UE 319 / PGE / 1200
Dammen – Riter

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 319

Load Forecast

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Sarah Dammen
Amber Riter

February 28, 2017

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I. Introduction and Summary

Q. Please state your names and positions with Portland General Electric (PGE).

A. My name is Sarah J. Dammen. I am the Manager of Financial Forecasting and Economic Analysis at PGE.

My name is Amber M. Riter. I am an Economist and the Lead Load Forecast Analyst at PGE.

We are responsible for developing PGE's energy deliveries forecast. Our qualifications appear at the end of this testimony.

Q. What is the purpose of your testimony?

A. Our testimony presents PGE's 2018 test year energy and customer forecast. We note that we use the terms "energy deliveries" and "load forecast" interchangeably in this testimony.

Q. What load forecast related request does PGE make of the Commission in this proceeding?

A. We request the Commission: 1) accept as a preliminary matter our forecast of energy deliveries which reflects methodological and modeling changes described below; and 2) set a schedule in this proceeding allowing for periodic updates of the energy delivery forecast for 2018.

Q. Please describe PGE's delivery forecast.

A. PGE's 2018 test year energy forecast is for energy deliveries of 19,124 thousand megawatt-hours (MWh), on a cycle-month (billing) basis, including deliveries to customers who opted out of PGE cost-of-service rates for direct access under Schedules 485 and 489. The forecast reflects current expected economic conditions for Oregon in 2018, as well as operational changes among PGE's largest customers and savings from incremental energy efficiency (EE) programs that are funded through Schedule 109 Incremental EE Funding per Senate Bill 838 (SB 838).

Q. How does the 2018 forecast compare to recent historical demand?

A. Similar to the energy delivery trends of recent years, the 2018 forecast reflects stronger growth in deliveries to industrial (primary voltage service) customers relative to significantly lower growth anticipated in the residential and commercial customer classes. Industrial deliveries growth is related to high-tech expansion and new data centers; and while stronger than other customer classes, the rate of growth in deliveries to industrial customers has slowed as a large high-tech construction project nears completion.

Table 1, below, summarizes the MWh delivery forecast in annual percentage changes by voltage service customer class on a weather adjusted billing cycle basis from 2014 through 2018.

Table 1

Percent Change in MWh Delivery from Preceding Year: 2014-2018

Voltage Service Class	2014	2015	2016	2017 (E)	2018 (E)
Residential	0.1%	-0.7%	0.5%	-0.6%	0.0%
Secondary	1.7%	0.3%	-1.3%	-0.2%	-0.7%
Transmission	-21.9%	4.2%	-56.2%	-5.5%	-2.2%
Primary	8.3%	7.0%	1.5%	1.0%	2.5%
Street Lighting	-9.7%	-14.2%	-13.9%	-15.8%	-12.2%
Total	0.8%	1.2%	-2.6%	-0.3%	0.2%

Q. Does PGE adjust the base forecast for price elasticity effects?

A. No. PGE expects customers to respond to price increases by making behavioral changes to decrease usage in the short-term and making changes to the capital stock including purchasing more energy efficient appliances and equipment in the long term. However, as stipulated in PGE's 2016 General Rate Case (UE 294) no price elasticity adjustments are made to the 2018 test-year forecast.

Q. Did you make any adjustments for incremental energy efficiency to the forecast?

A. Yes. We adjusted the forecast to account for the impact of PGE's incremental EE programs funded through Schedule 109 Incremental EE Funding, enabled by SB 838, as forecasted by the Energy Trust of Oregon (ETO), and updated in November of 2016. Since EE trends, including Senate Bill 1149 (SB 1149)[1] measures, are assumed to be captured implicitly in the forecast model, no explicit adjustments are made for SB 1149 savings. The incremental EE program levels reflect the increased funding for EE programs under Senate Bill 838, starting in November 2016, the first month of the forecast. As stipulated in UE 262, PGE implemented a quarterly ramping of incremental EE savings to reflect the ETO's historic pattern of EE savings and updated the quarterly ramping to reflect the 5-year average of quarterly achieved savings from 2011 to 2015.

Q. What is the impact of incremental EE programs savings on the forecast?

A. We estimate a total of 301.7 thousand MWh or 1.6% savings from these programs in the 2018 test year based on the EE savings starting in November 2016 and accumulating through December 2018. PGE Exhibit 1202 shows the forecast adjusted for incremental EE savings and PGE Exhibit 1203 shows the savings from the incremental EE programs that are included in PGE's delivery forecast.

[1] Among other things, Oregon Senate Bill 1149 established the 3% public purpose charge to fund and encourage energy conservation.

II. Model and Forecast Process

Q. Please summarize the process you use to develop the retail energy delivery forecast.

A. We use monthly time-series regression models to estimate the residential, commercial and manufacturing sectors, based on the historic relationship between energy deliveries and economic variables, weather variables, and seasonal control variables. The most current forecasted explanatory variables are applied to the coefficients from the regression models to develop the energy delivery forecast.

Q. Are these models new or different from previous PGE energy delivery models?

A. No. The forecast models and process remain fundamentally the same as those used in previous filings with the Commission. PGE's past load forecast testimony describes, in detail, the theory and structure of our model, as well as our forecast processes. These were most recently submitted in PGE's 2017 Net Variable Power Cost filing[2] and 2016 General Rate Case[3].

Q. Does PGE intend to update its 2018 forecast during this case?

A. Yes, we intend to update the test-year forecast as we have in prior cases. Updates include model re-estimation to incorporate actual load and economic data as they become available and changes in forward looking inputs, including the economic outlook for the U.S. and Oregon, and any changes to large customers' usage forecasts.

Q. What sources of information do you use to forecast electricity deliveries?

A. PGE relies on two sources of economic information for the forecast: 1) IHS Global Insight for a national economic forecast; and 2) the Oregon Department of Administrative Services'

[2] See Docket No. UE 308, Load Forecast Work Papers
[3] See Docket No. UE 294, Exhibit 1200

Office of Economic Analysis (OEA) for the Oregon economic forecast. Global Insight's November 2016 forecast and OEA's December 2016 forecast were used to develop the forecast for this proceeding. In addition, customers who are large energy users provide us with specific operational information, direct inputs and, if available, forecasts of energy use. PGE's Corporate Finance Group performs credit-risk analysis for these large customers, providing additional credit-risk and financial performance information on our large customers.

Q. What assumption did you make regarding weather variables in the forecast?

A. The test-year forecast is based on a trended normal weather assumption to capture gradual warming observed in the Portland area over the last 40 years. The normal weather series is estimated using monthly degree day data from 1941 to 2015, with a simple average from 1941 to 1975 and a linear trend fit to data from 1976 to 2015.

Q. Is the assumption regarding weather variables used in the forecast different from that used in prior PGE forecasts?

A. Yes. Since UE 180, PGE has used a 15-year moving average to represent normal weather conditions.

Q. Why is PGE proposing a change in the weather forecast assumption?

A. PGE strives for an expected mid-point load forecast; that is, a "50/50" load forecast where there is a 50 percent chance that the actual outcome falls short of or exceeds the forecast. To achieve this, forecast assumptions must also be based on an expected mid-point, where it is equally likely that the outcome falls short of or exceeds the assumption. In the case of a persistent warming trend, as experienced in the Pacific Northwest, a moving average approach contains a cold bias[4] and does not achieve a 50/50 forecast. PGE proposes the trended weather approach to better approximate a 50/50 forecast for expected weather.

Q. Why is a trended approach recommended rather than a shortening of the time period used for the normal weather assumption?

A. The justification for using a 15-year moving average to represent normal weather conditions as presented in UE 180 was to better capture warming trends experienced in PGE's service area as compared to a 30-year moving average. Importantly, this approach balanced the need to minimize bias without subjecting PGE's models to increased volatility which can be associated with too short a time frame for a normal weather assumption. While the 15-year moving average is an improvement from a 30-year moving average, the trended weather approach can further reduce bias without sacrificing stability due to the long historical series used to estimate the expected weather. See PGE Exhibit 1211 for a comparison of these two approaches.

Q. How was this approach developed?

A. The trended normal weather approach used for the test year load forecast was developed in alignment with analysis published in several academic journals and used by the National Oceanic and Atmospheric Association (NOAA) to produce a trended series available through its Local Climate Analysis Tool (LCAT). *"Estimation and Extrapolation of Climate Normals and Climatic Trends"*[5] lays the groundwork for this approach and compares results to several alternatives. The authors find that their 'hinge-fit' model (i.e., the approach that PGE refers to as trended weather) outperforms a single straight line fit and optimal climate

[4] A cold bias in the weather assumptions means that we systematically underestimate average temperature.
[5] Livezey, Robert E. et al. "Estimation and Extrapolation of Climate Normals and Climatic Trends." Journal of Applied Meteorology and Climatology, vol. 46, 2007, pp. 1759-1776.

normal (shortened time period), making a strong case for the application of a hinge-fit model with a 1975 breakpoint (hinge) for much of the United States and Canada. An important condition for the application of the trended weather (hinge-fit) approach is that regional trends are "approximately linear" and that the 1975 breakpoint, which is applied in a standardized fashion based on climate scientist reports that the period of steady global warming began in the mid-1970s, is relevant to the region of interest. PGE's analysis finds weather trends as measured at Portland International Airport meet the assumption of "approximately linear" and also finds 1975 to be generally consistent as a midpoint for breakpoint analysis.

Q. What are the primary impacts of this weather assumption on PGE's load forecast results?

A. Using the trended weather assumption decreases PGE's annual energy deliveries forecast by approximately 61.2 thousand MWh's, or 0.3%, in 2018 compared to the use of a 15-year normal weather assumption. Within this total change is a seasonal shift in PGE's energy deliveries, primarily to PGE's residential customers, decreasing deliveries in the heating months and increasing deliveries in the cooling season.

Q. How does this weather assumption impact the weather adjustment used in PGE's decoupling calculation?

A. The weather assumption, based on the trended weather approach, will be used for the weather adjustment in the decoupling calculation beginning in 2018. Using the trended weather normal for the weather adjustment is appropriate and has no impact on decoupling since the baseline use-per-customer would also be set using the trended weather forecast assumption. Per Special Condition 2 of PGE Schedule 123-6, "Weather-normalized energy usage by applicable rate schedule will be determined in a manner equivalent to that used for determining the forecasted loads used to establish base rates."

Q. How current are the data you use to estimate the model?

A. The models estimated for use in this proceeding are based on data through the October 2016 billing cycle. The model estimation periods vary by forecast group with the estimation period shortened for many models based on analysis of the relationship between energy deliveries and the economic drivers in the models described in UE 294.

Q. What end-use sectors do you forecast in the model?

A. We forecast demand (MWh delivery) by residential, commercial, manufacturing customers and energy served under miscellaneous rate schedules. Residential customers are mostly households. We group commercial and manufacturing customers according to the North America Industrial Classification System (NAICS) definition of business segments. Commercial customers typically are businesses providing services, such as retail and wholesale establishments, schools, hospitals, government, and financial institutions. Manufacturing customers include producers of paper, lumber, steel, machinery, micro-processors, computers, and transportation equipment.

Q. How do you forecast the ultimate loads delivered to the PGE system?

A. This process involves three steps: 1) aggregated cycle-based NAICS sector MWh deliveries are converted into voltage service levels using ratios based on historical data; 2) cycle-based energy deliveries are converted to calendar-based deliveries using cycle-to-calendar ratios; and 3) transmission and distribution (line) losses are added to deliveries at the meter to obtain the bus bar energy (MWh or MWa) required to meet the end users' demand. For test year 2018, we apply updated line loss factors beginning in 2015 as established in UE 283.

Q. How do you forecast monthly net system peak demand?

A. Regression-based models are used to forecast PGE's monthly peak demand. The regression-based approach estimates monthly and seasonal peak demands as a function of peak day heating degree days, cooling degree days, prior day cooling degree days, average wind and monthly energy interacted with season. The coefficients are applied to forecasted monthly energy deliveries (MWa), weather variables and appropriate seasonal dummy variables to estimate the forecast. PGE Exhibit 1209 displays the forecast of total distribution loads in annual average energy (MWa) and peak demand (MW).

Q. Is this approach different from previous general rate case monthly peak demand models?

A. Yes. In prior forecasts, PGE used a load factor build-up approach where monthly voltage-level and system load factors were used to calculate the monthly peak MW based on the projected average energy (MWa). The difference between the annual net system peak demand under these two approaches is approximately 47 MW in 2018.

Q. What benefit does PGE see in using regression based peak demand models?

A. PGE proposes regression-based peak forecast models to align with recommendations made in the industry benchmarking performed by Itron in 2014 and referenced in testimony provided in UE 294. Regression-based models offer flexibility in addressing seasonal patterns exhibited in PGE's recent historical peaks apart from modeling of seasonal trends in the energy models. This approach also allows for a more direct analysis of the impact of extreme weather events on PGE loads. The regression-based models were reviewed with stakeholders in PGE's 2016 Integrated Resource Plan (IRP) public process with a workshop held in July 2015.

III. Forecast Results

Q. What are the key results of PGE's residential sector forecast?

A. For the test year 2018, we forecast deliveries of 7,563 thousand MWh to 772,010 residential customers. Declines in residential use per customer, driven by assumed incremental energy efficiency programs, are offset by customer growth of 1.3% in 2018 for annual residential energy deliveries growth of 0.0%. The residential forecast includes residential outdoor area lighting energy. PGE Exhibit 1204 shows the forecast of building permits, new connects, and customer counts. PGE Exhibit 1205 displays the forecast of kWh use per customer and deliveries to residential customers in detail.

Q. What are the key results of PGE's commercial sector forecast?

A. For test year 2018, we forecast deliveries of 6,819 thousand MWh to NAICS-based commercial customers, a 0.9% decrease over forecasted 2017 energy deliveries of 6,878 thousand MWh. Declining energy deliveries to the commercial NAICS groups reflect savings from incremental EE programs larger than those projected in the residential sector, impacting the NAICS-based commercial sector by -2.5% for 2018. PGE Exhibit 1206 contains the detailed forecast of deliveries to commercial consumers.

Q. What are the key results of PGE's manufacturing sector forecast?

A. For the test year 2018, we forecast deliveries of 4,589 thousand MWh to NAICS-based manufacturing customers, 2.0% higher than forecasted 2017 deliveries, following growth of 6.3% in 2015 and a decline of 9.1% in 2016. The manufacturing forecast reflects continued expansion by high-tech and related companies in our service territory (on primary voltage service). Manufacturing sector deliveries can show large swings from year to year due to specific individual company operations and industry conditions. PGE Exhibit 1207 presents the detailed delivery forecast of the manufacturing sector.

Q. What are the key results of PGE's miscellaneous rate schedules forecast?

A. Deliveries to miscellaneous rate schedules account for approximately 1% of total retail deliveries in 2018. PGE Exhibit 1208 displays the miscellaneous schedules forecast.

Q. Did you make a separate forecast of delivery to Rate Schedule 485/489 customers?

A. Yes. PGE separates the delivery of energy to customers who chose service under Schedule 485/489 (direct access) by 2016 year-end from the energy delivery forecast to customers served under PGE cost-of-service (COS) rates, including variable-price (market power) customers. Schedule 485/489 is the only service under which we forecast customers to receive direct access service in 2018. We prorate the COS and Schedule 485/489 deliveries by applying these customers' respective historical shares of service level or revenue class energy to the forecast. PGE Exhibit 1210 shows the forecast of deliveries in 2018 to PGE COS customers and direct access (Schedule 485/489) customers.

V. Forecast Uncertainty

Q. Is the forecast subject to uncertainty?

A. Yes. The MWh delivery forecast we submit in this filing is our "expected" or mid-point estimate but is subject to uncertainty. As such, it is a 50/50 "point" forecast, 50% chance that the actual outcome falls short of or exceeds the forecast. As with any forecast, actual conditions may differ from what we assumed or anticipated in the forecast, resulting in a different outcome.

As mentioned with respect to the proposed trended weather approach, the accuracy of a forecast depends not only on the performance of the model specification, but also on the accuracy of the independent variables driving the forecast. In our model, the independent variables include weather variables and the economic forecast drivers.

The other major areas of uncertainty involve inputs and assumptions surrounding implementation of EE programs, key customers' operational decisions, new customers' entry or existing customers' exit, and the absence of unforeseen natural disasters, wars or geopolitical turmoil. Future outcomes of these variables could result in a significant variance from the forecast.

Q. How do you address uncertainty in your forecast?

A. PGE aims to use the best information available as input assumptions to reduce uncertainty and updates the forecast as conditions change. This includes using current information, sales data and forecast drivers. Conditions could and will likely change between the time PGE developed this forecast and the start of the test year. Our assumptions will be revisited as updated forecasts are released for input assumptions.

Q. Do changing economic conditions have an effect on PGE's forecast?

A. Yes. Changing economic conditions are an important source of uncertainty in PGE's delivery forecast. All else equal, economic outcomes that differ from the economic forecast assumption used to drive PGE's forecast of MWh delivery result in delivery outcomes that differ from the initial forecast. In addition to changing economic conditions, the changing relationship between economic conditions and energy deliveries can also affect the forecast.

The economic climate could also lead PGE's key customers to operate differently than planned. They could shut down plants, curtail operations, or add new capacity that we did not anticipate because of their own specific circumstances. In fact, since the onset of the Great Recession in 2008 a number of large customers have filed for bankruptcy, liquidated business, changed ownership or permanently shut down operations, which has substantially affected PGE's actual and anticipated MWh delivery. With respect to announced new developments, we specifically include in this forecast planned expansions and operational changes by high-tech and metals manufacturing customers. If any of these assumptions fail to materialize, significant deviations from the test year forecast would result. While the forecast is developed to account for both upside potential (expansion) as well as downside risk, the inherent risks are biased toward the downside because it takes longer for a customer to plan and increase capacity than to shut down.

Q. Is weather also an area of uncertainty?

A. Yes. In UE 180, PGE discussed extensively the uncertainty of the delivery forecast with regard to weather, in terms of the average or the mean condition and the variance or departure from the average condition in the forecast year. The impact of this uncertainty, expressed as deviation from the mean, is significant because of the large impact of temperature on MWh usage. The proposed trended weather approach addresses the mean condition; however weather will likely deviate from the assumed weather in any given year. PGE estimates that one degree variation in temperature could affect (total retail) MWh usage by as much as 1.5% in peak months and as much as 0.7% on an annual basis.

VI. Qualifications

Q. Ms. Dammen, please describe your qualifications.

A. I received my Bachelor of Arts and Master of Science, both in Economics from Oregon State University. I have been a practicing Economist for the past 13 years. I am currently a member of the Northwest Power Planning Council's Demand Forecasting Advisory Committees and have previously served on TriMet's General Manager's Budget Task Force. Prior to joining PGE in 2012, I worked at NW Natural, performing load forecasting and developing the IRP; I was an economic consultant at ECONorthwest, specializing in quantitative economics and transportation economics; and was an economist for the U.S. Department of Transportation at the Volpe Transportation Systems Center.

Q. Ms. Riter, please describe your qualifications.

A. I received my Bachelor of Arts in Economics from New Mexico State University and my Master of Arts in Economics from The University of New Mexico. I have been working as an Economist in energy deliveries forecasting for the past 7 years. Prior to joining PGE in 2014, I worked at PNM Resources, the parent company of Public Service Company of New Mexico (PNM) and Texas New Mexico Power (TNMP), performing load forecasting and load research analysis.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
1201	(Base) Delivery Forecast by Market Segment and Service Level
1202	(Post EE Adjustment) Delivery Forecast by Market Segment and Service Level
1203	Forecast of Incremental Energy Efficiency Program Savings
1204	Residential Building Permits, New Connects, and Customer Counts (Accounts)
1205	Forecast of Residential Use per Customer and Ultimate Deliveries
1206	Commercial Deliveries Forecast by NAICS Cluster
1207	Manufacturing Deliveries Forecast by NAICS Cluster
1208	Forecast of Deliveries to Miscellaneous Rate Schedules
1209	Total Deliveries and Demand Forecast
1210	Forecast of 2018 Deliveries to Cost-of Service and Direct Access Customers
1211	Trended Weather HDD and CDD Comparison
1212	Trended Weather Literature

Exhibit 1201: Delivery Forecast (Base) by Market Segment and Service Level

(at average weather)

Base (not adjusted) Forecast (1)

	(in thousand MWh)					% Change (2)				
	2014	**2015**	**2016**	**2017**	**2018**	**2014**	**2015**	**2016**	**2017**	**2018**
Schedule 7	7,613	7,563	7,600	7,599	7,661	0.2%	-0.7%	0.5%	0.0%	0.8%
Residential Lighting	5	3	3	3	3	-25.9%	-33.6%	-2.2%	1.3%	0.0%
Total Residential	7,618	7,567	7,604	7,602	7,664	0.1%	-0.7%	0.5%	0.0%	0.8%
Commercial (3)	6,994	6,988	6,920	6,948	6,985	1.2%	-0.1%	-1.0%	0.4%	0.5%
Manufacturing (3)	4,616	4,907	4,458	4,512	4,624	1.7%	6.3%	-9.1%	1.2%	2.5%
Miscellaneous Customers	193	190	166	160	154	-4.9%	-1.4%	-12.8%	-3.4%	-4.0%
Secondary Voltage	7,312	7,320	7,239	7,296	7,344	1.7%	0.1%	-1.1%	0.8%	0.7%
Total General Service	7,504	7,510	7,405	7,456	7,498	1.5%	0.1%	-1.4%	0.7%	0.6%
Primary Voltage Service	3,459	3,700	3,756	3,803	3,911	8.3%	7.0%	1.5%	1.2%	2.8%
Transmission Voltage Service	839	874	382	361	353	-21.9%	4.2%	-56.2%	-5.5%	-2.2%
Total Retail	19,420	19,651	19,147	19,222	19,426	0.8%	1.2%	-2.6%	0.4%	1.1%

1/ SDEC16B

2/ calculated from rounded numbers

3/ by NAICS grouping

4/ Total Retail equals Total Residential + Commercial + Manufacturing + Miscellaneous. Also equals Total Residential + Total General + Primary Voltage Service + Transmission Service, totals may not foot due to rounding.

Exhibit 1202: Delivery Forecast (Price & Incremental EE) by Market Segment and Service Level

(at average weather)

Net of Price Elasticity and Incremental Energy Efficiency (1)

	(in thousand MWh)					% Change (2)				
	2014	**2015**	**2016 (3)**	**2017**	**2018**	**2014**	**2015**	**2016**	**2017**	**2018**
Schedule 7	7,613	7,563	7,600	7,556	7,560	0.2%	-0.7%	0.5%	-0.6%	0.0%
Residential Lighting	5	3	3	3	3	-25.9%	-33.6%	-2.2%	1.3%	0.0%
Total Residential	7,618	7,567	7,604	7,560	7,563	0.1%	-0.7%	0.5%	-0.6%	0.0%
Commercial (3)	6,994	6,988	6,920	6,878	6,819	1.2%	-0.1%	-1.0%	-0.6%	-0.9%
Manufacturing (3)	4,616	4,907	4,458	4,497	4,589	1.7%	6.3%	-9.1%	0.9%	2.0%
Miscellaneous Customers	193	190	166	160	154	-4.9%	-1.4%	-12.8%	-3.4%	-4.0%
Secondary Voltage	7,312	7,320	7,239	7,220	7,166	1.7%	0.1%	-1.1%	-0.3%	-0.7%
Total General Service	7,504	7,510	7,405	7,380	7,320	1.5%	0.1%	-1.4%	-0.3%	-0.8%
Primary Voltage Service	3,459	3,700	3,756	3,793	3,888	8.3%	7.0%	1.5%	1.0%	2.5%
Transmission Voltage Service	839	874	382	361	353	-21.9%	4.2%	-56.2%	-5.5%	-2.2%
Total Retail	19,420	19,651	19,147	19,094	19,124	0.8%	1.2%	-2.6%	-0.3%	0.2%

1/ SDEC16E

2/ calculated from rounded numbers

3/ by NAICS grouping

4/ Total Retail equals Total Residential + Commercial + Manufacturing + Miscellaneous. Also equals Total Residential + Total General + Primary Voltage Service + Transmission Service, totals may not foot due to rounding.

Exhibit 1203: Forecast of Incremental Energy Efficiency (EE) Savings

(in thousand MWh)

	2017	2018
Base (B) Forecast	19,222	19,426
Incremental EE Savings (1)	(128)	(302)
Post-EE Forecast (E) (2)	19,094	19,124

1/ Energy Trust of Oregon (ETO) annual savings deployment forecast.

2/Totals and differences may not foot due to rounding.

Exhibit 1204: Residential Building Permits, New Connects, Vacancy Rates and Customer Counts History and Forecast

	2014	2015	2016 (1, 2)	2017	2018
Building Permits (3)					
Single-Family	8,482	9,999	10,629	10,472	10,813
Multi-Family	7,372	6,371	8,082	8,129	8,597
New Connects					
Single-Family	3,259	4,480	5,291	5,737	5,849
Multi-Family	3,539	3,965	4,503	5,266	5,287
Mobile Home	49	64	112	60	60
Other	10	41	13	24	24
Total Residential Connects	6,857	8,550	9,919	11,087	11,220
Commercial Connects	1,669	1,935	2,025	2,136	2,141
Total New Connects	8,526	10,485	11,944	13,223	13,361
Residential Customer Counts					
Single-Family Heat	109,246	109,572	110,374	110,730	111,083
Single-Family Non-Heat	350,673	354,075	358,731	362,999	367,473
Multiple-Family Heat	178,802	180,880	184,326	188,476	192,087
Multiple-Family Non-Heat	57,604	58,743	59,641	60,929	62,484
Mobile Home Heat	30,401	30,417	30,501	30,335	30,147
Mobile Home Non-Heat	3,886	3,908	3,932	3,922	3,904
Other	4,892	4,872	4,883	4,860	4,831
Total Number of Accounts (4)	735,504	742,467	752,388	762,251	772,010

1/ includes actuals through December 2016, except for connects which include actuals through November 2016

2/ forecasted values are identical for base, price-effect and energy efficiency forecast

3/ Oregon building permits

4/ includes vacant accounts

Exhibit 1205: Forecast of Residential Use per Occupied Account and Ultimate Deliveries

(at average weather)

Net of Price Elasticity and Incremental Energy Efficiency (1)

Use per Customer (kWh)	2014 (2)	2015 (2)	2016 (2)	2017	2018
Single-Family Heat	15,052	14,808	14,813	14,347	14,119
Single-Family Non-Heat	10,312	10,112	10,010	9,959	9,873
Multiple-Family Heat	8,302	8,220	8,090	7,890	7,804
Multiple-Family Non-Heat	6,074	6,004	5,959	5,916	5,872
Mobile Home Heat	13,993	14,028	14,167	13,622	13,497
Mobile Home Non-Heat	10,626	10,722	10,914	10,385	10,294
Other	10,561	10,703	10,828	10,500	10,472
Average Use per Customer	10,351	10,191	10,102	9,913	9,793
Ultimate Deliveries (million of kWh)					
Single-Family Heat	1,644	1,623	1,635	1,589	1,568
Single-Family Non-Heat	3,616	3,580	3,591	3,615	3,628
Multiple-Family Heat	1,484	1,487	1,491	1,487	1,499
Multiple-Family Non-Heat	350	353	355	360	367
Mobile Home Heat	425	427	432	413	407
Mobile Home Non-Heat	41	42	43	41	40
Other	52	52	53	51	51
			0	0	0
Schedule 7 Deliveries	7,613	7,563	7,600	7,556	7,560
Residential Lighting	5	3	3	3	3
Total Residential Deliveries	7,618	7,567	7,604	7,560	7,563

1/ SDEC16E

2/ weather-adjusted

Exhibit 1206: Commercial Deliveries Forecast by NAICS Cluster

(at average weather)

Net of Price Elasticity and Incremental Energy Efficiency

	(in thousand MWh)					% Change (1)				
	2014 (2)	2015 (2)	2016 (2)	2017	2018	2014	2015	2016	2017	2018
Food Stores	466	456	431	426	419	2.1%	-2.0%	-5.5%	-1.1%	-1.7%
Govt. & Education	995	998	969	962	960	1.8%	0.3%	-3.0%	-0.7%	-0.1%
Health Services	731	729	721	725	726	0.3%	-0.3%	-1.2%	0.6%	0.1%
Lodging	105	105	107	104	103	-0.6%	0.8%	1.6%	-2.6%	-1.6%
Misc. Commercial	639	640	665	643	632	0.7%	0.1%	4.0%	-3.3%	-1.6%
Department Stores/Malls	351	350	343	354	353	1.1%	-0.3%	-2.1%	3.2%	-0.2%
Office & F.I.R.E. (3)	1,050	1018	993	969	957	1.7%	-3.1%	-2.5%	-2.4%	-1.2%
Other Services	803	834	863	860	855	0.3%	3.8%	3.5%	-0.3%	-0.6%
Other Trade	724	727	720	714	703	1.5%	0.5%	-1.0%	-0.8%	-1.6%
Restaurants	478	481	480	488	486	0.7%	0.5%	-0.2%	1.6%	-0.4%
Trans., Comm. & Utility	652	649	629	632	625	1.5%	-0.5%	-3.1%	0.6%	-1.2%
Total Commercial	6,994	6,988	6,920	6,878	6,819	1.2%	-0.1%	-1.0%	-0.6%	-0.9%

1/ calculated using rounded-numbers

2/ weather-adjusted

3/ Finance, Insurance, and Real Estate

Exhibit 1207: Manufacturing Deliveries Forecast by NAICS Cluster

(at average weather)

Net of Price Elasticity and Incremental Energy Efficiency

	(in thousand MWh)					% Change (1)				
	2014 (2)	2015 (2)	2016 (2)	2017	2018	2014	2015	2016	2017	2018
Food & Kindred Products	236	247	257	263	264	5.4%	4.8%	3.9%	2.2%	0.5%
High Tech	2,142	2,368	2,459	2,512	2,614	10.3%	10.6%	3.8%	2.1%	4.1%
Lumber & Wood	98	95	93	97	96	-0.9%	-2.8%	-2.9%	4.5%	-0.4%
Metal Manufacturing and Fab	493	478	450	427	426	-1.5%	-2.9%	-5.9%	-5.2%	-0.1%
Other Manufacturing	750	737	712	729	729	10.1%	-1.7%	-3.4%	2.3%	0.0%
Paper & Allied Products	712	788	313	301	292	-23.1%	10.7%	-60.2%	-4.0%	-3.1%
Transportation Equipment	185	191	173	169	167	10.0%	3.5%	-9.6%	-2.4%	-0.9%
Total Manufacturing	4,616	4,907	4,458	4,497	4,589	1.7%	6.3%	-9.1%	0.9%	2.0%

1/ calculated using rounded-numbers

2/ weather-adjusted

Exhibit 1208: Forecast of Deliveries to Miscellaneous Rate Schedules

Net of Price Elasticity and Incremental Energy Efficiency

	(in thousand MWh)					% Change (1)				
	2014	2015	2016	2017	2018	2014	2015	2016	2017	2018
Residential										
Outdoor Area Lighting (15R) (3)	5	3	3	3	3	-25.9%	-33.6%	-2.2%	1.3%	0.0%
Secondary (Commercial)										
Outdoor Area Lighting (15C) (4)	15	13	13	13	13	-7.5%	-9.0%	-1.8%	-0.7%	-0.1%
Farm Irrigation et al. (5)	80	92	80	86	87	2.5%	15.6%	-13.4%	7.3%	1.3%
Street and Other Lighting (6)	98	84	73	61	54	-9.7%	-14.2%	-13.9%	-15.8%	-12.2%
Total Miscellaneous Commercial	193	190	166	160	154	-4.9%	-1.5%	-12.8%	-3.4%	-4.0%
All Miscellaneous Schedules (7)	198	193	169	163	157	-5.6%	-2.3%	-12.6%	-3.3%	-3.9%

1/ calculated from rounded numbers

2/ identical for non-price, price-effect and post-EE forecasts

3/ existing Schedule 15R

4/ existing Schedule 15C

5/ existing Schedules 47 & 49

6/ existing Schedules 91, 92 & 93, and Schedule 95 beginning in 2013. Rate schedule 93 moved to Rate Schedule 38 in 2014.

7/ equals line 2 + line 7

Exhibit 1209: Total Delivery and Demand Forecast

Net of Incremental Energy Efficiency (4)

	Million kWh (1)	Average MW (2)	Peak MW (3)
2009	19,165	2,337	3,949
2010	18,893	2,274	3,582
2011	19,138	2,334	3,555
2012	19,248	2,312	3,597
2013	19,265	2,346	3,869
2014	19,420	2,329	3,866
2015	19,651	2,344	3,914
2016	19,147	2,287	3,726
2017	19,094	2,320	3,594
2018	19,124	2,323	3,603

1/ cycle-month basis, at end-user meters, weather adjusted; includes actual deliveries through 2016

2/ calendar basis, at the bus bar, actual through 2016, not adjusted for weather.

3/ coincidental annual system peak at bus bar; includes actual through 2016, not adjusted for weather.

4/ 2017 and 2018 are the incremental EE adjusted forecast.

Exhibit 1210: Forecast of 2018 Deliveries to Cost of Service and Direct Access Customers

Net of Incremental Energy Efficiency

(in thousand MWh)

	Cost of Service (1)	Direct Access (2)	Total Delivery (3)
Residential	7,563	0	7,563
Secondary	6,746	521	7,266
Primary	2,785	1,103	3,888
Transmission	59	294	353
Lighting	54	0	54
Total Retail (2)	17,207	1,918	19,125

1/ Includes economic replacement VPO deliveries

2/ Schedule 485/489 deliveries.

3/ Totals may not add due to rounding.

Exhibit 1211: Trended Weather HDD and CDD Comparison

	2018 Weather Variables Based on Trended Weather Approach		2018 Weather Variables Based on 15-Year Average (2001-2015)	
Billing Month	HDD65	CDD65	HDD65	CDD65
January	750.9	0.0	767.5	0.0
February	648.5	0.0	675.1	0.0
March	567.5	0.0	584.5	0.0
April	419.7	0.0	449.2	0.1
May	282.3	5.9	307.7	5.6
June	141.3	33.6	158.4	29.8
July	46.1	117.4	45.9	106.6
August	12.8	195.3	5.2	173.2
September	22.4	170.6	18.8	144.9
October	101.9	46.1	121.4	38.3
November	331.0	1.5	351.8	1.9
December	650.3	0.0	662.0	0.0
Annual	3,974.6	570.3	4,147.7	500.5

Exhibit 1212: Trended Weather Approach Resources

Livezey, Robert E. et al. "Estimation and Extrapolation of Climate Normals and Climatic Trends." *Journal of Applied Meteorology and Climatology* , vol. 46, 2007, pp. 1759-1776, http://journals.ametsoc.org/doi/pdf/10.1175/2007JAMC1666.1. Accessed Nov. 2016.

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