BEFORE THE CITY OF LOS ANGELES
DEPARTMENT OF WATER AND POWER

2017 Reform of Electric Transmission Tariff
and Electric Transmission Rates

BRIEF

OF

THE CITIES OF BURBANK AND GLENDALE, CALIFORNIA
DEPARTMENTS OF WATER AND POWER

April 14, 2017

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The City of Burbank, California's Department of Water and Power ("Burbank" or "BWP") and the City of Glendale, California's Department of Water and Power ("Glendale" or "GWP") (collectively the "Cities") submit this Brief in response to the City of Los Angeles, California's Department of Water and Power's ("LADWP") 2017 Reform of Electric Transmission Tariff and Electric Transmission Rates ("Tariff Update"), pursuant to the "Revised Schedule Updated March 7, 2017" for the LADWP Tariff Stakeholder process ("Stakeholder Process") and §10.(b) of LADWP's Business Practice on "Procedures for Public Participation in Tariff Changes for the Department of Water and Power of the City of Los Angeles" ("Tariff Changes BP").

I. EXECUTIVE SUMMARY

The Cities are municipal utilities embedded within LADWP's system. As a result, they are dependent on transmission service from LADWP to provide reliable electric service to their residents and businesses. For years the Cities have relied on long-term transmission service contracts with LADWP to meet their transmission needs. Those existing contracts, however, are expected to be unable to satisfy the Cities' transmission requirements in the future. Under longstanding FERC precedent and FPA Sections 211, 212 and 211A, LADWP has an obligation to provide the Cities, and other Tariff customers, transmission service (1) at rates that are just, reasonable and comparable to rates under which LADWP provides transmission service to itself and (2) on terms and conditions that are just, reasonable and comparable to which LADWP provides itself and that are not unduly discriminatory or preferential.[1/] Despite these established

[1/] *Iberdrola Renewables, Inc., et. al. v. Bonneville Power Administration*, 137 FERC ¶ 61,185, P 32 (2011).

standards, LADWP's Tariff Update fails to offer the Cities transmission service in compliance with these obligations.

The Cities submit this brief because they have serious concerns about: (1) the Tariff Update process; (2) certain terms and conditions within Tariff itself; and (3) the proposed rates resulting from the Tariff Update. With regard to the Stakeholder process, the Cities acknowledge that the process was better than the process provided in 2014. However, the process continues to fall far short of both industry practice and what is expected at the Federal Energy Regulatory Commission ("FERC"). Stakeholders were provided only approximately 60 working days to review and comment on the materials. This is an unreasonably limited amount of time to conduct discovery and prepare of testimony. LADWP compounded this issue by asserting claims of privilege over necessary information, responding late or not responding at all to discovery requests, and drafting several responses in a manner that required follow-up to achieve clarity and receive requested documentation. LADWP's use of its consultants to shield it from answering certain information requests is of particular concern. This happened on numerous occasions when the Cities requested information that was critical to determining if LADWP's proposal was justified. Together, these factors resulted LADWP's failure to provide the Cities the information they needed to fully understand and analyze LADWP's various proposals. LADWP must provide adequate time and answers to Stakeholders if it wants them to accept its Tariff Updates. Without this, the Stakeholders cannot rely on this process to address their concerns. LADWP's process and behavior does not meet industry standards, nor does it satisfy the FERC's requirements. For these reasons, we recommend the General Manager

suspend the process until the Cities can conduct proper discovery to fully understand the issues present.

With regard to the concerns raised by the terms and conditions of the proposed Tariff, the Cities are again (like in 2014) concerned about the Tariff's failure to adequately prevent undue discrimination and to fully explain and justify LADWP's calculation of Available Transmission Capacity ("ATC"). LADWP contends that it avoids discrimination by treating the "LADWP Wholesale Energy Resource Management ("WERM") group" the same way that it treats other entities. However, it has not provided support for this claim. Instead, the evidence the Cities have uncovered suggests that WERM does not pay for the same ancillary services as other Tariff customers. This clearly provides WERM a competitive advantage over the Cities' generators when they use LADWP Tariff service to make sales. LADWP should rectify this undue discrimination by applying the same rates, terms and conditions for transmission to others that it applies to WERM and the generators that it uses to make sales.

The Cities have found that the Tariff Update also overstates the purchase obligation for Ancillary Services and includes Real Power Loss Factors that are both outdated and inaccurate. Further, LADWP has failed to fully explain and adequately justify how it ATC. Without such an explanation and justification it is impossible for the Cities to determine if they are receiving open and transparent access to the LADWP transmission system. Finally, the Tariff Update requires Tariff customers to pay interest on a variety of fees and costs but does not require LADWP to pay interest on deposits that customers make to it. This asymmetrical treatment of customers violates FERC precedent and industry practice. These issues, along with others detailed below,

demonstrate that the terms and conditions of the Tariff must be modified before the Tariff Update is implemented.

With regard to the Tariff rate issues, the Cities have uncovered numerous problems with the Tariff Update's Cost-of-Service Study ("COSS") and the associated proposed Tariff rates. LADWP proposes to use a 12 coincident peak ("CP") divisor to calculate its rates, even though it is a summer peaking utility. Under longstanding FERC precedent and industry standards, it is incorrect for LADWP to use a 12 CP divisor. Instead, LADWP should be using a 1 CP. The Return on Equity ("ROE") and the associated capital structure used in the COSS are equally flawed in their disregard for FERC precedent and industry standards. The proposed Tariff rates also improperly account for Native Load, inappropriately include the costs of transmission facilities that are not integrated into the LADWP system, and incorrectly charge Tariff customers ancillary services rates for facilities that cannot and do not provide ancillary services. The proposed Tariff rates also fail to properly account for and document offsetting sources of income, revenues, receivables, and other credits that would help reduce OATT rates and rely on a return on equity that is inconsistent with FERC precedent.

Together, these defects in the COSS and rate calculations cause LADWP's proposed Tariff rates to be dramatically overstated in direct contravention of the principle of cost causation. The Cities respectfully request that LADWP either suspend the process until the issues raised herein by the Cities are resolved, or adopt each of proposals presented in this Brief and the Cities' testimony that resolve these issues, in LADWP's General Manager's Certification ("GM Certification"), pursuant to §10.(b) of the LADWP Tariff Changes BP.

II. BACKGROUND

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

The Cities 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"). 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.

In the future, both BWP and GWP will 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. Therefore, it is vital that LADWP fix the problems with its Tariff Update, identified in this Brief, so that the Cities can get transmission service and ancillary services under the LADWP Tariff at rates on terms and conditions that are just, reasonable, not unduly discriminatory and comparable to rates, terms and conditions, which LADWP provides to itself.

III. ARGUMENT

A. Process Concerns

The Stakeholder process and the associated information request process developed and implemented by LADWP for the Tariff Update failed to comport with industry standards or FERC precedent. The duration of the entire public process was January 19 through April 14, 2017, which is merely 86 calendar days or 60 business days. If this proceeding were held at FERC, a tariff update that included the magnitude of changes proposed here by LADWP, would have been afforded double or triple the amount of time that LADWP allotted. Sixty normal working days is an unreasonably short period for a Tariff Update of this size.

During the process, the Cities worked with LADWP staff, outside counsel and consultants to modify and slightly extend the schedule, however, those extension were not sufficient to provide the Cities the requisite time they needed to analyze and conduct discovery on the Tariff Update. The unreasonably truncated Stakeholder process was further exacerbated by LADWP delaying its responses to discovery requests. As a result, 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).

In addition to the unreasonable duration of the process, LADWP used various tactics to avoid fully and accurately participating in the information sharing component of the process. On numerous occasions during the few in-person meetings LADWP conducted with Stakeholders, trumpeted the "open and transparent" nature of the process, but when substantive questions arose during these meetings the Stakeholders were directed to submit them in writing, which they did. Unfortunately, when Stakeholders submitted questions in writing, LADWP frequently failed to completely answer the question, and on multiple occasions LADWP ignored the requests entirely. As a result of these delays, the Cities were denied the information needed to fully understand and analyze the Tariff Update. Frequently responses lacked a clear identification of who was answering the request, resulting in responses that appeared to be neither prepared, nor endorsed by LADWP. Numerous responses specifically stated that information was not being produced because consultants to LADWP in this proceeding did not consider or have this information. *See e.g.*, Exhibit No. BWP/GWP-100 at pp. 7-10 referencing LADWP's Responses to IR-73e, IR-73f, IR-75b.

In other instances, LADWP's delayed responses on the basis of privilege, despite the fact that the Cities had agreed to and executed a Protective Order. On multiple occasions LADWP provided the responses well after the agreed upon deadline. Of particular concern were the

instances when LADWP's Responses did not answer the Cities' questions at all. *See e.g*, LADWP Response to IR-126a-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).

Finally, although LADWP promised to provide regular transcripts of stakeholder meetings, transcripts were not posted until the afternoon of the day of the deadline for comments in this proceeding, and therefore could not be used effectively by stakeholders.

As of the date of this Brief, the Cities have yet to receive the requisite data and information needed to understand and analyze the Tariff Update. Accordingly, the Cities request the LADWP General Manager suspend the process until the issues raised in this Brief are resolved. This will minimize disputes and the potential for action by the Cities at FERC after adoption of the General Manager's proposal by the LADWP Commission and ultimately the Los Angeles City Council. In the alternative, if LADWP decides not to suspend the process, the Cities request that LADWP adopt each of proposals presented in the Cities' Brief and testimony to resolve the Cities' concerns.

B. OATT Rate Issues

1. Rate Design

In the Tariff Update, LADWP proposes to use a twelve coincident peak ("12 CP") methodology for establishing the divisor (in MW) used to set LADWP's annual rates for transmission and ancillary services. LADWP's 12 CP proposal calculates an *average* of the monthly coincident peak loads on LADWP's retail system, and then uses that average amount as the divisor for all rate calculations.

FERC precedent is clear, it is only appropriate to allocate demand on a 12 CP basis when "[a] company that has a relatively flat demand curve" because such a methodology "assumes that a utility's fixed costs are related to the demand throughout all 12 months of the year." *Golden Spread Electric Co-Op, Inc.*, Opinion No. 501-A, 144 FERC ¶61,132 at P 46 (2013). Thus, "a summer (or winter) peaking company would ***not*** typically allocate demand on a 12 CP basis." *Id*. (emphasis added).

To determine if a 12 CP cost allocation is appropriate for a particular utility, FERC will analyze the full range of a company's operating realities, which include: (1) system demand; (2) scheduled maintenance; (3) unscheduled outages; (4) diversity; (5) reserve requirements; and (6) off-system sales commitments. *Id.*, at P 45. When assessing the first and most predictive operating reality, "system demand," FERC analyzes "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, in which 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, 61,147 (1981); *see also, American Electric Power Service Corporation* ("AEP"), 80 FERC ¶ 63,006 (1997) (rejecting AEP's proposed use of a 12 CP divisor and holding that a 1 CP divisor for transmission rates is appropriate for utilities that have concentrated peaks).

To assess a utility's system demand, FERC uses the following three tests: (1) The On and Off Peak test, in which the Commission compares the average of the system peaks during the

peak period, as a percentage of the annual peak, to the average of the system peaks during the off-peak months, as a percentage of the annual peak; (2) The Low to Annual Peak test, in which the Commission calculates the lowest monthly peak as a percentage of the single annual peak; and (3) The Average to Annual Peak test, in which the Commission computes the average of the twelve monthly peaks as a percentage of the annual peak. Opinion No. 501-A, 144 FERC ¶ 61,132, at P 54. These three tests follow in a long line of cases holding 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, 61,147 (1981) (71% 12 CP); *Lockhart Power Co.*, 4 FERC ¶ 61,337, 61,807-61,808 (1978) (73% - 12 CP); Carolina Power & Light Co., 4 FERC ¶ 61,107, 61,230 (1978) (72% - 12 CP); Southern California Edison Co., 59 FPC ¶ 2167, 2181 (1977) (79% - 12 CP).

In assessing system demand, in Opinion No. 501-A, FERC has rejected the use of 12 CP even when the "results of the Low to Annual Peak test narrowly indicate that a 12 CP demand allocation is appropriate, . . . the other two tests indicate that SPS is a 3 CP utility." Therefore, FERC ruled it was wrong for 12 CP to be used and ordered SPS to use a 3 CP. Opinion No. 501-A, 144 FERC ¶ 61,132, at P 55.

To assess the scheduled maintenance factor, the second component in the test, FERC looks at when the utility schedules maintenance across the months of the year. Opinion No. 501-A, at P 59. 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. *Id.*

To assess the unscheduled outages factor, the third component in the test, FERC analyzes when the unscheduled outages occur. If the majority of the unscheduled outages occur during the summer months, this indicates the utility is not a 12 CP utility, but rather is a utility for whom summer is an important time for peak usage.

To assess a utility's diversity factor, the test's fourth component, FERC reviews the types of generation the utility has in its portfolio and how and when generation units 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 a large peak in the summer or winter months will tend to have a greater relative number of peaker units and thus, a more diverse generation portfolio. The underlying goal of this diversity analysis 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 Opinion No. 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 61.

To assess a utility's a reserve requirements, the test's fifth component, FERC reviews 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 62. If the pattern shows that the utility was more concerned with 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 501-A, FERC rejected the use of 12 CP even though SPS had a couple of non-summer months with low reserve margins. *Id.*

The off-system sales commitments factor, the final component in the test, involves FERC reviewing the utilities 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" are excluded from the demand allocation analysis.

When the above listed factors are applied to LADWP, they clearly indicate that LADWP does not qualify to use a 12 CP divisor.

a. System Demand

When the system demand analysis is applied to LADWP, the outcome of each of the three tests is that LADWP does not qualify to use a 12 CP divisor. Opinion No. 501-A, 144 FERC ¶ 61,132; *see also, Southwestern Pub. Serv. Co.*, 144 FERC ¶ 61,133, P 48-51 (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 in BWP/GWP-100 at p. 16.

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.					

b. Scheduled Maintenance and Unscheduled Outages

LADWP's scheduled maintenance and unscheduled outages data demonstrate that LADWP is a "summer-peaking utility." BWP/GWP-100 at pp. 17-18. [redacted]

c. Reserve Requirements

[redacted]

d. Diversity

Like other summer peaking utilities, LADWP has a generation portfolio that is diverse and includes a relatively large number of peaking units, which you do not see in a utility with a flat load. *See e.g.*, DWP 104. LADWP's peaking units are deployed in the summer to meet its peak demand. BWP/GWP-100 at pp. 18-19. LADWP's unit commitment strategy requires an

increase in the number of in-Basin generating units which are committed to be online during increasing loads, such as you see during the summer peak. *Id*. In addition, LADWP's load profile indicates that 12 CP should not be used. Opinion No. 501-A, at P 61.

e. LADWP Should Use A 1 CP Divisor

The above analysis demonstrates that LADWP does not qualify to use of 12 CP divisor. 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. *Id* at 61. Because LADWP peaks once a year in the summer, it should use a 1 CP divisor for the calculation of all transmission and ancillary services rates. *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).

f. LADWP's Arguments Do Not Support Its Use of a 12 CP Divisor

In response to IR 27(a), LADWP provided its reasoning for retaining the 12 CP methodology. See BWP/GWP-E-101. However this reasoning does not support LADWP's use of a 12 CP divisor because it is based on irrelevant facts or inapplicable and outdated FERC precedent. LADWP argues that its use of a 12 CP divisor is justified because it is consistent with: (a) current rate design, (b) Order No. 888, (c) FERC's conclusions in *Louisiana Public Service Commission v. Energy Services, Inc.*, 113 FERC ¶ 61,282, at P 92 (2005) and *Golden Spread Electric Cooperative, Inc. et al. v. Southwestern Public Service Co.,* 123 FERC ¶ 61,047, at P 75 (2008), and (4) LADWP's planning standards. LADWP also contends that its position is supported by: (a) the year-round diversity of system stresses, (b) the relative contributions of retail native load and third-party users, (c) the four tests 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), (d) LADWP's planning standards, and (e) California's Renewable Portfolio Standards ("RPS"). Each of these arguments is without merit.

Consistency with rate design: This argument is flawed because LADWP does not have existing FERC approved rates. Moreover, the Tariff Update's rates are being significantly overhauled. For example, LADWP proposes new reserve requirements for Schedules 3, 5, 6, and 10, based on a new study completed after the test year that incorporates data on Variable Energy Resources ("VERs") from the test year and a new reliability standard (confidence interval). Therefore, the fact that LADWP used a 12 CP divisor for past and current rates has no bearing here. There is however, ample justification for changing LADWP's 12 CP divisor to a 1 CP divisor.

Year-round diversity of system stresses: This argument is equally flawed because it contradicted by LADWP's own planning studies, which, as discussed in detail above, clearly indicate that LADWP is a summer peaking utility that plans for and has a generation portfolio designed to meet its summer peak.

Relative contributions of native load and third-party users: This argument attempts to suggest 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 Native Load in its calculation of 12 CP.

Consistency with FERC Order No. 888: LADWP inappropriately quotes FERC Order No. 888 out of context to suggest that transmission providers should 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, 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 or that have established specific tests for the limited applicability of 12 CP, all of which LADWP's system fails. *See, e.g.*, Order No. 501-A; *see also AEP*, 88 FERC ¶ 61,141, 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, 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 and reliance on this case to support its use of a 12 CP divisor 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 or its components are found to be unjust and unreasonable by FERC. No such filing at or finding by the FERC 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.

LADWP's planning standards: This argument is equally without merit and should be disregarded because it contravenes 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. Nothing in LADWP's planning standards indicate otherwise.

California's RPS: LADWP's references to its growing RPS obligations is also flawed. It appears LADWP is trying to make a generation diversity argument by referencing the fact it uses renewable resources to meet part of its load. However, this argument fails because it ignores the fact that FERC uses diversity to assess a utility's *load profile*. Here, as explained above,

LADWP's load profile makes it clear that LADWP is a summer peaking utility. Again, LADWP does not have double peaks or multiple peaks. LADWP solely peaks in the summer.

LADWP's flawed arguments further demonstrate why its proposal to use 12 CP should be rejected. A 12 CP allocation methodology would be 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. Therefore, as a summer peaking utility, LADWP should allocate costs on a 1 CP basis to reflect the operating realities of the LADWP system.

2. Native Load

In addition to using the wrong coincident peak for the divisor, LADWP has also failed to properly account for all the load that should be included in the divisor. In section 1.20 of the proposed OATT, LADWP has adopted the language from the *pro forma* OATT, and defined "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.)

BWP and GWP meet the definition of "Native Load" because they are wholesale customers of LADWP, on whose behalf LADWP has undertaken an obligation to construct and operate the LADWP transmission system to meet their reliable electric needs in addition to LADWP's own needs. However, LADWP does not believe that BWP and GWP are included in this definition of "Native Load." See LADWP Response to IR 39(b) ("BWP and GWP are not a [sic] Native Load Customer of LADWP.").

LADWP refusal to treat the Cities as Native Load for the purpose of calculating the Update Tariff rates is erroneous because 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." Under this definition, the Cities should be included in Native Load if *any one* of the five criteria are met. Nevertheless, the Cities actually meet *all five* of these criteria.

With regards to the regulatory requirements criteria, 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.

With regards to the contractual obligations criteria, LADWP has numerous contracts with the Cities that obligate it to take on various duties 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).

With regards to the construction obligations criteria, 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.

With regards to the operational obligations criteria, 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.

With regards to the reliability obligations criteria, 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.

The Cities cannot even perform those functions independent of LADWP because they 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 of the Cities to conduct the analyses needed to plan separately and independently for the transmission needs of their own systems or to investigate third party suppliers for their ancillary services. To do so, the Cities 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 it does not appear as though this situation will change. Similarly, 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 violates both LADWP's Tariff definition and the *pro forma* Tariff's definition of Native Load.

In addition to including the Cities' loads in the Native Load used to calculate LADWP's Tariff rates, LADWP should also revise its calculation of Native Load so that it does not wrongfully exclude other loads that should not be excluded. Specifically, LADWP's Native Load calculation should not exclude behind the meter auxiliary/station service loads or pumping loads.

According to LADWP's response to Information Request 122(a), it calculates its Native Load 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.

However, LADWP does not provide a definition of the term "LA Native Load area" anywhere in the OATT and neither FERC, nor NERC provide a definition of "Native Load area" in any of their orders, directives or glossaries.

LADWP also uses Balancing Authority Area ("BAA") Load, which in LADWP's response to Information Request 122(a), it calculates 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.

These calculation of BAA Load and Native Load contain the same six elements, 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. Nevertheless, equations (1) and (2) are not consistent with other statements in LADWP's responses to IR 86(e) and 122(a). In LADWP's response to IR 86(e), it indicates "LADWP considers the Castaic pumping load as part of its native load." The subtraction of pumping load in equations (1) and (2) 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).

Similarly, it is wrong for LADWP to subtract Station Use/Auxiliary power in equation (1) or (2) because 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. *Id.* 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.*

Finally, LADWP has not accurately measured all generation in the BA in equation (1) and (2) because, as detailed above, it has explicitly excluded BWP's and GWP's generation. See IR 86(e). Thus, LADWPs calculation of Native Load and BAA Load are incorrect because they ignore retail loads in each City despite the fact these are are "wholesale customers" to whom LADWP has a variety obligations that have been detailed above.

To correct these errors, LADWP should revise the formula it uses to determine Native Load for the purpose of calculating OATT rates as follows:

> (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).

3. Return on Equity and Capital Structure

This proceeding requires identifying a just and reasonable ROE to include in the rates reflected in Power System's OATT. A just and reasonable ROE must be "commensurate with returns on investment in other enterprise having corresponding risks" and "should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain [a utility's] credit and to attract capital."[2] As a result, comparable risk is a pivotal determination because a utility "has no constitutional right to profits such as are realized or anticipated in highly profitable or speculative ventures."[3] The FERC relies on a two-stage discounted cash flow ("DCF") methodology for establishing ROEs because it is forward-looking, market-oriented analysis that reliably estimates investors' earnings requirements and therefore satisfies the requirements of *Hope* and *Bluefield*.[4]

LADWP requests an ROE of 8.57 percent, which is the median of its two-stage DCF analysis. DWP-200 at 6:12. LADWP asserts that its DCF analysis follows FERC precedent and that the median therefore is the "presumptive appropriate return on common equity." However, as discussed in more detail below, LADWP's DCF analysis violates FERC precedent and

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[2] *Fed. Power Comm'n v. Hope Natural Gas Co.* ("*Hope*"), 320 U.S. 591, 603 (1944); *see also Bluefield Waterworks and Improvement Co. v. Public Serv. Comm'n of West Virginia* ("*Bluefield*"), 262 U.S. 679, 692 (1923) ("The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.").

[3]

[4] *Minnesota Power and Light Co.*, Opinion No. 12, 3 FERC ¶ 61,045, 61,133 (1978) ("because the DCF approach examines evidence regarding expectations of investors which are critical in determining the attractiveness of a company's securities…it is a particularly helpful technique for determining the rates required to meet the *Hope* and *Bluefield* tests"); *Southwestern Public Service Co.*, 49 FERC ¶61,354, 62,276-62,277 (1989) ("In determining the appropriate allowed rate of return on equity, the Commission has long favored the use of the forward-looking, market-oriented DCF analysis.").

produces a zone of reasonableness that is upwardly biased and does not represent the returns investors would require for a utility with LADWP's superior bond credit rating.[5] As a result, should LADWP's DCF zone of reasonableness be accepted, Power System's ROE should be set at 7.04% which represents the low end of the zone of reasonableness.

As a threshold matter, LADWP uses a six month study period that runs from September 1, 2015 to February 29, 2016 for its DCF analysis despite the fact that its testimony was filed in January of 2017. This outdated study period violates FERC's requirement that a DCF analysis use a six month study period that reflects the most recent financial data available.[6] For testimony filed in January of 2017, the most recent financial data available would be the six months ending in December of 2016. The use of recent financial data is critical for two reasons. First, the Supreme Court has held that a return "may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market, and business conditions generally."[7] Second, the ROE identified in this proceeding will be used on a going forward perspective, making it vitally important that the determination be based on the most recent financial data available given the "particularly volatile" nature of capital market conditions.[8] BWP-GWP-100 at 93:20-94:1-2.

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[5] LADWP's DCF analysis contains multiple flaws that do influence the identification of the outer bounds of the zone of reasonableness, and are therefore not the focus of this Brief. These errors include the inappropriate inclusion of Duke, Southern Company, and NextEra in the proxy group despite their ongoing merger activities (BWP-GWP-100 at 94:5-96:11), the mixed use of actually paid dividends, dividends that were paid outside of the study period and dividends that were announced in one month but paid in another month (BWP-GWP-100 at 96:14-97:2).

[6] Opinion No. 531, at P 64.

[7] *Bluefield*, 262 U.S. at 693.

[8] *Consumer Advocate Div. of the Pub. Serv. Comm. of West Virginia v. Allegheny Generating Co.*, 68 FERC ¶61,207, 61,998 (1994).

In addition to using an outdated study period, LADWP's proxy group does not satisfy FERC precedent. In Opinion No. 531 FERC reaffirmed the following criteria for developing a proxy group and calculating the zone of reasonableness:

> (1) the use of a national group of companies considered electric utilities by Value Line; (2) the inclusion of companies with ratings no more than one notch above 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; and (5) companies whose DCF results pass threshold tests of economic logic.[9]

It is "crucial that the firms in the proxy group be comparable to the regulated firm whose rate is being determined," and as a result it is vital that LADWP's proxy group be "risk-appropriate" to LADWP itself.[10] However, as LADWP itself concedes, its superior credit rating makes it impossible to comply with FERC's requirement that the proxy group be composed of utilities whose credit rating is no more than one notch above or below its own. DWP-200 at 3:18-20.

Power System's bond rating from Moody's is Aa2, and its rating from S&P is AA- (DWP-200 at 3:17), which means that a comparable risk proxy group should include utilities with a Moody's rating between Aa1 and Aa3, and an S&P rating between AA and A+. BWP/GWP-100 at 91:9-12. However, the highest rating for utilities covered by Value Line is A3/A- (DWP-200 at 3:20-21), meaning LADWP's proposed proxy group includes utilities with credit ratings that are *three* notches below the floor on the appropriate Moody's rating bandwidth and *two* notches below the floor for the S&P rating bandwidth. BWP/GWP-100 at 91:11-16.

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[9] *Martha Coakley et al. v. Bangor Hydro-Electric Co. et al.*,Opinion No. 531, 147 FERC ¶61,234 at P 92 (2014) ("Opinion No. 531").

[10] Opinion No. 531 at P. 96 n. 184, *citing Proxy Group Policy Statement*, 123 FERC ¶ 61,048 at P 48 (2008).

As a result, LADWP's proxy group is composed entirely of utilities that are significantly more risky than LADWP. This results in an upward bias because as the financial risk of an investment increases, so does the rate of return investors will require. BWP/GWP-100 at 92:17-20. LADWP's superior credit rating prevents the creation of a proxy group that conforms to FERC precedent or reflects a risk profile comparable to that of LADWP.

LADWP's assertion that the median of its zone of reasonableness is the "presumptive[ly]" reasonable ROE is incorrect. FERC recognizes the importance of comparing the risk profile of the target utility to that of the proxy group, and has frequently adjusted the placement of the ROE within the zone to adjust for any disparity.[11] LADWP not only has a significantly higher credit rating than the members of its proxy group, but as Moody's notes, has the "continued ability to pass through about 50% of costs that can be automatically passed through to customers without governing board action, a decoupling mechanism, an elimination of certain caps and a new power access and tier rate structure [each of which] provide positive changes…including revenue certainty." BWP/GWP-E-104. KMPG, LADWP's auditors, have noted LADWP's seven pass-through factors "assure" LADWP's ability to collect its revenue requirement. BWP-GWP-100 at 100:7-10. The evidence in this proceeding illustrates that

[11] *Portland Natural Gas Transmission Sys.*, 142 FERC ¶ 61,197, 62,020 (2013) ("We find that Portland's below investment grade credit rating, combined with its inability to reflect its unsubscribed capacity in its rate design, present unusual circumstances justifying setting Portland's ROE at the top of the range of reasonable returns."); *Transcontinental Gas Pipeline Corporation*, 84 FERC ¶ 61,084 (1998) ("The Commission has concluded that requiring the ROE to be set at one of only three possible positions in the range established by reference to the proxy companies does not give the Commission the necessary flexibility required to evaluate the specific circumstances of each case. Thus, the Commission has determined that the parties to a rate proceeding may present evidence they believe is warranted to support any ROE that is within the DCF derived zone of reasonableness"); *S. Cal. Edison Co.*, 92 FERC ¶61,070, 61,266 (2000) ("We will next consider where, within this zone of reasonable returns, SoCal Edison's ROE should be set. In making this determination, it is necessary to measure the business and financial risks faced by SoCal Edison relative to the overall risks attributable to the appropriate proxy group of companies.").

LADWP is significantly less risky than the utilities included in the proxy group, which justifies setting Power System's ROE at 7.04%, which is the low end of the identified zone of reasonableness.

Finally, LADWP's argument that it is necessary to adopt a hypothetical capital structure to ensure its ROE is just and reasonable is factually incorrect and runs contrary to FERC's strong preference for using a utility's actual capital structure.[12] LADWP asserts it is necessary to adopt a hypothetical capital structure of 48 percent equity and 52 percent debt (DWP-200 at 8:15-18) because "there is more financial risk in Power System's capitalization than there is in the proxy group companies." DWP-200 at 7:9-10, Table 1. 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. BWP-GWP-100 at 110:7-10. This argument cannot be reconciled with the multiple retail rate adjustment clauses which additionally mitigate LADWP's risk. BWP-GWP-100 at 100:1-17. LADWP's "net position" should be adjusted to exclude "restricted assets," because it would be unduly discriminatory to charge OATT customers more than the City of Los Angeles can otherwise earn from restricted assets.

4. Classification and Functionalization

In addition to using the wrong divisor, the Tariff Update's rates are also erroneous because they inappropriately allocate the costs of certain transmission and generation facilities to

[12] *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).

the revenue requirement for either (i) open access transmission service or (ii) open access ancillary services. The Cities have determined that the following facilities should be excluded from the LADWP OATT rate because they are not integrated transmission facilities: (1) 230-kV Inyo – Barren Ridge Line 1; and (2) 230-kV Barren Ridge – Rinaldi Line 1 (collectively referred to as "Inyo-Rinaldi Path"). The Cities have also found several 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. These facilities are: (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").

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

Under FERC precedent, 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 transmission customers are not inappropriately required to subsidize the cost of facilities that benefit only other users. Such a result would contravene 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. Generally, FERC will start with 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 will then employ 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*). In some instances, FERC has found that lower voltage facilities, which normally are viewed as distribution under the Seven Factor Test, will be rolled-in to transmission costs if they meet certain aspects of the *Mansfield* test. For gen-tie facilities, FERC has employed the "sole use" test which excludes from transmission rates gen-tie facilities that are used exclusively to generate power, step up power, or transmit power from the generator to the grid. *Cal. Dep't of Water Res. v. FERC,* 489 F.3d 1029, 1035 (9th Cir. 2007).

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.

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.

Although FERC relies heavily on the *Mansfield* test to determine what facilities should be rolled-in to transmission rates, FERC has held 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 found the transmission provider Electric District No. 3's ("ED3") representations as supporting a finding of non-integration. *Id.*, at P 46. Specifically, 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 held 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 it alleged the facilities were integrated with. *Id.*, at P 48.

As noted above, since *Mansfield,* the FERC and Court of Appeals have also found that facilities 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. *See e.g., 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 the facilities discussed below.

1) Inyo-Rinaldi Path Facilities

The Inyo-Rinaldi Path should be excluded from the Tariff Update's rates because these facilities are not integrated into the LADWP system. The facilities in the Inyo-Rinaldi Path are part of the original Owens Gorge-Rinaldi 230 kV transmission line; and, like the original Owens Gorge-Rinaldi, 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).

The *Mansfield* factors are "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.

LADWP disagrees with this conclusion and argues that the Inyo-Rinaldi Path is integrated under factors (1) and (4) of the *Mansfield* test. Specifically, LADWP claims the Inyo-Rinaldi Path facilities are looped (*i.e.*, not radial) and provide reliability benefits to Tariff customers. LADWP contends the Inyo-Rinaldi Path is looped on the grounds that any level of flow changes (an "any degree of integration" argument) constitute a non-radial looped system. LADWP's argument on this point rests solely on the presupposition 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.[13]

[13] 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."

LADWP's presupposition is flawed because the Inyo Tie actually does not create a looped configuration. The tie at Inyo was built by SCE and remains under SCE's ownership, including everything from the 230-kV Circuit Breaker 612 to SCE. And as LADWP's Responses to the Cities Information Requests make it clear, the Inyo Tie is also 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. By terminating this service, which relied on SCE's control of a phase shifter, LADWP changed the Inyo Tie's operations making it operate 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."[14] As such, the Inyo Tie 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 interpretation of the term because, during the test year, LADWP did not even have contractual rights over the Inyo Tie. Therefore, LADWP's contention that the Inyo Tie makes the Inyo-Rinaldi Path looped, is without merit.

Without any rights over the Inyo Tie, LADWP also cannot use it to access energy or ancillary services from third-parties. This fact is demonstrated by LADWP's responses, which

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

indicate that 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.

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 and its costs cannot be included in OATT rates.

[redacted]

significantly [redacted]

[redacted]

[redacted]

9 **b. Facilities That Should Be Excluded from LADWP's Production Costs**

10 Under longstanding FERC precedent, facilities should be excluded from the production
11 component of a transmission provider's ancillary service Tariff costs if they cannot actually
12 provide ancillary services. *See e.g., Entergy Service, Inc.*, 109 FERC ¶ 61,095, P 56-57 (2004);
13 *Ocean Vista Power Generation, et. al.*, 82 FERC ¶ 61,114, 61407 (1998). LADWP's testimony,
14 studies, and data responses make it clear that generation facilities discussed below cannot
15 actually provide the ancillary services to LADWP's OATT customers that LADWP's COSS
16 assumes they can provide.

17 Tab "Gen AS Matrix" in DWP-104 contains *assumptions* made by LADWP regarding the
18 provision of specific ancillary services under Schedules 1, 2, 3, 5, 6, and 10. These
19 "assumptions" provide no empirical evidence that these generation facilities *actually* provide
20 ancillary services. When asked in discovery about these assumptions, LADWP only stated that
21 certain LADWP personnel identified which generation units allegedly provide ancillary services.
22 When asked in discovery to identify the LADWP personnel who had made these identifications,

LADWP declined to do so. The following facilities listed in the Gen AS Matrix cannot and do not provide ancillary services to LADWP's OATT customers.

1) Owens Gorge Units

The Owens Gorge units (37.5-MVA and 37.5-MW each per cells H55 – H57, and I55 – I57) are too small to provide effective voltage and VAr control beyond the Owens Valley Electric System ("OVES"). BWP/GWP-100 at p. 71. That is to say, the impact of their range of control does not reach the LADWP grid, which is approximately 240 miles away. The capacitive reactance of the lines between Control Gorge and Rinaldi exceeds the ability of the units to compensate. [redacted]

In addition, although these units do supply energy, these units are "block loaded" to a "water schedule" created to move water down the Los Angeles Aqueduct. LADWP does not and

cannot rely on these units to deviate from their water schedule, or to turn them on when there is no water scheduled to be moved. Thus, contrary to the assumptions in Gen AS Matrix, these units cannot provide spinning and supplemental reserves. *See* LADWP's Response to IR 75.

2) San Francisquito Units

In the Gen AS Matrix, LADWP assumes the San Francisquito units can provide reactive and voltage control, however this assumption is not supported by the facts. 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. BWP/GWP-100 at p. 72. Additionally, these plants supply power to the housing camps at each of the plants and to "fringe loads" of SCE. 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. Therefore, the units cannot provide reactive and voltage control.

3) Scattergood 3

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." Thus, Unit 3 was not available during the test year to provide ancillary services. Accordingly, at least some of the costs of Unit 3 should be removed from the cost-of-service study.

4) Intermountain Generating Station

LADWP claims that Intermountain Generating Station ("IGS" or "IPP") 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.

IPP cannot provide Schedule 2 service because it 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. 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).

This is important because 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. Thus, IPP really is not capable for providing Schedule 2 Reactive Supply and Voltage Control as LADWP contends.

IPP also cannot provide Schedule 5 service because, 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 IPP 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.

5. Segmentation

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.

Segmentation is a reasonable approach to setting transmission rates because it 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). The FERC has ordered segmentation where it ensures that the principle of cost causation is met. *Puget Sound Energy, Inc.*, 88 FERC ¶ 63,001, 65,002 (1999) (holding transmission costs were properly segmented into three discrete rates in light of fact Puget could not provide transmission service over noncontiguous lines without obtaining use of other transmission providers' facilities).

Based on the above listed cases, the Cities have determined that LADWP should segment its transmission system, and set separate rates for the following facilities: (a) the PDCI; (b) the Southern/Northern DC/AC Transmission System ("STS/NTS"); and (c) the Beltline. The Cities believe that segmentation would be appropriate for these facilities due to their non-contiguous configuration and the fact that LADWP already segments them in its system. For example, LADWP calculates separate loss factors for each of these three segments. In addition, 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.

Furthermore, LADWP has explicitly excluded DC facilities from its Large Generator Interconnection Agreement ("LGIA") and Large Generator Interconnection Procedures ("LGIP"). The LGIP states:

> 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. Together, this pre-existing segmentation of the PDCI and STS/NTS demonstrates why segmentation for transmission rate purposes is needed in order to ensure that LADWP's rates are consistent with the principle of cost causation. *Puget Sound Energy, Inc.*, 88 FERC ¶ 63,001, 65,002 (1999) (holding transmission costs were properly segmented into three discrete rates in light of fact Puget could not provide transmission service over noncontiguous lines without obtaining use of other transmission providers' facilities).

To be consistent with FERC segmentation 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.

6. Revenue Requirements for Transmission Service

LADWP has not provided sufficient documentation of offsetting sources of income, revenues, receivables, and other credits in the Tariff Update's COSS. 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.

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. 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.

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). Therefore, there is the possibility that LADWP's OATT rates are overstated by the lack of recognition of payments made to LADWP by other PDCI owners.

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. LADWP 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."[15] 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 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

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

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*.

7. Revenue Requirements for Ancillary Services

LADWP improperly includes certain generation units' costs in the proposed ancillary service rates and failed to justify the tripling of its Schedule 6 revenue requirement. This is in addition to LADWP possibly failing to properly account for the use of LADWP's ancillary services by LADWP's Wholesale Marketing group (a.k.a., "WERM" or "LAWM").

Under Schedules 5, 6 and 10 of the proposed Tariff, WERM is permitted to "self-supply" reserves *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." This is demonstrated by the fact that LADWP's documentation of compliance with these posted Business Practices by WERM 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 WERM. *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 WERM 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.

In addition, the application of Schedule 10 to WERM 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 WERM is exporting energy from the LADWP Balancing Area, WERM should either purchase Schedule 10 (presumably for dispatchable resources) or self-supply. To the extent WERM (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 WERM to make system sales at least part of the time. Because the Monthly Transfer Reports do not show which generator was tagged or whether WERM was making system sales, we cannot calculate the appropriate charges for Schedule 10 exports by WERM, and thus we do not know the extent to which the Schedule 10 rates are too high. However, we do know that WERM 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).

If facilities are segmented out and not rolled-in to the Tariff Update's rates, the ancillary services associated with those facilities should also be segmented out. However, using the data LADWP has provided, the Cities cannot determine exactly what these ancillary services costs would be. LADWP's data and accounting systems do not separate out these costs, even though LADWP has separate charges for losses on these facilities. Because the Cities cannot determine the exact costs included in the ancillary service rate without LADWP providing them with segmented cost data, the schedules should be segmented and their costs should be provided to the Cities.

In the case of the STS/NTS, which the Cities believe should be segmented for transmission service, LADWP also incurs certain energy-related costs that are included in the revenue requirements for certain 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. To rectify these problems, LADWP must: (1) fully explain and justify its tripling of the Schedule 6 revenue requirement; (2) amend its COSS so that it fully and accurately accounts for the use of LADWP's ancillary services by the WERM; and (3) must segment out the ancillary services costs associated with the transmission facilities that the Cities recommended be segmented from the LADWP OATT rates.

C. Tariff Issues

1. Purchase Obligations for Ancillary Services

The Tariff Updates proposed purchase obligations for ancillary services should be rejected because it incorrectly applies a study conducted well after the test year to determine the capacity purchase obligations for some ancillary services. In addition, the 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.

The Tariff Update proposes to significantly increase Tariff customers' purchase obligation for ancillary services. The following table compares LADWP's current and proposed purchase obligations for each ancillary service rate schedule, in megawatts. *See also* 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			

In support of this dramatic increase, 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. The Cities disagree with a large number of these increases because they have not been justified. Of particular concern is the fact that LADWP relied on a study of Variable Energy Resource ("VER") integration requirements ("VER Study") 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 indicating it would use 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.

The use of post-test-year data violates LADWP's own restrictions against using data out of the test year. For example, LADWP 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.[16]

The January 2017 VER Study purports "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. It is unclear whether the VER Study designed to determine the amount of capacity required to provide traditional load-based regulation and frequency response (RFR) service. The VER Study 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." VER Study, at 1 (emphases added).

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

The VER Study identifies the need for balancing reserves for (a) load, (b) VERs, and (c) dispatchable resources. However, it does not adequately address the differences between 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. Loads and VERs do not always display similar or identical error distribution. The VER Study begins with the task of separating forecast errors for loads and VERs but fails to adequately address this point. VER Study, at 2-3. 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.[17] "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, at 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, at 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

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

modeled as Normally [sic] distributed and curtailed at three standard deviations." VER Study, at 5.

With regard to the relative variability of "load less VER," the VER Study provides a summary Table 5, 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, at 11-12.

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

With regards to the forecast errors of load, the VER Study was even more ambiguous. 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.

Based on the VER Study, LADWP increased the capacity reserved for load forecast error from +25/-25 MW, 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. However, 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.

Interestingly, the VER Study does not recommend an increase in the confidence interval for load forecast errors to determine the appropriate reserve requirement for Schedule 3. In fact, 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 for Schedule 3. The VER Study also does not provide any analysis 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).

Contrary to LADWP's contentions, the VER Study is irrelevant to Schedule 3 and should not be applied to Schedule 10 because it is flawed and outside the test year. As noted above, 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. Therefore, the actual load-following/regulation bandwidth from the test year should have been used. According to the VER Study, this bandwidth in use at in the test year was "a load-following/regulation bandwidth of +/- 25 MW," which "covers the 21st to 79th percentiles of the deviations between hourly forecast and 1-minute actual data for load only." VER Study, at 11. This +/- 25 MW bandwidth of remained in place as late as December 31, 2015, *after* the test year. *See* LADWP's *Power Integrated Resource Plan* (p. 113), which states that "[t]he Regulation Requirement of 25 MW is related to system load variations due to customer load changes."

However, in the Tariff Update, LADWP has chosen 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. However, LADWP has not justified this increase other than to say that it is moving to the *Westar* standard, even though there is no evidence that +/-25 was inadequate during the test year.

LADWP's reliance on the *Westar* decision should be rejected because that case is not relevant to the facts at issue in this case. First, *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"). Here, LADWP has not shown that it has any requests from 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, when compared with its *historical* need, LADWP proposes to more than triple the reserve requirement for load (*i.e.*, from 50 MW to 174 MW). Though growth of VERs may support updates to Schedule 10, if certain conditions are met, 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".[18] In contrast, LADWP 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. Therefore, *Westar* does not support LADWP's reliance on the VER Study.

It is also inappropriate for LADWP to rely on the VER Study because LADWP has not met the requirements of Order No. 764. *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).

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[18] *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.").

Under Order No. 764, 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 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.[19] *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

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

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 No. 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 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.[20] *See* BWP/GWP-E-104, "LGIA_Final_August_14_2014.pdf" and "LGIP_Final)_August_14_2014.pdf".

[20] *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.

LADWP has also not met the condition in Order No. 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.

Finally, the VER Study should not be used for Schedule 10 because LADWP has not established a sufficient record for the proposed updates. Several issues still 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.

LADWP also has not established that the confidence interval used for Schedules 3 and 10 should be increased to the 1st and 99th percentiles. Although LADWP presented evidence of the various sizes of confidence intervals, it did not provided evidence of the *appropriate or correct sizes, which could be different for different Schedules.* Moreover, as alluded to above, LADWP did not experience any reliability violations in the test year due to holding inadequate reserves for Schedule 3 service. 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." This is important because, 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*. This conclusion is further supported by the fact that LADWP has not conducted a study on the scheduling accuracy of dispatchable resources. When asked about this point LADWP indicated, in response to 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).

Thus, there is no evidence on the record supporting 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." LADWP has no grounds for increasing the load-following/regulation bandwidth from +/- 25 MW.

To rectify all of the problems associated with LADWP's use of the VER Study, LADWP should take the following actions. First, for 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 50/8,159. Further, the Purchase Obligation for all rate schedules should be corrected for other

problems identified in this testimony. For the reasons discussed above, 6,343 MW is far too low. 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.

2. Real Power Loss Factors

In the Tariff Update, LADWP proposes 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 and disregards the fact that LADWP is proposing to reclassify certain transmission facilities.[21] New equipment normally leads to lower losses, because each generation of transmission equipment tends to be more efficient than previous generations. 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").

[21] 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.

These loss factors are outdated for two reasons. First, 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. Second, 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 at 61,702, *reh'g denied,* 8 FERC ¶ 61,224 (1979)*; Union Electric,* 47 FPC 144, 150 (1972).

[redacted]

[redacted]

blown Real Power Loss Factors

[redacted]

3. Available Transmission Capacity

LADWP's has not fully explained or justified how it calculates ATC generally or on specific paths. The "black box" nature of LADWP's ATC calculations makes it impossible for the cities to determine whether LADWP has used incorrect or even biased assumptions to reduce ATC to benefit retail loads and disadvantage transmission customers. The Cities have submitted several Information Requests asking LADWP to provide data, assumptions, models, and calculations for specific posted ATC amounts. *See* IR 41(c). However, LADWP refused to provide this information. Without this information, the Cities cannot confirm whether LADWP is not misrepresenting ATC to its own advantage. 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.

4. Interest on Deposits

In its Tariff Update, LADWP requires customers to pay interest on delinquent amounts but LADWP has inappropriately excluded any obligation to pay interest on amounts customers pay to LADWP for deposits in Sections 17.3, 17.4, 17.6, 19.1, 19.4, and 20.3. LADWP's proposal violates FERC's policy to require payment of interest on deposits or study costs that are refunded to a interconnection customer. *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). LADWP should amend Sections 17.3, 17.4, 17.6, 19.1, 19.4, and 20.3 in its Tariff Update so that these sections include an obligation for LADWP to pay interest on OATT customers' deposits that is symmetrical to the customers' obligation to pay interest to LADWP.

5. Undue Discrimination

The Tariff Update must be amended so that it protects against undue discrimination. The following are areas of concern must be addressed.

First, as detailed above LADWP allows WERM to avoid paying Schedules 5, 6 and 10, without requiring WERM to comply with posted Business Practices on self-supply. This means that WERM has an advantage over other transmission customers when conducting business on the LADWP transmission network. WERM can avoid applying for self-supply status, monitoring by LA-Transmission, and compliance with self-supply protocols.

Second, the undocumented self-supply by WERM 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, as detailed above, 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, LADWP must include the Cities as Native Load, to ensure that they receive non-discriminatory treatment in all aspects of operations and OATT service.

Fifth, LADWP must use its actual capital structure, minus restricted assets, to ensure that OATT customers do not provide returns to the City of Los Angeles that exceed the returns that the City can otherwise earn due to such restrictions.

IV. CONCLUSION

Based on the foregoing, the Cities respectfully request that LADWP either suspend the process until the issues raised herein by the Cities are resolved, or adopt each of proposals presented in this Brief and in the Cities' testimony that resolve these issues.

Respectfully Submitted,

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