Exhibit No. BWP/GWP-100

BEFORE THE CITY OF LOS ANGELES
DEPARTMENT OF WATER AND POWER

2017 Reform of Electric Transmission Tariff
and Electric Transmission Rates

TESTIMONY IN OPPOSITION TO THE PROPOSED RATES, TERMS AND CONDITIONS OF LADWP'S 2017 ELECTRIC TRANSMISSION TARIFF REVISIONS

Lon L. Peters, Riley Rhorer, and Michael Wenzinger

Witnesses for the
Cities of Burbank and Glendale, California
Departments of Water and Power

April 14, 2017

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TESTIMONY OF PETERS, RHORER AND WENZINGER

Subject: Proposed Rates, Terms and Conditions for the
LADWP 2017 Open Access Transmission Tariff

Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Lon L. Peters, and my qualifications are attached as BWP/GWP-Q-01.

A. My name is Riley Rhorer, and my qualifications are attached as BWP/GWP-Q-02.

A. My name is Michael Wenzinger, and my qualifications are attached as BWP/GWP-Q-03.

Q. On whose behalf are you testifying?

A. We are testifying on behalf of the Cities of Burbank and Glendale, California, Departments of Water and Power ("BWP" and "GWP" or together "the Cities").

Q. What is the purpose of your testimony?

A. In this testimony, we discuss LADWP's proposed rates, terms and conditions of open access transmission tariff ("OATT"), as released on January 17 and February 21, 2017.

Q. Do you have any exhibits to your testimony?

A. Yes. In addition to our qualification statements, there are five exhibits. BWP/GWP-E-101 contains copies of responses by LADWP to Information Requests ("IRs") submitted by the Cities to LADWP and referenced in this testimony. Any responses that included Confidential Energy Infrastructure Information ("CEII") are in BWP/GWP-E-102, which is marked "CEII

Data" and is being transmitted under separate cover and marked "CEII".[1] BWP/GWP-E-103 contains tables and charts developed by the Cities to support this testimony. BWP/GWP-E-104 contains other documents relied on in the preparation of this testimony that should be part of the record in this proceeding, because they contain information that the LADWP General Manager should consider in any finding or recommendation. Finally, BWP/GWP-E-105 is a modified version of DWP-104, which incorporates changes to the rate calculations to the extent possible at this time. The tab marked "Cover Page" in BWP/GWP-E-105 shows the specific changes made by the Cities to DWP-104.

Section 2: Interests of BWP and GWP

Q. Please describe the interests of the Cities in this proceeding.

A. Burbank and Glendale each operates a Department of Water and Power, which supplies electricity to retail loads within each City; generates, imports, and exports power; and engages in wholesale market transactions that help reduce the overall retail cost of electric service. The Cities are "embedded" in the Balancing Area of LADWP, and thus must buy certain services from LADWP, including transmission and ancillary services. The embedded nature of the Cities' systems severely limits their opportunities to find other suppliers of power, transmission, and ancillary services. Purchases from any third-party suppliers require the cooperation of and contractual commitments by LADWP and in some instances require access over LADWP's

[1] Some excerpts from CEII materials are included in this testimony, but are also redacted in the public version and a non-redacted version of the testimony is being transmitted under separate cover marked "CEII."

transmission system. The Cities are thus "captive customers" who rely on LADWP in a variety of ways to serve their customers' electricity demands.

Q. Are BWP and GWP current OATT customers of LADWP?

A. Yes. BWP and GWP hold short-term OATT transmission service agreements with LADWP, which are normally renewed annually. GWP pays LADWP OATT rates for Schedules 1, 2, 3, 5, 6 and 7 when it takes service under the Balancing Authority Area Services Agreement between Los Angeles Department Water and Power and Glendale Water and Power ("GWP BAASA"). BWP pays LADWP OATT rates for Schedules 1, 2, 3, 5, 6 and 7 when it takes service under the Balancing Authority Area Services Agreement between Los Angeles Department Water and Power and Burbank Water and Power ("BWP BAASA") (collectively referred to as the "BAASAs").

Q. How do BWP and GWP use their agreements with LADWP?

A. BWP and GWP use the short-term transmission agreements for wholesale transactions, the margins on which help reduce retail rates. BWP and GWP use the BAASA to purchase certain ancillary service from LADWP, which also requires payments under Schedule 7.

Q. What are the long-term interests of BWP and GWP in LADWP's OATT?

A. In the long-term, both BWP and GWP will most likely require additional transmission and ancillary services from LADWP to integrate new renewable resources to comply with California's Renewable Portfolio Standards. The timing and amount of such new service are unknown at this point. In addition, GWP is planning to repower the Grayson Power Plant in Glendale in the near future, and must secure "bridge" energy supplies during demolition, construction, and testing. GWP should have the alternative of requesting unbundled

transmission service from LADWP at just and reasonable rates in order to access third-party supplies of energy during the repowering.

Section 3: Summary of Testimony

Q. Please provide an outline of your testimony.

A. As an initial matter, BWP and GWP have serious reservations regarding the process of LADWP's OATT proceeding. BWP and GWP had limited time to conduct discovery and prepare testimony. This issue was compounded by LADWP's claims that some information was privileged, by late responses or no responses at all, and by several responses that required follow-up to achieve clarity and/or receive requested documentation. For these reasons, we recommend that the General Manager suspend the process until the Cities can conduct proper discovery to fully understand the issues present.

In regards to the specifics of LADWP's proposal, based on the information presented by LADWP in this OATT proceeding, BWP and GWP have multiple concerns. First, LADWP's proposal to use a twelve coincident peak divisor ("12 CP") to set its rates is incorrect. Federal Energy Regulatory Commission ("FERC") precedent requires seasonal peaking utilities, which LADWP is, to calculate their rates using a 1 CP, 2 CP, or 3 CP methodology. The record shows that LADWP should apply a 1 CP method to calculate its rates.

Second, LADWP miscalculates its Native Load obligation by failing to include GWP and BWP's loads in its calculations. Under LADWP's OATT's and FERC's pro-forma OATT's definition of Native Load, GWP and BWP should be included in LADWP's calculations. LADWP also fails to include station service and pumping load in contradiction of FERC

precedent. LADWP should update their calculations to include BWP, GWP, station service, and pumping load in LADWP's calculation of Native load.

Third, LADWP incorrectly applies a study conducted well after the test year to determine the capacity purchase obligations for some ancillary services. This study does not support LADWP's proposals for Schedules 3 and 10, and also fails to follow FERC Order No. 764. LADWP should withdraw Schedule 10, conduct the required studies, put the required systems into place, and then issue a new Schedule 10 that complies with FERC Order No. 764.

Fourth, the "black box" nature of LADWP's Available Transmission Capacity ("ATC") calculations makes it possible that LADWP has used incorrect or even biased assumptions to reduce ATC to benefit retail loads and disadvantage transmission customers, thereby unduly discriminating against wholesale transmission customers. LADWP must provide, both to the Cities and to all existing and eligible transmission customers, a clear explanation of how it calculates ATC generally and how specific MW amounts are used in calculating ATC for each posted path.

Fifth, LADWP's proposal to use loss factors based on an outdated and likely flawed study of transmission losses inappropriately overstates LADWP's losses, at least by excluding significant upgrades made to the transmission system since the study at issue was conducted. The costs of these upgrades have been rolled in to LADWP's OATT rates but the benefits of these upgrades have been essentially ignored, thus violating FERC's long held principle of cost causation.

Sixth, LADWP's proposed assignment of facilities identified below – both transmission and generation – to the provision of either open access transmission service or open access

ancillary services is not appropriate. The facilities are either not transmission facilities or cannot provide the services LADWP alleges they can. Accordingly, these facilities and their costs should be removed from LADWP's OATT rates.

Seventh, LADWP must segment its transmission system, and set separate rates for the PDCI, the Southern/Northern DC/AC Transmission System ("STS/NTS"), and the AC Beltline. FERC precedent requires the allocation of the cost of transmission facilities among customers whether facilities are or are not integrated. For a variety of reasons, the facilities in question are not integrated, and thus do not provide system-wide benefits. Therefore, these facilities must be directly assigned to those customers who use the facilities via segmentation.

Eighth, LADWP fails to provide sufficient documentation of offsetting sources of income, revenues, receivables, and other credits that would help reduce OATT rates. GWP and BWP understand that LADWP provides certain O&M-type services to other utilities and joint-action agencies. These sources of income must be properly credited to LADWP customers.

Ninth, LADWP fails to properly account for the use of LADWP's ancillary services by LADWP's Wholesale Marketing group ("LA-Merchant", "WERM" or "LAWM"). This is clear evidence of discrimination against OATT customers, who must comply with LADWP's Business Practices, and of rates under Schedules 5, 6 and 10 that are too high because they reflect no revenue credits from LA-Merchant. Accordingly, the proposed rates under these Schedules are too high.

Tenth, LADWP's approach to calculating a return on equity and a weighted average cost of capital ("WACC") is flawed, contains multiple errors, and is not consistent with FERC Opinions. Accepting LADWP's return-on-equity ("ROE") and capital structure proposals would

violate Supreme Court precedent, which establishes that a just and reasonable ROE will be no higher than what is required to maintain LADWP's financial integrity, permit LADWP to raise sufficient capital, and permit it to achieve a return commensurate with the returns earned by utilities of comparable risk. Correcting these errors sets LADWP's ROE at 7.04 percent and the WACC at 4.48 percent.

Eleventh and final, LADWP inappropriately requires customers to pay interest on delinquent amounts, which violates FERC's policy. LADWP should amend its proposal to ensure consistency with FERC precedent.

In sum, correction of these errors will minimize potential for action by the Cities at the FERC after adoption of the General Manager's proposal by the LADWP Commission and ultimately the Los Angeles City Council.

Section 4: Procedural Concerns

Q. What is the purpose of this section?

A. In this section, we describe the limited discovery process developed and implemented by LADWP, and describe the lack of support for certain data, inputs and assumptions in LADWP's proposed rates, terms and conditions of service. We also discuss LADWP's failure to fully and accurately respond to information requests, inadequate responses to IRs, lack of sufficient time for discovery, and the limited schedule for discovery, comments and the preparation of testimony.

Q. What are your concerns regarding the process?

A. The duration of the entire public process was January 19 through April 14, 2017: 86 calendar days or 60 normal work days. This year, LADWP has been much more open and forthcoming about the bases for its proposal than was the case in 2014. However, that means that the Cities have had more information to gather and understand than in the 2014 LADWP OATT proceeding. Based on our experience, this is an unusually short process, especially compared with much longer FERC proceedings. The compressed time frame is the result of LADWP's arbitrary goal of asking the Los Angeles City Council to approve new rates, terms and conditions by June 30, 2017. During the process, we worked with LADWP staff and outside counsel and consultants to modify and extend the schedule, and in some cases have been successful in small changes that have given us more time to understand the proposal. Nonetheless, given the relatively short schedule and delays in getting responses to discovery requests, the Cities have not been provided due process. The fact that LADWP is not a public utility does not excuse it from employing reasonable procedures. *See Minnesota Municipal Power Agency v. Southern Minnesota Municipal Power Agency*, 68 FERC ¶ 61,060, 61,208 (1994) (holding that even when a non-public utility is involved "we believe it is appropriate to employ procedures similar to those specified under [Federal Power Act Sections 205 and 206]" when the non-public utility seeks to changes rates).

Q. Who responded to information requests submitted to LADWP?

A. It is not entirely clear who responded to the information requests. It appears that many responses were not prepared or endorsed by LADWP. The evidentiary value of such responses in this proceeding is unclear. In many cases the responses specifically stated that consultants to LADWP in this proceeding did not consider or have certain information. For example, when

LADWP was asked in IR 73(e) what control it has over the operation of the Inyo PS, LADWP responded: "nFront does not know the control LADWP has over the Inyo PS." Similarly, when asked in IR 73(f) whether the Owens Valley Transmission Service Agreement or a successor agreement, if any, were in effect, LADWP avoided answering and responded: "nFront has no knowledge of the referenced agreement. It was not considered in the preparation of Exhibit DWP-503." Further, when asked in IR 75(b) to explain how and when the Upper Gorge, Middle Gorge and Control Gorges are dispatched, LADWP sidestepped the question and stated that "nFront's conclusions reached in Exhibit DWP-503 did not allocate the transmission facilities from Upper Gorge to Inyo to Transmission. Specific dispatch information was not considered as part of nFront's analysis." There are numerous other answers like this. These answers demonstrate that LADWP may have used its consultants in this proceeding to shield itself from information requests that it wanted to avoid answering, which would be a violation of FERC rules of procedure, if this were a proceeding at FERC. All answers to information requests should be based on LADWP's knowledge and data, not what its experts have on hand at the time.

Q. Did you receive timely and adequate responses to all Information Requests?

A. No. The Cities experienced several problems; some responses claimed privileged information, even though the Cities had agreed to a Protective Order; in other cases, responses were received well after the admittedly informal but proffered deadline for responses; several responses required follow-up to achieve clarity and/or receive requested documentation; and multiple responses did not answer the questions at all. *See, e.g.*, LADWP Response to IR

126(a)-(o) (LADWP refused to explain and provide examples of how certain facilities included in the OATT ancillary services rates actually provided ancillary services to OATT customers).

Q. What is your recommendation based on these concerns?

A. We recommend that the General Manager suspend the process until the issues raised herein by the Cities are resolved. This will minimize disputes and the potential for action by the Cities at the FERC after adoption of the General Manager's proposal by the LADWP Commission and ultimately the Los Angeles City Council.

Section 5: Rate Design

Q. What is the purpose of this section of your testimony?

A. In this section, we address the divisor (in MW) used to set LADWP's annual rates for transmission and ancillary services, for any given rate Schedule's revenue requirement.

Q. What is the divisor?

A. Each annual rate, whether for transmission or ancillary services, is the ratio of the annual revenue requirement for the specified service, divided by a MW amount – *i.e.*, the divisor. Rates for shorter-term service are based on and derived from the annual rates.

Q. What does LADWP propose as the divisor?

A. LADWP proposes the twelve coincident peak methodology, which (a) calculates an *average* of the monthly coincident peak loads on LADWP's retail system, and then (b) uses that average amount as the divisor for all rate calculations.

Q. Is 12 CP the only possible methodology for determining the correct divisor?

A. No. Depending on the pattern of monthly peak loads on the transmission provider's system and other factors, FERC requires the use of other methodologies such as 1 CP, 2 CP, 3 CP, *etc.*. *See e.g.*, *Golden Spread Electric Co-Op, Inc.*, Opinion No. 501-A, 144 FERC ¶61,132 (2013). Utilities that have a single seasonal peak (*e.g.*, summer or winter) generally are required to use a 1 CP to 3 CP methodology because their load peaks in one season and they plan, invest and build for this peak. *Id.*, at P 46.

Q. How does FERC determine which methodology is appropriate?

A. Opinion No. 501-A, a recent FERC decision, explains how FERC makes this determination in allocating capacity costs. Opinion No. 501-A, 144 FERC ¶61,132. This case demonstrates the issues and facts that FERC considers in determining when a 12 CP divisor is appropriate in allocating costs. In Opinion No. 501-A, FERC indicated that in selecting the proper method of demand cost allocation, the full range of a company's operating realities should be considered, including: (1) system demand; (2) scheduled maintenance; (3) unscheduled outages; (4) diversity; (5) reserve requirements; and (6) off-system sales commitments. *Id.*, at P 45. Based on these "operating realities," FERC found that Southwestern Public Service Company ("SPS") was a 3 CP utility and transmission provider. *Id.*, at P 42.

When assessing the first and most predictive operating reality, "system demand," FERC analyzed "a utility's pattern of monthly peak demands throughout the year" to help it determine the utility's demand allocation. *Id.*, at P 46. Demand allocation refers to the method of apportioning fixed capacity costs among customer classes. *Id.* at P. 66. FERC typically uses a coincident peak method to allocate demand costs. Under this method, demand costs are allocated based on the customer class' demand at the time of (coincident with) the system peak

demand. FERC uses an identical rationale when allocating transmission costs. *See e.g., El Paso Electric Co.*, 14 FERC ¶ 61,083 at p. 61,147 (1981); *see also, American Electric Power Service Corporation* ("AEP"), 80 FERC ¶ 63,006 (1997) (holding that a 1 CP divisor for transmission rates is appropriate for utilities that have concentrated peaks).

FERC precedent is clear, only when "[a] company that has a relatively flat demand curve" is it correct to allocate demand [*i.e.*, calculate rates] on a 12 CP basis, because such a methodology "assumes that a utility's fixed costs are related to the demand throughout all 12 months of the year." *Id.* Accordingly, "a summer (or winter) peaking company would ***not*** typically allocate demand on a 12 CP basis." *Id*. (emphasis added).

Q. How does FERC assess a utility's system demand?

A. FERC uses three tests to examine these patterns, which it describes as follows: (1) the On and Off Peak test, (2) the Low to Annual Peak test, and (3) the Average to Annual Peak test. FERC precedent has set certain benchmarks against which the results of these tests are compared to help determine the appropriate demand allocation for a particular utility. *Id.*, at P 46. In the On and Off Peak test, the Commission compares (a) the average of the system peaks during the peak period, as a percentage of the annual peak, to (b) the average of the system peaks during the off-peak months, as a percentage of the annual peak. In the Low to Annual Peak test, the Commission calculates the lowest monthly peak as a percentage of the single annual peak.) In the Average to Annual Peak test, the Commission computes the average of the twelve monthly peaks as a percentage of the annual peak. *Id.*, at P 54.

FERC has long held that a 12 CP divisor should only be used when the lowest monthly peak is more than 70% of the single highest peak. *See e.g., El Paso Electric Co.*, 14 FERC ¶

61,083 at p. 61,147 (1981) (71% 12 CP); *Lockhart Power Co.*, 4 FERC ¶ 61,337 at p. 61,807-61,808 (1978) (73% - 12 CP); *Carolina Power & Light Co*., 4 FERC ¶ 61,107 at p. 61,230 (1978) (72% - 12 CP); and *Southern California Edison Co*., 59 FPC ¶ 2167 at p. 2181 (1977) (79% - 12 CP). Even in instances where the "results of the Low to Annual Peak test narrowly indicate that a 12 CP demand allocation is appropriate," FERC will not allow a 12 CP divisor if the other two tests are not met. Opinion No. 501-A, at P 55.

Q. How does FERC's assessment of a utility's scheduled maintenance factor into the analysis?

A. FERC looks at when the utility schedules maintenance across the months of the year. If the utility schedules maintenance in the non-summer months rather than during the peak summer months, FERC views this as evidence that the utility is not a 12 CP utility, but rather is a utility for whom summer is a critical time for peak usage. Opinion No. 501-A, at P 59.

Q. How does FERC's assessment of a utility's unscheduled outages factor into the analysis?

A. FERC looks at when a utility's unscheduled outages occur. If the majority of the unscheduled outages occur during the summer months, FERC has held that this also indicates the utility is not a 12 CP utility, but rather is a utility for whom summer is an important time for peak usage.

Q. How does FERC's assessment of a utility's diversity factor into the analysis?

A. The diversity of generation is assessed by looking at the types of generation the utility has in its portfolio and how and when they are deployed. A utility that has a flat load will typically have more base load generation and less peaking generation. In comparison, a utility that has large peak in the summer or winter months will tend to have more peaker units and thus,

a more diverse generation portfolio. Notwithstanding the generation portfolio, however, the goal is to determine if the utility's load profile exhibits diversity that supports the use of 12 CP. In addressing this issue, FERC concluded in Order 501-A as follows:

> SPS's load profile does not exhibit the diversity that would support a 12 CP demand allocation. From a diversity perspective, basing SPS's demand cost allocation on all months equally, as under the 12 CP demand cost allocation methodology, would be inappropriate, because SPS has neither a flat load profile nor a load profile demonstrating a double peak. *Id.*, at P 61.

Q. How does FERC's assessment of a utility's reserve requirements factor into the analysis?

A. FERC looks at multiple years of data on the utility's reserve margins to see if there is a pattern of low reserve margins during the year. *Id.*, at P 62. If the pattern shows that the utility was more concerned about meeting the reserve margins during the summer period than in non-summer periods that indicates a 12 CP should not be used. *Id.* In Opinion No. 501-A, FERC held that even though SPS had a couple of non-summer months with low reserve margins, this was not sufficient to conclude that 12 CP was appropriate.

Q. How does FERC's assessment of a utility's off-system sales commitments factor into the analysis?

A. FERC has held that, when determining an appropriate demand allocation, the Commission will consider the full range of a company's operating realities, including off-system sales commitments, *if those sales are not revenue-credited*. However, "off-system opportunity sales that are not included in the demand allocator, but are revenue credited" should be excluded from the demand allocation analysis and the determination of the appropriate rate design. Opinion No. 501-A, at P 51.

Q. Have you applied the above factors and tests to LADWP's proposal to use 12 CP?

A. Yes, we have.

Q. What have you concluded from your application of the above factors to LADWP's proposal to use 12 CP?

A. Taken as a whole, the evidence points to 1 CP as the correct demand allocator for LADWP, and not 12 CP as LADWP proposes. The following subsections review the evidence and conclusions.

1. System Demand

Q. How did you apply FERC's system demand analysis to LADWP?

A. We applied FERC's tests to the facts in this case. As we mentioned above, the three tests address three distinct sets of facts.

Test No. 1: "On and Off Peak Test." This test first calculates the average of the coincidental peaks in the months with the three highest system peaks as a percentage of the annual system peak. Second, the test calculates the average of the coincidental peaks in the three months with the lowest system peaks as a percentage of the annual system peak. A 12 CP allocation is considered appropriate only if the difference between these two percentages is 19% or less.

Test No. 2: "Low-to-Annual Peak Test." This test calculates the lowest monthly peak as a percentage of the annual system peak. Only if that ratio is 66% or higher is the 12 CP method permitted.

Test No. 3: "Average to Annual Peak Test." This test calculates the average of the twelve monthly peaks as a percentage of the annual system peak. Only if that ratio is 81 percent or greater is the 12 CP method permitted. *See e.g.*, Opinion No. 501-A, 144 FERC ¶ 61,132

(2013); *see also, Southwestern Pub. Serv. Co.*, 144 FERC ¶ 61,133, P48-51 (2013); Opinion No. 501-A, 144 FERC ¶ 61,132 (2013).

Table 1 in BWP/GWP-E-103 shows the application of FERC's three tests to LADWP's retail monthly peak loads presented in DWP-104. The summary of the results of applying the three FERC tests is replicated immediately below.

FERC Tests for 12 CP						
	Ave. of Off-Peak Monthly MW	Ave. of Peak Monthly MW	Difference (MW)	Difference (%)	FERC Standard	Pass/Fail?
Test No. 1	3,945	6,376	2,431	38%	19% or less	Fail
				Lowest/Highest	FERC Standard	Pass/Fail?
Test No. 2				54%	66% or greater	Fail
		Ave. of 12 CP MW	1 CP MW	Ratio	FERC Standard	Pass/Fail?
Test No. 3		4,978	6,995	71%	81% or greater	Fail
Conclusion	LADWP's monthly load pattern fails all three FERC tests for the use of the 12 CP methodology.					
Note	Test No. 1 defines the peak and off-peak periods as the three highest and three lowest CPs.					

Q. What do you conclude about LADWP's proposed use of the 12 CP divisor to calculate specific OATT rates?

A. LADWP fails all three tests, which FERC has held is indicative of a utility that should *not* use 12 CP. *See, e.g.*, Order 501-A, at P 59. Therefore, LADWP should not use the 12 CP divisor. Instead, we conclude that the correct divisor for LADWP is 1 CP.

2. Transmission Planning Standards

Q. What planning information have you consulted in determining the reasonable divisor for LADWP?

A. We have reviewed the 2014 "Long-Term Transmission Assessment," approved December 2014, provided in response to IR 116. See BWP/GWP-E-102 (CEII). This assessment was released during the test year, and thus reviews conditions at that time.

Q. What do you conclude from the 2014 Assessment? ***BEGIN CEII REDACTION.***

[redacted] ***END CEII REDACTION.***

1 **3. Scheduled Maintenance and Unscheduled Outages**

2 *Q. Does LADWP's scheduled maintenance and unscheduled outages data suggest that*

3 *LADWP is a "summer-peaking utility"?* ***BEGIN CEII REDACTION.***

4 [redacted]

[redacted]. ***END CEII REDACTION.***

11 **4. Reserve Requirements**

12 *Q. How did you apply FERC's reserve requirements standards to LADWP?*

13 A. We reviewed the 2014 Assessment.

14 *Q. What did you learn from your review?* ***BEGIN CEII REDACTION.***

15 A. [redacted] ***END CEII REDACTION.***

21 **5. Diversity**

22 *Q. How did you apply FERC's diversity analysis to LADWP?*

A. We reviewed the types of generation LADWP has in its portfolio and how and when these generators are deployed. Like other summer peaking utilities, LADWP has a generation portfolio that is diverse and includes a relatively large number of peaking units, which is different from a utility with a flat load. *See e.g.*, DWP-104. LADWP's peaking units are deployed more in the summer to meet peak demand. LADWP's unit commitment strategy requires an increase in the number of in-Basin generating units that are committed to be online during increasing loads, such as during the summer peak. In addition, LADWP's load profile does not support the use of 12 CP because its load peaks in the summer. It would be inappropriate to allocate LADWP's transmission costs on all months equally because LADWP has neither a flat load profile, nor a load profile demonstrating a double peak, nor a load profile that is anything other than summer peaking. *Id.*, at 61. LADWP's load profile indicates that 12 CP should not be used. *Id.*

Q. Based on FERC precedent and LADWP's own planning studies, which divisor is appropriate for LADWP's rates?

A. LADWP should use the 1 CP divisor, because 1 CP represents LADWP's summer-peaking load profile, which is reinforced by LADWP's planning documents. *See e.g.*, *AEP*, 80 FERC ¶ 63,006 (1997) (holding that a 1 CP divisor for transmission rates is appropriate for utilities that have concentrated peaks).

Q. What was the 12 CP divisor used by LADWP during the test year?

A. According to Tab BB of DWP-104, the 12 CP divisor was 4,978 MW, which was the sum of LADWP peak load and long-term PTP contract demand.

Q. What was the 1 CP in the test year?

A. According to LADWP, the highest instantaneous peak during the test year was 6,995 MW on September 16, 2014. This 6,995 MW included LADWP peak load and long-term PTP contract demand, not LADWP Balancing Authority Area ("BAA") Load. This amount must be increased to reflect the discussion of Native Load below.

Q. For which rates should the 1 CP divisor be used?

A. The 1 CP divisor should be used for the calculation of all transmission and ancillary service rates.

Q. Please discuss LADWP's support of its use of the 12 CP methodology.

A. In response to IR 27(a), LADWP has discussed the potential grounds for retaining the 12 CP methodology. See BWP/GWP-E-101. LADWP relies on irrelevant facts, as well as inapplicable and outdated FERC precedent to support its use of 12 CP. LADWP makes the following arguments or observations:

1) consistency with current rate design;
2) year-round diversity of system stresses;
3) relative contributions of retail native load and third-party users;
4) consistency with Order No. 888;
5) four tests as applied in *Commonwealth Edison Co.*, 15 FERC ¶63,048 at pp. 65, 196-199 (1981), aff'd Opinion No. 165, 23 FERC ¶61,219 (1983);
6) FERC's conclusions in *Louisiana Public Service Commission v. Energy Services, Inc.*, 113 FERC ¶61,282 at P92 (2005) and *Golden Spread Electric Cooperative, Inc. et al. v. Southwestern Public Service Co.*, 123 FERC ¶61,047 at P75 (2008);
7) LADWP's planning standards; and

8) California's Renewable Portfolio Standards (RPS).

Q. Please discuss each of these points.

A. Consistency with rate design: This argument makes no sense in light of the fact that LADWP does not have FERC approved rates. If this were a reasonable argument, LADWP would never update any inputs, assumptions, or methodologies. In this case, LADWP proposes new reserve requirements for Schedules 3 and 10, based on a study completed after the test year that incorporated data on Variable Energy Resources ("VERs": solar and wind) from the test year and a new reliability standard (confidence interval in an error distribution). As to the new reliability standard, LADWP has provided no support or justification. Here, in contrast, there is ample support, justification and FERC precedent for changing from 12 CP to 1 CP.

Year-round diversity of system stresses: This argument contravenes and is undermined by LADWP's own planning studies, which, as discussed above, clearly indicate that LADWP is a summer peaking utility that plans for its summer peak.

Relative contributions of native load and third-party users: This argument seems to attempt to show that LADWP's load profile supports the use of 12 CP. However, this argument is refuted by LADWP's own data in this case (DWP-104, Tab BB), which show that third-party OATT use of LADWP's system is only 11 percent of monthly peak demand, on average over the test year. In addition, LADWP does not include all Native Load in its calculation of 12 CP, as Native Load is defined in the OATT.

Consistency with FERC Order No. 888: LADWP inappropriately interprets Order No. 888 to require transmission providers to allocate their transmission costs using a 12 CP methodology. *Promoting Wholesale Competition Through Open Access Non-Discriminatory*

Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, FERC Stats. & Regs. ¶ 31,036, at p. 31,736 (1996), *order on reh'g*, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048, *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998). This interpretation is inaccurate because all Order No. 888 provides is that 12 CP can be used *if the circumstances allow for its use*. Thus, LADWP's reference to Order No. 888 takes the statement out of context and ignores subsequent FERC decisions that directly and expressly refute LADWP's position. *See, e.g.,* Opinion No. 501-A; *see also AEP,* 88 FERC ¶ 61,141 at p. 61,452 (1999) ("In Order No. 888 we did not give transmission providers an automatic and immediate right to develop their rates using a 12 CP divisor; rather, we stated that commencing with the ordered improvements in the tariff services we would no longer summarily reject filings on this basis but would instead allow transmission providers seeking a 12 CP divisor to make a filing with the Commission supporting such a proposal and to pursue this at hearing."); *AEP,* 80 FERC ¶ 63,006 at p. 65,066 (1997) ("Staff evidently interpreted Order No. 888 as now requiring the use of the 12 CP methodology. I do not agree. Such interpretation seems to ignore the Commission's clear language. A more reasonable interpretation is that, as the Commission says, it will now permit the use of the average of the 12 monthly peaks as an alternative." . . . "The argument by AEP and Staff that in Order No. 888 the Commission reversed its position on the use of a 1 CP divisor does not withstand scrutiny. The Commission could have but did not mandate the use of a 12 CP divisor.")

Commonwealth Edison decision (1983): LADWP's references to this case should be disregarded because the case is over 30 years old, and has been superseded by subsequent FERC decisions that we have discussed in detail above. *Id.*

Louisiana Public Service and *Golden Spread* decisions: LADWP's references to these cases should also be disregarded because these cases are inapplicable to LADWP. These cases stand for the proposition that a utility may continue to use a previously FERC-approved rate or rate component(s) under the filed rate doctrine until that filed rate and or associated filed rate component(s) is found to be unjust and unreasonable by FERC. No such filing at or finding by the Commission has occurred regarding (a) LADWP's current 12 CP proposal, (b) LADWP's current proposal to continue to use 12 CP, or (c) LADWP's proposed OATT rates. Therefore, these cases and the underlying filed rate doctrine are inapplicable to LADWP. If LADWP had a rate on file at FERC, this doctrine might apply.

LADWP's planning standards: This argument should be disregarded because it too contravenes and is undermined by LADWP's own planning studies, which clearly indicate, as we explained above, that LADWP plans for summer peak load conditions. LADWP does not plan for a double peak, for multiple peaks, or for specific contingencies in all 12 months. It plans for one summer peak.

California's RPS: It appears that LADWP is trying to make a generation diversity argument by referencing the fact that it uses renewable resources to meet part of its load. This argument fails because it ignores the fact FERC uses diversity to assess a utility's *load profile*, not its resource mix. The resource mix is irrelevant to FERC's policy on load-based rate design. Here, as explained above, LADWP's load profile makes it clear that LADWP is a summer

peaking utility. LADWP does not have double peaks or multiple peaks. LADWP solely peaks in the summer.

Q. What do you conclude from your analysis of LADWP's arguments?

A. Again, based on all of the above analysis and LADWP's failure to provide any support for its use of 12 CP, we conclude that LADWP's proposal to use 12 CP should be rejected. The 12 CP allocation methodology is incorrect, because LADWP has neither a flat load profile nor a load profile demonstrating a double peak or multiple peaks. *See* Opinion No. 501-A, at P 61. A summer peaking utility, like LADWP, must allocate demand on a 1 CP basis, which relates demand to the peak usage month. Thus, we conclude that LADWP should replace its 12 CP proposal with 1 CP so that it reflects the operating realities of the LADWP system, and calculate 1 CP correctly, as discussed next.

Section 6: Native Load

Q. What is the purpose of this section of your testimony?

A. In this section, we address the definition and calculation of "Native Load," as that term is used as the divisor in determining OATT rates.

Q. How does LADWP define "Native Load"?

A. In section 1.20 of the proposed OATT, LADWP defines "Native Load Customers" as follows:

> **Native Load Customers:**
> The *wholesale* and retail power customers of the Transmission Provider on whose behalf the Transmission Provider, *by statute, franchise, regulatory requirement, <u>or</u> contract*, has undertaken an *obligation to construct and*

> *operate* the Transmission Provider's system to meet the *reliable electric needs* of such customers. (Original Sheet Nos. 15-16, emphases added.)

Q. Are GWP and BWP wholesale customers of LADWP?

A. Yes. They purchase transmission and certain balancing and ancillary services from LADWP.

Q. Do BWP and GWP meet LADWP's and FERC's definition of "Native Load"?

A. Yes. They are wholesale customers of LADWP, on whose behalf LADWP has undertaken an obligation to construct and operate the LADWP transmission system to meet BWP's and GWP's reliable electric needs in addition to LADWP's own needs.

Q. Does LADWP believe that BWP and GWP meet LADWP's Tariff definition of "Native Load"?

A. No. LADWP has stated that "BWP and GWP are not a [sic] Native Load Customer of LADWP." See LADWP Response to IR 39(b).

Q. Are there any differences between LADWP's definition of "Native Load" and FERC's definition?

A. No. The definition in FERC's *pro forma* OATT is the same as LADWP's.

Q. Is LADWP's conclusion that the Cities are not Native Load correct?

A. Absolutely not. LADWP has "wholesale" obligations to the Cities "by regulatory requirement, or contract" to "construct and operate" LADWP's system "to meet the reliable electric needs of [the Cities'] customers." Although a strict reading of the definition of "Native Load" allows the Cities to be included if *any one* of the five standards or criteria are met, the Cities actually meet *all five* standards.

Q. First, what regulatory requirements does LADWP have to the Cities?

A. LADWP admits that both BWP's and GWP's systems are located within the LADWP BAA and as such LADWP meets all NERC Balancing Authority functions on GWP's and BWP's behalf, and meets all the NERC BA Standards that relate to BWP and GWP. In addition, BWP and GWP provide LADWP, at LADWP's request, their loads and their future load forecasts, which LADWP in-turn provides to WECC and Peak RC. See BWP/GWP-E-102, Glendale 2014 Native Load by hour MWhs.xlsx and GLENDALE idwpss14_Submitted 2-20-2015.xlsx.

Q. Second, what contractual obligations does LADWP have to BWP and GWP that pertain to the definition of "Native Load"?

A. LADWP has numerous contracts with the Cities that obligate it to take on various obligations that relate to the definition of "Native Load." For example, under the BAASAs, LADWP is responsible for provide the Cities their entire reserves. In addition, under Section 6.8 of the LADWP-BWP TSA Adelanto/RSE 4/15/94 (LADWP No. 10412), LADWP has agreed to take on certain transmission construction obligations for the Cities when the capacity on these facilities is expanded. LADWP has also agreed to be the Operating Agent for the Cities' share of the capacity on Intermountain Power Project ("IPP"), under the Cities' Transmission Services Agreements (LADWP Nos. 10006 and 10007). Other agreements between the Cities and LADWP have created similar duties. *See e.g.*, The Cities Pacific Intertie D-C Transmission Facilities Agreement 1968 (LADWP No. 10129); the Cities 1968 Interchange Agreement 4/12/69 (LADWP Nos. 10134 and 10135); and the Cities' TSA Hoover (LADWP Nos. 10928 and 10929).

Q. Third, what construction obligations does LADWP have to the Cities?

A. LADWP has various construction obligations depending on the agreement. For example, under contract LADWP No. 10412, Section 6.8, if LADWP constructs a new transmission line between either Adelanto or Victorville Switching Station and the Beltline Component it will offer and build a share for the Cities.

Q. Fourth, what operational obligations does LADWP have to the Cities?

A. LADWP has a variety of operational obligations to the Cities under the various agreements both directly with the Cities and indirectly through the Southern California Public Power Authority ("SCPPA"). For example, under Article 10 of the Cities Interconnection Agreement with LADWP (LADWP Nos. 10131 and 10132), LADWP has the duty to operate and maintain a significant part of the Cities' interconnections with LADWP. LADWP is also the Operating agent for the Cities' share of STS associated with IPP.

Q. Fifth, what reliability obligations does LADWP have to the Cities?

A. It is undisputed that LADWP is the Cities' Balancing Authority. NERC defines the "Balancing Authority Area" as "[t]he collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. *The Balancing Authority maintains load-resource balance within this area*." NERC Glossary (emphasis added). This definition demonstrates that LADWP has reliability obligations to the Cities as the Cities' Balancing Authority Area Operator.

Q. Can the Cities perform those functions independently of LADWP?

A. No. As we noted above, both BWP and GWP are fully embedded systems within the LADWP network, more specifically in the Beltline AC system ("Beltline") segment, and are

essentially captive customers of LADWP. It would be impossible for either BWP or GWP to conduct the analyses needed to plan separately and independently for the transmission needs of their own systems, and at least investigate third party suppliers for certain ancillary services. In order to do so, BWP and GWP would have to rely on LADWP for data, analyses, tools, and knowledge of the details of LADWP's own transmission and generation system. Such data from LADWP has not been available up to this point in time, and we see no reason to expect that situation to change. Finally, delivery of third-party supplies of ancillary services would require contractual agreements among the Cities, LADWP, and any third parties. Because LADWP *must* be a party to such arrangements, LADWP must treat the Cities as Native Load. To do otherwise would be potentially discriminatory.

Q. How does LADWP calculate Native Load?

A. According to LADWP's response to Information Request 122(a), Native Load is calculated as follows:

> (1) LADWP Native Load = Interchange in to the LA Native Load area – Interchange Out of the LA Native Load area + Generation in the LA Native Load area – Aux/Station Service in the LA Native Load area – IPP switchyard & Conv Station banks – Castaic Pumping Load.

Q. Is "LA Native Load area" defined in the OATT or anywhere else?

A. Not that we know of. We have not found a definition of "LA Native Load area," nor do we know of any FERC or NERC definition of "Native Load area."

Q. How does LADWP calculate BAA load?

A. According to LADWP's response to Information Request 122(a), BAA load is calculated as follows:

(2) Balancing Authority Area (BAA) Load = Interchange In – Interchange Out + BAA Generation – Aux/Station Service – "IPP SWITCHYARD & CONV STA" Banks K & L MWh – Castaic Pumping Load.

Q. What are the differences between these two calculations?

A. The six elements of the calculation are the same, but the "boundaries" differ. According to LADWP's response to IR 122(a), interchange amounts (in/out), generation amounts, and Aux/Station Service amounts are measured in the "LA Native Load area" in equation (1), but in the BAA in equation (2). LADWP also states in IR 122(a) that equation (1) was used in DWP-104, Tab BB, to determine the divisor for rate calculations.

Q. Are equations (1) and (2) consistent with other statements in LADWP's responses to IR 86(e) and 122(a)?

A. No. LADWP has stated in the response to Information Request 86(e) that "LADWP considers the Castaic pumping load as part of its native load." BWP/GWP-E-102, CEII – Exhibit IR86(e). The subtraction of pumping load is therefore inconsistent with LADWP's *own* definition of its Native Load. The Castaic pumping load should not be subtracted. *See e.g., Mid. West. Indep. Syst. Oper*. ("MISO"), 106 FERC ¶ 61,253, at P 26 (2004) (holding that MISO should include load served by behind-the-meter generation, including station power load met through on-site self-supply, in Network Load when it charges for Network Service), *citing* Order No. 888 at 31,736; Order No. 888-A at 30,258-261; *Florida Power & Light Co*., 105 FERC ¶ 61,287, at P 19 (2003); *see also* Consumers Energy Co., Opinion No. 456, 98 FERC ¶ 61,333, at 62,410 (2002) (affirming Initial Decision that generation located behind the retail meter should

be treated the same as generation located behind the wholesale customer's meter with respect to designation of Network Load).

Q. Is it appropriate for LADWP to subtract Station Use/Auxiliary power in equation (1) or (2)?

A. No. Power consumed in the production of power is part of LADWP's normal operations, and essential to the provision of reliable service to Native Load. There would be no generation without station service. Subtracting this consumption would be the same as selectively subtracting some retail or wholesale obligation, and analogous to omitting distribution losses. Station service is part of the "obligation" to ensure reliable service, just like the distribution system. There is no basis for such a subtraction. *Id.*

Q. Has LADWP correctly measured <u>all</u> generation in the BA in equation (1) and (2)?

A. No. LADWP has explicitly excluded BWP's and GWP's generation. See IR 86(e).

Q. How are the Cities treated in LADWP's calculation of Native Load?

A. Incorrectly. Based on the response to IR 86(e), LADWP calculates a "net interchange" amount for each hour for each City. This net interchange amount equals the net flow of power at the interchange point with each City. If the net amount is negative, power is flowing to the Cities, and *vice versa*. The calculation of net interchange is incorrect because it ignores retail loads in each City, which are, from LADWP's perspective, "wholesale customers" to whom LADWP has certain obligations, which we have detailed above.

Q. What formula should LADWP use to determine Native Load for the purpose of calculating OATT rates?

A. The following formula addresses the above problems:

(3) Native Load = All Generation in the BA (*including* the Cities' Generation) + All Interchange In (*except* from the Cities) – All Interchange Out (*except* to the Cities).

Q. Is LADWP's calculation of Native Load biased?

A. Yes. The bias is in the downward direction (*i.e.*, too low), because pumping loads, station service, and LADWP's wholesale obligations to the Cities are all omitted, subtracted, or incorrectly accounted for. This bias increases the LADWP OATT rates across the board, contravenes the definition of Native Load in the LADWP OATT, the *pro forma* OATT and violates FERC precedent because this calculation is discriminatory.

Q. Have you calculated Native Load reflecting the above discussion?

A. Yes. Please see the Table in BWP/GWP-102, "CEII – Exhibit IR86(e) Revised by Cities.xlsx". The correct 1 CP from the test year for rate design is 8,159 MW.

Section 7: Purchase Obligations for Ancillary Services

Q. What is the purpose of this section of your testimony?

A. In this section, we address the purchase obligations proposed by LADWP for ancillary services under Schedules 3, 5, 6, and 10.

Q. What are purchase obligations?

A. Purchase obligations, as implemented by LADWP, start with the amount of generating capacity (in MW) that must be "held aside" or "reserved" to ensure provision of each ancillary service. With the exception of Schedule 10, Part A, this capacity (in MW) is then divided by LADWP's 12 CP (in MW) in order to determine a "purchase obligation": a percentage that is applied to the revenue requirement (and thus each rate in the relevant Schedule) for the specified

ancillary service in the calculation of the annual rate for that service. In the case of Schedule 10, Part A, which applies to non-dispatchable generation, the required capacity is divided by "Incremental Nameplate VER Capacity," rather than LADWP's 12 CP.

Q. Does the 12 CP method overstate the purchase obligation?

A. Yes. LADWP should use the 1 CP method instead, for the reasons discussed above.

Q. Please compare current and proposed purchase obligations for each ancillary service rate schedule, in megawatts.

A. The Table 2 in BWP/GWP-E-103 shows data for Schedules 3, 5, 6, and 10 taken from Tab BL of DWP-104.

			Purchase Obligations			
			MW		**Percent**	
			Current	Proposed	Current	Proposed
SCHEDULE 3 - REGULATION AND FREQUENCY RESPONSE SERVICE			50	174	1.059%	3.496%
SCHEDULE 5 - OPERATING RESERVE - SPINNING RESERVE SERVICE			300	300	6.354%	6.027%
SCHEDULE 6 - OPERATING RESERVE - SUPPLEMENTAL RESERVE SERVICE			250	300	5.295%	6.027%
SCHEDULE 10 - GENERATOR REGULATION AND FREQUENCY RESPONSE SERVICE						
	Non-dispatchable resources		40	63	6.515%	9.278%
	Dispatchable resources		50	174	1.059%	3.496%
Justifications			Schedule			
Reserve Requirement for 2014 VER Integration Study For LADWP (January 2017)			3			
BAL-002-WECC-2 Contingency Reserve Requirements			5			
BAL-002-WECC-2 Contingency Reserve Requirements			6			
Reserve Requirement for 2014 VER Integration Study For LADWP (January 2017)			10			

Q. What studies or documentation has LADWP provided each of these changes?

A. LADWP has referred to two documents, as indicated in the Table 2 immediately above. See BWP/GWP-E-101, Attachment_9a_Reserve_requirements_for_2014_VER_integration_final.pdf.

Q. Do you agree with these changes?

A. Not in every case.

Q. Do you agree that these changes are justified and well-documented?

A. No. Some of these changes have not been justified or sufficiently documented.

Q. Has LADWP introduced evidence developed <u>after the test year</u> that allegedly supports future purchase obligations?

A. Yes. LADWP has relied on a study of Variable Energy Resource ("VER") integration requirements ("VER Study"), which was finalized *after* the release of the proposed 2017 rates in January of this year. See DNV GL – Energy Advisory Americas (Kema, Inc.), "Reserve requirements for 2014 VER integration," February 9, 2017, attached to IR 9(a). This approach contravenes LADWP's own statements, in which it indicated that it would be using only the "test year" data to develop its rates. It also contravenes industry standards, and FERC precedent, which require a transmission provider that uses a test year to establish its rates not veer from the test year data. *See, e.g.,* Williston Basin Interstate Pipeline Company, 87 FERC ¶ 61,265, 61,021 n.33 (1999)*;* Public Service Company of Indiana, 7 FERC ¶ 61,319, at 61,702, reh'g denied, 8 FERC ¶ 61,224 (1979); Union Electric, 47 FPC 144, 150 (1972). LADWP's 2017 VER Study did, however, use data as of the end of 2014.

Q. Is a reliance on post-test-year studies consistent with LADWP's approach to the remainder of its case?

A. No. LADWP has, for example, excluded revenues that BWP and GWP currently pay to LADWP for balancing area services, on the grounds that these revenues did not occur during the test year. LADWP appears to have cherry-picked test-year and post-test-year data with the objective of increasing the OATT rates. This raises a fundamental question about whether

LADWP should use actual test year data alone, or should apply "known and measurable changes" to the test year data.[2]

Q. What does the January 2017 VER Study purport to show?

A. LADWP retained Kema, Inc. "to estimate the additional load-following and regulation reserves necessary to integrate the variable energy resource (VER) capacity in LADWP's system as of 2014." VER Study, page 1.

Q. Is the VER Study designed to determine the amount of capacity required to provide traditional load-based regulation and frequency response (RFR) service?

A. That is also not clear. The VER Study (page 1, emphases added) explicitly states that "[i]n order to evaluate the *additional* balancing reserve requirements necessary to integrate the VER capacity in LADWP's system in 2014, DNV GL analyzed the balancing reserve requirements necessary for *load alone* as well as those for load less VER. Comparing the results of these analyses gives an estimate of the *additional* balancing reserve requirement necessary to integrate 2014 VER capacity."

Q. Please explain the importance of the "additional balancing reserve requirement."

A. The VER Study at least identifies the need for balancing reserves for (a) load, (b) VERs, and (c) dispatchable resources. These distinctions are critical to the application of the study's results to RFR rate Schedules 3 and 10, but the distinctions must be properly recognized.

Q. Do loads and VERs display similar or identical error distributions?

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[2] Without sufficient information, we take no position on this issue of possible adjustments to test year data in this testimony.

A. No. This is clear from the VER Study (pages 2-3), which begins with the task of separating forecast errors for loads and VERs. Kema recommended separate and distinct probability functions for loads and VERs. For example, the hour-ahead load forecast error was based on the results of a previous study, which relied on information provided by LADWP to the authors of the previous study.[3] "Following the MGREPS study, the HA load forecast error was simulated as a uniformly distributed random variable between -25 MW and 25 MW. Random samples from the forecast error distribution were added to the historical hourly data to simulate HA forecasts." VER Study, page 2. Kema did not recommend changing the assumption of a uniform distribution of HA load forecast error, and LADWP has not discussed any change in the load forecast error either. In contrast, the VER forecast error for three wind projects was "modeled as [n]ormally distributed and curtailed at three standard deviations" based on the actual hour-ahead forecast errors for Milford 1 and 2, and assuming that Pine Tree is uncorrelated with the Milford projects. VER Study, page 3. The VER forecast errors for the Copper Mountain, Adelanto and Pine Tree solar projects were assumed to have the same distribution as wind: "[l]ike the wind power forecast errors, solar power forecast errors were modeled as Normally [sic] distributed and curtailed at three standard deviations." VER Study, page 5.

Q. What did the VER Study conclude regarding the relative variability of "load less VER"?

[3] See Response to IR 101 – CEII, cited excerpts from which are provided under separate cover marked "CEII."

A. The VER Study provides a summary Table 5 (p. 12), reproduced below, and concludes that "[t]he wider distribution for load-less-VER reflects the increased sub-hourly variability and system-wide forecast error due to the VER capacity." VER Study, p. 11.

Table 5. Reserve requirements (MW) necessary to cover a given percentile of the difference between HA forecast/1-minute actual load and load-less-VER (using adjusted Copper Mountain Solar data).

Percentile	21st/79th		10th/90th		5th/95th		1st/99th		0.1/99.9	
Load	-25	25	-42	42	-58	58	-87	87	-123	122
Load-less-VER	-40	35	-64	58	-84	77	-122	115	-168	163
Difference (VER integration requirement)	-15	10	-22	16	-26	19	-35	28	-45	41

Q. What did the VER Study conclude regarding the forecast errors of load?

A. That is not clear. The VER Study began, as noted above, with the assumption that hour-ahead load forecast errors are uniformly distributed between -25 MW and +25 MW. Table 5 shows that this range is associated with the 21st and 79th percentiles of the uniform distribution. The remaining rows of Table 5 show *combinations* of load forecast errors and resource forecast errors, but do not provide any additional or different information about the distribution of load forecast errors. In fact, the VER Study does not explain how a uniform distribution between -25 MW and +25 MW can be, or was, expanded to an error distribution beyond +/- 25 MW. A different error distribution function would be required to estimate percentiles of the distribution beyond +/- 25 MW. It is also possible that the VER Study somehow combined the load and VER forecast error distributions. However, such a combination would not change the underlying load forecast error distribution, and the VER Study did not explain any such combination.

Q. What is your understanding of the way LADWP has implemented the VER Study?

A. The VER Study initially defined the capacity reserved for load forecast error as +25/-25 MW, but then widened that to +87/-87 MW based on two changes: (1) an increase in the "confidence interval" for load forecast errors, and (2) an assumption that forecast errors for load and dispatchable resources are identical. Neither change is justified by any evidence showing that the previous confidence interval was incorrect, inadequate or supported by FERC precedent. Further, the second change has not been documented, only asserted in responses to discovery.

Q. Does the VER Study recommend an increase in the confidence interval for load forecast errors to determine the appropriate reserve requirement for Schedule 3?

A. No. The VER Study does not discuss the appropriate confidence interval for *any* distribution of forecast errors, either loads or resources, and did not recommend changing the confidence interval.

Q. Does the VER Study provide any analysis of forecast errors for dispatchable generation?

A. No. The VER Study provided no data or analysis of the distribution of forecast errors for dispatchable generation; instead, LADWP only *assume*s that dispatchable generation and loads have the same forecast errors.

> While the study entitled "Reserve requirements for 2014 VER integration.pdf." evaluates the scheduling accuracy of load it *does not evaluate the scheduling accuracy of dispatchable resources*. That is, the study does not calculate the deviations between the forecast of hour ahead generation schedules and 1-minute actual metered generation. However, it is *reasonable to assume* the scheduling accuracy of dispatchable generation is the same as the scheduling accuracy of load because dispatchable generation is generally responsive to changes in load, and any deviation between the hour-ahead dispatchable generation schedule and the dispatchable generator's 1-minute output during the operating hour is likely the result of the unit's operator or automatic generation control device adjusting the level of output to track in-hour changes

> in load. Therefore, LADWP has proposed to use the same 3.496% purchase obligation for Schedule 3 and Schedule 10 as applied to dispatchable resources. (Response to IR 38(c), emphases added).

Q. Do you agree that the VER Study is relevant for Schedule 3?

A. No.

Q. Do you agree that the VER Study should be applied to Schedule 10?

A. No. As we discuss below, LADWP has not met the requirements of Order No. 764, issued on June 22, 2012, and the existing VER Study is not sufficient to overcome these deficiencies.[4] *See Integration of Variable Energy Resources*, Order No. 764, FERC Stats. & Regs. ¶ 31,331, 139 FERC ¶ 61,246 (2012), *order on reh'g*, Order No. 764-A, 141 FERC ¶ 61,232 (2012); *order on clarification and reh'g,* Order No. 764-B, 144 FERC ¶ 61,222 (2013).

Q. Did LADWP implement the findings of the VER Study during the test year?

A. No. That would be impossible. The VER Study was conducted after the test year, and LADWP admitted the actual FY2014-15 capacity held for Schedule 3 RFR service caused neither reliability problems nor violations of reliability standards.

Q. What is LADWP's historical standard for setting aside capacity for load-following/regulation?

A. According to the VER Study (p. 11), "LADWP has historically assumed a load-following/regulation bandwidth of +/- 25 MW. This bandwidth covers the 21st to 79th percentiles of the deviations between hourly forecast and 1-minute actual data for load only." Even as late as December 31, 2015, *after* the test year, LADWP's *Power Integrated Resource*

[4] Rehearing Orders 764-A and 764-B were issued on December 20, 2012 and September 19, 2013,respectively, well before the beginning of the test year in this proceeding.

Plan (p. 113) stated that "[t]he Regulation Requirement of 25 MW is related to system load variations due to customer load changes."

Q. Has LADWP proposed to change this standard?

A. Yes. In the current proposal, LADWP proposes to expand the confidence interval in the frequency distribution from the 21st/79th percentiles to the 1st/99th percentiles, citing *Westar*.

> The calculation of regulation and frequency response purchase obligations for generation and load using historical scheduling accuracy and statistical confidence intervals is consistent with FERC precedent. *See, e.g. Westar Energy, Inc.*, 130 FERC ¶61,215 (2010). Table 5 of the report [*i.e.*, the VER Study] also shows that 50 MW (or 25 MW up and down regulation) would be insufficient to cover anything exceeding the 21st/79th percentile of deviations between the hour-ahead forecast load and the 1-minute actual metered load value. See IR 38(c).

This expansion causes the RFR capacity requirement in Schedule 3 to increase from 50 MW to 174 MW.

Q. Has LADWP explained its proposal to increase the RFR bandwidth from the 21st/79th percentiles to the 1st/99th percentiles?

A. No. LADWP is proposing to move to the *Westar* standard even though there is no evidence that +/-25 was inadequate during the test year. Just because *Westar* would *allow* an increase in the confidence interval does not mean that the confidence interval *should* be increased.

Q. Is the Westar decision even relevant to the current proceeding?

A. No. <u>First</u>, *Westar* addresses a situation in which VERs sought to purchase ancillary services to support energy exports from the BA and to sell into the energy imbalance market operated by the Southwest Power Pool ("SPP"). We are unaware of any requests to LADWP by

developers or VERs to export energy to another BA or sell into any energy imbalance market. This distinction is important because the concerns about the potential for Westar's non-VER customers to subsidize exports from the Westar BA have no analogy here. See *Westar*, at P 3. Second, in contrast to LADWP, Westar proposed that the percentage requirement for *load* be based on "the average percentage of capacity that Westar *historically* has needed to commit to regulate, or balance, the output of generation to load in its balancing area." *Id.*, at P 9 (Emphasis added). In the current proceeding, LADWP proposes to more than triple the reserve requirement for load, compared with its *historical* need (*i.e.*, from 50 MW to 174 MW). The growth of VERs may support updates to Schedule 10, if certain conditions are met. However, the simple fact that LADWP is integrating more variable *resources* does not change the uncertainty (*i.e.*, deviation from forecast) of LADWP's *loads.* The only criterion driving the increase in the Schedule 3 purchase obligation is a shift from one confidence interval to another, as is demonstrated in the row labeled "Load" in Table 5 of VER Study, replicated above. That shift is not justified, as evidenced by the adequacy of the historical reserve requirement. The proposal to more than triple the reserve requirement under Schedule 3 implies that LADWP's load forecasters are becoming more fallible over time, which defies common sense.

Finally, Westar proposed that the confidence interval used to establish the reserve requirement for VERs should be two standard deviations from the mean, or the 5th and 95th percentiles – sometimes referred to as a "95 percent confidence interval".[5] In contrast, LADWP

[5] *Id.*, at P 11 n12 ("Westar states that by using two times the standard deviation, it was able to establish a 95 percent confidence interval, which ensures a high likelihood of compliance with NERC standards.").

proposed the confidence interval for load be *three* standard deviations from the mean, or the 1st and 99th percentiles (Table 5 of the VER Study). LADWP already achieved *actual compliance* with NERC standards during the test year using only 50 MW as the reserve requirement for load in Schedule 3. There is no need to impose more costs on any customers to achieve a likelihood greater than absolute certainty.

Q. Has LADWP established a sufficient record for the proposed updates to Schedule 10?

A. No. Several issues must sorted out: (1) what the correct confidence intervals are to establish specific MWs of reserves for specific purposes (*i.e.*, load variability, non-dispatchable resource variability, and dispatchable resource variability); (2) whether such confidence intervals all be the same; and the most basic, (3) whether LADWP has met the FERC standards in Orders Nos. 764, 764-A, and 764-B that govern the establishment of reserve requirements in Schedule 10.

Q. Has LADWP established that the confidence interval used for Schedules 3 and 10 should be increased to the 1st and 99th percentiles?

A. No. LADWP has presented evidence of the various sizes of confidence intervals, but has not provided evidence of the *appropriate or correct sizes, which could be different for different Schedules.*

Q. What does LADWP have to do to comply with Order No. 764?

A. Three requirements must be met before LADWP can distinguish within Schedule 10 between reserves required for dispatchable and non-dispatchable resources. Order No. 764, 139 FERC ¶ 61,246, at P 322. The intent of these requirements is for the utility to establish that it has the "situational awareness" necessary to efficiently respond to, and charge for, system

variability. First, LADWP must "fully implement" (or receive a waiver from the Commission from) intra-hour scheduling; LADWP has not met this requirement because (1) intra-hour scheduling is not allowed at all on the Pacific DC Intertie ("PDCI") and Southern Transmission System ("STS"), and (2) LADWP did not adopt intra-hour scheduling until September 26, 2016, well after the test year.[6] *See id.; see also Integration of Variable Energy Resources Notice of Proposed Rulemaking*, FERC Stats. & Regs. ¶ 32,664, at P 106 (2010) ("VER NOPR").

Second, LADWP must collect a full year of actual VER production data, and provide that on the record. LADWP has provided the VER Study, which incorporated by reference the 2015 "Maximum Generation Renewable Energy Penetration Study" (MGREPS). VER Study, at 1. However, LADWP has admittedly *not* conducted a study of the variability or forecast error for *all* resources, dispatchable and non-dispatchable. Thus, all of the required data is not on the record, and it is impossible to determine whether the proposed reserve requirement for non-dispatchable resources is commensurate with the incremental risk posed to the system, compared with dispatchable resources or loads. Without a study of all resources, both dispatchable and non-dispatchable, it is possible that the proposed Schedule 10 contains inappropriate cross-subsidies.

Third, LADWP must have "developed and deployed power production forecasting for VERs". Order 764, 139 FERC ¶ 61,246 at PP 282 and 323. FERC indicated:

> Without the increased situational awareness of projected variability provided by power production forecasts, the public utility transmission provider's ability to commit or de-commit resources

[6] See BWP/GWP-E-104, "Intra-Hour_Transmission_Service_Business_Practice.pdf". This illustrates another example of the use of post-test-year information.

> providing regulation reserves efficiently can be constrained. This lack of situational awareness potentially can result in rates for generator regulation service that are unjust and unreasonable or unduly discriminatory. *Id.*, at P 323.

The transmission provider is required to explain how the data required from VERs are incorporated into the power production forecast and how the resulting forecast is used to support the management of operating costs and/or reserves or otherwise ensure that capacity costs incurred to provide the service are prudently incurred. *Id.*, at P 325.

Here, there is no evidence in the record that LADWP has met this requirement, nor has LADWP proposed how such a requirement would be met in future. *See Id*. LADWP's LGIA has a placeholder for Interconnection Details in Appendix C, but there is no evidence that LADWP has an actual power production forecasting system in place.[7] See BWP/GWP-E-104, "LGIA_Final_August_14_2014.pdf" and "LGIP_Final)_August_14_2014.pdf". Finally, LADWP has also not met the condition in Order 764 that "public utility transmission providers proposing to require different transmission customers to purchase or otherwise account for different quantities of generator regulating reserves should explain in their proposals how forecasting results will be shared." *Id.*, at P 327.

Q. Did LADWP experience any reliability violations in the test year due to holding inadequate reserves for Schedule 3 service?

[7] *Id.*, at P 327 (requiring "centralized forecast used by the public utility transmission provider [be] available through a secure information exchange to VER generators providing related data."). There is no evidence that LADWP has developed and implemented such a centralized forecast available to all VER generators via a secure information exchange.

A. No. According to LADWP's response to IR 38(c), "LADWP did not self-report violations of any BAL standards during the 2014-15 fiscal year, nor did WECC issue any notices of alleged violations for any such standards during the test period. Accordingly, no penalties or sanctions were imposed related to BAL standard violations during the test period."

Q. Why is this relevant?

A. If +/-25 MW was sufficient for reliability purposes during the test year, then absent any new evidence, +/-25 MW is both appropriate and proper for updating LADWP's OATT Schedule 3 *using test year data*.

Q. Should LADWP use the same MW amount for Schedules 3 and 10-B?

A. No. Schedules 3 and 10-B govern the provision of very different services, and so there is no reason for the reserved capacity amounts and percentages to be the same. In addition, Schedule 10 should be withdrawn at this time and not incorporated into the LADWP OATT until all the preconditions of compliance with Order No. 764 have been met.

Q. Has LADWP conducted a study on the scheduling accuracy of <u>dispatchable</u> resources?

A. No. According to the response to IR 38(c),

> the [VER] study does *not* calculate the deviations between the forecast of hour ahead generation schedules and 1-minute actual metered generation. However, it is reasonable to *assume* the scheduling accuracy of dispatchable generation is the same as the scheduling accuracy of load because dispatchable generation is generally responsive to changes in load, and any deviation between the hour-ahead dispatchable generation schedule and the dispatchable generator's 1-minute output during the operating hour is likely the result of the unit's operator or automatic generation control device adjusting the level of output to track in-hour changes in load. Therefore, LADWP has proposed to use the same 3.486% purchase obligation for Schedule 3 and Schedule 10 as applied to dispatchable resources. (Emphasis added).

There is thus no evidence on the record regarding the forecast error and scheduling accuracy of dispatchable resources, only an *assumption* that "the scheduling accuracy of dispatchable generation is the same as the scheduling accuracy of load."

Q. Does this lack of data on dispatchable resources violate Order 764-A?

A. Yes. In Order No. 764-A, the Commission concluded that "[a]s a general matter, all transmission customers are required to account for ancillary services in a similar manner. To the extent that a public utility transmission provider proposes to allocate to VERs their share of system variability, it must also allocate to *all other generation resources* as transmission customers their corresponding share of system variability." Order No. 764-A, at P 46 (emphasis added).[8]

Q. Given that LADWP does not permit intra-hour scheduling on the PDCI and the STS, what does Order 764-A require of LADWP's imbalance service?

A. In Order No. 764-A, FERC stated that "*in the absence of sub-hourly settlement and dispatch*, a public utility transmission provider *must* account for intra-hour imbalances in order to ensure that they are properly factored into the calculation of hourly imbalance charges." Order No. 764-A, at P 19. Given the lack of intra-hourly scheduling on the PDCI and the STS, LADWP must implement two procedures for Energy Imbalance charges: one where sub-hourly settlement is practiced, and one where sub-hour settlement is not practiced. LADWP's Schedule

[8] *See also Id.*, at P 55: "public utility transmission providers proposing a generator regulation charge must calculate their total regulating reserve need with respect to *all* operational causes that drive the need for regulating reserves. . . . [W]e emphasize that the public utility transmission provider must explain how the variations of *all* resources and loads are accounted for in its section 205 filing." (Emphases added.)

4 (Energy Imbalance Service) contains only one procedure, and thus is in violation of Order No. 764-A.

Q. Does FERC address the relationship between Schedules 3 and 10 in Order 764-A?

A. Yes. In Order No. 764-A , FERC states that the "use of intra-hour scheduling can reduce the amount of imbalance energy for which a balancing authority is potentially responsible and, in turn, lower reserve-related costs. Order No. 764-A, at P 26. Such benefits could manifest themselves in the form of reduced regulation charges under Schedule 3 of the *pro forma* OATT as well as any other ancillary service schedule through which a public utility transmission provider recovers the costs of capacity needed to provide generator imbalance service." Thus, to the extent that LADWP has denied intra-hourly scheduling on the PDCI and the STS, the reserve requirement in Schedule 3 may be overstated.

Q. What do you recommend?

A. In Schedule 3, LADWP should recalculate the Purchase Obligation based on an assumption that 50 MW of capacity is required for RFR service and 1 CP is the correct divisor. *See, e.g.,* Williston Basin Interstate Pipeline Company, 87 FERC ¶ 61,265, 61,021 n.33 (1999)*;* Public Service Company of Indiana, 7 FERC ¶ 61,319, 61,702, reh'g denied, 8 FERC ¶ 61,224 (1979); Union Electric, 47 FPC 144, 150 (1972). Based on data in LADWP's January proposal, the Purchase Obligation in Schedule 3 should be changed to 50/1CP = 50/8159 = 0.613 percent. Further, the purchase obligation for all rate schedules should be corrected for other problems identified in this testimony: 6,343 MW is far too low, as we have discussed above. Finally, LADWP should withdraw the proposed Schedule 10, conduct the required studies, put the

required systems into place, and then issue a new Schedule 10 that fully complies with Order No. 764.

Section 8: Available Transmission Capacity

Q. What is the purpose of this section?

A. In this section, we review the information provided by LADWP on the calculation of Available Transmission Capacity ("ATC"), which is an essential characteristic of the OATT and can be judged by FERC standards as well.

Q. Is the definition of "Native Load" important in the calculation of ATC?

A. Yes. Native Load is an obligation that encumbers a portion of Total Transmission Capacity ("TTC"), and thus reduces ATC.

Q. Has LADWP provided data, assumptions, models, and calculations for specific posted ATC amounts?

A. No. The Cities submitted several Information Requests on this subject, and received no data, assumptions, models or calculations. See IR 41(c). Because of the "black box" nature of LADWP's ATC calculations, it is at least possible that LADWP has used incorrect assumptions to reduce ATC to the advantage of retail loads and to the disadvantage of transmission customers. If so, LADWP would be using ATC to discriminate against wholesale transmission customers.

Q. What information is available regarding Available Transmission Capacity?

A. The only information we have been able to locate is posted on LADWP's OASIS. This information only describes in very general terms how ATC is calculated. There is no data and there are no formulas. See BWP/GWP-E-104 for public documents on ATC.

Section 9: Real Power Loss Factors

Q. What is the purpose of this section?

A. This section addresses LADWP's proposal to use loss factors based on an outdated and likely flawed study of transmission losses. The use of an outdated study inappropriately overstates LADWP's losses by excluding significant upgrades made to the transmission system since the study at issue was conducted. Also since the study, LADWP is proposing to reclassify certain transmission facilities.[9] New equipment normally leads to lower losses, because each new cohort of transmission equipment tends to be more efficient than previous generations. Furthermore, the costs of these upgrades have been rolled in to LADWP's OATT rates but the benefits that these upgrades provide in reducing LADWP's system losses have been ignored in LADWP's out-dated Real Power Losses analysis. LADWP's imposition of such higher losses obligations violates FERC's long held principle of cost causation. *See e.g., Midwest ISO Transmission Owners v. FERC,* 373 F.3d 1361, 1368 (D.C. Cir. 2004) (the court determines compliance with the principle of cost causation "by comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party").

[9] For example, the River to Market 230 kV cables A, B, C and D, like a number of other facilities, are being reclassified from transmission to distribution. Transmission customers would be held responsible for the distribution losses associated with these facilities if the loss factors were not adjusted to account for the reclassification.

Q. What proposed Real Power losses are you concerned about?

A. LADWP's outdated Real Power Losses study yielded the following results, which have been carried over from the current OATT to the proposed OATT:

> Transmission Customers are responsible for Real Power Losses associated with delivery of the energy they Schedule on each path. The Real Power Loss factors that LADWP uses to charge by path under its OATT are:
>
> - 6.2% for any path using the Pacific Direct Current Intertie or Intermountain Power Project Direct Current segments.
> - 4.8% for any path using only Alternating Current segments.
> - An additional 5.89% loss factor will be included for any path using the SYLMAR to PALOVERDE500 segments.
>
> **Note:** The Real Power Loss factors are subject to change from time to time. For paths using a combination of segments, the highest loss factor will apply. For example:
>
> 1. Scheduling transmission on the path NOB to MEAD230, the 6.2% loss factor will be used.
> 2. Scheduling transmission on the path MARKETPLACE500 to MEAD230, the 4.8% loss factor will be used.
> 3. Scheduling transmission on the path NOB to PALOVERDE500, the 12.09% (6.2%+5.89%) loss factor will be used.
> 4. Scheduling transmission on the path MARKETPLACE500 to PALOVERDE500, the 10.69% (4.8%+5.89%) loss factor will be used.

These loss factors are outdated. <u>First</u>, the loss study at issues was conducted outside the test year and it appears to be from long before LADWP's 2014 OATT proposal. It is clear that, since the study was conducted, LADWP has made modifications to its transmission system that were intended to reduce losses. <u>Second</u>, the above cited loss factors are not consistent with the power flow studies used by LADWP in this proceeding to determine the proposed functionalization of facilities among distribution, generation, and transmission. Because of the upgrades that LADWP has installed since the last losses study the losses reflected in LADWP's rates should reflect the losses LADWP experienced in the test year. *See, e.g.,* Williston Basin Interstate Pipeline Company, 87 FERC ¶ 61,265, 61,021 n.33 (1999)*; Public Service Company of Indiana,*

7 FERC ¶ 61,319, 61,702, *reh'g denied,* 8 FERC ¶ 61,224 (1979); Union Electric, 47 FPC 144, 150 (1972).

Q. Have you reviewed the study LADWP relied upon to establish its OATT losses requirements?

A. No, we have not. When we asked LADWP to produce the losses study and the loss factors it relied upon, LADWP refused to produce both of these items. See LADWP's Response to IR 25(a).

Q. *Did LADWP compare posted loss factors with losses from power flow studies posted for this proceeding?*

A. No, LADWP did not. See LADWP's Responses to IR 11(a) and IR 111(c). Therefore, we have no way of knowing exactly how LADWP determined its OATT loss factors.

Q. If LADWP were to conduct a full losses analysis, what should such an analysis include?

A. The most appropriate loss analysis would be one that is based on measured actual real power losses (i.e., MWh) over all facilities properly designated as transmission and for all hours during the test year. Lacking measurement of actual real power losses, LADWP should use power flow analysis under a study approach that accounts for the variation in losses over the entire test year in as accurate a manner as possible.

Q. Please explain these approaches.

<u>The Loss Factor Numerator</u>

A. Whether LADWP measures actual real power losses or calculates transmission losses using power flow analysis, the losses included in the loss factor calculation should result from summing transmission losses on a branch-by-branch basis, including only the branches

(transmission lines and transformers) that are properly classified as transmission and only including LADWP's and its transmission customers' share of losses over facilities in which LADWP's ownership or capacity rights are not 100%.

If LADWP uses power flow analysis to calculate real power losses, the study approach should:

1) Acknowledge that losses during off-peak periods are considerably less than on-peak periods, based on the I^2R nature of transmission losses. Consequently, LADWP should either:
   a) calculate losses using simulations for every hour during the test year, based on actual hourly BA generation, scheduled deliveries over jointly owned facilities, load and interchange data, or
   b) calculate losses using a sufficient number of "band-widths" that account for a given range of hourly loadings, using actual hourly BA generation, scheduled deliveries over jointly owned facilities, load and interchange data to develop average data for each band-width. Others have used the band-width approach. For example, in a 2010 transmission rate case, PNM used 22 bandwidths (11 summer and 11 winter) in it transmission loss analysis "to capture the full effects of seasonal loading and transactions on PNM's transmission facilities, including the use of historical measurements from numerous parameters."[10] Such an analysis can still overstate transmission losses; and, upon settlement, PNM agreed to measure actual transmission losses going forward. If

[10] See the testimony of Jeff R. Mechenbier in FERC Docket ER11-1915-000.

LADWP uses a band-width approach, it should acknowledge the I^2R nature of transmission losses within each band-width.

2) Acknowledge that the resistance value used in power flow calculations changes throughout each day, depending on factors such as solar radiation, and is measurably lower during the morning and evening hours. LADWP should determine a system proxy adjustment factor (applied retrospectively to the power flow results) to account for the lower losses that are attributable to a lower resistance value during off-peak hours. The proxy adjustment factor should be determined through a sampling of real-time data for several representative transmission lines. Each sampling of real-time data should cover a period of 24 hours; and there should be multiple samplings to account for low load and high load days.

3) Calculate losses for jointly owned facilities based on test year historical flows and actual power schedules by LADWP and others. For example the Navajo – Crystal 500 kV transmission line is jointly owned by NV Energy, Western Area Power Administration and LADWP. From the power flow data, the losses over this line appear to be assigned 100% to LADWP's BA (Area 26 in the power flow data). If LADWP does, in fact, supply the real power losses for all uses of this line, the other owners are obviously responsible for their share of losses and must compensate LADWP accordingly. LADWP should only include its share of actual losses over this and other jointly owned lines in the numerator of the loss factor calculation. Finally, with respect to jointly owned facilities outside of LADWP's BA, LADWP should calculate native load to include all transmission system losses for which

LADWP and its transmission customers are responsible, not just BA losses as in its current native load calculation.[11]

The Loss Factor Denominator

It is imperative that the loss factor divisor account for all MWh uses of the transmission system by LADWP and its transmission customers, including all non-native load MWh uses by LADWP (e.g., Castaic pumping requirements and off-system sales). If the non-native load MWh uses are not included in the divisor, the losses attributed to such uses should be subtracted from the total losses (i.e., the numerator).

Q. Have you conducted any losses analysis on the LADWP system for the test year?

BEGIN CEII REDACTION.

[redacted]

END CEII REDACTION.

[11] LADWP calculates native load by adding BA generation and net area interchange (imports-exports) and subtracting BA generating station service and auxiliary power requirements, Castaic pumping load and IPP Banks K and L MWh. See LADWP's CEII – Exhibit IR86(e).

[12] The provided Base Case is described within the power flow data as the WECC "2013 HS2-OP BASE CASE" and is purported to be the base case used by nFront in its transmission analysis. However, on solving the Base Case, there are minor but not insignificant differences in the resulting flow distributions. Moreover, there were a number of bus numbering and naming differences that made comparisons to nFront's results difficult (see "(CEII) IR18(i) 7-Factor PF Results 201609023.xlsb").

Q. Please describe the steps involved in your Loss Analysis. **BEGIN CEII REDACTION.**

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]. ***END CEII REDACTION.***

[redacted]

[redacted]

Q. Can you summarize the results and conclusions reached in performing the Loss Analysis?

A. Yes. The following table summarizes the results of our Loss Analysis.

	Total BA	nFront "T" Only	B&G "T" Only
BA Losses	235.2	121.9	112.7
Non-BA Losses	-	9.8	7.8
Total Losses		131.7	120.5
Rate Divisor		6,995.0	6,995.0
Loss Factor		1.88%	1.72%
Note: the above values represent peak-hour MW.			

Q. Please describe your conclusions.

A. Our conclusions are as follows:

1) The primary conclusion is that LADWP's 4.8% loss factor "for any path using only Alternating Current segments" is greatly overstated.[20]

2) The sum of losses on all lines and transformers within LADWP's BA is approximately double the sum of losses on only the lines and transformers that are classified as transmission (and only for LADWP's share if jointly owned). If LADWP has improperly calculated its loss factor to include losses on non-transmission classified facilities or others' losses on jointly owned facilities, this could easily account for much of the excess in its overstated 4.8% loss factor. LADWP needs to share its loss factor studies with the transmission stakeholders.

[20] *See* "Real Power Loss Factors" posted on LADWP's OATI OASIS site.

3) Any loss analysis that is performed without LADWP's direct input, including our Loss Analysis, is subject to errors and omissions which can be attributed to: (1) the voluminous nature of power flow data, (2) the inability of the power flow model to capture all losses (*e.g.*, corona and no-load transformer losses) and especially (3) not having the information needed to assign responsibility for losses over jointly owned transmission facilities.

4) Notwithstanding the potential for errors and omissions, our Loss Analysis is overly conservative in a number of ways that more than compensate for any such errors and omissions. Several ways in which the Loss Analysis is overly conservative include:

   a) The use of peak hour data results in a calculation of significantly higher losses than experienced for most hours during the year.

   b) The excessive flow over the Navajo-Crystal 500 kV transmission line, as modeled in the Base Case, causes calculated losses to be on the order of two to three times a "real world" amount, which could be as much as 20 MW for LADWP's share.

   c) The divisor only uses LADWP's Native Load MW and should be increased substantially to include LADWP's non-native load uses and any other uses for which there is currently no accounting (*e.g.*, it is possible that certain exchange arrangements could introduce an unaccounted use of LADWP's transmission system).

5) Even though the Loss Analysis is overly conservative, it is more accurate than the 4.8 percent loss factor that LADWP now assesses for the "Alternating Current segments" of its

transmission system or the "6.2% for any path using the Pacific Direct Current Intertie or Intermountain Power Project Direct Current segments."[21]

Section 10: Classification and Functionalization

Q. What is the purpose of this section?

A. In this section, we (a) review LADWP's proposed assignment of facilities, both transmission and generation, to the provision of either (i) open access transmission service or (ii) open access ancillary services, as those are defined in the LADWP OATT and by FERC standards, and (b) make findings about the need to re-assign such facilities. Specifically, we demonstrate why the following facilities are not transmission facilities and should be excluded from the LADWP OATT rate: (1) 230-kV Inyo – Barren Ridge Line 1; (2) 230-kV Barren Ridge – Rinaldi Line 1 (collectively referred to as "Inyo-Rinaldi Path").

In addition, we show why the following facilities should be reclassified within or excluded from LADWP's production-related ancillary services costs because they did not provide the ancillary services that LADWP's contends they were able to provide during the test year: (1) Upper Gorge, Middle Gorge and Lower Gorge (collectively referred to as "Owens Gorge Units"); (2) San Francisquito Units; (3) Scattergood Unit 3; and (4) Intermountain Generating Station ("IGS" or "IPP").

Q. What information have you reviewed in making these findings?

[21] Based on the examples provided in the "Real Power Loss Factors" document posted on LADWP's OATI OASIS node, the 6.2% loss factors contemplate the combined use of HVDC segments and Alternating Current segments (i.e., HVDC+AC). The same reduction in losses that apply to the 4.8% AC loss factor would also apply to the 6.2% HVDC+AC loss factor.

A. We have reviewed LADWP's information responses, CEII data responses, proffered power flow studies and the other relevant information provided in LADWP's OATT proposal. In addition, Messrs. Wenzinger and Rhorer are former LADWP employees with over 45 years combined years of experience operating LADWP's system. They have extensive knowledge of the LADWP Control Area, including its facilities and operations. See BWP/GWP-Q-102 and BWP/GWP-Q-103, attached to this testimony.

Q. What criteria have you relied on to make these findings?

A. We have relied on FERC and Court of Appeals precedent addressing both how to determine what facilities should be rolled-in to the transmission rates and how to determine what facilities should be included in the production components of a particular ancillary service rate.

1. Facilities That Should Be Excluded from LADWP's Transmission Costs

Q. What precedent have you relied upon to make your findings regarding the facilities that should be excluded from LADWP's OATT transmission rates?

A. Under FERC precedent addressing the allocation of the cost of transmission facilities among customers, when facilities are integrated and provide system-wide benefits, facilities' costs are generally rolled-in and charged to all customers served. *See e.g., Pinnacle W. Capital Corp.*, 131 F.E.R.C. ¶61,143 at P 42 (2010) ("*Pinnacle West"*). Such an allocation is intended to comport with the principle of cost causation "that costs should be recovered in the rates of those customers who utilize the facilities and thus cause the cost to be incurred." *Id.* However, when facilities are not integrated and thus do not provide system-wide benefits, direct assignment typically is used to allocate costs to those customers who use the facilities. *Id.* This ensures that the transmission customers are not inappropriately required to subsidize the cost of facilities that

benefit only other users in contravention of the principle of cost causation. To determine which facilities are integrated and therefore should be rolled-in to a transmission provider's rates, FERC uses a variety of tests depending on the facility and entity at issue.

Q. Please explain the Seven Factor and Mansfield Tests.

A. FERC uses the "Seven Factor Test" to address the threshold issue of whether a facility is transmission or distribution. *See e.g., Southwest Power Pool, Inc.,* 149 F.E.R.C. ¶61,051, at P16 (2014) ("*SPP Case"*), *citing Order No. 888,* 61 Fed Reg. 21,540, 21,620 (1996). If the facility is determined to be a transmission facility, FERC then uses the *Mansfield* test to determine whether the facility is integrated. *Mansfield Municipal Electric Dept. v. New England Power Co*., 97 FERC ¶ 61,134 (2001) (*Mansfield*). Facilities that are not integrated or that are used exclusively to generate power, step up power, or transmit power from the generator to the grid are to be excluded from and not be rolled-in to the transmission provider's tariff rates. *Cal. Dep't of Water Res. v. FERC,* 489 F.3d 1029, 1035 (9th Cir. 2007).

Q. What are FERC's Seven Factors?

A. FERC's Seven Factor Test considers: (1) the proximity of facilities to retail customers; (2) radial configuration; (3) one-way power flows into the local distribution system; (4) whether power that enters is reconsigned or transported to another market; (5) whether the consumption of the power is in a restricted area; (6) the use of meters to measure flows into the system; and (7) reduced voltages. The seven factor test is applied on a facility-by-facility basis and the analysis under each factor should also be performed on a segment-by-segment basis. *See e.g., Southwest Power Pool, Inc.,* 149 FERC ¶ 61,051, at P 169.

Q. Please describe the components of the Mansfield test.

A. Under *Mansfield*, facilities are considered to be integrated, thereby justifying rolled-in pricing, *unless* all five of the following factors are satisfied: (1) the facilities are radial, not looped; (2) energy flows in just one direction over the facilities at issue; (3) the applicant is able to serve only its own customers over these facilities; (4) the radial configuration prevents the applicant from providing support and added reliability to the other looped lines; and (5) an outage on any one of these facilities would not affect the power flows on the remainder of the system. A negative showing on one of the factors suggests some degree of integration.

Q. Is Mansfield dispositive?

A. No. FERC has indicated that the *Mansfield* test is not dispositive for resolving the question of whether every facility is part of the integrated network. *Pinnacle West*, 131 FERC ¶ 61,143, at P 44. For example, in *Pinnacle West*, FERC disregarded the *Mansfield* test even though the facilities satisfied some of the Mansfield factors. FERC concluded that the *Mansfield* framework was ill-suited to address the facts of the case, noting that "[g]iven the topology of the ED3 system and our understanding of its normal use, the *Mansfield* factors are inappropriate as a test for integration." *Id.*, at P 16. FERC looked to the transmission provider Electric District No. 3's ("ED3") representations regarding the facilities at issue, the applicable Transmission Plan of Service Report, finding "ED3's own description of its system belies such a characterization." *Id.*, at P 46. FERC pointed out that "ED3 has expressly acknowledged the radial nature of certain components of its current system in its transmission plan and stated that '[a]dditional activity has also been to rebuild older facilities that are being integrated from a radial system to a 'looped' system as the opportunities occur.' We conclude, therefore, that these radial facilities provide no parallel capability to either the 69 kV system or the rest of the 12 kV system and are

unlikely to support system-wide contingencies." *Id.*, at P 47. FERC also found that a further demonstration was required to show why the facilities should not be rolled-in because the ED3 facilities at issue were remote from the load with which ED3 alleged the facilities were integrated. *Id.*, at P 48.

Q. Please describe generation integration facilities and FERC's relevant rulings.

A. FERC and the Court of Appeals have also found that facilities that are used exclusively to generate power, step up power, or transmit power from the generator to the grid are to be excluded from and not be rolled-in to the transmission provider's tariff rates. *Cal. Dep't of Water Res. v. FERC*, 489 F.3d 1029, 1035 (9th Cir. 2007). Such facilities are viewed as not being integrated. *Id.* Here, to justify its proposal to roll-in the costs of all the proposed facilities, LADWP must demonstrate that all of its facilities at issue qualify as transmission under FERC's Seven Factor Test and function as a single, integrated transmission system that is used to serve its OATT customers. *Pinnacle West*, 131 FERC ¶ 61,143, at P 43. LADWP has failed to make this demonstration for several facilities.

Q. Why do you conclude that the Inyo-Rinaldi Path is not integrated into the LADWP system and does not meet the relevant FERC tests?

A. The facilities in the Inyo-Rinaldi Path are part of the original Owens Gorge-Rinaldi 230 kV transmission line; like the original Owens Gorge-Rinaldi line, the primary function of the Inyo-Rinaldi facilities is to import power from remote LADWP generation into the Los Angeles Basin (i.e., gen-tie facilities). As such, the Seven Factor test, which is used to determine whether facilities are distribution or transmission, is not applicable. The *Mansfield* factors are also "inappropriate as a test for integration", given the topology of Inyo-Rinaldi facilities (a 200

mile radial feed that connects remote generation into LADWP's integrated transmission network) and their normal use (delivering LADWP generated power to the LA Basin). Nevertheless, under *Mansfield*, these facilities are not integrated into the LADWP system because: (1) the facilities are radial and not looped; (2) energy flows in one direction on these facilities when they are operated as a gen-tie; however, when generation is insufficient to meet Owens Valley Electric System ("OVES") load, these facilities act as a distribution line to feed that load; (3) LADWP is only able to provide itself gen-tie service over these facilities and does not provide open-access transmission service over these facilities; (4) the radial configuration of the facilities prevents the applicant from providing support and added reliability to the other looped lines; and (5) an outage on these facilities would not have reliability or other effects on the LADWP transmission system.

Q. On what grounds do LADWP claim the Inyo-Rinaldi Path is integrated into the LADWP system?

A. LADWP argues that the Inyo-Rinaldi Path is integrated under factors (1) and (4) of the *Mansfield* test. Specifically, LADWP claims the Inyo-Rinaldi Path are looped, not radial, and that the facilities provide reliability benefits.

Q. Why does LADWP contend the Inyo-Rinaldi Path is looped?

A. LADWP argues that any level of flow changes (an "any degree of integration" argument) defines a non-radial looped system. For the Inyo-Rinaldi facilities, LADWP's argument rests solely on the notion that the phase shifter-controlled tie at Inyo to the Southern California Edison

("SCE") system (the Inyo Tie) completes a "looped" configuration. LADWP offers "evidence" of inadvertent flow changes in their power flow scenarios to support their argument. [22]

Q. Please discuss the tie between SCE and LADWP at Inyo.

A. The tie at Inyo was built by SCE and remains under the ownership and control of SCE, including everything from the 230-kV Circuit Breaker 612 to SCE. LADWP contends that the existence of this tie allows the Inyo-Rinaldi Path to provide reliability benefits to LADWP's system. However, LADWP's responses to the Cities' Information Requests make it clear that Inyo Tie is owned and controlled by SCE. SCE constructed the Inyo Tie to receive service from LADWP under a contract that terminated long ago and was not in effect during or after the test year. As a consequence of terminating a service that relied on SCE's control of a phase shifter, the Inyo Tie now operates much the same as a normally open connection, which means SCE is required by contract to "operate the Phase Shifter in accordance with prudent utility practices and in such a manner that the transfer of energy between the Parties' systems at the Inyo Interconnection shall be equal to or less than the amount of transmission capacity agreed to be made available by Los Angeles to Edison pursuant to the Transmission Service Agreement."[23] It does not offer any system-wide benefits. FERC distinguishes between a radial and a looped configuration in order to identify facilities that actually provide system-wide benefits and only truly looped configuration do so. The Inyo-Rinaldi facilities are not looped under any

[22] See the Edison-Los Angeles Inyo Interconnection Agreement: "12. INADVERTENT FLOWS: It is recognized that flows of energy may occur through interconnections between the electric systems of the Parties as a result of parallel operation of the electric systems of the Parties with each other and with other entities. Each Party shall use reasonable efforts at all times to maintain as nearly as practical the scheduled quantities of power and energy into and out of its Control Area."

[23] See the Edison-Los Angeles Inyo Interconnection Agreement, Amendment 1, Section 8.1.4.

interpretation of the term. During the test year, LADWP had no contractual rights over the Inyo Tie. Therefore, LADWP cannot use the Inyo Tie to access energy or ancillary services from third-parties. In addition, as LADWP's responses also indicate, there have been no OATT or third-party transactions on the Inyo-Rinaldi Path during the test year or in recent years. *See* LADWP Responses to IR 73 and IR 82.

Further, when asked to provide documentation for the amount of transmission offered or posted on the LADWP OASIS for the Inyo interconnection during the test year, LADWP stated that "Inyo Control, Path 60 is not a posted path." See LADWP Response to IR 81. LADWP also indicated that "[d]uring the FY14/15 Test Year there are no etags for the Inyo Control, Path 60 because it is not a posted path." *See* LADWP Response to IR 82. If the path is not posted it cannot be used by OATT customers.

When the Cities investigated LADWP's answers, they learned that the Inyo Tie is listed in the LADWP OASIS as a POR, but not a POD, which means it cannot be used by LADWP's OATT customers as a tie to other entities. Furthermore, there are no paths available from Inyo to any other location in the LADWP OASIS.

Q. What about the changed flows upon which LADWP bases its argument to roll-in the costs of the Inyo-Rinaldi facilities? ***BEGIN CEII REDACTION.***

[redacted]

[redacted]. ***END CEII REDACTION.***

Q. Please describe in more detail your concerns regarding Case 13. ***BEGIN CEII REDACTION.***

[redacted] ***END CEII REDACTION.***

Q. Please describe in more detail your concerns regarding Case 12. ***BEGIN CEII REDACTION.***

A. [redacted]

[redacted]

[redacted]

[redacted]. ***END CEII REDACTION.***

Q. Why does LADWP contend that the Inyo-Rinaldi Path provides reliability benefits?

BEGIN CEII REDACTION.

[redacted]

examples [redacted]

[redacted]. ***END CEII REDACTION.***

Q. Does the existence of a request in the LGIA queue mean that the transmission path or line should be included in the OATT revenue requirement?

A. No. If the path is not posted, it is not available for OATT service until LADWP processes a "path posting request", which takes time, may have conditions, and may expire. Second, some of the requests in the LGIA queue were submitted *after* the test year, so the current queue cannot and should not be used as evidence that the path was part of the transmission system *during* the test year.

2. Facilities That Should Be Reclassified or Excluded from LADWP's Production Costs in Its OATT Rates

Q. What precedent have you relied upon to make your findings regarding the facilities that should be excluded from LADWP's OATT ancillary services rates?

A. We have relied on FERC and Court of Appeals precedent, which dictates that these facilities should be excluded from the production component of LADWP's OATT costs because these facilities cannot provide ancillary services. *See e.g., Entergy Service, Inc.*, 109 FERC ¶ 61,095, P 56-57 (2004); *Ocean Vista Power Generation, et. al.*, 82 FERC ¶ 61,114, 61407 (1998). LADWP's testimony, studies, and data responses make it clear that these generation facilities cannot actually provide the ancillary services to LADWP's OATT customers that LADWP's COSS assumes that they can provide.

Q. Please describe tab "Gen AS Matrix" in DWP-104.

A. This tab contains *assumptions* made by LADWP regarding the provision of specific ancillary services under Schedules 1, 2, 3, 5, 6, and 10. We describe these as "assumptions" because LADWP has provided no empirical evidence that these generation facilities *actually* provide ancillary services. When asked in discovery, LADWP only stated that certain LADWP personnel identified which generation units allegedly provide ancillary services. When asked in

discovery to identify the LADWP personnel who had made these identifications, LADWP declined to do so.

Q. Do you agree with all of LADWP's assumptions?

A. No. As we noted above many of the facilities listed in the Gen AS Matrix cannot and do not provide ancillary services to LADWP's OATT customers.

a) Owens Gorge Units

Q. Please discuss the ability of the Owens Gorge Units to provide reactive and voltage control. ***BEGIN CEII REDACTION.***

[redacted]

required f[redacted] ***END CEII REDACTION.***

Q. Please discuss the ability of the Owens Gorge Units to provide spinning and supplemental reserves. ***BEGIN CEII REDACTION.***

[redacted] ***END CEII REDACTION.***

b) San Francisquito Units

Q. Please discuss the ability of the San Francisquito units to provide reactive and voltage control.

A. These two power plants (limited by restricted water flow south of Power Plant 1 ("PP1") at San Francisquito) do not impact the voltage or VAr other than on the Production path to Olive Switching Station. The three 115-kV lines (PP-1 – Olive Line 1, PP-2 – Olive Line 1, and PP1 – PP2 tie line) create more capacitive reactance than the power plants can absorb. Additionally, these plants supply power to the housing camps at each of the plants and to "fringe loads" of Southern California Edison. The limited size and extent of these distribution loads requires that the units maintain proper voltage on a very small distribution system, not to the larger LADWP grid beyond the Olive Switching Station.

c) Scattergood 3

Q. Please discuss the ability of the Scattergood units to provide ancillary services during the test period.

A. According to the LADWP "2015 Power Integrated Resource Plan" (December 31, 2015, p. 18), "[o]n September 29, 2013 LADWP broke ground on the Scattergood Unit 3 Repowering Project which will be the first of two major repowering phases at Scattergood to completely eliminate once–through cooling and provide flexible, efficient combined cycle and simple cycle gas turbine units to help facilitate the integration of renewable energy. This project will include one 308 MW combined cycle and two simple cycle gas turbines with a combined replacement of 508 MW of older gas fired generation and is expected to be place in-service by December 2015." We conclude that Unit 3 was not available during the test year, and at least some of the costs of Unit 3 should be removed from the cost-of-service study.

d) Intermountain Generating Station

Q. Please discuss the ability of the Intermountain Generating Station ("IGS" or "IPP") to provide ancillary services.

A. LADWP claims that IGS can provide Schedule 2 Reactive Supply and Voltage Control and Schedule 5 Spinning Reserves. The IGS has a 345/230-kV switchyard, and the Milford wind farm connects to that switchyard. These plants are not on the 500-kV DC. The 345-kV switchyard connects to the Intermountain Converter Station which then connects to the IPP HVDC. In fact, LADWP has identified the IGS as the Most Severe Single Contingency ("MSSC") on its system, which determines the level of Schedule 5 and 6 reserves that must be

carried *elsewhere* on the LADWP system. It is contradictory to claim that IGS is *both* the MSSC *and* a source of operating reserves.

Q. Can IPP provide Schedule 2 service?

A. No. IPP is almost 500 miles from the LA Basin, and is connected through an HVDC transmission system, with reactors, filters, and power factor capacitors at both ends to supply the reactive needs of the converter stations. There is no reactive capacity left over to provide voltage support for the LADWP Beltline system or other downstream AC facilities. The reactive capacity of IPP should be assigned to the STS/NTS segment as a segment-specific ancillary service, with a separate revenue requirement and rate schedule.

Q. Do you have any other observations about IPP?

A. Yes. According to DWP-104, Tab "Gen AS Matrix," cell B130,

> DWP entitlement out of (900x2) MW maximum generation is as follow[s]: DWP direct entitlement of 44.617% + 4% purchase from Utah Power & Light Co. + 86.281% of up to 21.057% from other Municipals['] purchase power. The aggregated DWP share is about 66.79%[.] *However, DWP power purchase share is often reduced on a yearly basis due extended outages of the power plant and/or due to Milford wind resources competing for the existing available transmission capacity. For instance DWP['s] share was reduced to 1,202 MW for fiscal year 2014/2015 due to excess recall.* (Emphasis added).

Q. What does this mean for the assumptions and calculations in DWP-104?

A. If "excess recall" poses a risk that LADWP's entitlement rights at IPP may be reduced, this risk must be taken into account when the generating units at IPP are assigned to ancillary services. If LADWP cannot count on its entire share of IPP, then LADWP's OATT customers cannot count on LADWP's entire share of IPP either.

Q. Can IPP provide Schedule 5 service?

A. No, it cannot. As LADWP's Business Practices make clear, LADWP does not offer intra-hour scheduling on the NTS or STS. Therefore, LADWP could not provide Schedule 5 service from IGS to OATT customers. Moreover, as we pointed out above, even if LADWP did offer intra-hour scheduling, it would be highly unlikely for LADWP to provide spinning reserves from its MSSC.

Section 11: Segmentation

Q. What is the purpose of this section?

A. In this section, we address the need for LADWP to segment its transmission system, and set separate rates for: (a) the PDCI; (b) the Southern/Northern DC/AC Transmission System ("STS/NTS"); and (c) the Beltline.

Q. What precedent have you relied upon to make your findings in this section?

A. We have relied on the FERC precedent we discussed above in the preceding section that addresses the allocation of the cost of transmission facilities among customers, when facilities are or are not integrated. This allocation must comport with the principle of cost causation; therefore, facilities that are not integrated, and thus do not provide system-wide benefits, are typically directly assigned to those customers who use the facilities. *See e.g., Pinnacle West*, 131 F.E.R.C. ¶61,143 at P 42. This ensures that all transmission customers are not inappropriately required to subsidize the cost of facilities that benefit only some users or even one specific user.

Q. What is "segmentation"?

A. Segmentation is the separation of transmission and ancillary service costs into separate revenue requirements that yield separate rates for each segment. This enables a utility to directly assign the costs of the segmented facilities to the customers who use them. Transmission customers who want to use only one segment would pay only for that segment while customers who want to use two or more segments would pay separately for each segment. This prevents all transmission customers from being required to subsidize the cost of facilities that benefit only some users.

Q. Why is segmentation a reasonable approach to setting transmission rates?

A. Most fundamentally, segmentation is consistent with cost causation, one of the basic premises of rate-making. *See e.g., California Power Exchange Corp*., 106 FERC ¶ 61,196, at P 17 (2004) ("[t]he well-established principle of cost causation" requires allocation of costs "where possible, to customers based on customer benefits and cost incurrence"); *California Indep. Sys. Operator Corp*., 106 FERC ¶ 61,032, at P 10 (2004) ("while the fundamental idea of matching costs with customers is often referred to in terms of cost causation, it has also been described in terms of the costs which should be borne by those who benefit from them") (internal quotations omitted).

Q. What has LADWP <u>already done</u> to segment its system?

A. <u>First</u>, as noted above, LADWP calculates separate loss factors for these three segments. <u>Second</u>, LADWP does not allow intra-hour scheduling on the PDCI and IPPDC (a.k.a., the "STS") facilities, referring to them as separate "segments" of its system. See *Intra-Hour Transmission Service and Schedule Business Practice*, Version No. 2, Effective Date 9/27/2016: "LADWP does not allow intra-hour scheduling on paths containing the PDCI or IPPDC

segments. Intra-hour scheduling is only allowed for AC paths." The lack of intra-hour scheduling on *all* segments means that transmission customers who want to schedule across both AC and DC facilities are limited to hourly schedules even over the AC segment. Third, LADWP explicitly excluded DC facilities from its Large Generator Interconnection Agreement ("LGIA") and Large Generator Interconnection Procedures ("LGIP"). In the LGIP,

> 2.1 Application of Large Generator Interconnection Procedures
> Sections 2 through 13 of this LGIP apply to the processing of an Interconnection Request pertaining to a Large Generating Facility, *excepting any and all Interconnection Requests to interconnect to High Voltage Direct Current (HVDC) transmission facilities* owned, controlled or operated by Transmission Provider or Transmission Owner that are used to provide Transmission Service under the Tariff, which such requests shall be processed under a separate and distinct HVDC LGIP/LGIA. (Emphasis added.)

LADWP has not posted a "separate and distinct HCDC LGIP/LGIA", so there is no standard process for interconnecting generation to the PDCI or the STS. A new generator seeking service across both DC and AC facilities faces unknown costs and potential delays that cannot be compared to AC facilities.

Q. Please describe the ownership rights on each segment.

A. LADWP owns a 40 percent share of the PDCI. The Intermountain Power Agency ("IPA") owns the STS/NTS segment. LADWP owns the Beltline segment.

Q. How does LADWP have access to the NTS and the STS?

A. LADWP's access to the NTS and STS is governed by contracts between LADWP and the Intermountain Power Agency. LADWP also is the Operating Agent for these transmission lines,

under an agreement with IPA, and is paid by IPP participants via IPA for certain fees charged and costs incurred by LADWP in its role as Operating Agent.

Q. How much does LADWP earn from services provided to IPA?

A. According to KPMG (p. 34), "[t]he Power System earned fees under the IPP project manager and operating agent agreements totaling $27.9 million and $24.1 million in fiscal years 2015 and 2014, respectively." See IR 89(g)(1) and BWP/GWP-E-101, IR89.g.1.

Q. Does LADWP have complete control over the NTS?

A. No. First, the NTS belongs to IPA, not LADWP. Second, LADWP does not have the right to operate and use the NTS at its will. LADWP's operation of the NTS is subject to the directives of the Utah participants and LADWP's use of the NTS is subject to, and dependent on, the Utah participants' use of their NTS rights. If the Utah participants choose to exercise all of their NTS rights, LADWP's ability to use the NTS is limited.

Q. Which transmission segments are Direct Current vs. Alternating Current?

A. The PDCI and the STS are both Direct Current ("DC") segments. The NTS and the Beltline are Alternating Current ("AC") segments.

Q. Have you found examples of transmission providers that have segmented transmission systems approved by FERC?

A. Yes. We have identified seven transmission providers with segmented facilities: the Bonneville Power Adminstration ("BPA"), Allete, Avista, Black Hills, El Paso, Oncor, and Puget Sound Energy. This may or may not be the universe of such transmission providers, but the rates for transmission service of these providers have all been approved by FERC.

Q. How do you recommend that LADWP segment out these facilities?

A. To be consistent with FERC policy, LADWP should calculate three separate rates for the PDCI segment, the STS/NTS segment, and the Beltline segment. Three separate and segmented transmission revenue requirements should be calculated, and three segmented rate schedules should be established using the appropriate methodology for rate design in each segment, and separate ancillary service rate schedules. LADWP has already calculated separate loss factors for these three segments, so it already considers them distinct.

Q. Please explain your recommendation to assign the STS and NTS to a separate segment.

A. First, as noted above, LADWP has calculated separate loss factors for the STS and NTS. Second, the STS and NTS are *contractually* distinct from the Beltline. That is, the STS and NTS are owned by IPA and subject to the relevant contracts with IPA. LADWP cannot offer OATT service on the STS and NTS beyond the life of the relevant contracts with IPA. The Beltline is owned by LADWP.

Third, the STS is a Direct Current ("DC') facility. FERC has permitted, even in contested cases, the separation of DC facilities from AC facilities and the creation of separate segments and associated rates.

Fourth, the STS/NTS transmission facilities were built *because* the IPP was constructed in the 1980s. We know of no proposals to build this specific combination of AC (NTS) and DC (STS) lines independently of the construction of IPP. In the test year and to this day, the STS was and continues to be "fully subscribed" by the existing participants in the *generation units* at IPP. Although those participants make various uses of the STS based on decisions subsequent to the construction of IPP, the original subscriptions to transmission capacity were driven *solely* by

generation at IPP. Thus, the principle of cost causation dictates that the STS, and by extension the NTS, must be segmented from LADWP's AC Beltline network.

Section 12: Revenue Requirements for Transmission Service

Q. Has LADWP provided sufficient documentation of offsetting sources of income, revenues, receivables, and other credits that would help reduce OATT rates?

A. No. LADWP provides certain O&M-type services to (a) other owners of the PDCI, (b) the Intermountain Power Agency ("IPA"), and (c) the SCPPA. LADWP is the operating agent for assets owned by itself (PDCI) and others (PDCI, IPA and SCPPA). These services generate income for LADWP. In the case of IPA, it appears that a separate Fund has been established in LADWP's General Ledger, which *may* be evidence that all costs incurred to provide services to IPA and all revenues (or payments, credits or receivables) from IPA are not mixed with costs and revenue credits appropriately assigned to OATT services. See response to IR 31(a). However, in the case of the PDCI and SCPPA, LADWP has not provided any evidence of the same kind of separation of Funds within the LADWP accounting system, and has not made even an initial case that costs incurred to provide OATT service and services to SCPPA are not mixed to some extent.

Q. What other information have you found on this topic?

A. According to IR 89(a)(1), LADWP is the Project Manager and/or Operating Agent for several SCPPA projects: the Apex Power Project, the Southern Transmission System Project, the Mead-Phoenix and Mead-Adelanto Projects, the Don A. Campbell 2 Geothermal Energy Project. *See* Moss Adams LLP, *Report of Independent Auditors and Combined Financial*

Statements for Southern California Public Power Authority, June 30 2015 and 2014. BWP/GWP-101, "IR89.a.1.pdf". Further, it appears from the response to IR 89(c) that LADWP billed or invoiced SCPPA almost $2.4 million during the test year for "Billable LADWP In-House Costs." See BWP/GWP-E-101, IR89.c.1.xlsx, IR 89(c), Tab "SCPPA Billing Jul14 to June15". These "in-house costs" were identified with several projects: Palo Verde, Mead-Phoenix, STS, Hoover, Mead-Adelanto, San Juan Unit 3, Magnolia, Natural Gas-WY, Natural Gas-TX, Prepaid NGP #1, Canyon Power, Pebble Springs Wind, Tieton Hydropower, Windy Point/Windy Flats, MWD Small Hydro, Ormat Geothermal, Linden Wind, Milford One Wind, Milford Two Wind, Ameresco, Don A Campbell, Apex, and Copper Mountain. LADWP has admitted that "receivables" were paid by SCPPA to LADWP, but argues that such "receivables" are not "revenues". The tab "GL Recon. Monthly Flow" lists "Receipt of Funds" during the test year in the same amount (almost $2.4 million). LADWP has not demonstrated that the costs and receipts associated with LADWP's relationship to SCPPA are fully segregated from LADWP's accounts associated with OATT costs and revenues.

Q. Please describe your understanding of the relationship of LADWP to the other owners of the PDCI.

A. LADWP has provided no evidence that amounts paid to LADWP by other PDCI owners on a monthly basis for O&M services provided by LADWP, and capital improvements to the PDCI, are fully and correctly accounted for in the calculation of OATT rates. In response to IR 31(a), LADWP refers to its response to IR 18(g) for the PDCI. The response to IR 18(g) addresses the LADWP shares of jointly-owned facilities, stating that only LADWP's share of plant ownership and operating costs is recorded in the accounting system of the Power System.

Response 18(g) does not discuss payments by other PDCI owners to LADWP for services provided by LADWP as Operating Agent, nor does it provide any answer to the question in IR 31(a). There is thus the possibility that LADWP's OATT rates are overstated by the lack of recognition of payments made to LADWP by other PDCI owners.

Q. Please describe your understanding of the financial relationship between LADWP and SCPPA.

A. SCPPA owns several transmission projects on behalf of SCPPA members, and LADWP provides services to SCPPA in support of at least some of these projects, as well as accounting services in general. Regarding SCPPA-owned projects, in response to IR 31(a), LADWP pointed to its response to IR 8(g), in which LADWP made various statements about SCPPA's accounting system, and then stated that (a) LADWP bills SCPPA monthly for costs incurred by LADWP under an agency agreement, (b) SCPPA participants "reimburse" SCPPA for these costs, (c) LADWP records such reimbursables not as "revenues" but as "receivables," (d) LADWP classifies costs associated with SCPPA "work orders" to the "appropriate receivable account," and (e) the relationship between LADWP and SCPPA is thus "revenue neutral" and no revenue credits are "applicable."[24] In response to IR 89(h), LADWP stated that "LADWP does not receive revenues from SCPPA for the services provided to SCPPA. LADWP is reimbursed for expenses incurred related to services provided to SCPPA, but such reimbursements do not exceed LADWP's costs, and never reside in a revenue account on LADWP's general ledger." The statement that reimbursements do not exceed LADWP's costs is irrelevant, as is the

[24] SCPPA is not a party to this proceeding, and thus LADWP's response to IR 89(a) is inappropriate.

statement that the reimbursements never reside in a "revenue account." If LADWP provides services to SCPPA and is reimbursed for such services, and if the costs of such services are also included in any of LADWP's OATT rates, then the reimbursements must be recognized as credits against such costs. The evidence suggests strongly that LADWP has not established a separate Fund for its relationship with SCPPA, and therefore it is not possible, based on the evidence in the record, to verify that all costs incurred on behalf of SCPPA are properly segregated from LADWP's OATT-related costs, or barring such segregation, that all reimbursements are fully recognized. This concern is reinforced by LADWP's responses to IR 89(i) and 90(b), which state that the information sought is "outside the scope of this proceeding." In any proceeding to establish rates based on costs, a complete understanding of the nature of those costs and the sources of any related revenues is *well within the scope of the proceeding*. In addition, LADWP's response to IR 89(n) states that "[i]f receivable amounts were left in GL account 125XXX at the end of the test year, they are [sic] collected in the subsequent year." If receivables were actually "collected" by LADWP, they may or may not be assignable to the test year as credits.[25]

Section 13: Revenue Requirements for Ancillary Services

Q. Has LADWP improperly included certain generation costs in the proposed ancillary service rates?

[25] The reference to GL account 125XXX in IR 89(n) and to JV 12-XXX46 and JV21-XXX02 in IR 90(b) raise further concerns about the opaque nature of the responses to requests for information about LADWP's accounting system. Without adequate explanation, the simple results of queries to any accounting system do not demonstrate anything.

A. Yes. We discuss above the incorrect assumption that certain generation units provide ancillary services. The costs of these units are incorrectly included in the proposed ancillary service rates. In addition, we have discovered that the revenue requirement for Schedule 6 has tripled since the 2014 proceeding. Given that other ancillary service revenue requirements are *not* tripling, we are unsure what the grounds for such an increase could be.

Q. Does LADWP properly account for the use of LADWP's ancillary services by LADWP's Wholesale Marketing group?

A. No. LADWP's Wholesale Energy Marketing group (a.k.a., "WERM" or "LAWM") is permitted to "self-supply" reserves under Schedules 5, 6 and 10 *without* complying completely with the requirements of LADWP's Business Practice(s) on self-supply or third-party supply. BPW/GWP-104 provides the Business Practices of LADWP regarding self-supply and third-party supply of operating reserves under Schedules 5, 6 and 10. See "Contingency_Reserves_Requirement.pdf" and "Products_Offerings_and_General_Business_Practices.pdf". LADWP's documentation of compliance with these posted Business Practices by LA-Merchant consists of the following statement: "[i]n response to (c)(ii), when LADWP-Wholesale Marketing self-supplies ancillary services it utilizes the resources it owns and controls." *See* IR 129(c)(ii). This is clear evidence of discrimination against OATT customers, who must comply with LADWP's Business Practices, and of rates under Schedules 5, 6 and 10 that are too high because they reflect no revenue credits from LA-Merchant. *See also* 16 U.S.C. § 824j-1(b)(1) ("the Commission may, by rule or order, require an unregulated transmitting utility to provide transmission services (1) at rates that are comparable to those that the unregulated transmitting utility charges itself. . . .").

Based on the Monthly Transfer Reports provided by LADWP in response to IR 109, we estimate that the "missing revenue credits" under Schedules 5 and 6 are approximately $4.34 million in the test year: over $3.97 million under Schedule 5 and over $362,000 under Schedule 6. *See* Table 3 in BWP/GWP-E-103. If LADWP (a) charges OATT customers under Schedules 5, 6 and 10, (b) monitors and imposes conditions on self-supply and third-party supply under these Schedules, but (c) allows LA-Merchant to self-supply without documentation or appropriate internal financial accounting, then the proposed OATT is *prima facie* discriminatory, and the proposed rates under these Schedules are too high, and thus unjust and unreasonable.

Q. Does LA-Merchant self-supply under Schedule 10 when making off-system sales?

A. The application of Schedule 10 to LA-Merchant is not addressed in LADWP's proposed OATT, which raises concerns about the potential for discriminatory application of terms and conditions, as well as potentially unjust and unreasonable rates. If LA-Merchant is exporting energy from the LADWP Balancing Area, LA-Merchant should either purchase Schedule 10 (presumably for dispatchable resources) or self-supply. To the extent that LA-Merchant (or any generator inside or outside the BA) self-supplies Schedule 10 service, certain protocols must be met. Two Business Practices are attached – the first covers Schedules 5 and 6 only and the second covers all ancillaries.

Schedule 10 requires dispatchable generators to pay 1.1% of the nameplate capacity of the generator supplying the export, unless the Contingency Reserves Requirement BP implicitly applies to Schedule 10 – which it does not explicitly. Schedule 10 requires the identification of a specific generator to an Interchange point, although we would expect LA-Merchant to make system sales at least part of the time. Because the Monthly Transfer Reports do not show which

generator was tagged or whether LA-Merchant was making system sales, we cannot calculate the appropriate charges for Schedule 10 exports by LA-Merchant, and thus we do not know the extent to which the Schedule 10 rates are too high. However, we do know that LA-Merchant did not pay for Schedule 10 service in the test year, at least according to the Monthly Transfer Reports. Absent compliance with the self-supply protocols for Schedules 5, 6 and 10, we conclude that LADWP is discriminating against non-LA generators who want to export from the BA. This is different from discriminating against non-LA OATT customers who want to schedule *into* or *through* the BA, and who would prefer to self-supply Schedules 5 and 6 (and perhaps other services).

Q. What costs included in ancillary service rate schedules should be segmented?

A. We are only able to provide a partial answer to this question, because of a lack of detail in LADWP's accounting systems. In the case of the STS/NTS, which we find should be segmented for transmission service, LADWP also incurs certain energy-related costs that are included in the revenue requirements for the ancillary services schedules. In the case of the PDCI and those SCPPA transmission assets for which LADWP provides operating services, there is insufficient information to determine which costs should be removed and/or which revenue credits (or similar) should be included.

Section 14: Undue Discrimination

Q. Does LADWP engage in discriminatory conduct?

A. Yes. <u>First</u>, LADWP allows LA-Merchant to avoid paying Schedules 5, 6 and 10 and does not require LA-Merchant to comply with posted Business Practices on self-supply. This

means that LA-Merchant has an advantage over other transmission customers when conducting business on the LADWP transmission network. LA-Merchant can avoid applying for self-supply status, monitoring by LA-Transmission, and compliance with self-supply protocols. This discrimination is compounded by the ability of LA-Merchant to avoid paying Schedule 3, but any LADWP load forecast errors are incorporated into Schedule 3 for non-LADWP OATT customers.

Second, the undocumented self-supply by LA-Merchant means that revenue credits to those rate schedules are too low, leading to unjust and unreasonable rates for transmission customers who *do* have to pay the rates those under those Schedules. *See e.g., Southwest Power Pool, Inc.* 127 FERC ¶ 61,247, at P 16 (2009), *citing Midwest Indep. Transm. System Oper. Inc.*, 106 FERC ¶ 61,293, at P 24 (2004).

Third, LADWP does not post the requisite data and calculations associated with ATC, which creates a disadvantage for transmission customers who can only accept LADWP's conclusions regarding the lack of ATC, without being able to confirm the accuracy and reasonableness of those conclusions.

Fourth, delivery of third-party supplies of ancillary services would require contractual agreements among the Cities, LADWP, and any third parties. Because LADWP *must* be a party to such arrangements, LADWP must treat the Cities as Native Load. LADWP's refusal to recognize the Cities as Native Load is discriminatory.

Fifth, as discussed at greater length in the following section, LADWP has proposed a "return-on-equity" and a capital structure that both deviate from the corresponding components of retail rates, and are based on assumptions and calculations that yield returns to restricted assets

that are greater than those available without OATT service. This proposal thus creates undue discrimination between LADWP's retail and OATT customers, in favor of the former.

Section 15: Return on Equity and Capital Structure

Q. What is the purpose of this section of your testimony?

A. In this section, we discuss the appropriate return on equity and capital structure for LADWP. This portion of testimony responds to Exhibits DWP-200 through DWP-205.

Q. Please briefly summarize your understanding of LADWP's proposal.

A. LADWP states that it has followed Opinion Nos. 531, 531-A, 531-B and 551 of the FERC, by developing a proxy group for application of the Discounted Cash Flow ("DCF") model normally used at FERC to set the returns on equity ("ROEs") for investor-owned utilities. *See* DWP-200, p. 3, lines 11ff.

Q. Have you reviewed FERC Opinion Nos. 531, 531-A, 531-B and 551?

A. Yes.

Q. What is your overall opinion of LADWP's approach?

A. We conclude that LADWP's approach is flawed, contains multiple errors, and is not consistent with FERC Opinions. LADWP's analysis deviates significantly from FERC Opinion Nos. 531, 531-A, 531-B, [26] and 551,[27] mainly because the proxy group in DWP-200 violates

[26] *Martha Coakley, e. al. v. Bangor Hydro-Electric Co.*, Opinion No. 531, 147 FERC ¶ 61,234 (2014), Opinion No. 531-A, 149 FERC ¶ 61,032 (2014), *order on rehearing* Opinion No. 531-B, 150 FERC ¶ 61,165 (2015).

[27] Assoc. of Businesses Advocating Tariff Equity, et. al. v. MISO, et. al., Opinion No. 551, 156 FERC ¶ 61,234 (2016).

FERC precedent. Accepting LADWP's ROE determination would also violate the *Hope* and *Bluefield* standards, which establish that a just and reasonable ROE will be no higher than what is required to maintain LADWP's financial integrity, permit LADWP to raise sufficient capital, and permit it to achieve a return commensurate with the returns earned by utilities of comparable risk.[28]

Q. LADWP uses a discounted cash flow ("DCF") analysis in this proceeding. Is the DCF appropriate for a non-investor owned utility like LADWP?

A. Potentially, but only if the required conditions are met. FERC has accepted the use of a DCF for non-investor owned utilities. *See City of Vernon*, 109 FERC ¶ 63,057 (2004), *affirmed City of Vernon*, Opinion No. 479, 111 FERC ¶ 61,092 (2005). However, as discussed in more detail below, a proxy group of *comparable* risk utilities is required for the DCF methodology to properly identify a just and reasonable ROE. LADWP's superior bond rating prevents the creation of a proxy group that conforms to FERC precedent or reflects risk profiles comparable to that of LADWP. As a result, we believe a strict application of the DCF methodology does not identify a just and reasonable ROE as interpreted by LADWP. For the reasons addressed below, should the DCF methodology be used in this proceeding, LADWP's ROE must be set at the low end of the identified zone of reasonableness, yielding an ROE of *no more than* 7.04%.

Q. Does LADWP put forward a DCF analysis that is consistent with FERC precedent?

[28] Bluefield Waterworks and Improvement Co. v. Public Serv. Comm'n of West Virginia ("Bluefield"), 262 U.S. 679, 692 (1923); Fed. Power Comm'n v. Hope Natural Gas Co. ("Hope"), 320 U.S. 591, 603 (1944).

A. No. As discussed in detail below, LADWP's DCF does not follow FERC precedent. Specifically, LADWP's DCF proxy group includes utilities that are significantly more risky than LADWP. This results in a proxy group with ROEs that are skewed upward, because as the financial risk of an investment increases, so does the rate of return investors will require. Therefore, LADWP's proxy group as a whole produces a DCF range that reflects the higher returns investors require for these more risky utilities, and not the return investors would require for a utility like LADWP, were LADWP an investor-owned utility.

Q. Is there precedent on the importance of identifying utilities of comparable risk?

A. Yes. The Supreme Court has made it clear that a just and reasonable return is "commensurate with returns on investments in other enterprises having corresponding risks."[29] Comparable risk is a critical consideration because the Supreme Court has recognized that a utility "has no constitutional right to profits such as realized or anticipated in highly profitable or speculative ventures."[30]

Q. How has FERC reflected this precedent in its DCF methodology?

A. FERC has established criteria for compiling a proxy group that is intended to produce a group of utilities similarly situated to the target utility, *i.e.*, the utility whose ROE is being evaluated. As a result, FERC uses the following standards to select the proxy group: (1) a national group of companies considered electric utilities by Value Line Investment Survey ("Value Line"); (2) the inclusion of companies with credit ratings no more than one notch above

[29] *Hope*, 320 U.S. at 603.

[30] *Bluefield*, 262 U.S. at 692-93.

or below the utility or utilities whose rate is at issue; (3) the inclusion of companies that pay dividends and have neither made nor announced a dividend cut during the six-month study period; (4) the inclusion of companies with no major merger activity during the six-month study period; and (5) companies whose DCF results pass threshold tests of economic logic.[31]

Q. Does LADWP's proxy group satisfy these conditions?

A. No. LADWP was unable to apply one essential criterion of FERC Opinions No. 531 *et al.*, which requires the identification of a potential proxy group including "companies with bond ratings a notch above or below Power System's ratings." *See* DWP-200, page 3, lines 18-20. Power System's bond rating from Moody's is Aa2, and its rating from S&P is AA- (*see* DWP-200 at page 3, line 17), resulting in a Moody's one notch bandwidth of Aa1 to Aa3, and an S&P one notch bandwidth of AA to A+.[32] However, LADWP asserts that the highest ratings for utilities covered by Value Line is A3/A-. (DWP-200 at page 3, line 20-21). As a result, LADWP's proxy group is composed of utilities that are all *three* notches below the bottom of the Moody's Aa3 credit bandwidth, and *two* notches below the bottom of the S&P A+ credit bandwidth, which represents an increase in financial risk relative to LADWP. *See* DWP-200, page 3, lines 20-21.[33] This increase in financial risk is particularly concerning because most

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[31] Opinion No. 551, at P 17.

[32] DWP-200 states that the "relevant bond rating range is A1/A+ to Aa1/AA+." DWP-200 at page 3, line 18. This is incorrect. One notch above LADWP's Aa2/AA- rating is Aa1/AA+, and one notch below LADWP's Aa2/AA- rating is Aa3/A+. Therefore, we have identified the credit rating bandwidth that follows FERC precedent.

[33] Proxy groups based on screening with a greater number of total notches are allowed by FERC *if* the target is a *group* of utilities, rather than just one utility, and the group has a range of credit ratings. See, *e.g.*, Opinion 531, at PP 106-108. That is not the case here.

proxy groups would be composed of utilities with credit ratings one notch above that of the target utility, and utilities with identical credit ratings to the target utility. LADWP's proxy group lacks this diversity entirely.

Q. Did LADWP nonetheless use a proxy group that fails to meet FERC precedent?

A. Yes. LADWP tried to get "as close as possible to Power System's bond rating," which yielded 19 companies. *See* DWP-200, page 4, lines 1-5. We are not aware of any FERC standard that allows "as close as possible" when the resulting (initial) proxy group has bond ratings that are *several* notches *below* the utility whose ROE is at issue. DWP-200 concluded that 19 utilities belong in the initial proxy group. DWP-200, page 4, lines 1-5. However, "as close as possible" could mean "A3 *and* A-", instead of "A3 *or* A-", which would yield an initial proxy group of six utilities (Alliant, ConEd, OGE, Pinnacle West, WEC, and Xcel, based on DWP-202), rather than nineteen.

Q. Did LADWP make any adjustments to take into account the fact that the initial proxy group did not meet FERC's first criterion related to bond ratings?

A. No. See LADWP's response to IR 52(a).

Q. Does this lack of adjustment bias LADWP's results?

A. Yes. Without an explicit adjustment that takes into account the several-notch gap between the bond ratings of LADWP's proxy group and LADWP, the natural result of the DCF analysis will be an *overstatement* of the cost of capital to LADWP, because LADWP's superior credit rating will be ignored. This overstatement of the cost of the non-debt portion of LADWP's weighted average cost of capital ("WACC") is compounded by the use of an equity-

heavy hypothetical capital structure, which, as discussed below, violates FERC precedent and is both inappropriate and incorrect.

Q. Did LADWP apply the FERC standard study period for his DCF analysis?

A. No. In Opinion 531, FERC stated that "[o]ur general policy has also been to base the zone of reasonableness on the most recent financial data in the record." (P 64, footnote omitted). In this case, LADWP chose a six-month period running from September 1, 2015 through February 29, 2016. LADWP has also stated that "[a]t the time the DCF analysis was performed, the six-month period ending February 2016 was the most recent six-month period available." See the response to IR 51. This is both factually incorrect and a violation of FERC precedent. FERC requires that the DCF analysis use the *most recent* six-month period available. Exhibit DWP-200 was dated January 6, 2017, making the most recent six-month period available July 1, 2016 through December 31, 2016. LADWP's DCF analysis should have been updated to incorporate this more recent financial data.

Q. Why is the use of the most recent financial data important?

A. There are two reasons. First, a just and reasonable ROE will change over time as market conditions change. For this reason, the Supreme Court has warned that a return "may be reasonable at one time and become too high . . . by changes affecting opportunities for investment, the money market and business conditions generally."[34] Second, any identified ROE will be applied on a going forward basis, making it vitally important that the determination be based on the most recent financial data available. FERC has noted that the use of current data is

[34] *Bluefield*, 262 US at 693.

"particularly critical" to ROE determinations which are "particularly volatile" due to the ever changing nature of capital market conditions.[35]

Q. Did LADWP apply FERC's criterion that excludes utilities that were engaged in mergers or acquisitions during the test period?

A. Yes, but with incorrect analysis and results. FERC precedent requires the exclusion of any utility engaged in major merger activity during the study period. (Opinion 551, at P 17). As an initial concern, LADWP's DCF does not use the appropriate study period, making it difficult to assess which proxy group members were or were not engaged in major merger activity during the correct study period. However, setting that issue aside, we have concerns with LADWP's application of FERC's merger screen. LADWP properly excluded ITC Holdings, Inc. due to an announcement on November 30, 2015, during the test period. DWP-200, page 4, lines 6-9. However, LADWP concluded that Duke, NextEra Energy and Southern Company did not need to be excluded, despite merger activity that impacted the DCF inputs during the study period. In the case of Duke's purchase of Piedmont Natural Gas, LADWP concluded that the announcement on October 26, 2015 "had minimal impact on Duke Energy's common stock price." DWP-200, page 4, lines 10-12. This is an insufficient justification for including Duke. FERC precedent requires exclusion from the proxy group of any utility engaged in merger activity that is "significant enough to *distort* the DCF inputs". *See* Opinion No. 551, at P 37

[35] *Consumer Advocate Div. of the Pub. Serv. Comm. of West Virginia v. Allegheny Generating Co.*, 68 FERC ¶ 61,207, 61,998 (1994). Also, DWP-200 states that the DCF analysis used the high and low intra-monthly share prices of the members of the proxy group. LADWP apparently erred in extracting data from *Yahoo Finance* for four utilities in five months. Table 5 in BWP/GWP-E-103 shows these errors, the correction of which does not change our conclusions here.

(emphasis in original), Opinion No. 531, at P 114. Stock price is a DCF input, so by LADWP's own admission Duke's purchase of Piedmont Natural Gas had an impact on Duke's stock price. Even a "minimal" distortion triggers the Commission's merger screen, and Duke should be excluded from the proxy group.

In the case of NextEra and Southern Company, LADWP concluded that the announcements occurred prior to the study period, which was sufficient reason to determine that this merger activity did not distort any DCF input during the study period. DWP-200, p. 4, lines 14-21. This position illustrates a fundamental misunderstanding of both how financial markets react to mergers and acquisitions and FERC's merger screen. The fact that an announcement occurred outside of the study period is not enough to conclude that the merger did not distort DCF inputs. First, announcing a merger is just the first step in the merger or acquisition process. The market continues to arbitrage the likelihood of success of the merger or acquisition as it progresses through the regulatory approval process. Therefore, it is entirely inappropriate to limit the examination to when a merger was announced. In the case of Southern Company, while the transaction was announced prior to the study period, the merger was not consummated until July 1, 2016, meaning that this was a merger actively proceeding through the regulatory approval process during LADWP's study period for this proceeding. *See* DWP-202. Similarly, NextEra's attempt to acquire Hawaiian Electric failed after the Hawaii Public Utility Commission rejected the deal on July 18, 2016. *See* DWP-202. As a result, this transaction was certainly active during LADWP's study period and the market continued to react to news that influenced investor opinions on whether the transaction would succeed or fail.

Further, the impact of a merger announcement can be "baked" into the stock price that is reflected in the study period. For example, LADWP testifies that Southern Company's stock fell by 4.85% when it announced its proposed purchase of AGL Resources. *See* DWP-200 at page 4, line 20. LADWP provides no evidence to show that Southern company's stock price rebounded prior to the study period, and engaged in no inquiry as to whether or not the prospect of the success or failure of the merger continued to distort the stock price or other DCF inputs during the study period. LADWP's failure to consider or examine whether or not Southern Company's or NextEra's merger activity distorted the DCF inputs violates FERC precedent, and therefore does not support their position that these utilities should be excluded from the proxy group. We conclude that Duke, NextEra, and Southern Company should all be excluded from the proxy group due to their merger activity.

Q. Did LADWP consistently use data from the proxy group on <u>actually paid or "indicated" dividends</u> during the chosen test period?

A. No. LADWP used a mixture of (a) "actually paid" dividends, (b) dividends that were paid outside the test period, and (c) dividends that were announced in one month but paid in another month during the test period. *See* DWP-200, page 5, lines 7-9. We have no concerns about dividends that were announced and paid during a given month of the test period; that is consistent with our understanding of P 77 of Opinion 531. However, a dividend for ALLETE, Inc. was announced or declared in January 2016 (inside the test period) but not paid until March 2016 (outside the test period). We asked LADWP for the justification for including ALLETE's March 2016 dividend, but received no response from LADWP. *See* IR 58(c). In contrast, see

"Allete, Inc. Dividend Date History – NASDAQ" in BWP/GWP-E-104. Including ALLETE's March 2016 dividend violates Opinion 531.

Q. What zone of reasonableness does LADWP identify as a result of its application of the DCF methodology?

A. DWP-205 shows a zone of reasonableness based on the DCF approach of 7.04 percent to 9.65 percent. We have concluded that Duke, Southern Company, and NextEra should be excluded from the proxy group identified in DWP-205 on the basis of those utilities' merger activities. However, the exclusion of these utilities does not alter the outer bounds of the identified zone of reasonableness.

Q. Given that LADWP's credit rating is higher than any member of the proxy group, how would you apply the results of the LADWP DCF analysis?

A. Given the multi-notch gap between the proxy group and LADWP, we conclude that LADWP's ROE should be set at the low end of the identified zone of reasonableness, yielding an ROE of no more than 7.04%. *Hope* and *Bluefield* require that a just and reasonable ROE be one that is "commensurate with returns on investments in other enterprises having corresponding risks."[36] As discussed above, LADWP's superior credit ratings are not reflected in the proxy group that LADWP has put forward in this proceeding. As a result, the zone of reasonableness produced by LADWP's DCF analysis has a significant upward bias because it reflects the ROE that investors require for utilities that are two to three credit rating notches below LADWP. FERC has recognized that under certain circumstances a "mechanical application" of its DCF

[36] *Hope*, 320 U.S. at 603.

methodology will not satisfy FERC's obligation to ensure that identified ROEs be set at a level sufficient to attract investment.[37] Further, as the Commission found in Opinion 531-B, "[n]ot every ROE within that relatively broad DCF 'zone of reasonableness' is a just and reasonable ROE for the particular public utility or utilities at issue." Opinion 531-B, at P 25.

As a result, while FERC generally requires that the ROE be set at the median of the zone of reasonableness, it also examines the riskiness of the proxy group as compared to the target utility to ensure a just and reasonable ROE.[38] Here, the proxy group is composed of utilities facing significantly more risk than LADWP, which justifies selection of the *lowest* value in the zone of reasonableness. Selecting the low end of the zone of reasonableness partially adjusts for the fact that LADWP is significantly less risky than the proxy group. Therefore, if we were to apply the DCF model, 7.04 percent would be the maximum recommended return-on-equity. This ROE would more accurately reflect the measure of the investment communities' likely current risk assessment of LADWP.

Q. Are there additional factors that necessitate setting the ROE at a maximum of 7.04 percent?

A. Yes, LADWP has made no adjustment in recognition of Moody's April 2016 announcement regarding the Power System Revenue Bonds, which noted LADWP's "continued ability to pass through about 50% of costs that can be automatically passed through to customers

[37] *See e.g.* Opinion No. 531, at P 150.

[38] *Portland Natural Gas Transmission Sys.*, 142 FERC ¶ 61,197, at P 381 (2013) (FERC "has recognized that an examination of the risk factors specific to a particular pipeline [or electric utility] may warrant setting its ROE either higher or lower than the middle of the zone of reasonableness established by the proxy group").

without governing board action, a decoupling mechanism, an elimination of certain caps and a new power access and tier rate structure provide positive changes including . . . revenue certainty."[39] This ability to pass through costs automatically was in existence during the test year (see the KPMG audit discussed *infra*). LADWP has also admitted in testimony that retail "customers who aren't going anywhere are effectively assigned the vast majority of the business and financial risk associated with Power System's low net position ratio." *See* DWP-200, page 8, lines 5-8. If retail customers bear "the vast majority . . . of the risk" of the Power System, then DWP-200 overstates the risks associated with OATT service. See BWP/GWP-E-104, "Moody's April 2016 on LADWP.pdf".

Q. What risks can be passed directly through to LADWP's retail power customers?

A. According to http://www.myladwp.com/2016_2020_rate_request, retail power customers currently face three "pass-through adjustment factors":

> **Power access charge:** This proposal recommends a consumption-based charge to be connected to the power grid. The goal is to ensure that all customers contribute to the fixed costs of operating the power system in proportion to the amount of power they use.
> **Infrastructure reliability:** The infrastructure pass-through factor will support ramping up replacement of aging power equipment. To protect customer costs, the reliability adjustment includes an annual cap and only collects for expenses that have been incurred.
> **Restructuring for conservation- "decoupling":** The power rates will be restructured to encourage conservation while maintaining appropriate revenues.
> **Rebalancing:** The power rates will be rebalanced among customer sectors, based on the recently completed Cost of Service Study.

The KPMG audit, discussed below, expands on this list.

[39] See BWP/GWP-E-104.

Q. Do these adjustment factors help LADWP maintain its credit rating?

A. Yes. As Moody's noted in April 2016, LADWP's retail customers bear "the vast majority . . . of the risk" of the Power System. Thus, these retail adjustment provisions *are* relevant to LADWP's credit rating, and thus to the appropriate return-on-equity and WACC in this proceeding.

Q. Have these adjustment factors been recognized by auditors of LADWP's Power System?

A. Yes. KPMG's report on FY2014-15 (at pages 24-25) notes seven "pass-through factors". *See* BWP/GWP-101, IR89.g.1. The combination of all of these factors was described by KPMG as follows: "[e]ffectively, the Department is *assured its revenue requirement* to operate the Power System."

Q. Did LADWP make any adjustments to the calculation of capital costs in recognition of this assurance, as described by KPMG?

A. No.

Q. Did LADWP calculate a "net position" for LADWP's Power System?

A. Yes. *See* DWP-200, p 7, lines 2-3 and Table 1.

Q. What is the source of LADWP's "net position"?

A. The net position used in DWP-200, $5,415,775,000, can be found in the response to IR 49(a), page 16 of the KPMG report on the test year.

Q. Is LADWP's net position analogous to the equity component of an investor-owned utility's capital structure?

A. Not exactly. The equity component of an investor-owned utility's capital structure reflects choices made by investors in stock markets to take on certain risks of the utility, as well

as decisions by management of the company under rate-of-return regulation. An allowed return-on-equity in combination with debt proceeds, is designed to permit sufficient equity capital to be "attracted" to the utility to cover capital requirements. Investors *require* a return in order to be induced to invest. As FERC stated in Opinion 531-B, "to estimate the return necessary to attract equity investors, the Commission uses the DCF model, which identifies a zone of reasonable returns." Opinion No. 531-B, at P 17. The allowed ROE for an IOU may be calculated via DCF. The application of DCF to a municipal utility is problematic at best.[40]

Q. Did LADWP use LADWP's actual capital structure to calculate a WACC?

A. No. LADWP concluded that its actual capital structure was inappropriate, because "there is more financial risk in Power System's capitalization than there is in the proxy group companies." See DWP-200, page 7, lines 9-10 and Table 1. This conclusion violates FERC's preference to use *actual* capital structures. Further, any argument that LADWP is somehow riskier than the proxy group cannot be reconciled with the fact that the proxy group includes *only* utilities that are two and three credit ratings *below* LADWP, and is ultimately refuted by Moody's credit report and the KPMG audit discussed above. Finally, the "risk in Power System's capitalization" must take into account the multiple retail rate adjustment clauses, which

[40] Opinion 479-A (¶9) addresses the application of the DCF model to a non-investor-owned utility. "On the issue of Vernon's rate of return and return on equity, the Commission concluded that that the Discounted Cash Flow (DCF) model for a non investor-owned entity such as Vernon is appropriate. The Commission explained that although Vernon does not have securities that are traded in the marketplace, companies with similar bond ratings can and do serve as an appropriate proxy for Vernon's cost of common equity. Additionally, Opinion No. 479 stated that Vernon's bond rating should be used as a basis to develop a group of proxy companies that have a similar level of risk." 112 FERC ¶61,207, Docket Nos. EL00-105-008 and ER00-2019-016, Order on Rehearing, August 23, 2005. However, that opinion does not apply to LADWP because there are *no* companies with "similar bond ratings" and a "similar level of risk" that can serve as proxies for LADWP.

help ensure the collection of LADWP's fixed costs. LADWP's approach to capital structure ignores the risk mitigation that these adjustment clauses generate.

Q. Did LADWP provide support for this comparison of financial risk?

A. No. DWP-200 ignored LADWP's numerous retail rate adjustment factors, which alleviate *both* financial *and* operating risk.

Q. Which hypothetical capital structure did LADWP use?

A. LADWP created a hypothetical structure based on the non-standard proxy group. LADWP combined the holding company preferred and common equity stated in DWP-200, Table 1, to create an "average holding company capital structure" of 48 percent common equity and 52 percent long-term debt. See DWP-200, page 8, lines 15-18.

Q. Is this conclusion consistent with FERC precedent?

A. No. FERC *rarely* allows the use of a hypothetical capital structure for investor-owned utilities, although FERC does allow a wide range of *actual* capital structures.[41] As far as we are aware, in only one case has FERC allowed a municipal utility to use a hypothetical capital structure. In a 2004 Initial Decision, the City of Vernon was allowed to use a hypothetical capital structure. See *City of Vernon*, Initial Decision, 109 FERC ¶ 63,057, at P 111 (2004) ("Vernon Initial Decision"). The Initial Decision was upheld in *City of Vernon*, Opinion 479, 111 FERC ¶ 61,092 (2005).

[41] *See e.g. Ky. W. Va. Gas Co.*, Opinion No. 7, 2 FERC ¶ 61,139, 61,325 (1978) ("A just and reasonable rate of return must be related to the capital structure of the regulated firm. The first choice is to use the actual capital structure of the firm being regulated."); *Transcontinental Gas Pipe Line Corp.*, Opinion No. 414-A, 84 FERC ¶ 61,084 (1998); *Bus. Advocating Tariff Equity v. MISO*, 149 FERC ¶ 61,049 at PP 190-99 (2014).

Q. Is the Commission's Opinion regarding the City of Vernon relevant to LADWP as it relates to capital structure?

A. No. The discussion in the Initial Decision shows that the factual and regulatory circumstances of Vernon differ significantly from those of LADWP. Even though both Vernon and LADWP are entities that do not issue common stock, Vernon is very different from LADWP. First, Vernon "financed its transmission facilities with cash." Vernon Initial Decision, *Id.* at P 111. Vernon did not finance the facilities at issue with tax-exempt debt or bonds. *Id.,* at P 115 and 119. In contrast, LADWP's cost-of-service study demonstrates that debt is a component of LADWP's transmission capital structure. LADWP's cost-of-service study shows no cash financing of OATT transmission facilities, so LADWP's and Vernon's sources of funds are very different. DWP-104, Tab AV. Second, Vernon relied on a return on equity "sufficiently high to fund future construction." *Id.,* at P 112. LADWP does not, to our knowledge, rely on a return on equity to fund future transmission construction. Third, Vernon pointed specifically to Southern California Edison ("SCE") as the foundation for its return on equity, *based on a FERC mandate. Id.,* at P 113. There is no FERC mandate covering LADWP's rates. Fourth, the evidence in the record at FERC established that "Vernon's risk profile was not likely to have been significantly different from that of Southern California Edison in 1999". *Id.,* at PP 113-124. The Commission found that Vernon was *riskier* than the proxy group but *similar in risk* to SCE. LADWP's testimony in this proceeding demonstrates that the bond ratings of the proposed proxy group are several notches lower than LADWP's, which means that LADWP's risk profile is *not* similar to the proxy group. The proxy group cannot be used to establish a hypothetical capital structure. Finally, Vernon's Transmission Revenue

Requirement was subject to a "Section 205 like review"; LADWP has not received such a review by the Commission, and has not received a determination by the Commission that its current rates are just and reasonable. *Id.*, at P 127.

Q. What is the result of applying the hypothetical capital structure that LADWP proposes?

A. In this instance, developing and using an equity-heavy hypothetical capital structure increases the Weighted Average Cost of Capital ("WACC") compared with using LADWP's calculation of its actual capital structure; the hypothetical capital structure does not actually use LADWP's "net position" in combination with long-term debt. The hypothetical capital structure thus compounds the error associated with using the incorrect proxy group.

Q. Are you familiar with the use of hypothetical capital structures in the calculation of retail electric rates?

A. No. Retail rates for municipal utilities are normally based on actual debt service requirements plus a "pay-as-you-go" (or "pay-go") amount for some capital investments.

Q. Is "pay-go" appropriate for setting OATT rates?

A. No. OATT customers do not have any long-term "ownership" claim on the assets purchased with "pay-go" capital contributions, some of which are outside the transmission and ancillary service functions in any event. Furthermore, FERC permits the payment by OATT customers of capital costs only in certain circumstances, where a *specific* request for transmission service cannot be filled without system modifications. FERC does not permit general "pay-go" capital amounts in filed OATT rates that are based on embedded costs. LADWP has therefore created a significant inconsistency between its retail and OATT rates, which raises questions of potential discrimination. *See e.g., Southwest Power Pool, Inc.* 127

FERC ¶ 61,247, at P 16 (2009), *citing Midwest Indep. Transm. System Oper. Inc.*, 106 FERC ¶ 61,293, at P 24 (2004).

Q. What is your understanding of the capital component of LADWP's retail rates?

A. LADWP's FY14-15 retail power rates include a "pay-go" component that represents 15 percent of operating revenues. See http://www.myladwp.com/2016_2020_rate_request.

Q. Is LADWP's analysis sufficient to conclude that no cross-subsidies exist between LADWP's retail and OATT customers? (See DWP-200, page 3, lines 4-8.)

A. No. LADWP has not provided any information on its retail rates in this proceeding. See also LADWP's response to IR 50(a) (no documentation was relied on to ensure a lack of cross-subsidies).

Q. In your opinion, has LADWP provided a complete and accurate comparison of LADWP's retail and OATT rates, to demonstrate the lack of cross-subsidies?

A. No. LADWP has presented no data on retail rates, so there is no evidence in the record regarding cross-subsidies. LADWP has also stated that "[q]uestions about LADWP's retail rates are outside the scope of this proceeding," notwithstanding the statements in DWP-200 about cross-subsidies. *See* IR 50(b). It is not possible to determine that Customer Class A is or is not cross-subsidizing Customer Class B if the record only contains information about Customer Class A.

Q. How should LADWP's capital structure be established for this proceeding?

A. DWP-200 reports an "actual" capital structure consisting of a 40.19 percent "net position" and 59.81 percent long-term debt. *See* DWP-0200, Table 1. This calculation is based on a combination of data from issued bond series and a net position reported by KPMG. There

are two problems with this calculation. First, the "net position" includes assets that are "restricted" for various reasons, according to KPMG. Such restrictions limit the types of investments available for these assets, which in turn lowers their return. The City of Los Angeles (a.k.a., LADWP's "investor") should not be permitted to use OATT service to earn indirectly a return on restricted investments that is not available to the City directly. Restricted assets should be removed from "net position." Second, KPMG reports a different amount for long-term debt, on the same page where "net position" is reported. We have used KPMG's report of the amount of outstanding long-term debt, because it was audited, rather than the calculated amount in DWP-200. Table 4 in BWP/GWP-E-103 shows the resulting actual capital structure that is appropriate for this proceeding: 66.42 percent long-term debt and 33.58 percent "equity" or "unrestricted net position."

Q. What is your overall conclusion about the correct component of return-on-equity and the resulting WACC in LADWP's proposed OATT rates for transmission and ancillary services?

A. We conclude that LADWP's approach contains several significant flaws and should not be adopted as proposed. Furthermore, LADWP's approach is inconsistent with both FERC precedent and the standard approach for setting retail rates. As we have discussed above, LADWP's superior credit rating makes it difficult to apply FERC's DCF methodology in this proceeding. However, if the DCF methodology *is* used, the appropriate ROE for LADWP is at most 7.04%, which represents the low end of the identified zone of reasonableness. In combination with the correct capital structure, this ROE yields a Weighted Average Cost of Capital (WACC) of 4.48 percent, or 129 basis points below LADWP's proposal.

Section 16: Interest on Deposits

Q. What is the purpose of this section?

A. LADWP inappropriately requires customers to pay interest on delinquent amounts, while eliminating any obligation for LADWP to pay interest on amounts that customers deposit with LADWP pursuant to OATT Sections 17.3, 17.4, 17.6, 19.1, 19.4, and 20.3. LADWP should adopt a reciprocal obligation, and pay interest on OATT customers' deposits. LADWP's proposal violates FERC's policy that requires payment of interest on deposits or study costs that are ultimately refunded to interconnection customers. *See Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, FERC Stats. & Regs. ¶ 31,146, at P 123 (2003), *order on reh'g*, *Order No. 2003-A*, FERC Stats. & Regs. P 31,160, *order on reh'g*, *Order No. 2003-B*, FERC Stats. & Regs. ¶ 31,171 (2004), *order on reh'g*, Order No. 2003-C, FERC Stats. & Regs. ¶31,190 (2005), *aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC*, 475 F.3d 1277, 374 U.S. App. D.C. 406 (D.C. Cir. 2007), *cert. denied*, 552 U.S. 1230, 128 S. Ct. 1468, 170 L. Ed. 2d 275 (2008); *see also Midwest Indep. Transmission Sys. Operator, Inc.*, 138 FERC ¶ 61,233, at PP 166-168 (2012) (rejecting MISO's proposal to eliminate the payment of interest on refunded portions of generator interconnection study deposits); *Midwest Indep. Transmission Sys. Operator*, 142 FERC ¶61,215 (2013) (directing MISO to revise its Tariff so that interest will be paid on any refunded portion of the deposit that a transmission developer submitted with its bid).

Q. Does this conclude your testimony?

A. Yes.