fleet in 2016 and 2017 due to the loss of these efficient combined cycle units. Outside of these contingencies, EPE was able to achieve and maintain consistent and reasonable levels of unit efficiency despite the necessity to operate the older, local units outside of their intended designed role of base load resources.

Q. HAS THE COMPANY PROVIDED A COMPARISON OF EPE'S FOSSIL UNIT HEAT RATES TO THE HEAT RATES OF UNITS OWNED OR OPERATED BY OTHER UTILITIES?

A. No. There are a number of unit-specific factors that can affect unit heat rate, such as unit design, unit age, fuel quality, unit dispatch, elevation, ambient temperatures, humidity, regional weather patterns, maintenance and operating history, and the effects of normal wear and tear. These various factors make it difficult to produce an apples-to-apples comparison between units owned by different utilities.

Q. WHAT IS A MORE APPROPRIATE GAUGE OF PERFORMANCE EFFICIENCY?

A. Typically, a better indicator of performance efficiency is to measure the consistency of efficiency attained over a period of time. A reasonable period of net heat rate data should indicate whether performance is stable or trending upward or downward and to what degree. The three years of information presented above, which almost coincides with the Reconciliation Period, provides a sufficient period of time to determine if any such trends exist. The steam turbine outages associated with Newman Blocks 4 and 5 indicate a drop in overall fleet efficiency in 2016 and 2017 and are discussed later in my testimony. Schedule FR-4.2a identifies individual generator heat rate data which reflect consistent and reasonable levels of efficiency when units are in operation.

2. Unit Availability

Q. WHAT WAS THE EAF FOR EPE'S LOCAL GENERATING FLEET FOR THE ENTIRE RECONCILIATION PERIOD?

A. The average EAF for EPE's local generating fleet was 77 percent for the entire Reconciliation Period (that is, during both peak and non-peak periods).

As a point of reference, the annual average EAF as reported by the North American Electric Reliability Corporation ("NERC") in the 2014-2018 Generating Unit Statistical Brochure is 81.93 percent for gas primary units with nameplate sizes 1-99 MW, and 80.75 percent for gas primary units with nameplate sizes 100-199 MW.

Also, for EPE availability in off-peak periods is not as material as availability during the summer peak periods. That is because if a unit is taken off-line for maintenance or experiences an unplanned outage during off-peak months, other economical resource options are typically available, either from EPE's local fleet, from remote assets, or from the wholesale market.

Q. IS THE NERC AVERAGE EAF AN APPROPRIATE BENCHMARK FOR EPE'S LOCAL FLEET AVAILABILITY?

A. The NERC data provides a point of reference that can be used to gauge EPE's performance with respect to availability. The NERC average EAF is an indicator of industry performance, although differences such as unit age and operational and maintenance history make it difficult to consider NERC average performance as an absolute benchmark. In addition, as I explained above, summer peak availability is a more important criterion for EPE, because the summer months are when availability matters most for EPE's customers.

Q. WHAT WAS EPE'S SUMMER PEAK LOCAL UNIT AVAILABILITY DURING THE RECONCILIATION PERIOD?

A. The EAF attained by EPE's local generation fleet during the summer peak periods of May through September (2016-2018) during the Reconciliation Period was 84 percent.

Q. IS IT REALISTIC TO EXPECT GENERATING UNITS TO ATTAIN 100 PERCENT AVAILABILITY?

A. No. One-hundred percent availability is neither reasonable nor realistically attainable over an extended period of time. Scheduled maintenance is necessary to maintain acceptable levels of overall unit integrity, and other events may affect unit availability during the normal course of business (*e.g.*, environmental operating constraints).

Q. WOULD YOU EXPECT EAF TO VARY FROM YEAR TO YEAR?

A. Yes. Unit operations are dynamic. Scheduled and unscheduled outages affect unit availability and often vary in scope and timing. As a result, availability will vary over time.

Q. ABOVE YOU EXPLAINED THAT THE EAF IS AFFECTED BY FORCED OUTAGES. DID EPE EXPERIENCE ANY SIGNIFICANT FORCED OUTAGES AT ITS LOCAL GENERATION FLEET DURING THE RECONCILIATION PERIOD?

A. Yes. During the Reconciliation Period, EPE experienced unusually long forced outages on the Newman Unit 4 and Newman Unit 5 steam turbines that impacted the economic dispatch of EPE's generating units. These outages are identified in schedule FR-3.2a.

Both Newman Block 4 and Block 5 are combined cycle facilities. A combined-cycle power facility uses both gas-fired combustion turbines (GT1 and GT2 in Block 4 and GT3 and GT4 in Block 5) and a steam turbine together to produce more electricity from the same fuel than a traditional simple-cycle plant. The waste heat from the combustion turbines is routed to the nearby steam turbine, which generates extra power.

Q. WHAT WAS THE CAUSE OF THE OUTAGE ON NEWMAN UNIT 4 STEAM TURBINE?

A. An EPE maintenance crew was repairing a leak on one of the heat recovery steam generators, with the other combustion turbine and steam turbine remaining in service with the unit in one by one ("1x1") configuration. A 1x1 configuration means that one combustion turbine was supplying heat to one heat recovery steam generator to produce energy from the steam turbine. During post-repair testing of the repaired heat recovery steam generator, water leaked through an isolation valve on a small bypass line into the main steam line which delivers the steam generated by the two heat recovery steam generators to the steam turbine. This essentially became a water induction incident, whereby water is introduced into the steam path of the rotating blades on the steam turbine, causing damage. As a result, all three generating components of Newman 4 (GT1, GT2, and ST4) were forced out June 7, 2016 due to steam turbine vibration. GT1 and GT2 returned to service June 18, 2016. The Newman Unit 4 steam turbine (ST4) returned to service on October 7, 2016. The effect of this incident was that from June 18, 2016, until October 7, 2016, Newman 4 was without approximately 167 MW of capacity.

Q. WHY DID IT TAKE FROM JUNE TO OCTOBER 2016 TO RETURN THE NEWMAN UNIT 4 STEAM TURBINE TO SERVICE?

A. Before returning the Newman Unit 4 steam turbine to service, the unit had to be completely disassembled, repaired and reassembled. During disassembly, a replacement rotor was purchased and modified for this unit. By purchasing a replacement rotor, this dramatically reduced the outage length and allowed the unit to be returned to service earlier.

Q. WHAT WAS THE CAUSE OF THE OUTAGE ON THE NEWMAN UNIT 5 STEAM TURBINE?

A. The 138 MW steam turbine on Newman Block 5 experienced a lubrication oil control system failure which resulted in loss of lubrication-oil supply-pump pressure. This resulted in a trip from unit full load operation with no supply of lubricating oil to the turbine and generator bearings. Damage to the steam turbine and generator bearings, rotors and steam path components occurred. The forced outage began July 10, 2016. During the forced outage, the turbine was disassembled and sent off site for repairs before it could be reassembled. These repairs included blade replacement, bearing repairs and machining, and off-site high-speed balancing. The Newman Block 5 gas turbines were available, 70 MW each.

The unit was reassembled and a restart attempted on April 18, 2017. The unit tripped during start-up. The steam turbine high pressure rotor was damaged due to high vibration and, as later discovered upon inspection, a rotor bow (bend in the rotor which causes a mass imbalance), which had occurred during the initial loss of lubricating oil incident, was causing thermally induced metal-to- metal rubs during startups that resulted in high rotor vibration. Newman Block 5 was returned to service on November 29, 2017 after further repairs.

Q. WHAT SCHEDULES CONTAIN INFORMATION ABOUT FOSSIL UNIT OUTAGES?

A. Schedules FR-3.2a and FR-3.2b list each unit outage that occurred during the Reconciliation Period.

Q. WITH RESPECT TO AVAILABILITY, DID EPE'S LOCAL FLEET PERFORM AT A REASONABLE LEVEL DURING THE RECONCILIATION PERIOD?

A. Yes, except for the unusual outages at Newman Units 4 and 5 during the summer of 2016 that I discussed above. EPE’s long term planning reserves account for the potential loss of MWs associated with the loss of either one of the steam turbines individually. However, the forced outages of Newman Block 4 steam turbine during the summer of 2016, and Newman Block 5 steam turbine from the summer of 2016 through November 2017 were significant with regard to the availability of resources during EPE’s peak season. Otherwise, EPE’s local fleet performed at a reasonable level during the Reconciliation Period. The appropriate standard for availability is a range of reasonable operations that recognizes that availability will fluctuate over time.

B. Performance and Maintenance of Palo Verde Generating Station

Q. HOW DOES EPE MEASURE OR GAUGE THE PERFORMANCE OF ITS NUCLEAR UNITS?

A. Palo Verde is subject to fixed performance standards established by the Commission. The performance standards consist of a range of three-year rolling average annual capacity factors for each Palo Verde unit, with the possibility of rewards or penalties on the high and low ends of the range, respectively, and neither a reward nor a penalty for performance within the dead band. EPE witness Melody Boisselier provides additional background and information regarding the performance reports filed during the Reconciliation Period.

Q. DID PALO VERDE OPERATE WELL DURING THE RECONCILIATION PERIOD?

A. Yes, it did. Palo Verde achieved an average capacity factor of 92.4 percent for the reconciliation period. In 2016, the capacity factor was 93.5 percent; in 2017, Palo Verde achieved a capacity factor of 93.8 percent; and in 2018, Palo Verde achieved a 90.2 percent capacity factor.

Q. HOW DID PALO VERDE'S PERFORMANCE MEASURE AGAINST THE PERFORMANCE STANDARDS IN EFFECT DURING THE RECONCILIATION PERIOD?

A. During the Reconciliation Period, Palo Verde operated, on average, above the "dead band" of the performance standards, such that EPE earned a reward. Palo Verde generated 47.3 percent of the energy utilized by EPE to serve its customers during the Reconciliation Period. Customers benefited from utilization of these low fuel-cost nuclear units in lieu of higher cost gas-fired generation.

1. Four Corners Power Plant

Q. PLEASE DESCRIBE THE FOUR CORNERS POWER PLANT.

A. The Four Corners Power Plant ("Four Corners") is located near Farmington, New Mexico, and consists of two coal-fired units, Units 4 and 5, and common facilities. Each unit is rated at 770 MW net, and EPE's seven percent ownership share totaled 108 MW. As I described above, effective July 6, 2016, EPE's participation in the plant ended when an affiliate of APS purchased EPE's share in the plant. This sale was presented in Docket No. 44805, in which the Commission made public interest findings in accordance with a settlement.

Before selling its interest, EPE owned 7 percent, APS owned 63 percent, and there were three other co-owners. APS operates Four Corners pursuant to a contract among the owners, the Four Corners Project Operating Agreement ("Operating Agreement"). The contracts governing the operation of Four Corners expired in July 2016, including the contract for the supply of coal to the plant. The other co-owners decided to extend their participation in Four Corners, and EPE decided not to, as presented in Docket No. 44805.

Q. BEFORE EPE SOLD ITS INTEREST, WHAT ROLE DID EPE HAVE IN THE OPERATION AND MAINTENANCE OF AND CAPITAL EXPENDITURES FOR FOUR CORNERS UNITS 4 AND 5?

A. EPE had a limited role in the direct operation and maintenance of Four Corners. APS was the operating agent for Four Corners and was therefore responsible for the operation and maintenance of Units 4 and 5. EPE exercised its oversight as permitted by the Operating Agreement.

EPE was a member of the Four Corners Engineering and Operating Committee ("E&O Committee") the Four Corners Coordination and Audit Committees, as well as the Fuel and Switchyard Committees. In addition to serving on the Four Corners committees, EPE evaluated APS's budget proposals for capital additions and for O&M and performed variance reporting and reconciliation of actual costs to cash requests. In addition, actual costs were monitored, reconciled, and checked for accuracy and reasonableness.

Q. GIVEN THAT EPE OWNED PART OF FOUR CORNERS ONLY FROM APRIL 1, 2016 THROUGH JULY 5, 2016 OF THE RECONCILIATION PERIOD, ARE THE PERFORMANCE METRICS YOU DESCRIBED ABOVE HELPFUL IN EVALUATING THE REASONABLENESS OF FOUR CORNERS OPERATION?

A. Not really. Usually, one would want to evaluate performance metrics over a far longer period, so that planned outages and forced outages over the course of a calendar year could be taken into account and compared to past performance and perhaps the performance of other coal-fired facilities.

With that caveat, during April - June 2016, both Unit 4 and Unit 5 experienced forced outages, and Unit 4 experienced the remainder of a planned outage. And in June 2016, during EPE's peak season, Unit 4 operated at a capacity factor of 73.4 percent, and Unit 5 operated at a capacity factor of 88.3 percent.

Q. WHICH EPE WITNESS ADDRESSES FOUR CORNERS FUEL MATTERS?

A. EPE witness Martinez addresses Four Corners fuel matters in his testimony.

VII. Rate Treatment of the Macho Springs and Newman Solar Purchased Power Agreements ("PPAS")

Q. DID EPE CONTINUE TO TAKE POWER UNDER SOLAR POWER PPAS THAT IT ENTERED INTO DURING THE LAST FUEL RECONCILIATION PERIOD?

A. Yes, EPE did. There are two such solar PPAs. First, EPE has a 20-year 50 MW solar power PPA for the Macho Springs New Mexico project. This project became operational in May 2014. Second, EPE has a 30-year 10 MW PPA for the solar project located near EPE's Newman station. This PPA became operational in December 2014. EPE continued to take power under these two PPAs during the Fuel Reconciliation period.

Q. WERE THE RATE TREATMENT AND JURISDICTIONAL ALLOCATION OF THE COSTS OF THESE PPAS SETTLED AND APPROVED IN EPE'S LAST BASE RATE CASE IN DOCKET NO. 46831?

A. Yes, they were, as reflected in Findings of Fact 32 and 39 in the Commission's Order. First, the rate treatment was established as follows:

> Under the [settlement] agreement, the classification of costs incurred by EPE as either base-rate capacity charges or fuel charges for the 50-MW Macho Springs solar PPA and the 10-MW Newman solar PPA shall be as follows for the term of these contracts: Effective beginning August 1, 2017, the imputed capacity charge for the 50-MW Macho Springs solar PPA shall be $2.35 per kilowatt ("kW") per month, and the imputed capacity charge for the 10-MW Newman solar PPA shall be $2.33 per kW per month. All remaining costs incurred under these two PPAs shall be classified as fuel expenses. (Agreement art. I.F.)[1]

Second, the parties agreed, and the Commission approved, that the contracts should be allocated as system resources for the purposes of jurisdictional allocation.[2]

EPE witness Boisselier addresses the accounting for the Macho Springs and Newman Solar PPAs consistent with Docket No. 46831.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

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EL PASO ELECTRIC COMPANY'S RESPONSE TO
CITY OF EL PASO'S FIFTH REQUEST FOR INFORMATION
QUESTION NOS. CEP 5-1 THROUGH CEP 5-42

CEP 5-28:

Reference page 8 of EPE witness Olson's direct testimony, please provide any regulatory disallowances of costs incurred due to the referenced Newman 5 steam turbine lubrication oil control system failure, along with the regulatory orders addressing any such disallowances.

RESPONSE:

El Paso Electric Company has not experienced any regulatory disallowance of costs incurred expressly due to the referenced Newman 5 steam turbine lubrication oil control system failure.

Preparer: James Schichtl Title: Vice President – Regulatory and Governmental Affairs

Sponsor: James Schichtl Title: Vice President – Regulatory and Governmental Affairs

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CEP 5-29:

Reference page 8 of EPE witness Olson's direct testimony, please provide any root cause analysis prepared by or for EPE addressing the referenced Newman 5 steam turbine lubrication oil control system failure and related damages.

RESPONSE:

Please see attachment CEP 5-29, Attachment 1.

Preparer: Aaron A. Arzaga — Title: Sr. Data Scientist & Business Intelligence Analyst

Sponsor: J Kyle Olson — Title: Manager- Power Generation Engineering

ROOT CAUSE ANALYSIS (RCA)

<NEWMAN U5 INCIDENT>

EL PASO ELECTRIC CO
NEWMAN POWER STATION
FM 2529
EL PASO TEXAS 79934

DATE: 10/10/2016

TABLE OF CONTENTS

1. INTRODUCTION

The purpose of this RCA is to discuss the incident that occurred at Newman Power Station Unit 5 on July 10th, 2016. The objective is to come up with a solution to prevent this incident from reoccurring.

2. EVENT DESCRIPTION

The steam turbine balance of plant primary controller (Drop 5) and backup controller (Drop 55) failed at approximately 11:22 PM on the night of July 9th. At this time, the unit remained running with both controllers failed. Upon seeing both controllers failed, the technician rebooted the controllers at approximately 1:49 AM on July 10th. At this time, the unit tripped and coasted down without the operation of either main lube oil pump or the emergency DC lube oil pump.

3. INVESTIGATIVE TEAM AND METHOD

The investigation team consisting of Kyle Olson (El Paso Electric) and Adam Schreiner (Burns and McDonnell). The team was brought together on July 27th, 2016 to troubleshoot and all precautions were taken while the units were offline.

- Investigated the statuses of the primary and backup controllers.
- Investigated logic configuration to assure proper control and provide recommendations.
- Investigated wiring to assure proper control and provide recommendations.

4. FINDINGS AND ROOT CAUSE

The initial investigation led to the discovery that while both the primary and backup controllers indicated they were operating properly, a failure of the primary controller resulted in an immediate failure of the backup controller. This was attributed to an unidentified mismatch in the backup controller’s flash memory. The failure of the primary controller is believed to be due to a network communication error but due to the backup controller faulting all diagnostics were lost.

Upon failure of both primary and backup controllers, the memorization of equipment statuses (e.g. running pumps, valve positions, etc.) is lost. Upon reboot of the controllers these are initialized into a default state. Upon investigation, it was discovered that the initialization state of the emergency DC lube oil pump is in the manual state, which is not per the OEM (Fuji) design.

The OEM design calls for the emergency DC lube oil pump auto/manual memorization to occur electrically, utilizing latching relays, and the DCS control to issue only pulsed commands to operate these relays. The wiring is per design, however the DCS configuration is such that the memorization also occurs within the control logic, effectively defeating the latching relays. Furthermore, the initial state of this DCS memorization is in the manual state which defeats the auto start of the emergency DC lube oil pump. The result of this misconfiguration is that upon initialization of the controllers after a dual controller failure, as was experienced, the emergency

DC lube oil pump is placed into manual and off and not permitted to start under any circumstances without operator action.

5. Corrective Action

The emergency DC lube oil pump wiring and logic configuration was modified so as the pump auto start cannot be defeated. To accomplish this, the DC motor starting cubicle was rewired to remove all auto/manual relays. The DCS start request and the auto start should be wired in parallel. The DCS stop request should be wired as to only break the electrical run command seal in. This will result in the emergency DC lube oil pump auto start string always being primed and the pump only able to be stopped upon reestablishment of a main oil pump.

Additionally, the DCS network is being upgraded to a dual connection, fully redundant network which will minimize any future network communication errors.

Sponsor Acceptance

Approved by the Plant Manager:

____ Date: ____________________

David Aranda – Plant Manager

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CEP 5-30:

Reference page 8 of EPE witness Olson's direct testimony, please provide EPE's insurance claims and supporting analysis addressing the cause and damage costs associated with the referenced Newman 5 steam turbine lubrication oil control system failure.

RESPONSE:

Reference CEP 5-30, Attachment 1 for El Paso Electric Company's ("EPE") insurance claims and supporting analysis addressing the cause and damage costs associated with the referenced Newman 5 steam turbine lubrication oil control system failure.

Reference CEP 5-30, Attachment 2, which is an analysis that supports the cost information that EPE witness Olson's summarizes on page 8 of his direct testimony.

Preparer: Nydia Torres — Title: Manager – Claims and Risk Management

Sponsor: J Kyle Olson — Title: Manager – Power Generation Engineering

Unit/Type of Loss	Date of Loss	Claims Collected	Description of the Event	
Mechanical Damage Unit 5 Steam Turbine	July 10, 2016	$ 18,279,831	On 10 July 2016, Newman Unit 5 reportedly experienced a control system malfunction (i e Emerson DCS) An initial investigation into the loss of the control system did not reveal other problems The control system computer was rebooted by an El Paso Electric Electronic Specialist Upon reboot of the control system, the AC and DC lube oil pumps went to the off position Following a steam turbine trip, the unit rolled down without lubrication	Reference Page 2 for Details
Mechanical Damage Unit 5 Steam Turbine	April 25, 2017	$ 5,608,914	On 25 April 2017, the Insured was in the process of starting Newman 5 following completion of restoration work after the forced outage event on 10 July 2016 The unit startup included a preliminary 'heat soak' of the HP-IP turbine for a period of approximately 30 minutes at low speed (≈ 1250 rpm) This would allow for the gradual thermal expansion of components prior to the turbine being placed on full steam load with the rotor turning at operational speed (3600 rpm) However, the HP-IP turbine was manually tripped at approximately 11 56 AM when bearing vibration levels exceeded the set points Examination of the HP-IP turbine revealed damage to both rotating and stationary components caused by severe rubbing	Reference Page 3 for Details
	Total Claims Collected	**$ 23,888,745**	Reference CEP 05-30 Attachment 2	

RESERVE

The followıng assessment ıs representıng the net claım value of the subject loss event

		Proposed Value	Fınal Value
Adjusted Loss Value		$ 19,707,460	$ 19,779,831
PD Deductıble		$ (1,500,000)	$ (1,500,000)
	Total	18,207,460	**18,279,831**
Fırst Partıal Payment		6,000,000	6,000,000
Second Partıal Payment		8,000,000	8,000,000
Net Reserve		4,207,460	4,279,831

			Incident Related	Not Related	Subject to Review	Adjuster Issue
Invoıces		$ 19,796,002	$19,752,911	$25,437	$ 17,653	-
Purchase Accruals (Completed Work Pendıng Receıpt of Invoıce)		624,164		$ 624,164		
Materıals Issued from EPE Warehouse		26,920	$26,920	-	-	-
Internal Labor and Related Payroll Benefits		59,723	-	-	-	$59,723
Internal Overheads						
Allowance for Funds Used Durıng Constructıon (AFUDC)	$483,127		-	-	-	$ 483,127
Capıtalızed Admınıstratıve & General Costs (A&G)	99,299		-	-	-	$ 99,299
Transportatıon expense allocatıons	250	582,676	-	-	-	$ 250
Total Costs Incurred to Date		$ 21,089,485	$ 19,779,831	$ 649,601	$ 17,653	$ 642,399

El Paso Electrıc Company claımed $21,089,485 ın charges and expenses related to the loss event These values do not ınclude addıtıonal costs related to a subsequent loss occurrence related to a faıled restart of Newman 5 on 25 Aprıl 2017 The costs assocıated wıth the second event (EPE reference Phase 2) were submıtted separately, as a new claım

FINAL RESERVE

Based on the final assessment of the claim submission from the Insured that included supporting documentation representing incurred event-related costs through 31 December 2017, I am recommending a final reserve reflected in the following calculation

Final Restoration Value $7,108,914	$	7,108,914
PD Deductible	$	(1,500,000)
Reserve	**$**	**5,608,914**

El Paso Electric Company
Newman Unit 5 Outage Costs
Phase 2
As of December 31, 2017

			Incident Related	**Not Related**	**Subject to Review**	**Phase 3**
Invoices through December 2017		$6,473,870	$6,075,749	$2,946		$395,174
January 2018 Invoices (December Accruals)		$1,075,279	$987,106	-	-	$88,173
Materials Issued from EPE Warehouse		$4,156	$4,156	-	-	-
Internal Labor and Related Payroll Benefits		$71,655	$29,931	$28,157	-	$13,567
Internal Overheads						
Allowance for Funds Used During Construction (AFUDC)	$ 83,624			$83,624		
Capitalized Administrative & General Costs (A&G)	8,870			$8,870		
Transportation expense allocations	301	$ 92,795		$301		
40% Burden			$11,972	$(17,399)	-	$5,427
Total Costs Incurred To Date		**$ 7,717,755**	**$ 7,108,914**	**$ 106,500**	-	**$ 502,341**

As noted above, El Paso Electric Company submitted costs totaling $7,717,755 representing property damage sustained by the Newman Unit 5 steam turbine during a failed startup attempt on 25 April 2017 There was significant rubbing of the HP-IP rotor against the steam turbine shell that required a full outage to repair the damage The items most affected by the event included seals and bearings Consequently, the HP-IP rotor was pulled and shipped to the Siemens facility in Charlotte, NC for inspection and repair There was also work performed on site for the inspection, assessment and repair of stationary components The restoration work associated with the subject loss event was concluded in September 2017 with a startup of Unit 5 attempted on 24 September 2017 This startup was also unsuccessful due to imbalance and high vibration issues Unit 5 was placed again in outage status while technicians and support personnel investigated the latest event Additional work was performed on the journal bearings that eventually allowed the facility to successfully restart Unit 5 on 29 November 2017 This additional work and costs incurred beyond 24 September 2017 were treated as a separate event (i e Phase 3) These charges and expenses were identified in the review of materials submitted for consideration, which resulted in a reduction of the claim in the amount of $502,341 In addition to the costs removed from the claim for the 'Phase 3' work, there were other charges and expenses totaling $106,500 that were found to be either unrelated or unsubstantiated As such, these costs were removed to arrive at the final loss exposure value in the amount of $7,108,914

NEWMAN MAJOR OUTAGE SUMMARY

	ACTUAL COSTS INCURRED			*INSURANCE CLAIMS*			*NET RECOGNIZED*		
	GROSS CAPITAL	**GROSS O&M EXPENSES**	**TOTAL EXPENDED BEFORE INSURANCE**	**CAPITAL**	**O&M**	**TOTAL CLAIMS COLLECTED**	**CAPITAL**	**O&M**	**TOTAL NET RECOGNIZED**
NEWMAN UNIT 5 TURBINE REPAIR									
GN162 (CAPITAL)	$ 16,595,076	$ -	$ 16,595,076	$ 14,686,565	$ -	$ 14,686,565	$ 1,908,512	$ -	$ 1,908,512
GN750 (O&M)	-	4,061,381	4,061,381	-	3,593,267	3,593,267	-	468,115	468,115
TOTAL UNIT 5 PHASE 1	$ 16,595,076	$ 4,061,381	$ 20,656,458	$ 14,686,565	$ 3,593,267	$ 18,279,831	$ 1,908,512	$ 468,115	$ 2,376,627
GN162 (CAPITAL)	$ 4,809,130	$ -	$ 4,809,130	$ 3,459,590	$ -	$ 3,459,590	$ 1,349,540	$ -	$ 1,349,540
GN750 (O&M)	-	2,987,747	2,987,747	-	2,149,324	2,149,324	-	838,423	838,423
TOTAL UNIT 5 PHASE 2	$ 4,809,130	$ 2,987,747	$ 7,796,878	$ 3,459,590	$ 2,149,324	$ 5,608,914	$ 1,349,540	$ 838,423	$ 2,187,963
GRAND TOTAL	**$ 21,404,207**	**$ 7,049,129**	**$ 28,453,335**	**$ 18,146,155**	**$ 5,742,590**	**$ 23,888,745**	**$ 3,258,052**	**$ 1,306,538**	**$ 4,564,590**
TOTAL CAPITAL	$ 21,404,207	$ -	$ 21,404,207	$ 18,146,155	$ -	$ 18,146,155	$ 3,258,052	$ -	$ 3,258,052
TOTAL O&M	-	7,049,129	7,049,129	-	5,742,590	5,742,590	-	1,306,538	1,306,538
TOTAL UNIT 5 PHASES 1 AND 2	**$ 21,404,207**	**$ 7,049,129**	**$ 28,453,335**	**$ 18,146,155**	**$ 5,742,590**	**$ 23,888,745**	**$ 3,258,052**	**$ 1,306,538**	**$ 4,564,590**

SOAH DOCKET NO. 473-21-2606
PUC DOCKET NO. 52195

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QUESTION NOS. CEP 5-1 THROUGH CEP 5-42

CEP 5-31:

Reference page 12 of EPE witness Olson's direct testimony, please provide the estimated lead times for delivery of replacement boosters or power turbines in the event of a failure of these critical components.

RESPONSE:

The estimated lead time for a replacement booster at the time of purchase was 210 days. Currently, GE has an available booster in stock so there is no lead time; however, in the event GE does not have a booster in stock, the estimated current lead time is 24 months.

The estimated lead time for a replacement power turbine at the time of purchase was 90 days. Currently, GE does not have a power turbine in stock and the estimated current lead time for a replacement power turbine is 24 months.

Preparer: Pedro Vega — Title: Senior Accountant – Power Generation

Sponsor: J Kyle Olson — Title: Manager – Power Generation Engineering

SOAH DOCKET NO. 473-21-2606
PUC DOCKET NO. 52195

APPLICATION OF EL PASO ELECTRIC COMPANY TO CHANGE RATES	§ § §	BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS

EL PASO ELECTRIC COMPANY'S RESPONSE TO
CITY OF EL PASO'S FIFTH REQUEST FOR INFORMATION
QUESTION NOS. CEP 5-1 THROUGH CEP 5-42

CEP 5-32:

Reference page 12 of EPE witness Olson's direct testimony, please provide the estimated capacity loss (MW) due to failure of an LMS100 booster or power turbine.

RESPONSE:

A failure of either an LMS100 booster or power turbine would result in the unit being unavailable and a capacity loss of 88 MW.

Preparer: Pedro Vega Title: Senior Accountant – Power Generation

Sponsor: J Kyle Olson Title: Manager – Power Generation Engineering

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APPLICATION OF EL PASO ELECTRIC COMPANY TO CHANGE RATES	§ § §	BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS

EL PASO ELECTRIC COMPANY'S RESPONSE TO CITY OF EL PASO'S FIFTH REQUEST FOR INFORMATION QUESTION NOS. CEP 5-1 THROUGH CEP 5-42

CEP 5-33:

Reference page 12 of EPE witness Olson's direct testimony, please provide the estimated lead times for delivery of a replacement booster or power turbines in the event of a failure of these critical components.

RESPONSE:

Please refer to El Paso Electric Company's response to CEP 5-31.

Preparer: Pedro Vega — Title: Senior Accountant – Power Generation

Sponsor: J Kyle Olson — Title: Manager – Power Generation Engineering

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CEP 5-34:

Reference page 12 of EPE witness Olson's direct testimony, please provide the capital cost of the referenced spare LMS100 power turbine.

RESPONSE:

The total capital cost of the spare LMS100 power turbine is $5,735,590.

Preparer: Barbara J. Torres — Title: Principal Plant Accountant

Sponsor: Larry J. Hancock — Title: Manager – Plant Accounting
J Kyle Olson — Manager – Power Generation Engineering

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CEP 5-35:

Reference page 12 of EPE witness Olson’s direct testimony, please provide the capital cost of the referenced spare LMS100 booster.

RESPONSE:

The total capital cost of the spare LMS100 booster is $1,894,232.

Preparer:	Barbara J. Torres	Title:	Principal Plant Accountant
Sponsor:	Larry J. Hancock J Kyle Olson	Title:	Manager – Plant Accounting Manager – Power Generation Engineering

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CEP 5-36:

Reference page 12 of EPE witness Olson's direct testimony, please provide the date and duration of past forced outages due to failure of a LMS100 power turbine owned by EPE along with the estimated replacement power costs due to each failure.

RESPONSE:

El Paso Electric Company has not experienced a failure of a LMS100 power turbine. A project overview and justification can be found in the direct testimony of El Paso Electric Company ("EPE") witness J Kyle Olson, page 12, lines 12-27.

Preparer: J Kyle Olson Title: Manager – Power Generation Engineering

Sponsor: J Kyle Olson Title: Manager – Power Generation Engineering

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CEP 5-37:

Reference page 12 of EPE witness Olson's direct testimony, please provide the date and duration of past forced outages due to failure of a booster on an LMS100 owned by EPE along with the estimated replacement power costs due to each failure.

RESPONSE:

El Paso Electric Company has experienced no forced outages due to failure of a booster on an LMS100. A project overview and justification can be found in the direct testimony of El Paso Electric Company ("EPE") witness J Kyle Olson, page 12, lines 12-27.

Preparer: J Kyle Olson Title: Manager – Power Generation Engineering

Sponsor: J Kyle Olson Title: Manager – Power Generation Engineering

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CEP 5-38:

Reference page 12 of EPE witness Olson's direct testimony, please provide the annual cost of the referenced GE multi-year service agreement and a copy of the agreement.

RESPONSE:

A copy of the GE multi-year service agreement is attached as CEP 05-38, Attachment 1 – Highly Sensitive Protected Materials. Please see Article 5 of the agreement for detail on the agreement's costs.

Preparer: Pedro Vega — Title: Senior Accountant – Power Generation

Sponsor: J Kyle Olson — Title: Manager – Power Generation Engineering

PUBLIC

CEP 5-38 Attachment 1 is CONFIDENTIAL and/or HIGHLY SENSITIVE PROTECTED MATERIALS attachment and VOLUMINOUS.

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CEP 5-39:

Reference page 12 of EPE witness Olson's direct testimony, please indicate whether the referenced GE multi-year service agreement has been reviewed and approved by the Commission, and if so, provide the date and docket number of the order approving the agreement.

RESPONSE:

The Multi-Year Service Agreement with General Electric, an extended service plan for El Paso Electric Company's five LMS-100 combustion turbines and spare supercore, has not been reviewed or approved by the Commission.

Preparer: James Schichtl — Title: Vice President – Regulatory and Governmental Affairs

Sponsor: James Schichtl — Title: Vice President – Regulatory and Governmental Affairs

J Kyle Olson — Manager- Power Generation Engineering

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CEP 5-40:

Reference page 12 of EPE witness Olson's direct testimony, please explain whether the referenced GE multi-year service agreement with EPE provides for replacement costs of equipment due to failure of LMS100 boosters or power turbines.

RESPONSE:

Please see CEP 5-40, Attachment 1 – Highly Sensitive Protected Materials.

Preparer: J Kyle Olson Title: Manager – Power Generation Engineering

Sponsor: J Kyle Olson Title: Manager – Power Generation Engineering

PUBLIC

CEP 5-40 Attachment 1 is CONFIDENTIAL and/or HIGHLY SENSITIVE PROTECTED MATERIALS attachment and VOLUMINOUS.

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CEP 5-41:

Please provide the annual EAF, capacity factor, and forced outage hours for each EPE local area generating unit for each of the last five calendar years.

RESPONSE:

Please see attachment CEP 05-41, Attachment 1.

Preparer: Kara Randle   Title: Staff Data Scientist & Business Intelligence Analyst

Sponsor: J Kyle Olson   Title: Manager – Power Generation Engineering

	EAF			
UNIT	**2016**	**2017**	**2018**	**2019**
Rio Grande 6	99.8	98.6	90.2	-
Rio Grande 7	82.8	89.5	68.0	82.4
Rio Grande 8	77.9	87.4	59.3	70.3
Rio Grande 9	70.6	92.8	90.2	79.3
Newman Unit 1	94.3	46.4	76.1	80.2
Newman Unit 2	92.8	80.9	49.9	88.3
Newman Unit 3	79.8	67.9	74.3	87.4
Newman 4-GT1	57.1	84.8	74.0	59.0
Newman 4-GT2	69.2	68.5	98.6	87.2
Newman 4-ST	44.0	61.4	88.1	67.0
Newman 5-GT3	84.2	85.5	91.5	83.4
Newman 5-GT4	86.8	88.3	91.2	81.5
Newman 5-ST	38.7	14.2	89.5	69.0
Copper	89.2	95.0	96.8	85.8
Montana Unit 1	97.7	90.1	84.6	91.7
Montana Unit 2	99.8	88.2	92.8	91.2
Montana Unit 3	99.9	68.7	89.1	92.1
Montana Unit 4	100.0	92.0	89.1	92.2

Notes:

Rio Grande 6 went into inactive reserve 1/8/2019

Montana Unit 3 COD 5/3/2016

Montana Unit 4 COD 9/15/2016

Average capacity factor (%)

UNIT	**2016**	**2017**	**2018**	**2019**
Rio Grande 6	32.3	26.2	18.7	-
Rio Grande 7	27.1	28.7	28.1	38.4
Rio Grande 8	33.6	40.2	29.7	39.6
Rio Grande 9	21.2	18.4	10.6	33.1
Newman Unit 1	34.4	26.2	36.3	39.0
Newman Unit 2	45.4	43.8	23.9	45.1
Newman Unit 3	32.3	32.0	35.5	40.9
Newman 4-GT1	28.7	58.1	47.3	41.5
Newman 4-GT2	46.4	43.5	68.2	67.5
Newman 4-ST	26.8	34.7	40.7	39.9
Newman 5-GT3	27.3	16.3	67.4	61.1
Newman 5-GT4	26.8	19.0	68.5	62.1
Newman 5-ST	7.4	4.8	45.4	45.2
Copper	5.9	3.4	8.4	7.0
Montana Unit 1	36.5	44.6	35.6	37.3
Montana Unit 2	34.5	37.6	43.9	36.1
Montana Unit 3	38.8	14.3	28.8	26.3
Montana Unit 4	28.8	34.6	32.7	33.4

Notes:

Rio Grande 6 went into inactive reserve 1/8/2019
Montana Unit 3 COD 5/3/2016
Montana Unit 4 COD 9/15/2016
Average Capacity Factor is Net

Forced Outage Hours

UNIT	2016	2017	2018	2019	2020
Rio Grande 6	8.5	10.9	125.9	0.0	0.0
Rio Grande 7	26.0	33.6	2156.9	1004.7	3930.1
Rio Grande 8	345.1	238.0	123.0	59.5	1113.9
Rio Grande 9	18.0	10.0	230.8	297.4	5.6
Newman Unit 1	323.9	10.7	527.5	12.6	818.6
Newman Unit 2	46.9	146.9	2377.5	23.5	28.6
Newman Unit 3	302.2	0.7	26.1	499.4	960.0
Newman 4-GT1	274.8	191.3	919.7	1466.9	1271.3
Newman 4-GT2	307.8	269.0	79.5	289.6	1212.4
Newman 4-ST	3181.3	2098.8	261.3	186.6	915.9
Newman 5-GT3	59.3	79.4	95.8	0.0	93.5
Newman 5-GT4	66.2	5.0	18.5	139.9	10.6
Newman 5-ST	4374.0	6468.9	69.5	23.8	41.0
Copper	140.7	43.2	177.3	367.5	3567.4
Montana Unit 1	199.6	0.9	429.6	97.3	40.1
Montana Unit 2	8.3	248.4	129.5	265.1	230.6
Montana Unit 3	0.5	39.5	213.8	94.7	216.3
Montana Unit 4	0.0	38.2	513.9	165.6	31.9

Notes:

Rio Grande 6 went into inactive reserve 1/8/2019
Montana Unit 3 COD 5/3/2016
Montana Unit 4 COD 9/15/2016
2020 Forced Outage Hours include a total of approximately 1776 hours of planned outage extensions due to Covid-19 parts delays.

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QUESTION NOS. CEP 5-1 THROUGH CEP 5-42

CEP 5-42:

Please provide the monthly net generation, average capacity factor, and forced outage hours for each EPE local area generating unit for each month of 2020.

RESPONSE:

Please see attachment CEP 05-42, Attachment 1.

Preparer: Aaron A. Arzaga   Title: Sr. Data Scientist & Business Intelligence Analyst

Sponsor: J Kyle Olson   Title: Manager – Power Generation Engineering

2020 Net Generation												
	January	February	March	April	May	June	July	August	September	October	November	December
Copper	185	4,839	4,874	2,660	3,221	6,518	9,608	1,507	(3)	(5)	(3)	(3)
Montana 1	13,984	23,474	7,829	25,109	24,700	28,984	35,513	35,564	18,509	21,676	16,065	19,863
Montana 2	17,327	23,941	14,393	36,177	20,425	25,013	33,182	29,413	18,615	13,629	12,160	10,791
Montana 3	2,550	7,868	10,241	7,608	11,144	12,643	15,403	20,483	6,766	(394)	(307)	(347)
Montana 4	25,721	33,733	28,776	16,973	18,539	22,744	28,591	22,144	15,324	14,112	11,488	12,048
Newman 1	2,582	31,202	(319)	14,355	30,739	31,931	17,877	5,628	31,129	18,432	11,334	20,916
Newman 2	(150)	27,309	28,354	18,452	31,822	32,833	34,244	34,073	33,091	35,152	28,398	34,988
Newman 3	(89)	11,791	33,143	34,404	30,283	27,619	36,336	32,336	18,186	28,647	28,042	12,201
Newman 4-GT1	32,346	2,799	(216)	(254)	29,115	38,181	34,622	39,440	31,479	1,952	-	-
Newman 4-GT2	32,231	27,073	-	-	-	26,901	36,654	30,182	31,280	1,929	-	-
Newman 4-ST	26,263	12,489	-	-	10,915	29,840	34,650	33,489	31,154	1,844	-	-
Newman 5-GT3	46,486	10,719	39,310	37,720	37,286	39,961	43,257	39,229	39,556	40,254	41,018	43,624
Newman 5-GT4	46,478	2,368	44,137	43,832	42,522	40,350	44,115	39,928	39,713	40,519	41,205	43,689
Newman 5-ST	62,774	8,988	57,614	62,021	57,770	59,223	67,739	61,157	58,437	58,565	55,110	53,436
Rio Grande 6	(62)	(39)	(72)	(74)	(81)	(49)	(64)	(87)	(83)	(83)	(81)	(83)
Rio Grande 7	(84)	(78)	(71)	(60)	5,010	15,707	6,831	16,665	14,612	15,787	14,659	6,674
Rio Grande 8	13,443	22,403	53,271	56,139	53,182	169	49,284	57,762	61,107	49,280	38,540	51,498
Rio Grande 9	20,690	36,683	14,195	13,764	41,191	40,464	57,310	41,766	16,086	-	-	-