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Douglas C. Tingey
Associate General Counsel

August 20, 2013

Via Electronic Filing and U.S. Mail

Oregon Public Utility Commission
Attention: Filing Center
Oregon Public Utility Commission
PO Box 1088
Salem, OR 97308-1088

Re: UE 262 – PGE's Request for a General Rate Revision

Attention Filing Center:

Enclosed for filing in the above-referenced docket are an original and five copies of the stipulating parties':

- **Joint Testimony in Support of Second Partial Stipulation (UE 262/ Compton – Kaufman – Deen – Jenks – Higgins – Hendrix - Cody/200-201).**

These documents are also being filed by electronic mail with the Filing Center and electronically served upon the UE 262 service list.

Thank you in advance for your assistance.

Sincerely,

DCT

Douglas C. Tingey
Associate General Counsel

DCT:jrb
Enclosures
cc: Service List-UE 262

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 262

PORTLAND GENERAL ELECTRIC COMPANY

Joint Testimony in Support of Second Partial Stipulation

George Compton
Lance Kaufman
Michael Deen
Bob Jenks
Kevin Higgins
Chris Hendrix
Marc Cody

August 20, 2013

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I. Introduction

Q. Please state your names and positions.

A. My name is George Compton. I am a Senior Economist, employed in the Rates, Finance, and Audit Section of the Energy Division of the Oregon Public Utility Commission (OPUC). My qualifications appear in OPUC Exhibit 301.

My name is Lance Kaufman. I am a Utility Economist, employed in the Rates, Finance, and Audit Section of the Energy Division of the OPUC. My qualifications appear in OPUC Exhibit 401.

My name is Michael Deen. I am employed by Regulatory and Cogeneration Services, Inc. (RCS), a utility rate and consulting firm. I am testifying on behalf of the Industrial Customers of Northwest Utilities (ICNU). My qualifications appear in ICNU Exhibit 101.

My name is Bob Jenks. I am the Executive Director of the Citizens' Utility Board of Oregon (CUB). My qualifications appear in CUB Exhibit 101.

My name is Kevin Higgins. I am a principal in the firm Energy Strategies, LLC and am testifying on behalf of both Noble Americas Energy Solutions LLC (Noble) and The Kroger Co. My qualifications appear in Noble Exhibit 100.

My name is Chris Hendrix. I am the Director of Markets and Compliance for Wal-Mart Stores, Inc. (Wal-Mart). My qualifications are also contained in Exhibit 201 to this testimony.

My name is Marc Cody. I am a Senior Analyst for Portland General Electric (PGE). My qualifications appear in PGE Exhibit 1500.

Q. What is the purpose of your testimony?

A. Our purpose is to describe the Second Partial Stipulation (the Stipulation) reached among the OPUC Staff (Staff); CUB; ICNU; the City of Portland (COP); Noble; Wal-Mart; and PGE (the Stipulating Parties) regarding the direct access, decoupling, and streetlighting issues in this docket (UE 262). While there are other parties to this case, we are not aware of any who oppose this Partial Stipulation.

Q. Please describe the process that led to this Stipulation.

A. PGE filed this general rate case on February 15, 2013. During the next three to four months, Staff, CUB, ICNU, and other parties submitted over 750 data requests regarding PGE's filing. On May 16, Staff provided an initial analysis of issues and the Stipulating Parties participated in Settlement Conferences on May 29, June 3 and June 6, during which other parties also identified issues. Staff and the COP submitted testimony on June 14 regarding PGE's long-term direct access program and decoupling, and the COP submitted testimony on several streetlighting issues. The Stipulating Parties participated in additional Settlement Conferences on July 2 and July 9. During those Settlement Conferences, proposals were advanced and modified by the Stipulating Parties and ultimately compromises were made and a resolution satisfactory to all was reached.

II. Resolved Direct Access Issues

Q. Please summarize the long-term direct access issues raised by either Staff or the COP?

A. Staff or the COP variously made the following proposals:

1) Revise Schedule 129 Long-term Transition Adjustment to better capture fixed generation costs.

2) Spread the Schedule 129 revenues to all rate schedules instead of just Schedules 85 and 89 and their direct access equivalents.

3) Simplify the Schedule 129 price structure such that the prices for different enrollment vintages would no longer be differentiated.

4) Provide for annual updating of the Schedule 129 transition adjustments.

5) Change the advance notification for customers desiring a return to cost-of-service (COS) energy pricing from the current two years to five years.

6) Consider changing the participation limits.

7) Offer long-term direct access to streetlight and traffic signal customers who meet certain size thresholds.

Q. Why did Staff initially propose to revise Schedule 129?

A. Staff proposed to revise Schedule 129 because of a concern that long-term direct access customers are not being assigned an adequate share of fixed generation costs, to the detriment of COS customers.

Q. How did the Parties resolve this issue?

A. For the five-year option, the Parties agree to allow updates to fixed generation costs during the period for which transition adjustments apply. These updates will reflect Commissionapproved fixed generation costs that are recovered in COS customer rates. For the three-year option, PGE will calculate Schedule 129 transition adjustments by including an amount equal to a projection of the revenue requirements of new generation resources expected to be brought online and put in rates during the three-year period for which the transition adjustments will be applicable. Including this amount helps to prevent the unwarranted shifting of costs to other retail electricity consumers of the electric company, as required under ORS 757.607(1). The three-year option will not be subject to any updates; hence it will conform to Oregon Administrative Rule 860-038-0275(5), which specifies that, "[a]t least once each year, electric companies must offer customers a multi-year direct access program with an associated fixed transition adjustment."

Q. Regarding the three-year option, how will the appropriate supplemental amount be determined if the commercial operation date of a projected new resource is other than January 1 of each year?

A. If the commercial operation date of an expected new resource is other than January 1, PGE will include an amount that is equal to the applicable first year revenue requirement, prorated to account for the anticipated commercial operation date. For any succeeding year, PGE will include an amount equal to the entirety of the annual revenue requirement associated with the new resource for such year..

Q. Why did Staff propose to spread the Schedule 129 revenues to all rate schedules?

A. Staff proposed this on the basis of equity. PGE currently allocates the Schedule 129 revenues (which currently are positive) as credits to Schedules 85 and 89 and their direct access equivalent schedules. When customers choose long-term direct access, the fixed generation costs are spread to a reduced amount of COS energy; therefore, transition adjustments (whether positive or negative) are appropriately allocated to all COS customers going forward.

Q. Did the Parties resolve this issue?

A. The Parties resolved this issue in the First Partial Stipulation filed on July 10.

Q. Why did Staff propose to simplify the Schedule 129 price structure and how was this issue resolved?

A. Staff, partially through PGE's Response to OPUC Data Request No. 311, identified PGE's Schedule 129 pricing structure as overly complex and burdensome. The Parties agreed to continue differentiating the Schedule 129 transition adjustments by schedule and delivery voltage. However, in order to reduce the number of Schedule 129 transition adjustments in any one enrollment window, the Parties agreed to levelize some (power costs for the five-year option) or all (for the three-year option) of these transition adjustments across the applicable period during which transition adjustments would apply (three or five years). This levelization of transition adjustments should reduce some of the administrative burden associated with each individual long-term direct access vintage while continuing to provide for the appropriate cost differences between the rate schedules and delivery voltages.

Q. How does the settlement prevent cost shifting and reduce administrative burden?

A. The levelization of prices should, as mentioned above, address some of the Schedule 129 administrative burden. Updating fixed generation costs for the five-year option will help address cost-shifting and accuracy. This is also true with supplementing the transition charge for the three-year option to account for the cost-shifting that occurs if new resources are brought online during the three years a direct access customer is not a COS customer.

Q. Why did Staff propose to change the notice period for returning to COS from two years to a minimum of five years and how was this issue resolved?

A. Staff proposed this change because it better represents how PGE adjusts its long-term resource portfolio to accommodate changes (mostly increases) in load. The Parties, in the interest of settlement agreed to change the advance notification provision from two years to three years for customers who select the five-year option for service beginning in the 2015 service year. This change is more consistent with PGE's long-term planning process and also provides some measure of reassurance to potential new direct access participants that they may access PGE energy pricing in the future.

Q. Why did Staff suggest that the long-term direct access participation limits could be increased?

A. Staff proposed a nonspecific change in the participation limits based on reduced risk of cost-shifting resulting from adoption of the Staff proposals including the change in the advance notification for the five-year option.

Q. How did the Parties resolve the participation limit issue?

A. The Parties agreed to maintain the current overall participation limits of 300 aMW in the interest of settlement of all the direct access issues specified above.

Q. What did the COP propose regarding long-term direct access?

A. The COP proposed that streetlight customers with at least 3,000 luminaires and traffic signal customers with at least 200 intersections be allowed to participate in long-term direct access. This proposal would create new Rate Schedules 491, 492, and 495.

Q. How was this issue resolved?

A. The Parties agreed that PGE will create these new rate schedules for customers with at least 30,000 lights and 500 intersections effective January 1, 2014 for the 2015 service year. This compromise will allow the COP to choose long-term direct access for their streetlight and signal accounts, while helping to mitigate the large set-up costs that PGE will incur in providing the option to applicable streetlight and signal customers.

Q. For what period of time do the Parties recommend the direct access portion of the Stipulation remain in effect?

A. The Parties agree the direct access portion of the Stipulation remain in effect for the four service years, 2015-2018. The Parties further agree that they will not propose or support changes to PGE's long-term direct access program during this period unless agreed to by all the Stipulating Parties. In addition, the Parties agree that they will not oppose PGE's request to seek a waiver of OAR 860-038-0275(5) as a result of the 300 aMW limit.

Q. For what service year are the direct access stipulated changes above expected to take effect?

A. The Parties agree that the changes discussed above will take effect commencing with the enrollment window in 2014 for the 2015 service year. Customers who enroll in long-term direct access on or before the 2014 service year will not be subject to fixed generation cost true-ups, and will continue to have a two-year advance notification period for return to COS pricing.

III. Resolved Decoupling Issues

Q. Please describe PGE's initial decoupling mechanism proposal.

A. In direct testimony, PGE proposed that decoupling as specified in Schedule 123 continue indefinitely in the same manner as it is currently, with provision for updates to the fixed costs recovered volumetrically during general rate proceedings. PGE also proposed changes to the time and manner of its Schedule 123 filings such that the effective dates will be moved back seven months from June 1 of the succeeding year, to the following January 1.

Q. What changes to PGE's decoupling mechanism did Staff propose in its Opening Testimony?

A. Staff proposed that PGE's decoupling mechanism be extended for three years, to 2016, and that Schedule 123 contain an additional Secondary Fixed Monthly Charge applicable to Schedule 7 Residential customers. This Secondary Fixed Monthly Charge would only be applicable when residential customer counts exceed the monthly customer count contained in the load forecast used to set rates in a general rate case. Staff also recommended a change to the Nonresidential Lost Revenue Recovery Adjustment (LRRA). This change was incorporated into the First Partial Stipulation dated July 10.

Q. Why does Staff propose a Secondary Monthly Fixed Charge and how does Staff propose to calculate it?

A. Staff proposed that the Secondary Monthly Fixed Charge be calculated by dividing the Base Monthly Fixed Charge (the monthly fixed costs recovered through volumetric charges), by the average annual residential energy use and multiplying by average annual energy use for customers connected within the previous year. Staff makes this proposal because they believe that the current decoupling mechanism allows PGE to recover more than its fixed costs when the Schedule 7 customer count exceeds that contained in the load forecast used to set the Base Monthly Fixed Charge. The Secondary Monthly Fixed Charge would apply only to monthly customer counts that exceed those contained in the final UE 262 load forecast. Staff supports their belief by citing PGE's declining use-per-customer for new connections. For the specific calculation, Staff used recent annualized consumption of customers connected during 2012 as the basis for calculating the Secondary Monthly Fixed Charge.

Q. How did the Parties resolve decoupling?

A. The Parties agree to modify the time and manner of filing Schedule 123 as proposed by PGE and to extend Schedule 123 for three years as proposed by Staff. In the interest of settlement, the Parties also agree to implement a Secondary Monthly Fixed Charge as recommended by Staff when reconciling Schedule 7 monthly revenues through Schedule 123. However, instead of using the annualized consumption for residential customers connected in 2012, the Parties agree to use a two-year average of weather-adjusted annualized consumption (for the twelve months ending February 2013) for customers connected during 2010 and 2011. This annualized weather-adjusted consumption is equal to 76% of the average annual residential consumption contained in PGE's initial load forecast. Hence, the Secondary Monthly Fixed Charge will be 76% of the Base Monthly Fixed Charge.

Q. Please describe how the Secondary Fixed Monthly Charge will be updated in the event PGE files a general rate case with either a 2015 or 2016 test period.

A. The Parties agree that both the Base Fixed Monthly Charge and the Secondary Fixed Monthly Charge will be updated during general rate cases. The Secondary Fixed Monthly Charge will be a percentage of the Base Fixed Monthly Charge. The percentage factor will be the average of the annualized consumption for new (connecting) residential customers during a two-year period, compared to the final Schedule 7 use per customer in the rate case test period. The two-year period shall begin three years prior to the initial filing date and end one year prior to the filing date.

To exemplify, should PGE file a 2015 test period general rate case in early 2014, PGE would calculate the Secondary Monthly Fixed Charge percentage rate by annualizing the 2013 consumption of residential customers who newly connected during 2011 and 2012.

IV. Resolved Streetlighting Issues

Q. Please describe the Partial Stipulation regarding application of the stipulated overall rate of return to lighting and pole prices.

A. The Stipulating Parties agree to apply the stipulated cost of capital to determine the prices for street and area light luminaire and pole investment prices rather than applying the cost of capital used in PGE's initial filing. The application of the stipulated cost of capital provides consistency with PGE's returns among its rate base assets.

Q. Please describe the partial stipulation regarding the reassignment of the cost of maintenance of associated circuits from distribution to the maintenance prices for Schedule 91 Options A and B, Schedule 95 Option A, and Schedule 15 prices.

A. The stipulating parties agree to directly assign the maintenance of associated circuits rather than recover the costs through distribution. PGE had proposed, with its initial filing, to change the way circuit maintenance is recovered by including it in general distribution O&M.

Q. How does PGE currently recover the maintenance of associated circuits?

PGE currently directly assigns the maintenance costs of associated circuits. The stipulating parties agree to disregard PGE's proposal to change the method used to recover the cost of maintaining associated circuits.

Q. Please describe the Partial Stipulation regarding the Option B pole price calculation.

A. The Stipulating Parties agree to use a replacement rate of 0.2% for calculating the Option B pole price for the purposes of settlement. The price for Option B poles is calculated by multiplying the Option A pole price by the 0.2% pole replacement rate.

Q. Please describe the Partial Stipulation regarding the resolution of the demarcation of the point of delivery for Option C circuits.

A. PGE and the COP commit to resolve the demarcation of the point of delivery on the circuit for Option C streetlights that are converted from existing Option B streetlights. Some Option B installations were done before the current standards. PGE and the COP commit to resolving the appropriate location on the circuit to demarcate the change in ownership and concerns including but not limited to code compliance, accessibility, and safety. The resolution will take place outside of the UE 262 proceeding.

Q. What is the significance of the demarcation of the point of delivery for Option C circuits?

A. The point of delivery determines the location on the circuit that ownership changes between PGE and the customer. PGE maintains the circuit on their side of the point of delivery and the customer maintains the circuit on their side of the point of delivery.

Q. Will this partial stipulation cause changes to the UE 262 revenue requirements?

A. No.

Q. Does this conclude your testimony?

A. Yes.

EXHIBIT 201

QUALIFICATIONS OF CHRIS W. HENDRIX

Chris W. Hendrix

Director of Markets & Compliance
Wal-Mart Stores, Inc.
Business Address: 2001 SE 10th Street, Bentonville, AR, 72716-5530
Business Phone: (479) 204-0845
Email: chris.hendrix@wal-mart.com

EXPERIENCE

2003 – Present
Wal-Mart Stores, Inc., Bentonville, AR
Director of Markets & Compliance (2009 – Present)
General Manager (2003 – 2009)

2002 –2003
TXU Energy, Dallas, TX
Manager – Retail Pricing (2002 –2003)

1997 - 2001
Enron Energy Services, Houston, TX
Manager – Target Markets (2002 –2003)
Manager – Product Development/Structuring (1999 – 2001)
Senior Specialist (1997 – 1999)

1990 - 1997
Tenneco Energy, Houston, TX
Senior Rate Analyst (1994 – 1997)
Accounting Analyst (1992 – 1994)
Accountant (1991 – 1992)

EDUCATION

1994	**University of Houston**	M.B.A, Finance & International Business
1991	**University of Houston**	B.B.A, Accounting (Magna Cum Laude)

INDUSTRY ORGANIZATIONS

COMPETE Coalition
Board Member (2008 – present)

National Energy Marketers Association
Executive Committee and Policy Chair (2006 – present)

NEPOOL (ISO New England)
Participants Committee (2011 – present)
Markets Committee (2011 – present)
Consumer Liaison Group (2011 – present)

PJM Interconnection
Members Committee (2011 – present)

Electric Reliability Council of Texas (ERCOT)
Technical Advisory Committee - TAC (2004 – 2006)

TESTIMONY

1998

Oklahoma Corporation Commission Cause No. PUD 980000177: Joint Application of Oklahoma Natural Gas Company, A Division of Oneok, Inc., Oneok Gas Transportation, a Division of Oneok, Inc., and Kansas Gas Service Company, a Division of Oneok, Inc., for Approval of Their Unbundling Plan for Natural Gas Services Upstream of the Citygates or Aggregation Points.

2012

Arizona Docket No. E-01345A-11-0224: Settlement Testimony in the Matter of the Application of Arizona Public Service Company for a Hearing to Determine the Fair Value of the Utility Property of the Company for Ratemaking Purposes, to Fix a Just and Reasonable Rate of Return Thereon, and to Approve Rate Schedules Designed to Develop Such Return.

CERTIFICATE OF SERVICE

I hereby certify that I served the **Joint Testimony in Support of Second Partial Stipulation** by electronic mail to those parties whose email addresses appear on the attached service list for OPUC Docket No. UE 262.

DATED at Portland, Oregon, this 20th day of August, 2013.

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