CASE: UE 213
WITNESS: George R. Compton

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 100

Staff Testimony in Support of Rate Spread and Rate Design Stipulation

December 15, 2009

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is George R. Compton. I am a Senior Economist, employed by the Economic Research and Financial Analysis Division (ERFA) of the Public Utility Commission of Oregon (OPUC). My business address is 550 Capitol Street NE, Suite 215, Salem, Oregon 97301-2551.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualification Statement is included as Exhibit Staff/101.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. This testimony supports the rate-spread/rate-design stipulation in this case that has been joined by Idaho Power (or Company), OPUC Staff, and Oregon Industrial Customers of Idaho Power (OICIP). The Citizens' Utility Board of Oregon (CUB) does not join the stipulation as it pertains to seasonally differentiated residential rate design.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized as follows:

Topic 1 – General Cost of Service, Revenue Spread, and Rate Design Discussions
Topic 2 – Revenue Spread
Topic 3 – An Affirmative Case for Seasonal Residential Rates
Topic 4 – Accommodating Simplicity/Stability in Rate Design While Minimally Compromising the Objective of Cost Based Rates
Topic 5 – Customer Preferences and the Relevance of Flat Monthly Billing Topic 6 – A Miscellaneous Minor Concern Regarding Residential Season Rates

Q. DID YOU PREPARE EXHIBITS FOR THIS CASE?

A. Yes, they are listed as follows:

101 – Witness Qualification Statement
102 – Stipulated Marginal Costs and Revenue Spread
103 – Stipulated Seasonal Residential Rate Design
104 – Monthly Residential Billing Comparisons

Q. PLEASE INTRODUCE YOUR PRINCIPAL THEMES FOR THIS TESTIMONY.

A. My testimony:

a) Explains the nature of the relatively minor modifications to the company's revenue spread proposal to which the parties stipulated;

b) Reaffirms the merits and benefits of imposing cost-based seasonal utility prices on residential customers; and

c) Present the stipulating parties' residential price structure, which achieves a large measure of rates simplicity/stability without unduly compromising cost accuracy.

TOPIC 1 – A BRIEF, GENERAL DISCUSSION OF COST OF SERVICE, REVENUE SPREAD, AND RATE DESIGN

Q. WHAT IS THE PURPOSE OF A COST-OF-SERVICE STUDY FOR UTILITIES?

A. Cost-of-service studies attempt to determine the full cost of serving each of the different customer classes/rate schedules. The first step is to ascertain the marginal costs of providing generation, transmission, distribution, and miscellaneous customer-classified services to the various customer classes. Relative shares of marginal costs are then translated to equivalent shares of the embedded accounting costs of those same functions. Those shares sum to the total jurisdictional revenue requirement. "Revenue spread," or "spreading of the revenue requirement,[1]" refers to how the utility's entire revenue requirement is allocated to the various customer classes. The purpose of the cost-of-service study is to provide a guide to the revenue spread process.

Q. WHAT IS THE CONNECTION BETWEEN THE COST-OF-SERVICE STUDY AND THE "SPREADING OF THE REVENUE REQUIREMENT?"

A. If cost-of-service studies were uncontestable, and if concerns were absent about a particular rate class receiving an unusually burdensome rate increase, then each customer class could be merely assigned the portion of the overall revenue requirement that was determined by the cost-of-service study. Because those conditions are seldom (if ever) met, the result is class revenue requirements that depart from strict cost-of-service levels in various ways and for various reasons. Among other expedients, the revenue spread "adjustments" in a given general rate case will often include the following: a) a particular customer class may be shielded from receiving a general increase that would take it all the way up to its full cost of service if the impact of such an increase is regarded as particularly onerous; b) some schedule(s) may receive no change in average rates even though the cost-of-service study would warrant a decrease; c) as a norm, most schedules will have their average

[1] "Rate spread" is another commonly used term.

rates increased by either a uniform percentage or by an amount that would place them at a uniform relationship with the cost-of-service results; and d) departing from the just-mentioned norm, some customer classes may receive a percentage overall rate increase that is at least as large as that received by some other class. As will be explained below, all but the last of those measures appear in the revenue spread stipulation for this case.

Q. WHAT IS THE CONNECTION BETWEEN RATE DESIGN AND REVENUE SPREAD?

A. Rate design consists of the service price elements that go into the various rate schedules/tariffs. If the test-year-projected sales volumes are achieved in both kW and kWh, revenues produced by the designed rates will precisely equal the respective schedules' revenue targets as they were spelled out in the revenue spread process.

TOPIC 2 – REVENUE SPREAD

Q. ASSUMING IDAHO POWER RECEIVES THE STIPULATED REVENUE INCREASE, WHAT IS THE REVENUE SPREAD TO WHICH THE AGREEING PARTIES STIPULATED?

A. The agreed upon average percentage rate increases are as follows (from Line 30 of Exhibit Staff/102):

Residential	26.30%
General Service Schedule 7 (Secondary)	24.65%
General Service Schedule 9 (Secondary)	3.24%
General Service Schedule 9 (Primary)	16.50%

Large Power Service Schedule 19 (Primary)	9.28%
Large Power Service Schedule 19 (Transmission)	0%
Unmetered General Service Schedule 40	16.67%
Irrigation Schedule 24 (Secondary)	27.96%
Area Lighting Schedule 15	0%
Municipal Street Lighting Schedule 41	15.09%
Traffic Control Schedule 42	45.20%
Overall Total	**15.42%**

Q. IN COMPARING THOSE STIPULATED FIGURES WITH THOSE FROM THE COMPANY'S ORIGINAL EXHIBIT (I.E., IDAHO POWER/804 TATUM/4),[2] THERE APPEARS TO BE, QUALITATIVELY, VERY LITTLE DIFFERENCE. PLEASE EXPLAIN THE BASES OF THE SIMILARITIES.

A. Besides accepting most of the elements of the Company's cost of service study, Staff also accepted the following Company-proposed ways by which the revenue spread departed from being a straight replication of its final cost of service results:

1. Irrigation Service (Schedule 24) and Traffic Control (Schedule 42) were limited to an increase that would put them at 75% (rather than 100%) of their cost-of-service levels. (*See* Columns I and L, Line 31 of Exhibit Staff/102.)
2. Instead of the cost-of-service-justified rates reduction, Area Lighting and Large Power Service-Transmission (respectively, Schedules 15 and 19-T)

[2] Exhibit Idaho Power/804 Tatum/4 is included as Exhibit Staff/102.

received neither an increase nor a decrease. (*See* Line 30, Columns F and H of Exhibit Staff/102.)

3. To achieve the required overall rate increase, the norm for the remainder of the rate schedules was for each to receive whatever increase would take it to 102.87% of its cost-of-service "target." (*See* Line 31 of Exhibit Staff/102. The Company's index was 103.14%.)

Q. IN YOUR PREVIOUS ANSWER, YOU REFERRED TO "ACCEPTING MOST OF THE ELEMENTS OF THE COMPANY'S COST OF SERVICE STUDY." WHAT WERE THE EXCEPTIONS?

A. Staff proposed, and the Parties accepted *for settlement purposes*,[3] changes to both how generation costs and how transmission costs were to be allocated. A portion (25%) of marginal transmission costs were classified as energy-related (instead of being purely demand-related) and allocated accordingly. Justification for that altered classification is the fact that much of the transmission system serves to reduce energy costs by providing access to distant, cheaper energy resources. In addition, functionalized embedded generation costs were *not* divided into energy-related and demand-related portions prior to their being allocated, but rather were allocated as an integrated whole. This practice comports with the way PacifiCorp's and PGE's production costs are allocated.

[3] Standard settlement protocol is for parties to accept final numerical results without necessarily agreeing to the concepts and theories that may have been originally employed in arriving at those results. In other words, the concepts and theories cannot be regarded as precedent setting.

Q. WHAT WERE OTHER BOTTOM-LINE CONSEQUENCES OF THE ALTERATIONS TO THE COMPANY'S COST-OF-SERVICE STUDY THAT YOU JUST DESCRIBED?

A. Cost-of-service estimates were shifted away from the Residential, Secondary General Service, and Irrigation Service Schedules (Nos. 7, 9-S, and 24) and onto the Large Power Schedules (Nos. 19-P and 19-T). While the shift to Large Power Schedule 19-P was the most consequential (19-T receives no increase in any event), under the stipulation it would still receive an increase that would be substantially below the system average (i.e., 9.28% rather than 15.42%, under the assumption that Idaho Power were to receive its full stipulated increase).

<u>TOPIC 3 – AN AFFIRMATIVE CASE FOR SEASONAL RESIDENTIAL RATES</u>

Q. FOR SOME TIME NOW, ALL OF IDAHO POWER'S MAJOR RATE SCHEDULES IN IDAHO, AND ALL BUT ITS RESIDENTIAL SCHEDULE IN OREGON, HAVE INCORPORATED SEASONALITY IN THEIR RATE DESIGNS. WHAT IS THE BASIS FOR ADJUSTING RATES FOR SEASONALITY?

A. The primary two-fold purposes of rate design as it is applied to a customer class are to recover the portion of the overall revenue requirement allocated to that class, and to provide a signal to customers regarding the costs they are imposing on the system as they consume the utility's output. In the latter regard, marginal-cost pricing comprises the economic-theoretic standard. Energy costs—in terms of market prices and marginal generation plant operating costs—tend to run higher in the summer than in the winter throughout the entire western United States, including Idaho.[4] (*See* Exhibit Idaho Power/802, Tatum/6, particularly July and August.) Incorporating seasonality in rate design enables the capturing of seasonal cost differences.

Q. IN SIMPLE ECONOMICS TERMS, WHAT ARE THE ADVANTAGES OF HAVING A PRICE OF ANYTHING REFLECT ITS COST?

A. If the price of a good or service is too high relative to its cost on the margin, that good or service will be under-consumed in the sense that the cost of its production will be less than the value that would have been achieved had it been produced and consumed. Conversely, if the price of a good or service is too low relative to its cost on the margin, that good or service will be over-consumed in the sense that the cost of its production will be greater than the value that is yielded by its consumption.

Q. YOU HAVE JUST PUT FORTH THE ECONOMIC EFFICIENCY ARGUMENT FOR HAVING PRICES ACCURATELY REFLECT COSTS. IS THERE ALSO A SOCIAL EQUITY ARGUMENT FOR THAT SAME KIND OF ACCURACY?

A. Social equity in ratemaking usually refers to avoiding having some customer classes being subsidized by other classes by virtue of some customer classes' revenue requirement allocations exceeding costs while others are beneath costs. However, there can also be a problem of customers' subsidizing other customers within the same schedule. Take the instant case of the rates for Idaho Power's residential customers in Oregon. If prices are the same year-round even though costs are greater in the summer, the upshot is for customers using electricity relatively more intensely

4 Because of lower air-conditioning loads, the Pacific Northwest can be the exception, particularly in the mid-peak and off-peak periods; i.e., when air conditioning loads are at lower levels.

in the low-cost winter season to be subsidizing customers whose relatively greater concentration of use falls in the high-cost summer season.[5]

Q. IS IDAHO POWER RECOMMENDING THE ADOPTION OF SEASONAL RATES FOR THE RESIDENTIAL SCHEDULE IN THIS CASE?

A. Yes, with the higher rates appearing in the summer.

Q. EVIDENCE IN THIS CASE SHOWS THAT LOADS FOR EASTERN OREGON RESIDENTIAL CUSTOMERS ARE WINTER PEAKING AND THAT THE CAUSE OF IDAHO POWER BEING SUMMER PEAKING OVERALL IS HEAVILY DUE TO AIR CONDITIONING LOADS (COMMERCIAL AND RESIDENTIAL) COINCIDING WITH THE AGRICULTURAL IRRIGATION SEASON.[6] THIS BEING THE CASE, IS IT APPROPRIATE TO DESIGN RATES FOR RESIDENTIAL CUSTOMERS THAT ARE HIGHER IN THE SUMMER THAN IN THE REST OF THE YEAR—I.E., EVEN THOUGH RESIDENTIAL LOADS AREN'T THE PRIMARY CAUSE OF THE HIGH SUMMER COST?

A. Idaho Power's generation and transmission cost allocations quite properly incorporate seasonal cost differences, with summer loads incurring the largest allocations.[7] All loads contribute to costs. Summer loads by every customer class contribute to the overall costs of Idaho Power. When a customer class's summer loads increase, the

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[5] In the case where prices will exceed marginal costs throughout the entire year, the fairness objection to having a uniform price in the presence of much higher costs in some seasons than in others is that the customers in the lower-cost season(s) are being required to pay a greater share of the utility's embedded costs than are customers whose greater use is concentrated in the higher-cost season(s).

[6] Page 401b of the 2008/Q4 FERC FORM No.1 shows June, July, and August as the three months having the highest peak loads and the highest levels of monthly energy consumption.

[7] Notably, some spring and autumn months receive a zero generation demand cost allocation.

cost allocation to that class increases. If summer prices do not reflect that season's incremental cost allocation, customers in the other seasons will end up bearing some of the burden of the costs incurred to meet summer loads.

Q. SO, YOU WOULD AGREE THATTHERE SHOULD BE A PRICE SIGNAL THAT FOSTERS CUSTOMERS' PAYING THEIR OWN WAY, AND NOT BURDENING OTHERS?

A. Yes. Actually, two points can be made in this regard:

1. For some time, the trend nationally has been for residential customers to install refrigerated air conditioning. This trend has not reached completion in low-humidity, arid areas where less energy-intensive evaporative coolers have long been in use. There should be a strong summer-costs price signal in place so as to discourage refrigerated air conditioning use where the benefits do not exceed the additional electricity costs.
2. The older houses in Eastern Oregon are more likely to be heated with electricity relative to newer houses. Those same newer houses, and other homes occupied by more affluent residents, are also more likely to be cooled with refrigeration than are the older houses in that area. The result of failing to have electricity prices that reflect the seasonal cost differences would be to have the generally less affluent winter-peaking customers subsidize the more affluent summer-peaking customers.

Q. YOU HAVE DISCUSSED HOW COST-BASED PRICES PROVIDE A PRICE SIGNAL BY WHICH CONSUMERS CAN ADJUST THEIR CONSUMPTION UP OR DOWN TO WHERE MARGINAL BENEFITS EQUATE TO MARGINAL COSTS. IS IT YOUR OPINION THAT ELECTRIC UTILITY CONSUMERS SOMETIMES DISREGARD PRICES IN FORMING THEIR CONSUMPTION HABITS? AND, IF THIS IS TRUE, WHY IS IT STILL IMPORTANT TO TRY TO MATCH RATES WITH COSTS?

A. Because of the relatively low historic price of Idaho Power's electricity and its commensurately small portion of many households' budgets, it is true many electric customers seem to ignore the rates charged for that service. But that inattention is far from universal. As budgets tighten, households look for ways to cut their utility bills—by substituting more efficient appliances (including light bulbs), by making energy-efficiency-promoting capital investments in their domiciles, etc. That kind of economizing behavior needs to continue to be recognized and rewarded—in particular by not having electricity rates that are too low for the high-cost season. There is also a social-equity argument as described earlier for having cost-based prices—even if no one were to respond to them by altering behaviors. It would be unfair in the current instance for the heavy winter users to have to subsidize heavy summer users, whether or not the latter in fact reduce their demands appreciably in the face of higher, unsubsidized electric prices.

Q. WHEN ELECTRIC RATES ARE ELEVATED, WHETHER AS PART OF A GENERAL INCREASE, A SEASONAL INCREASE, OR AS PART OF A RATE DESIGN REFORM (E.G., THE INTRODUCTION OF INVERTED

RATES, WHICH DISPROPORTIONATELY AFFECT LARGE CONSUMERS WITHIN A SCHEDULE), A CERTAIN NUMBER OF CUSTOMERS CAN BE EXPECTED TO COMPLAIN. DOES THAT CONCERN YOU?

A. I do have some ambivalence on the matter. No one likes to see customers who are distressed. But as an economist concerned about conservation and economic efficiency, I take some encouragement in observing customers paying attention to price signals, even if it is “only” to complain..

Recall that the focus of the seasonal rate proposal is to convey a more accurate price signal regarding high summertime energy costs. Given, for example, a desire to counter the expensive trend to install refrigerated air conditioning, there is something to be said about having messages delivered by any medium regarding the high summertime bills that can arise from high summertime use and prices that reflect the higher summertime costs.

As regards customer pushback in general, such can normally be counted upon whenever there is a change to the status quo. But the experience following the introduction of seasonal residential rates in Idaho (with Idaho Power) and Utah (with PacifiCorp[8]) has not been such as to cause the utility commissions in either state to roll back the seasonal rates.

[8] It is noteworthy that the May-through-September-*only* tail block rate in Utah is substantially, i.e., 2.2¢, greater than the price for the preceding block. PacifiCorp’s Oregon year-round residential tail block rate is only 1 cent above the previous block’s rate.

<u>TOPIC 4 – ACCOMMODATING SIMPLICITY/STABILITY IN RESIDENTIAL RATE DESIGN WHILE MINIMALLY COMPROMISING THE OBJECTIVE OF COST-BASED RATES</u>

Q. YOU HAVE SAID A NUMBER OF POSITIVE THINGS ABOUT SEASONAL RATES FOR RESIDENTIAL CUSTOMERS. DOES STAFF JOIN THE COMPANY IN SUPPORT THEREOF?

A. Yes, but with a caveat, to be discussed later in this testimony.

Q. IN RECOGNITION OF THE HIGHER SUMMERTIME COSTS, THE COMMISSION HAS PREVIOUSLY ADOPTED SEASONAL RATES FOR ALL OF IDAHO POWER'S MAJOR SCHEDULES. CONTRARILY, AND IN ACCORDANCE WITH STAFF'S RECOMMENDATION IN THE EARLIER CASE, THE COMMISSION REJECTED SUCH FOR THE RESIDENTIAL SCHEDULE. WHAT RATIONALE WAS GIVEN FOR THAT EXCEPTION?

A. Commission Order No. 05-871 at page 11 contained the following reference to Staff's recommendation: While "[g]enerally, Staff supports rates that reflect the cost of service…Staff agrees with CUB that a variable rate could be confusing to customers, and that a single rate will be more understandable…[A] simpler, single rate 'is of greater value than the potential benefits associated with lower use during the peak period.' [See Staff brief, 18 & 19 {June 13, 2005}]"

Q. DOES STAFF MAINTAIN THAT POSITION IN THE CURRENT CASE?

A. Obviously, Staff continues to "support rates that reflect the cost of service." However, Staff's views of the issue have evolved and this testimony reflects Staff's current policy position,, with the understanding that there will always be a trade-off between economic efficiency, customer equity and tariff simplicity. In this docket, and in recent rate cases involving other utilities, we are more compelled by the economic efficiency and social equity values of having rates that are more strictly cost-based as compared to rates that ignore seasonal variability. In the cited case, simplicity seemed to trump the efficiency potential of the higher summer rates; in this case, and in Staff's current policy perspective on the issue, equity may be regarded as the moving principle. Even if customers were totally unresponsive to the higher summer price signal (which would make electricity unique among normal consumer goods), the social equity arguments reviewed above make a compelling case for seasonality in rates.

Q. PLEASE SPEAK MORE TO THE "CONFUSING TO CUSTOMERS" AND "SIMPLER, SINGLE RATE" POINTS TO WHICH THE COMMISSION REFERRED IN ITS EARLIER ORDER WHICH YOU JUST CITED.

A. There are several factors operating here. Confusion can be the result of rates that are complex in structure, and can also be the result of rates being changed from a previous level. Regarding the former source of confusion, what already prevails is not terribly simple. The residential energy charge is a two-part rate, *not* a *single* rate. As is the case with the other two Oregon-regulated electric utilities, Idaho Power's residential tariff employs an inverted rate, with one price applied to the first 300 kWh's of consumption, and another, higher price applied thereafter.

Given its prior endorsement of inverted-block rates, the CUB-opposed "non-singularity" must lie in having inverted-block rates in the summer that are different from the non-summer's inverted-block rates. The "confusion" would apply to those customers who compare the prices on their bill from month-to-month and would in turn wonder what caused the tail-block rate, for example, to be higher in the summer than during the rest of the year. It would seem that a bill stuffer that explained the basis of the rate change—including the fact that the tail-block rate would go back down in the fall—should reduce any confusion concerns regarding rates changing. Having seasonal rates for Oregon's residential customers as well as for those in Idaho would itself eliminate the possible confusion to customers who reside in both jurisdictions and who wonder why rates for the same company were structured differently.

Q. REFER NOW TO IDAHO POWER'S RESIDENTIAL RATES PROPOSAL. (*SEE* EXHIBIT IDAHO POWER/901 WAITES/1), IS IT POSSIBLE TO MAKE SOME RELATIVELY MINOR ADJUSTMENTS TO THAT PROPOSAL SO AS TO SIMPLIFY ITS STRUCTURE?

A. The original Idaho proposal called for inverted rates in both the summer and non-summer, with the initial block rate slightly higher in the summer than in the non-summer, and the second block rate for the summer being substantially higher (i.e., more than 2¢) than the initial block's rate for that season. Substantial simplification can come from two modifications to the Company proposal. First, the initial block rate could be the same throughout the year; second, the demarcation point between the first and second block could be designed such that most customers stay at the first block level as they move from the non-summer to the summer. The latter is done by increasing the inversion point from 800 kWh's (in the original Company proposal) to 1000 kWh's. The objective is to avoid offending customers who might notice a summertime second-block rate increase. Acceptance on the part of the majority of customers would come from the fact that their own consumption left them at the unchanged, first-block price. The outcome would be for most of the Idaho Power-Oregon customers to "enjoy" the same status as if they were on PacifiCorp-Oregon's schedule: They would see a modest rate inversion step at 1000 kWh's, but only in the winter.

Q. HAVE YOU PREPARED AN EXHIBIT THAT DISPLAYS THE RESIDENTIAL RATE DESIGN THAT YOU JUST DESCRIBED?

A. Yes, Exhibit Staff/103. Also, the bill frequencies portion of the exhibit shows that in the summertime most residential customers would stay below the 1000 kWh inversion point.

Q. THE PREVIOUSLY MENTIONED IDAHO POWER/OPUC ORDER (NO. 05-871) CRITICIZED THE COMPANY FOR A LACK OF RESIDENTIAL CUSTOMER IMPACT INFORMATION. HAVE YOU PREPARED AN EXHIBIT WHICH DISPLAYS THAT INFORMATION?

A. Yes, Exhibit Staff/104. This exhibit also shows how the monthly bills under seasonal rates would compare with rates that stayed the same throughout the year.

Q. STAFF EXHIBIT/104 SHOWS THAT IN COMPARISONS WITH THE YEAR-ROUND ALTERNATIVE, THE SUMMERTIME INCREASE UNDER SEASONAL RATES EXCEEDS THE NON-SUMMER "DECREASE." PLEASE EXPLAIN.

A. Two factors are at work. First, the increases are incurred for only three months, while the decreases take place over nine months. Second, because summertime consumption tends to be lower than in the winter, decreases in the former season are incurred in correspondence with lower consumption levels than are the wintertime increases.

TOPIC 5 – CUSTOMER PREFERENCES AND THE RELEVANCE OF FLAT MONTHLY BILLING

Q. AN ARGUMENT AGAINST TIME-OF-DAY AND SEASONALLY DIFFERENTIATED PRICES IS THAT CUSTOMERS PREFER TO SEE THE SAME PRICE FOR ALL UNITS OF CONSUMPTION. DO YOU BELIEVE THAT ARGUMENT SHOULD BE DISPOSITIVE IN THE CASE OF SEASONALLY DIFFERENTIATED RESIDENTIAL ELECTRIC RATES?

A. Staff does not believe that argument iscompelling in this case, particularly in light of the stipulated actions discussed earlier in the interest of rate simplicity and stability. The reality in Oregon for a long time has been a different price for the first number of units of consumption than for the latter units—as a reflection of marginal costs exceeding embedded costs. Customers have accepted that degree of different prices for different units of consumption. The same principle suggests that insofar as summertime costs exceed wintertime costs, summertime rates should be higher than non-summertime rates. As long as customers are informed that wintertime rates are lower-than-otherwise in the presence of higher summertime rates, we should be able to count upon their general acceptance of seasonal rates along the lines proposed by the stipulation.

Having said that, let us look at what else customers prefer as it relates to utilities. They generally prefer a fixed monthly charge, *independent of usage*. Such has prevailed for decades with respect to local telephone service. As seen by their willingness to pay the associated premium, many customers also prefer the fixed monthly option with respect to long-distance and cell telephone service. But obviously, no one—including those who say that electric prices do not really matter—is going to propose a flat monthly rate for residential electric service that is not ultimately tied to usage.

Q. CAN RESIDENTIAL ELECTRIC CUSTOMERS RECEIVE THE BUDGETARY BENEFITS OF A FIXED MONTHLY BILL BY OPTING FOR FLAT MONTHLY BILLING OF THEIR ELECTRICITY?

A. They can. But those customers know that there will eventually be a true-up; they do not behave as if marginal usage—unlike the case with local telephone service—is free.

TOPIC 6 – A MISCELLANEOUS MINOR CONCERN REGARDING SEASONAL RESIDENTIAL RATES

Q. EXHIBIT IDAHO POWER/802, TATUM/6, SHOWS THAT JUNE'S COSTS WERE ACTUALLY QUITE LOW, YET THAT MONTH IS INCLUDED WITH THOSE RECEIVING THE HIGHER "SUMMER" RATES. IS THAT A CONCERN FOR STAFF?

A. It is a concern, but Staff has accepted it primarily because it matches the rate structure currently in effect in the Idaho territory of the Company. In the interest of minimizing confusion on the part of those who may be customers on both sides of the Oregon-Idaho border, it makes sense to have a common rate structure. With that in mind, I believe the proper course would be to engage in a dialogue involving the Company and the Idaho regulators regarding placing the rates on both sides of the border in greater conformance with the high-cost pattern that coincides more with the third quarter (July-September) than with the summer (June-August) *per se*.

Having said that, I observe that when seasonal rates were initiated by PacifiCorp in Utah, parties at that time did not strongly resist the concept of having an extended "break-in period" to enable customers "to get used to" the higher summertime rates. Accordingly, the first month receiving the high tail-block rate in that state is May. Perhaps analogous thinking prevailed in Idaho when the summertime high-rates period was adopted.[9] Admittedly, if the message is that summertime costs are higher than non-summertime costs, customers are less confused if the high rates are applied only in the summer and not partly in the fall.

Q. DOES THAT CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

[9] The common interpretation of "summer" as the months of June, July, and August is employed here.

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WITNESS: George R. Compton

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 101

Witness Qualification Statement

December 16, 2009

WITNESS QUALIFICATION STATEMENT

NAME:	George R. Compton
EMPLOYER:	Oregon Public Utility Commission
TITLE:	Senior Economist (3/4), Economic Research & Financial Analysis Division (ERFA)
ADDRESS:	550 Capital Street NE, Suite 215 Salem, OR 97301-2551
EDUCATION:	Doctor of Philosophy, Economics (1976) University of California, Los Angeles (UCLA) – Westwood, CA Master of Science, Statistics (1968) Brigham Young University (BYU) – Provo, UT Bachelor of Science, Mathematics and Psychology (1963) Brigham Young University – Provo, UT
EXPERIENCE:	I have been employed in utility regulation since receiving my Ph.D. in 1976. My primary employer was the Division of Public Utilities, within Utah's Department of Commerce (formerly Business Regulation). I also consulted for a couple of years, early in that period. I testified frequently during my career on rate design, cost-of-service, cost-of-equity, and various policy matters affecting electric, gas, and telephone utilities. While in Utah I also taught economics part-time for about ten years at BYU. Prior to my utility regulatory career I worked in aerospace for eleven years at McDonnell Douglas (now Boeing) in Southern California. I joined the OPUC staff soon after "retiring" to Oregon at the end of 2006. Principal cases of my involvement here have included the IRP/CO_2 Risk Guideline (UM 1302), the AVISTA General Rate Case (UG 181), the 2008 PGE General Rate Case (UE 197), and the 2009 PacifiCorp General Rate Case (UE210).

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OF
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STAFF EXHIBIT 102

MARGINAL COSTS AND REVENUE SPREAD

December 16, 2009

Marginal Costs and Revenue Spread By Class
Stipulated Settlement
2009 Test Period

Line	Description	(A) TOTAL SYSTEM	(B) RESIDENTIAL (1)	(C) GEN SRV (7)	(D) GEN SRV SECONDARY (9-S)	(E) GEN SRV PRIMARY (9-P)	(F) AREA LIGHTING (15)	(G) LG POWER PRIMARY (19-P)	(H) LG POWER TRANS (19-T)	(I) IRRIGATION SECONDARY (24-S)	(J) UNMETERED GEN SERVICE (40)	(K) MUNICIPAL ST LIGHT (41)	(L) TRAFFIC CONTROL (42)
1	*Normalized Sales (kWh)*	740,533,031	220,362,881	19,087,766	129,779,060	17,340,865	470,308	195,081,276	90,310,412	67,154,213	14,306	912,800	19,144
2	Current Revenue	$32,433,692	$11,262,377	$1,176,138	$6,331,332	$654,786	$98,625	$6,712,141	$3,243,600	$2,846,148	$772	$106,979	$794
3													
4	Generation Marginal Cost												
5	Generation Demand-Related	$5,368,907	$1,681,622	$160,628	$942,951	$119,727	$519	$1,078,999	$563,709	$819,581	$75	$995	$100
6	Generation Energy-Related	$46,251,305	$13,587,114	$1,187,823	$7,954,222	$1,055,870	$28,374	$11,838,944	$5,800,384	$4,741,513	$863	$55,044	$1,155
7	Generation Total	$51,620,212	$15,268,735	$1,348,451	$8,897,174	$1,175,597	$28,893	$12,917,943	$6,364,093	$5,561,094	$938	$56,039	$1,255
8	Transmission Marginal Cost												
9	Transmission Demand-Related (75%)	$14,714,881	$4,912,854	$433,698	$2,725,422	$348,347	$2,358	$3,117,028	$1,404,982	$1,765,148	$216	$4,540	$289
10	Transmission Energy-Related (25%)	$4,904,960	$1,459,585	$126,429	$859,599	$114,858	$3,115	$1,292,131	$598,176	$444,800	$95	$6,046	$127
11	Transmission Total	$19,619,842	$6,372,439	$560,127	$3,585,021	$463,205	$5,473	$4,409,159	$2,003,158	$2,209,948	$311	$10,586	$416
12	Distribution Marginal Cost												
13	Demand-Related	$9,658,948	$4,441,166	$280,793	$1,812,158	$171,415	$5,820	$1,102,323	$0	$1,833,817	$156	$11,191	$110
14	Customer-Related	$2,877,137	$1,831,719	$489,644	$230,216	$7,279	$0	$18,994	$6,595	$289,732	$261	$1,857	$838
15													
16	Total Functionalized Revenue Requirement												
17	Generation	$20,407,194	$6,036,241	$533,088	$3,517,350	$464,753	$11,422	$5,106,895	$2,515,939	$2,198,486	$371	$22,154	$496
18	Transmission	$3,694,492	$1,199,955	$105,474	$675,073	$87,223	$1,031	$830,262	$377,202	$416,142	$58	$1,993	$78
19	Distribution												
20	Demand-Related	$10,306,242	$4,738,791	$299,610	$1,933,600	$182,902	$6,210	$1,176,195	$0	$1,956,711	$166	$11,941	$117
21	Customer-Related												
22	Allocated	$2,611,035	$1,662,306	$444,358	$208,924	$6,606	$0	$17,238	$5,985	$262,935	$237	$1,686	$760
23	Direct Assignment	$414,826	$190,712	$42,634	$18,964	$71	$58,699	$85	$30	$21,595	$43	$81,908	$85
24													
25	Total	$37,433,790	$13,828,005	$1,425,163	$6,353,911	$741,555	$77,361	$7,130,674	$2,899,156	$4,855,869	$876	$119,683	$1,537
26	Revenue Deficiency	$5,000,098	$2,565,628	$249,025	$22,579	$86,769	($21,264)	$418,533	($344,444)	$2,009,721	$104	$12,704	$743
27	% Increase Required	15.42%	22.78%	21.17%	0.36%	13.25%	-21.56%	6.24%	-10.62%	70.61%	13.41%	11.88%	93.60%
28													
29	Stipulated Revenue Spread	$37,434,662	$14,224,869	$1,466,066	$6,536,268	$762,838	$98,625	$7,335,324	$3,243,600	$3,641,901	$901	$123,118	$1,153
30	% Increase Required	15.42%	26.30%	24.65%	3.24%	16.50%	0.00%	9.28%	0.00%	27.96%	16.67%	15.09%	45.20%
31	Cost of Service Index	100.00%	102.87%	102.87%	102.87%	102.87%	127.49%	102.87%	111.88%	75.00%	102.87%	102.87%	75.00%
32	Average Mills Per kWh	50.55	64.55	76.81	50.36	43.99	209.70	37.60	35.92	54.23	62.96	134.88	60.22

CASE: UE 213
WITNESS: George R. Compton

PUBLIC UTILITY COMMISSION
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STAFF EXHIBIT 103

SEASONAL RESIDENTIAL RATE DESIGN

December 16, 2009

UE 213
Idaho Power Company
Oregon Jurisdiction

Exhibit Staff/103

Settlement Stipulation: Seasonal Residential Rate Design

2008 Residential Bill Frequencies

	Share with consumption less than or equal 1,000 kWh's
JAN	32%
FEB	33%
MAR	40%
APR	44%
MAY	57%
JUN	65%
JUL	52%
AUG	50%
SEP	57%
OCT	65%
NOV	52%
DEC	39%

		Revenues Assuming 2009 Test Year Projections			
		Current		Settlement Stipulation	
2009 Test Year Projections		Rates	Revenues	Rates	Revenues
Billing ≤ 300 kWh =	44,027,050	$ 0.045117	$ 1,986,368		
Billing > 300 kWh =	154,531,872	$ 0.054533	$ 8,427,087		
Summer Billing ≤ 1,000 kWh =	29,230,259			$ 0.060832	$ 1,778,135
Summer Billing > 1,000 kWh =	11,843,167			$ 0.083123	$ 984,440
Non-Summer Billing ≤ 1,000 kWh =	92,729,929			$ 0.060832	$ 5,640,947
Non-Summer Billing > 1,000 kWh =	64,755,567			$ 0.069951	$ 4,529,717
Total Annual Billed kWh's =	198,558,922				
Customer-months =	160,983.1	$ 5.25	$ 845,161	$ 8.00	$ 1,287,865
Number of Minimum Charges =	1,253.5	$ 3.00	$ 3,761	$ 3.00	$ 3,761
Total =			**$ 11,262,377**		**$ 14,224,864**

Sales volumes source: C. Waites Workpapers, except "No. of Minimim Charges," which came from Idaho Power/901 Waites/1 (2009 Test Year Estimates).

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STAFF EXHIBIT 104

MONTHLY RESIDENTIAL BILLING COMPARISONS

December 16, 2009

Monthly Billing Comparisons
Residential Rate Design per Settlement Stipulation
Seasonal versus Year-round Rates

Energy Used (kWh's)	Year-Round Alternative: Current Revenue (a)	Proposed Revenue (b)	Percent Difference (c)	Seasonal Rate Design: Settlement Stipulation — Non-Summer: Current Revenue (d)	Proposed Revenue (e)	Percent Difference (f)	Δ $ from Yr-Round (g)	Summer: Current Revenue (h)	Proposed Revenue (i)	Percent Difference (j)	Δ $ from Yr-Round (k)
50	$7.51	$11.04	47.1%	$7.51	$11.04	47.1%	$0.00	$7.51	$11.04	51.5%	$0.00
100	$9.76	$14.08	44.3%	$9.76	$14.08	44.3%	$0.00	$9.76	$14.08	51.0%	$0.00
200	$14.27	$20.17	41.3%	$14.27	$20.17	41.3%	$0.00	$14.27	$20.17	50.5%	$0.00
400	$24.24	$32.33	33.4%	$24.24	$32.33	33.4%	$0.00	$24.24	$32.33	44.3%	$0.00
650	$37.87	$47.54	25.5%	$37.87	$47.54	25.5%	$0.00	$37.87	$47.54	36.8%	$0.00
1,000	$56.96	$68.83	20.8%	$56.96	$68.83	20.8%	$0.00	$56.96	$68.83	32.4%	$0.00
1,500	$84.22	$104.83	24.5%	$84.22	$103.81	23.3%	-$1.02	$84.22	$110.39	31.1%	$5.57
2,500	$138.76	$176.81	27.4%	$138.76	$173.76	25.2%	-$3.05	$138.76	$193.52	39.5%	$16.70
4,000	$220.56	$284.79	29.1%	$220.56	$278.69	26.4%	-$6.11	$220.56	$318.20	44.3%	$33.41
6,000	$329.62	$428.77	30.1%	$329.62	$418.59	27.0%	-$10.18	$329.62	$484.45	47.0%	$55.68

Billing Component	2009 Quantity	Current: Price	Current: Revenue	Year-Round: Price	Year-Round: Revenue	Seasonal -- Per Settlement Stipulation — Non-Summer: 2009 Quantity	Non-Summer: Price	Non-Summer: Revenue	Summer: 2009 Quantity	Summer: Price	Summer: Revenue	Annual Revenue
Customer Charge	160,983.1	$ 5.25	$ 845,161	$ 8.00	$ 1,287,865	Annualized	$ 8.00		Annualized	$ 8.00		$ 1,287,865
Minimum Charge	1253.5	$ 3.00	$ 3,761	$ 3.00	$ 3,761	Annualized	$ 3.00		Annualized	$ 3.00		$ 3,761
≤ 300 kWh's	44,027,050	$ 0.045117	$ 1,986,368									
> 300 kWh's	154,531,872	$ 0.054533	$ 8,427,087									
≤ 1,000 kWh's	121,960,188			$ 0.060832	$ 7,419,082	92,729,929	$ 0.060832	$ 5,640,947	29,230,259	$ 0.060832	$ 1,778,135	$ 7,419,082
> 1,000 kWh's	76,598,734			$ 0.071988	$ 5,514,156	64,755,567	$ 0.069951	$ 4,529,717	11,843,167	$ 0.083123	$ 984,440	$ 5,514,156
Energy Total	198,558,922		$ 11,262,377		$ 14,224,864	157,485,496			41,073,426			$ 14,224,864

NOTE: To allow a straightforward comparison between the seasonal and year-round alternatives, the first-block price is common to both

CASE: UE 213
WITNESS: Steve Storm

PUBLIC UTILITY COMMISSION
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STAFF EXHIBIT 200

Staff Testimony in Support of the Revenue Requirement Stipulation

December 16, 2009

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Steve Storm. I am employed by the Public Utility Commission of Oregon as Program Manager for Economic and Policy Analysis within the Economic Research and Financial Analysis Division. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualification Statement constitutes Exhibit Staff/201.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony supports the Joint Testimony in Support of Stipulation as to the stipulated rate of return, costs of capital, and capital structure.

Q. DID YOU PREPARE AN EXHIBIT FOR THIS DOCKET?

A. Yes. I prepared Exhibit Staff/201, consisting of one page.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. I discuss the rate of return (cost of capital) components in the Stipulation, the analysis performed by Staff of these components, briefly discuss the comparability of returns on equity between utilities in certain dockets, and conclude that rates resulting from the stipulated rate of return are just and reasonable.

Q. WHAT IS THE STIPULATED RATE OF RETURN AND ITS COMPONENTS?

A. Table 1 (following) includes Idaho Power Company's (IPC, or the Company) currently authorized rate of return and its composition as well as the values in the Stipulation. These latter values result in the stipulated rate of return of 8.061 percent as compared with the currently authorized 7.833 percent. I have included the values requested by the Company in its application.

Table 1

Current Authorization (UE 167)			
Component	Percent of Total	Cost	Weighted Average
Long Term Debt	54.03%	5.99%	3.24%
Preferred Stock	0.00%	0.00%	0.00%
Common Stock	45.97%	10.00%	4.60%
	100.00%		7.83%

Requested in Application (UE 213)			
Component	Percent of Total	Cost	Weighted Average
Long Term Debt	50.204%	6.131%	3.078%
Preferred Stock	0.000%		0.000%
Common Stock Equity	49.796%	11.250%	5.602%
	100.000%		8.680%

November Stipulation (UE 213)			
Component	Percent of Total	Cost	Weighted Average
Long Term Debt	50.200%	5.964%	2.994%
Preferred Stock	0.000%		0.000%
Common Stock	49.800%	10.175%	5.067%
	100.000%		8.061%

Q. HAS STAFF FILED TESTIMONY REGARDING COST OF CAPITAL IN THIS PROCEEDING?

A. My current testimony is the only testimony filed by Staff in this proceeding regarding rate of return, costs of capital, and capital structure. I have, however, conducted a full and thorough review of the Company's filing regarding its costs of capital and have performed considerable analysis of Idaho Power Company's cost of long-term debt,[1] cost of equity (or common stock[2]), and capital structure. My analysis is specific to Idaho Power Company in the context of this general rate case proceeding; i.e., my analyses of the Company's cost of long-term debt and cost of equity were newly-created for use in this general rate case.

Staff issued a total of 62 data requests to the Company related to its financing activities, cost of equity, cost of long-term debt, and capital structure.

Q. WHAT WERE THE RESULTS OF STAFF'S ANALYSIS OF IDAHO POWER COMPANY'S COST OF LONG-TERM DEBT?

A. This analysis, conducted by staff analyst Jorge Ordonez, provided a cost of long-term debt of 6.03 percent. This result was inclusive of the Company's issuance of $130 million in first mortgage bonds on November 20, 2009.[3]

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1 Mr. Ordonez, Staff's Senior Financial Economist, conducted the analysis of IPC's cost of long-term debt.

2 I use the term "cost of equity" and "cost of common stock" synonymously in this testimony. Note that the Company currently has no preferred stock in its capital structure, nor is any issuance of such securities planned prior to the end of the calendar 2009 test year.

3 Idaho Power Company issued the first mortgage bonds in the form of medium-term notes, with an original issue date of November 20, 2009 and a maturity date of March 1, 2020. *See*, at http://www.idacorpinc.com/pdfs/financials/8k/20091118.pdf , the Company's SEC Form 8-K filing related to this issuance.

Q. PLEASE DESCRIBE THE APPROACH USED IN STAFF'S COST OF EQUITY ANALYSIS.

A. My approach involved estimating the cost of equity for a group of companies believed to be similar to IPC in several significant ways. I selected these companies using multiple criteria, beginning with limiting the universe for my comparison group to the 59 U.S. companies operating primarily as electric utilities and covered by Value Line. Additional criteria included long-term debt composing between 45 percent and 55 percent of capital structure; no reduction in dividends paid over the past five years; a Value Line forecast of non-negative growth in dividends over the 2012 – 2014 period; a Standard & Poor's issuer rating between BBB- and BBB+ (inclusive); and having more than 80 percent of assets regulated, as determined by the Edison Electric Institute, as of December 31, 2008. In other words, I developed screening criteria reflecting specific attributes of IPC in order to identify comparable companies; i.e., my list of comparable companies was developed to include companies specifically comparable to IPC.

This screen for comparable companies yielded nine companies, for each of which I estimated the cost of equity using two different discounted cash flow (DCF) models. I adjusted each company's cost of equity for IPC's capital structure used in the Parties' Stipulation (i.e., composed of 50.2 percent long-term debt and 49.8 percent common equity).[4,5]

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[4] Note, as shown in Table 1, these values are rounded to the nearest 1/10th of a percent from those in the Company's filing.

Q. PLEASE DESCRIBE THE TWO DCF MODELS USED TO ESTIMATE IDAHO POWER COMPANY'S COST OF EQUITY CAPITAL.

A. I used two standard, "textbook" multi-stage discounted cash flow models for estimating each of the comparable companies' cost of equity capital. Each model used Value Line's estimated dividends for 2009 through 2014, and a long-term growth rate based on my estimated long-term growth rate for nominal U.S. Gross Domestic Product (GDP), applied to Value Line's estimated 2014 dividends for estimating values of dividends for 2015 and beyond. Each model used as the initial period's stock price—for each of the comparable companies—the average of that company's closing prices on three consecutive Wednesdays in October, 2009: the 14th, the 21st, and the 28th.

The first DCF model has a 40-year time horizon, with a terminal valuation in 2048 derived by dividing the 2048 dividend by the difference between the estimated required return on equity and the estimated long-term growth rate.[6]

The second DCF model used has a 150-year time horizon, with no terminal valuation. This DCF model, like the preceding model, is found in numerous contemporary finance textbooks.[7]

Q. WHAT LONG-TERM DIVIDEND GROWTH RATE DID YOU USE?

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[5] This adjustment to each company's cost of equity for capital structure varying from that of IPC ranged from -0.6% to +0.5% and averaged -0.2% (only two of the nine companies projected a capital structure less leveraged than that of IPC). These values are for each of the two DCF models using the base-case long-term annual growth rate.

[6] Many contemporary finance textbooks describe this common form of discounted cash flow model. *See*, for example, *Corporate Finance* by Stephen A. Ross, Randolph W. Westerfield, and Jeffrey Jaffe, Seventh Edition, 2005; pages 112 through 125.

[7] *Ibid.*

A. I used a "base-case" annual growth rate for dividends of 4.89 percent. This rate is based upon my estimated long-term annual growth rate for nominal GDP of 5.39 percent and my analysis of the relationship between the earnings of electric utilities and GDP. I also analyzed sensitivities at 90 percent and 110 percent of the 4.89 percent annual long-term growth rate in dividends.[8] These provided long-term dividend growth rates of 4.40 percent and 5.38 percent, respectively.

Q. WHAT ESTIMATED COST OF EQUITY FOR IDAHO POWER COMPANY RESULTED FROM YOUR ANALYSIS?

A. Table 2 (following) summarizes the results of my cost of equity analysis for the nine companies evaluated as being comparable to Idaho Power Company.

Table 2

Estimated Cost of Equity

Long-term Dividend Growth Rate	DCF Model	Range of Values for Individual Companies	Mean of Values for Comparable Companies	Median of Values for Comparable Companies
4.40%	40 Year	8.6% - 10.1%	9.4%	9.5%
4.40%	150 Year	8.7% - 10.2%	9.5%	9.6%
4.89%	40 Year	9.0% - 10.5%	9.8%	9.9%
4.89%	150 Year	9.1% - 10.6%	9.9%	10.0%
5.38%	40 Year	9.4% - 10.8%	10.2%	10.2%
5.38%	150 Year	9.5% - 10.9%	10.3%	10.4%

[8] The sensitivity analyses left all other input parameters unchanged.

Q. BASED ON YOUR ANALYSIS, WHAT IS A REASONABLE RANGE FOR IDAHO POWER COMPANY'S COST OF EQUITY?

A. Based on the input values used—such as stock prices—and the capital structure in the Stipulation, I conclude that a reasonable range for Idaho Power Company's cost of equity, at this time, is between 9.4 percent and 10.4 percent. The 10.175 percent return on equity (ROE) in the Stipulation, while above this range's mid-point of 9.9 percent, is well within the range.

Q. HOW DOES THE 10.175 PERCENT ROE IN THE ALL-PARTY REVENUE REQUIREMENT STIPULATION COMPARE WITH THAT RESULTING FOR OTHER ENERGY UTILITIES IN RECENT OREGON GENERAL RATE CASES?

A. These returns on equity are not strictly comparable for several reasons. First, the only general rate case dockets more or less contemporaneous with UE 213 are those of Avista (UG 186) and PacifiCorp (UE 210). Parties reached a stipulated settlement in the first docket (UG 186) without the filing of testimony from any party other than Avista. Additionally, Avista is, for purposes of Oregon regulation, considered to be a natural gas distribution utility. Such utilities are generally believed to have—all else being equal—lower risk than integrated electric utilities. The Commission authorized an ROE of 10.1 percent for Avista in Order No. 09-422, entered October 26, 2009. Per Standard and Poor's[9] (S&P), Avista's issuer credit rating is BBB-, with an Outlook of "Positive."

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[9] S&P Issuer credit rating and Outlook were taken on December 11, 2009 from the firm's website at http://www.standardandpoors.com/prot/ratings/entity-ratings/en/us .

PacifiCorp's ROE in the Stipulation[10] in UE 210 is not agreed upon by Parties *to* the Stipulation,[11] and has an intervening party in the docket (ICNU) currently opposing the Stipulation, specifically including opposition to the *notional*[12] 10.125 percent ROE of the Stipulation.[13] PacifiCorp's issuer credit rating from S&P[14] is A-, with an Outlook of "Stable."

Idaho Power Company's issuer credit rating from S&P[15] is BBB, with an Outlook of "Stable."

Q. DOES THE STIPULATED ROE FOR IDAHO POWER COMPANY OF 10.175 PERCENT, IN CONJUCTION WITH THE STIPULATED COST OF DEBT, CAPITAL STRUCTURE, AND RATE OF RETURN, RESULT IN RATES THAT ARE "JUST AND REASONABLE?"

A. Yes. Based on my analysis of the Company's costs of capital[16] and capital structure, as represented in the Stipulation, the resulting rates are both just and reasonable.

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[10] By "Stipulation" in this context of the UE 210 docket, I am referring to the Revenue Requirement Stipulation.

[11] *See* the Joint Parties' Opening Brief, page 3, lines 11 through 15.

[12] I consider the ROE *notional* as Parties agreed to its use only "for the calculation of taxes collected in rates for Oregon and other Oregon regulatory purposes…" *Ibid.*

[13] *See* the Opening Brief on Behalf of the Industrial Customers of Northwest Utilities, pages 15 through 23.

[14] S&P, *op. cit.*

[15] *Ibid.*

[16] This includes Staff's analysis of IPC's cost of long-term debt, conducted by Jorge Ordonez.

Q. WHAT DO YOU RECOMMEND, WITH RESPECT TO THE STIPULATION?

A. I recommend the Commission adopt the Stipulation and include the terms and conditions in its order in this case (subject to CUB's additional testimony on Residential Rate Design and the Commission's ruling thereon).

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

CASE: UE 213
WITNESS: Steve Storm

PUBLIC UTILITY COMMISSION
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STAFF EXHIBIT 201

Witness Qualification Statement

December 16, 2009

WITNESS QUALIFICATION STATEMENT

NAME	Steven T. Storm
EMPLOYER	Public Utility Commission of Oregon
TITLE	Program Manager, Economic Research and Financial Analysis Division
ADDRESS	550 Capitol Street NE Suite 215 Salem, Oregon 97301-2148
EDUCATION	M.B.A. University of Oregon; Eugene, Oregon A.B. (Economics) Harvard; Cambridge, Massachusetts
EXPERIENCE	I have been employed by the Public Utility Commission of Oregon since October 2007. I am currently the Program Manager of the Economic and Policy Analysis Section of the Economic Research and Financial Analysis Division. My responsibilities include leading a team of analysts engaged in economic and financial research and providing technical support on a wide range of policy issues involving electric, gas, and telecommunications utilities. I have testified before the Commission on policy and technical issues in UG 171, UE 197, UE 200, and UE 210. Prior regulatory experience includes four years in which I was responsible for developing responses to data requests regarding the financial analysis of new products and services at US WEST Communications.
OTHER EXPERIENCE	I was a self-employed financial planner for eight years following an 18 year career in management positions engaged in pricing and cost analysis; financial analysis, planning and management; and strategic planning in the publishing and telecommunications industries. I managed the pricing (rate spread and rate design) and cost accounting functions in the Directory department of Pacific Northwest Bell and its successor company, US WEST Direct for five years. I was responsible for departmental budgeting and management reporting functions for three years at US West Direct and was responsible for corporate financial planning, analysis, and management reporting for one year at Electric Lightwave. I have seven years experience in capital budgeting, financial analysis, and strategic planning functions at US West Communications.