—BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH—

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR AUTHORITY TO INCREASE ITS RETAIL ELECTRIC UTILITY SERVICE RATES IN UTAH AND FOR APPROVAL OF ITS PROPOSED ELECTRIC SERVICE SCHEDULES AND ELECTRIC SERVICE REGULATIONS.	))))))))	DOCKET NO. 11-035-200 DPU EXHIBIT 2.0DIR-COS

PRE-FILED DIRECT TESTIMONY

COST OF SERVICE

ARTIE POWELL

ON BEHALF OF

THE DIVISION OF PUBLIC UTILITIES

JUNE 22, 2012

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Artie Powell

Division of Public Utilities

Docket No. 11-035-200

INTRODUCTION

Q: PLEASE STATE YOUR NAME, EMPLOYER, JOB TITLE, AND BUSINESS ADDRESS FOR THE RECORD.

A: My name is Artie Powell; I am employed by the Division of Public Utilities; currently I am the manager of the energy section; my business address is 160 East, 300 South, Salt Lake City, Utah, 84114.

Q: ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS CASE?

A: The Division of Public Utilities (Division).

Q: PLEASE SUMMARIZE YOUR QUALIFICATIONS.

A: I hold a doctorate degree in economics from Texas A&M University. Prior to joining the Division, I taught courses in economics, regression analysis, and statistics both for undergraduate and graduate students. I joined the Division in 1996 and have since attended several professional courses or conferences including, the NARUC Annual Regulatory Studies Program (1995) and IPU Advanced Regulatory Studies Program (2005), dealing with a variety of regulatory issues. Since joining the Division, I have testified or presented information on a variety of topics including, electric industry restructuring, incentive-based regulation, revenue decoupling, energy conservation, evaluation of alternative generation projects, and the cost of capital.

SCOPE OF TESTIMONY

Q: WOULD YOU PLEASE EXPLAIN THE PURPOSE OF YOUR TESTIMONY?

A: In addition to introducing the Division's witnesses in this phase of the case and summarizing the Division's position on various issues, I will offer testimony on four issues and I am available to address policy issues that may arise throughout the development of the case.

Q: WOULD YOU PLEASE INTRODUCE THE DIVISION'S WITNESSES FOR THIS PHASE OF THE CASE?

A: The Division has two witnesses in this phase of the case, Ms. Lee Smith and me. The Division engaged the services of Ms. Lee Smith, a Managing Consultant and Senior Economist for the consulting firm La Capra Associates, to assist the Division in its analysis and review of the Company's cost of service proposals, and in formulating the Division's rate spread and design proposals. Ms. Lee (and her associates) reviewed the Company's cost of service model, conducted discovery, and performed independent research and analysis on a variety of issues on behalf of the Division. Ms. Smith provides supporting evidence on each of the Division's proposals in this phase of the case.

Q: WOULD YOU SUMMARIZE THE ISSUES THAT YOU TESTIFY ON?

A: My direct testimony deals with several issues. First, I present the Division's Guiding Rate Design Principles. These principles are consistent with those specified by Professor Bonbright,[1] and have been presented and used by Division witnesses in past cases.

Second, I will discuss the relationship or consistency between the Company's inter-jurisdictional and class cost of service allocations. In addition to some general discussion, I will address some specific remarks to the definition and classification of generation fixed costs, the System Generation (SG) factor and the class cost of service F10 factor. In past orders, the Commission has indicated a preference for consistency between these two sets of allocators. In general, the Division supports this position. However, in this case, the Division is proposing to allocate wind plant differently for

[1] James C. Bonbright, Principles of Public Utility Rates, [Columbia University Press, New York, New York], 1961, pp. 290-291.

class cost of service purposes. Ms. Smith will present the details of the Division's proposal.

Of late, there has been some discussion of regulation as a substitute for competition. One of the hall-marks of competition is marginal cost pricing. I therefore offer some comments on the role of marginal costs as a guide to setting utility rates.

Finally, I will respond to questions presented to the Division from the Commission. These questions, which came to the Division in the form of an Action Request, deal with the relationships among and the calculation or treatment of cash working capital, interest expense, and income taxes in the Company's inter-jurisdictional or JAM model and the Company's class-cost of service model. In brief, the jurisdictional and class cost service models treat these relationships differently. The Division has reviewed these differences and proposes that the JAM model treatments and relationships be adopted for the class cost of service. Additional specifics of the Division's proposal and its impacts are discussed in Ms. Smith's direct testimony.

SUMMARY OF DIVISION'S RECOMMENDATIONS

Q: WOULD YOU PLEASE SUMMARIZE THE DIVISION'S PROPOSALS IN THIS CASE?

A: Yes. The following summarizes the cost of service and rate design recommendations of the Division's consultant Ms. Lee Smith of La Capra Associates. The Division supports each of these recommendations.

- **Total Utah Revenue Requirement**: The Division recommends that the Utah revenue requirement be established at approximately $1.793 billion in this rate case. This amount is the revenue requirement to be allocated to the various rate classes.

- **Residential Customer Charge:** The Division supports increasing the residential customer charge to $5.00 from the current $4.00. The Company has requested that the charge be increased to $10.00; however, the Division has determined that that amount includes costs that are not tied directly to individual customer usage, but are general in nature.

- **Residential Tier Structure:** The Division is proposing no change in the first summer block rate, and an approximately one cent increase to both the second and third summer block rates. The Division is also proposing a two tier inverted block structure for the winter. The first winter block would be structured and priced as the first summer block; the second winter block would be for usage over 400 kWh and priced at approximately 10.5¢ per kWh.

- **Cash working capital, interest expense, income taxes, and revenue multiplier:** In an action request dated May 17, 2012, the Commission asked the Division to address apparent inconsistencies between the Company's jurisdictional and class cost of service studies. The Division's consultant, Ms. Smith, and I have specifically addressed these issues concluding that the Company's cost of service models do not treat these items consistent with the JAM. This inconsistency understates these costs for classes earning less than the average rate of return and overstates these costs to classes earning more than the average return. The result is that classes under earning continue to under earn, and those over earning continue to over earn. Ms. Smith has corrected these understatements and overstatements as explained in her direct testimony, these corrections are reflected in her calculations. The Division supports these corrections.

- **12CP, 75% Demand/25% Energy Split:** With the exception for wind generation discussed below, the Division supports the Company's computation of the SG interstate allocation factor based upon an unweighted 12 coincident peak average and the long-accepted 75 percent demand, 25 percent energy split.

- **Stress Analysis and Marginal Cost Studies:** While accepting the 12 CP methodology for computing the demand factor, the Division does not believe that the Company's "stress analysis" is useful in demonstrating the appropriateness of the 12 CP because it is based upon a generation portfolio that is far different from the Company's current portfolio. In particular, the Company has acquired significant wind resources since the stress analysis was originally performed which have much different characteristics from the remaining generation fleet.
- **The Marginal Cost Study**: The marginal cost study prepared by the Company is fraught with many problems; consequently the Division does not recommend reliance on this study. (In addition to the comments by Lee Smith, please refer to my additional general comments below on marginal cost pricing).
- **Demand/Energy split for Wind Resources:** As detailed in Ms. Smith's testimony, the Division supports the use of a much different demand/energy relationship for wind resources. As recommended by Ms. Smith, the Division believes that the demand/energy classification for wind resources should be 6 percent demand and 94 percent energy for interstate and intra-state/interclass allocation purposes.
- **Distribution Plant:** The Division believes that there are significant miss-allocations of service plant to different rate classes due to the Company's assumption that each individual customer requires individual services. While there is some problem with Schedule 6 customers in this regard, the majority

of the problem relates to residential customers as a result of multi-family housing. The Division believes that reducing the number of services required by residential customers by 129,953 is a conservative estimate. Ms. Smith has adjusted the rate spread to reflect the impact of the Company's over-allocation of services to residential customers.

- **Substations:** The Division is concerned that the weighting of substations and primary lines using the "distribution coincident peak" method, may not properly reflect the correct distribution of investment in this plant. However, at this time the Division is not recommending an adjustment.

- **Designation of Primary and Secondary Distribution Lines:** While it is apparent that some Schedule 6 customers receive power through secondary lines, the Company only allocates secondary distribution lines to Schedule 1 and 23 customers; thus overstating the assignment of secondary plant to these customers. The Company apparently cannot at this time reasonably allocate secondary line costs to those Schedule 6 customers taking secondary line service. The Division recommends that the Company analyze this issue of assigning secondary line costs to the appropriate Schedule 6 customers in future rate cases. At this time the Division is not recommending an adjustment for this issue.

- **Allocation of General Plant Based and Administrative and General (A&G) expenses:** The Division recommends allocating Accounts 920, 921 and 922 on a labor allocator because they are more closely tied to personnel rather than general plant.

- **Rate Caps:** The Division supports Ms. Smith's recommended caps on rate increases. For street lighting, she is recommending no change in current rates; otherwise she recommends a minimum increase of 2.00 percent and a maximum increase of 8.90 percent for the other rate schedules.

Given the analyses described herein and in Ms. Lee Smith's testimony, the Division recommends the that the Commission order the following rate design be implemented as set forth in Table 1 (duplicate of Lee Smith's Table 11):

Table 1: Division Recommended Rate Spread

Schedule No.	Description	Annual Revenue	Increase (Decrease) to = ROR	Percentage Change from Current Revenues	Capped %age Change	Revenue Impact of Caps	Final Increase (Decrease)	Final %age Change
1	Residential	649,980,899	50,547,518	7.78%	7.78%	0	50,547,518	7.78%
6	General Service - Large	475,082,792	(4,796,981)	-1.01%	1.50%	11,923,223	9,004,745	1.90%
8	General Service - > 1 MW	141,558,614	4,427,928	3.13%	3.13%	0	4,987,658	3.52%
7,11, 12	Street & Area Lighting	12,130,663	(523,098)	-4.31%	0.00%	523,098	0	0.00%
9	Gen Service-High Voltage	229,321,174	27,991,650	12.21%	8.82%	(7,756,463)	20,235,187	8.82%
10	Irrigation	13,174,523	1,868,052	14.18%	8.82%	(705,538)	1,162,513	8.82%
15	Traffic Signals	584,894	49,860	8.52%	8.52%	0	49,860	8.52%
15	Outdoor Lighting	1,144,626	(286,665)	-25.04%	0.00%	286,665	0	0.00%
23	General Service - Small	129,897,908	(2,394,142)	-1.84%	1.50%	4,342,611	2,462,092	1.90%
SpC	Customer 1	24,224,835	5,649,841	23.32%	23.32%	(5,649,841)	0	0.00%
SpC	Customer 2	26,946,218	5,915,612	21.95%	21.95%	(5,915,612)	0	0.00%
	Total Utah Jurisdiction	1,704,047,146	88,449,574	5.19%	0.00%	(2,951,857)	88,449,574	5.19%

Further details of the Division's rate spread and design, and other cost of service recommendations are contained in Ms. Smith's testimony.

Division's Cost of Service Principles

Q. What are the Division's Rate Design objectives?

A. Based on state code, the Division's cost of service and rate design objectives are for rates to be stable, simple, understandable and acceptable to the public, economically efficient, to promote fair apportionment of costs among individual customers within each customer class with no undue discrimination, and to protect against wasteful use of utility services. (See Utah Code Annotated § 54-4a-6)

Consistent with these statutorily defined objectives, the Division has developed a set of guiding principles. These principles are:

1. Simplicity— Rates should be as simple as possible in design and easy to understand and administer. Customers are more likely to accept and understood relatively simple rates. Tariff descriptions should be clear, unambiguous, and understandable by the public.
2. Correct Price Signals—Rates based on costs can incent customers to make appropriate decisions about energy use including energy conservation. While some customer classes are better able to understand complicated rates than others, a complicated rate that is not understood may not provide clear or correct price signals.
3. Rate Structures—Three part rates with customer, energy, and demand components will more fairly apportion the costs among individual customers than one or two part rates. However, a demand component for the residential class is normally not recommended since the added cost of demand meters usually outweighs the benefit of better cost apportionment.
4. Gradualism—Gradual changes in rates help to promote rate stability and to minimize impacts on individual customers.
5. Marginal and Embedded Costs—Regulated rates must be designed to recover the embedded revenue requirement of a rate schedule. Marginal and

average unit embedded costs should be reviewed and taken into account when setting prices.

6. Customer Charges—Costs that generally increase with the number of customers, but are not caused by each customer should be excluded from the customer charge and instead be included within the commodity portion of rates. (See Commission Order in Docket No. 82-057-15)

The Division has relied on these principles in this case in formulating its cost of service and rate design proposals.

On the Consistency of Inter-Jurisdictional Class Allocations

Q: In your summary you indicated that you believed that the Commission has stated a preference for consistency between inter-jurisdictional and class classification and allocation of costs. Would you provide examples where the Commission has stated such a preference?

A: In its 1997 general rate case order, in forming a task force to study allocation issues, the Commission directed that:

> The very basis for task force evaluation of allocations must be that all functionalization, classification, and allocation decisions are correct. This means that the decisions flow from an acceptable characterization of the engineering economics of an integrated, single system operation. We expect the task force to assure us that this is so. We also want to insure that these fundamental cost-of-service decisions are ***applied consistently*** at

> interjurisdictional and class levels.[2] (1997 GRC Order, Emphasis added)

In further instructions to that task force the Commission indicated that, "From our evaluation of the cost-of-service studies in the Docket, we find the following issues, at a minimum, are subjects for the task force: . . . Reestablish the link between interjurisdictional and class allocations."[3]

In its 2009 rate case order, the Commission stated,

> We affirm our commitment to having a consistent basis for allocating the Company's shared system costs to each state in the PacifiCorp utility system and among the classes within Utah.[4]

From these orders, it appears the Commission has consistently held a clear preference for consistency between inter-jurisdictional and class classification and allocation of costs.

Q: IS IT NECESSARY THAT THE CLASS ALLOCATION FACTORS BE CONSISTENT WITH THE INTER-JURISDICTIONAL FACTORS?

A: No, not necessarily. However, if the inter-jurisdictional factors had been developed according to a set of guiding principles, similar to the Division's principles discussed herein, it makes intuitive sense that, in the absence of evidence to the contrary, the class allocation factors would be similar. For example, if the classification of costs at the inter-jurisdictional level is based primarily on the cost causation principle, there would have to be a strong basis to utilize a different class classification, particularly since the

[2] "Report and Order," Docket No. 97-035-01, March 4, 1999, p. 108.

[3] 1997 GRC Order, p. 108.

[4] "Report and Order on Revenue Requirement, Cost of Service, and Spread of Rates," Docket No. 09-035-23, February 18, 2010. (2009 GRC Order)

Commission has previously expressed a preference for consistency between the two sets of allocation factors.

Q: GIVEN THE COMMISSION'S STATED PREFERENCE, COULD A PARTY RECOMMEND A CLASS CLASSIFICATION AND ALLOCATION DIFFERENT FROM THE INTER-JURISDICTIONAL CLASSIFICATION AND ALLOCATION?

A: Yes. The Commission's reference in its 1997 Order to an "**acceptable** characterization of the engineering economics,"[5] suggests that it may be appropriate to modify classification and allocation if the engineering economics of the system change significantly.

Additionally, Mr. Lowell Alt, a former Executive Staff Director at the Commission, acknowledges that for a multi-state utility, the inter-jurisdictional and class cost allocations may differ:

> An interjurisdicitional cost of service study may use the same methods as a class cost of service study. . . . [However,] The involvement of multiple states in interjurisdictional cost allocation may result in methods being used that are different than what each state uses for class cost of service.[6]

However, it is noteworthy that the Commission has indicated in past orders that the burden lies with the moving party:

> Other than treatment of MSP stipulation components, parties recommending changes to cost allocations for class cost of service purposes must provide analysis regarding the appropriateness of these changes for interjurisdictional cost

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[5] 1997 GRC Order, p. 108. Emphasis added.

[6] Lowell E. Alt, Jr., *Energy Utility Rate Setting*, [Copyright © 2011, 2006 Lowell E. Alt Jr.], p. 31.

> allocations and provide an estimate of the impact to Utah and the other states of any proposed change and an assessment of the likelihood such a change could also be made at the interjurisdictional level.[7]

In this case, the Division is arguing for an allocation of wind resources that differs from the inter-jurisdictional allocation. Ms. Smith will present these arguments and recommendations in her testimony for the Division and discuss some of differences in allocations in other PacifiCorp states.

Q: **ARE THE INTER-JURISDICTIONAL AND CLASS ALLOCATIONS CURRENTLY CONSISTENT?**

A: Although some differences exist, in general, I believe they are. In a Division report filed with Commission in November 2010 the Division indicated that "the allocation factors used in the JAM and COS models are consistent for most FERC accounts."[8] As an example, the class cost of service energy and demand factors are calculated or constructed in a similar manner to the inter-jurisdictional or system energy and demand factors.

Q: **COULD YOU PLEASE EXPLAIN WHAT YOU MEAN BY CONSISTENCY BETWEEN THESE PARTICULAR ALLOCATION FACTORS?**

A: Yes. Under inter-jurisdictional allocations, the 2010 Protocol, the necessary formulas for the System Generation (SG) factor is contained in Exhibit B (2010 Protocol-Appendix C) of the 2010 Protocol documents and is a weighting of the System Capacity (SC) and System Energy (SE) factors. The SC for a jurisdiction is defined as,

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[7] 2009 GRC Order, pp. 124-125.

[8] "Utah Work Group III, Consistency of Allocation Factors Between JAM and Class COS," November, 30, 2010, p. 3. (Reference Docket No. 09-035-23)

$$SC_i = \frac{\sum_{j=1}^{12} TAP_{ij}}{\sum_{i=1}^{8} \sum_{j=1}^{12} TAP_{ij}} \tag{1}$$

where

SC_i = System Capacity Factor for jurisdiction "i"; and

TAP_{ij} = Temperature Adjusted Peak Load of jurisdiction "i" in month "j" at the time of the system peak.

Thus, the SC for each jurisdiction is the average of that jurisdiction's 12-months coincident peaks (CP); or simply, a 12-month CP or 12CP. The SE for a jurisdiction is defined as,

$$SE_i = \frac{\sum_{j=1}^{12} TAE_{ij}}{\sum_{i=1}^{8} \sum_{j=1}^{12} TAE_{ij}} \tag{2}$$

where

SE_i = System Energy Factor for jurisdiction "i"; and

TAE_{ij} = Temperature Adjusted Input Energy of jurisdiction "i" for month "j".

The SG factor for a jurisdiction is then defined as,

$$SG_i = 0.75 * SC_i + 0.25 * SE_i \tag{3}$$

From the Company's Class Cost of Service model, the class allocation factor F10 is constructed in a manner similar to the inter-jurisdictional SG factor. Namely,

$$F10_c = 0.75 * F12_c + 0.25 * F30_c \tag{4}$$

where

$F10_c$ = the F10 allocation factor for class "c";

$F12_c$ = the Class Capacity Factor for class "c"; and

$F30_c$ = the Class Energy Factor for class "c".

The Class Capacity and Energy factors are defined similar to the system capacity and energy factors. Namely,

$$F12_c = \frac{\sum_{j=1}^{12} CP_{cj}}{\sum_{c=1}^{C}\sum_{j=1}^{12} CP_{cj}} \quad (5)$$

where, CP_{cj} is the monthly coincident peak at input for class "c" in month "j"; and

$$F30_c = \frac{\sum_{j=1}^{12} E_{cj}}{\sum_{c=1}^{C}\sum_{j=1}^{12} E_{cj}} \quad (6)$$

where E_{cj} is the monthly energy at input for class "c" in month "j".

Thus, the system or inter-jurisdictional and class demand allocation factors are defined similarly.[9] That is, both use a 12CP measure to define demand or the contribution to peak and a 75/25 weighting on demand and energy to classify demand related fixed costs.

Q: CAN YOU EXPLAIN HOW OR WHY THE INTER-JURISDICTIONAL SG FACTOR CAME TO USE A 12CP AND THE 75/25 WEIGHTING?

A: Yes. It is my understanding that before the merger between Utah Power and Pacific Power, Utah Power classified generation fixed costs 100% demand and allocated those costs to each of its jurisdictions using eight critical months of the test period, an 8CP. Pacific Power, on the other hand, classified generation fixed costs as 50% demand and

[9] In past recent cases, the Company's demand allocator used a weighted 12CP. In this case, the Company has moved to the total 12CP to be consistent with the inter-jurisdictional allocator.

50% energy. The demand component was developed from each of Pacific Power's jurisdiction's contribution to the coincident peak for the previous 60 months, while the energy component was based on the previous 24 months.[10]

According to a discussion paper prepared for the MSP process by Mr. Dave Taylor, an employee of the Company,

> Since the merger PacifiCorp has classified generation fixed costs as 75% demand related and 25% energy related with the demand component being allocated using contributions to the system coincident peak all 12 months of the year. . . .
>
> The choice of the 75% demand 25% energy classification for generation and transmission plant was the last allocation decision made by PITA after the merger. The PITA analysis indicated that a wide range of demand and energy classification[s] could be supported on a technical basis. The demand energy classification was the swing issue employed to balance a sharing of merger benefits between all the states and 75% demand and 25% energy was selected because it produced an overall allocation that was acceptable to all the states.[11]

In summary, the use of a 12CP and the 75/25 weighting or classification was a compromise adopted as part of the inter-jurisdictional allocations intended to equitably share the then perceived merger benefits among the various states.

[10] See, DPU Exhibit 2.1, Classification and Allocation of Generation Fixed Costs.

[11] Dave Taylor, "Classification and Allocation of Generation Fixed Costs: Discussion Paper," March 4, 2003, p. 3. (See DPU Exhibit 2.1 DIR-COS)

Q: YOU PREVIOUSLY INDICATED THAT IF A PARTY PROPOSED A DIVERGENCE BETWEEN THE INTER-JURISDICTIONAL AND CLASS ALLOCATIONS, THAT PARTY CARRIED THE BURDEN OF PROOF. SINCE THE SG FACTOR WAS THE RESULT OF A SETTLEMENT AT THE TIME OF THE PACIFIC AND UTAH POWER MERGER, WOULD THE PARTY RECOMMENDING A CHANGE OR DEPARTURE IN THE CLASS ALLOCATIONS BE RELIEVED OF THE BURDEN OF PROOF?

A: No. In general, as a matter of principle, I believe the moving party would still have the primary responsibility to demonstrate that its proposal was justified and would lead to just and reasonable rates.

Furthermore, in past orders the Commission has indicated that the current classification and allocation was based on supporting analysis and generally consistent with past orders.[12] Thus, unless supported by considerable evidence, classification and allocation of costs at the inter-jurisdictional and class levels should generally be consistent.

ON THE SYSTEM GENERATION FACTOR SG

Q: ARE YOU AWARE OF THE SUPPORTING ANALYSIS THAT THE COMMISSION REFERENCES?

A: There are two analyses that I am aware of concerning the inter-jurisdictional demand factors and the use of the 12CP and 75/25 split. The first is a Stress Factor analysis by the Company completed around 2003. The other is a statistical analysis that the Division performed, I believe, around 1995.

Stress Factor Analysis

Q: PLEASE EXPLAIN YOUR IMPRESSIONS CONCERNING THE COMPANY'S STRESS FACTOR ANALYSIS?

A: The Stress Factor analysis was provided in the current case in response to an Office of Consumer Services data request, OSC 3.2. The Company's response consisted of three

[12] "Report and Order on Revenue Requirement, Cost of Service, and Spread of Rates," Docket No. 09-035-23, February 18, 2010. (2009 GRC Order)

spreadsheets. The first spreadsheet consisted of one tab depicting for the years 2004 through 2008 three Stress Factors: (1) Peak Demand; (2) Probability of Contribution to Peak; and (3) Cost to Bring Reserve Margin to 15%. These Stress Factors were "rationalized" and then summarized in two ways.[13] The first summary measure is a simple average of the three factors by month for each year. The second summary measure is a weighted average of the three factors with a double weight on Peak Demand. The other two spreadsheets depict similar information with more underlying detail of the data and calculations, including data for 2001 and 2002, leading to the three Stress Factors.

There are several observations that are noteworthy about this particular study. First, the analysis appears to be dated. Information in the spreadsheets indicates that at the time the Company completed the analysis, the data for 2001 and 2002 was actual data, the rest being forecast data. From this it appears that the study would have been done sometime in 2003 and, thus, may not be an accurate reflection of current conditions or planning criteria. If, for example, the engineering economics of the system has changed significantly since completion of the study, any conclusions drawn from the study may lead to inappropriate outcomes relative to the current system.

Second, the Company's Stress Factor Analysis uses either a 15% or 20% planning margin. This is considerably higher than the 12% used in the most current IRP analysis and, thus, does not reflect current planning conditions.

Third, the Company's resource portfolio has changed considerably since 2003. For example, in a May 7, 2012 meeting kicking off the Company's 2013 IRP cycle, the Company indicated that in 2007 there were approximately 559 MWs of wind resources on or interconnected with PacifiCorp's transmission system. In 2011, that number had

[13] The rationalization process calculates the ratio of each month's "factor" value relative to the value for the highest month.

increased to approximately 2,135 MWs. The large majority of these resources are owned by or contracted to PacifiCorp. It appears likely that the intermittency of wind resources was not reflected in the Company's 2003 Stress Factor analysis, since there was little wind on the system at that time.

Fourth, the Company's data response provides no guidance on how to interpret the results of the analysis. The lowest value (for any month) for the simple average is approximately 30%; and the lowest value for the weighted average is approximately 43%. This latter simply means that, according to the weighting of the three stress factors, one month's weighted factor is only 43% of the weighted factors of the month with the most stress. Whether these numbers indicate months that should be included or excluded in the demand factors is not clear from the Company's data response. Specifically, given that a month's weighted factor is less than 75% of the peak month's weighted factor, it is not at all clear whether that month should be considered as contributing to decisions to build or acquire new capacity.

Q: WHAT CONCLUSIONS CAN BE DRAWN FROM THE STRESS FACTOR ANALYSIS?

A: While a Stress Factor analysis may provide useful information, given the caveats previously discussed, the Company's Stress Factor analysis provided in response to OCS 3.2 cannot reliably be used in determining in this case whether a 12CP or some lesser CP combination should be used in developing a demand allocator. Furthermore, as indicated in the NARUC Allocation Manual, an evaluation of the Company's planning objectives should be combined with any technical analysis in constructing an appropriate monthly CP combination.

DPU Special Study on PacifiCorp Allocations

Q: YOU MENTIONED TWO STUDIES RELATED TO THE COMPANY'S DEMAND FACTORS, THE COMPANY'S STRESS FACTOR ANALYSIS AND A DPU STUDY. WOULD YOU SUMMARIZE THE DPU STUDY?

A: Yes. The DPU performed a statistical analysis of the 12 CP and classification issue. The primary data for the study appears to be monthly system peak demand data for the years 1984 through 1993. As specified in the Issue section of the report, "This report contains a somewhat in-depth analysis of the 12 CP factor, a more subjective analysis of the 75-25 factor, and a sensitivity Study evaluating the impact of alternative decisions on Utah rates." A copy of this report is attached to my testimony as DPU Exhibit 2.2 DIR-COS.

Q: WHAT CONCLUSIONS DID THE DPU DRAW FROM THIS STUDY?

A: The conclusions are clearly spelled out in the Conclusions and Recommendations section of the report. Generally, the DPU concluded that the evidence was not inconsistent with using a 12CP, 75/25 allocator.

Q: DO YOU HAVE ANY COMMENTS ON THIS STUDY?

A: Yes, I believe there is at least one cautionary remark to consider. Similar to the Company's Stress Factor analysis, the DPU study is dated. The study was completed in September 1995 using system monthly peak data for the years 1984 through 1993. Given the age of the data, the results are likely not representative of the system today.

Therefore, I do not believe any current conclusions can be drawn from this study. However, at least some of the type of analysis contained in the DPU study combined with a new stress factor analysis may help shed light on the appropriate capacity factors. In particular, an updated study may shed light on the construction of a class capacity (F12) factor.

Q: DO YOU HAVE ANY RECOMMENDATIONS REGARDING THESE STUDIES?

A: Yes. The Division recommends that the Commission direct the Company to update its stress factor study. Prior to undertaking the study, the Division recommends that the

Company draft a proposed study including those elements or factors it believes important to consider and present that draft in a technical conference so that interested parties are allowed sufficient time to comment on the draft and make recommendations on the structure of the study. The study should be submitted with or prior to the Company's next rate case.

NARUC Allocation Manual

Q: YOU EARLIER MADE REFERENCE TO A NARUC ALLOCATION MANUAL. WOULD YOU EXPLAIN THE REFERENCE?

A: Yes. I was referring to NARUC's *Electric Utility Cost Allocation Manual*, dated January 1992.[14]

Q: WOULD YOU SUMMARIZE THE DISCUSSION IN THE NARUC MANUAL RELATED TO THE DEFINITION OF DEMAND AND THE CLASSIFICATION OF GENERATION FIXED COSTS?

A: Certainly. According to the NARUC Allocation Manual,

> In the past, utility analysts thought that production plant costs were driven only by system maximum peak demands. . . . Correspondingly, cost of service analysts used a single maximum peak approach to allocate production costs. Over time it became apparent to some that hours other than the peak hour were critical from the system planner's perspective, and utilities moved toward multiple peak allocation methods. The Federal Energy Regulatory Commission began encouraging the use of a method based on the 12 monthly peak demands, and many utilities

[14] A copy of the NARUC Allocation Manual is available for inspection in the Division's offices.

> accordingly adopted this approach for allocating costs within their retail jurisdictions as well as their resale markets.[15]

System planning as a guiding factor is emphasized later in the section on "Methods for Classifying and Allocation Production Plant Costs,"

> The common objective . . . is to allocate production plant costs to customer classes consistent with the cost impact that the class loads impose on the utility system. If a utility plans its generating capacity additions to serve its demand in the peak hour of the year, then the demand of each class in the peak hour is regarded as an appropriate basis for allocating demand-related production costs.
>
> If the Utility bases its generation expansion planning on reliability criteria—such as loss of load probability or expected unserved energy—that have significant values in a number of hours, then the classes' demands in hours other than the single peak hour may also provide an appropriate basis for allocating demand-related production costs.[16]

Additionally, the NARUC Allocation Manual indicates that, "The use of multi-hour methods also greatly reduces the possibility of atypical conditions influencing the load data used in cost allocation."[17]

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[15] "Electric Utility Cost Allocation Manual," National Association of Regulatory Utility Commissioners, January, 1992, p. 39.

[16] NARUC Allocation Manual, p. 39.

[17] NARUC Allocation Manual, p. 39.

It appears from these statements that system planning should play a key role in determining the appropriate number of (or which) months to include in defining allocation factors or methods for generation fixed costs.

IRP Planning Objectives

Q: ARE YOU AWARE OF ANY EVIDENCE REGARDING THE COMPANY'S PLANNING OBJECTIVES?

A: Yes. The Company's IRP provides some clues. From the Company's 2011 IRP it appears that in addition to meeting the peak, the Company's planning objectives include various risks, reliability, and long-run public policy objectives.

For example, the introduction to the 2011 IRP indicates that the IRP "presents a framework of future actions to ensure PacifiCorp continues to provide reliable, reasonable-cost service with manageable risks to customers. . . . Development of the 2011 IRP involved a balanced consideration of cost, risk, uncertainty, supply reliability/deliverability, and long-run public policy goals."[18] From these statements, it clearly appears that the Company's planning objectives are broader than just meeting a peak hour load.

This interpretation of the Company's planning objectives is supported by particular studies and metrics used in the 2011 IRP to select a preferred portfolio. For example, the Company performed or used loss of load probability and energy not served metrics in evaluating various portfolios as part of the 2011 IRP. Consistent with the NARUC Allocation Manual this would indicate that more than just the peak hour should be used in the definition of the Company's demand allocators. Exactly which months would be included in a demand factor would require technical or analytical support that is lacking in the Company's filing or responses to data requests.

[18] "2011 Integrated Resource Plan," Volume 1, March 31, 2011, p. 1.

MARGINAL COSTS

Q: ONE OF THE DIVISION’S GUIDELINES FOR DESIGNING RATES WAS TO RECOVER THE EMBEDDED REVENUE REQUIREMENT FOR A SCHEDULE. SHOULD THE COMMISSION RELY ON MARGINAL COSTS TO SET THE COMPANY'S TARIFF RATES?

A: Yes, using marginal costs is part of the Division’s guiding cost of service principles that I previously discussed. However, while marginal costs can be informative, marginal costs should be interpreted and applied with informed caution.

Q: WILL YOU PLEASE EXPLAIN WHAT MARGINAL COSTS ARE?

A: In economic theory, marginal cost is defined as the change in total cost given a small change in output. Of course a modern utility offers many different products and services each of which would have a marginal cost as defined here. For example, on-peak and off-peak are considered two separate products or services. Additionally, there are two “types” of marginal costs: short-run and long-run marginal costs.

Q: **WOULD YOU EXPLAIN THE DIFFERENCE BETWEEN SHORT-RUN AND LONG-RUN MARGINAL COSTS?**

A: In economics the concepts of short-run and long-run are not necessarily defined by or associated with a specific time interval. Rather they are defined with respect to the variability of the inputs into the production process. The short-run is defined as a period short enough such that at least one input is constant, or in other words, cannot be varied. The long-run, on the other hand, is defined as a period long enough such that all inputs are variable.

Intuitively, some economists have used the short-run to mean marginal costs that are estimated under the assumption that the increased output is temporary and will be met by increased utilization of existing resources; the long-run is used to mean estimates of marginal costs under the assumption that the increased output will be sustained for the foreseeable future and, thus, will be met by an increase in plant capacity.[19]

Q: WHY DO YOU SAY THAT MARGINAL COSTS SHOULD BE USED WITH INFORMED CAUTION?

A: Justification of marginal cost pricing is generally based on economic efficiency arguments. However, as explained in the NARUC Allocations Manual, "in contrast to embedded studies where the issues primarily involve the allocation of costs taken from the Company's books, the practical and theoretical debates in marginal cost studies center around the development of the costs themselves."[20] Therefore, before employing an estimate of marginal costs as a guide to utility rate setting, it is important to have a thorough understanding of the concepts of marginal cost pricing and the controversies and limitations inherent in such an approach. In short, there are some practical considerations or difficulties that need to be taken into account in using marginal costs as a guide to setting rates.

Practical Considerations in Estimating Marginal Costs

Q: WHAT ARE SOME OF THOSE PRACTICAL CONSIDERATIONS?

A: There are several concerns, in my opinion, that are important to keep in mind. First, remember, the argument for using marginal costs as a guide for setting utility rates is based on the economic concept that marginal cost pricing under competitive conditions leads to efficiency. However, there are several restrictive assumptions that are necessary for this outcome. Second, marginal costs are defined as the change in total cost given a (infinitesimally) small change in the inputs. Utility investment, however, is lumpy. We measure power plants, for example, in hundreds of megawatts. Third, there are practical difficulties in estimating marginal costs. Fourth, given a set of marginal

[19] Bonbright, p. 319.

[20] NARUC Allocation Manual, p. 108.

cost estimates, those costs estimates must be translated into effective rates given potentially conflicting objectives.[21] Additionally, there are differences of opinion about whether short-run marginal costs, long-run marginal costs, or some combination of the two provide the most appropriate guidance for rate design.

Restrictive Assumptions

To demonstrate the ability of markets to achieve a general level of efficiency under a marginal pricing rule, certain restrictive assumptions are required. These assumptions include, among others, (i) economic agents who act in a rational and predictable manner—economic agents act to maximize their own welfare; (ii) perfect information about prices and product quality, both under present and future conditions; (iii) absence of externalities—the market price reflects the total social costs of producing or consuming a good; and (iv) an absence of transactions costs. At best, these assumptions will only hold approximately.

The Nature of Utility Investment

Previously I defined marginal cost as the change in total cost given a small change in output. While this is approximately correct, it brushes over the more technical definition that marginal cost is the derivative of the total cost function with respect to output. [22] In other words, the change in the input is defined as infinitesimally small. Utility investment, however, is often lumpy in nature and means the utility will likely have excess capacity immediately following the investment. While the utility has excess capacity (*ceteris paribus*) its short-run marginal costs are likely to be relatively low. As the capacity becomes constrained, the utility's marginal costs will rise until the

[21] For a full discussion of these issues see, "Utility Tariff Setting for Economic Efficiency and Financial Sustainability: A Review," Herath Gunatilake, Pradeep Perera, and Mary Jane F. Carangal-San Jose, Asian Development Bank, ERD Technical Note No. 24, August 2008; James Bonbright, Principles of Public Utility Rates, [Columbia University Press, New York, New York], 1961, chapters 16-20.

[22] The derivative of a function y = f(x) with respect to x is defined as, $\lim_{\Delta x \to 0} \frac{f(x+\Delta x) - f(x)}{\Delta x}$.

next round of investment. A strict marginal cost pricing rule may mean that the utility earns less than a fair economic or normal profit when it has excess capacity and earns excessive economic profits as capacity becomes scarce.

Practical Difficulties

Estimating marginal costs can be difficult and controversial. Marginal cost estimation requires a great deal of information about the utility's past investments and expenses, and the important area of marginal capacity cost is particularly controversial even theoretically.

In addition to class variations, marginal cost will vary both spatially and temporally. For example, marginal costs may be higher in less dense or rural areas than in urban areas. Marginal costs will also vary depending on the time of day, week, and season. Strict marginal cost pricing rules would need to take these variations into account. However, doing so will increase the administrative and transactions costs, and may face legal or political obstacles.

Translating Marginal Costs into Rates

Traditionally, rates are set to collect the utility's embedded revenue requirement. Marginal costs can generate revenues that are greater or less than an embedded revenue requirement.[23] As the NARUC Allocation Manual explains, "Pricing a utility's output at marginal cost . . . will only by rare coincidence recover the allowed revenue requirement."[24] Furthermore, there are a number of different methods of using marginal costs in ratemaking but these different methods can still collect the

[23] Similarly, short-run marginal costs can be less than, equal to, or greater than average total costs or long-run marginal costs.

[24] NARUC Allocation Manual, p. 108. For a more detailed discussion see, James C. Bonbright, *Principles of Utility Rates*, [Columbia University Press, New York, New York], 1961, pp. 97-100.

correct revenues. These different methods are another source of contention, as the impact of different methods on class revenue targets will vary.

Miscellaneous Issues in Estimating Marginal Costs

Additionally, the standard economist's definition of long-run marginal cost is the change in costs required by a change in demand, assuming that the system is in equilibrium. Since utility systems are rarely in perfect equilibrium, this may be another complication in the estimation of marginal cost.

Another complicating issue is that the customers who should be guided by utility pricing are making both short-run, medium run, and long-term decisions – decisions about how much electricity to use, and decisions regarding investments that will affect their future use of electricity.

While this discussion is not meant as an exhaustive treatise on the use of marginal costs as a guide for rate setting, it does provide a flavor of the issues that must be considered. Again, the Division believes that marginal costs can be one useful guide in setting appropriate utility rates. Their application, however, should be done with caution.

Short-Run or Long-Run Marginal Costs, or Both

Q: IF MARGINAL COSTS CAN BE A USEFUL GUIDE IN SETTING RATES, WHICH MARGINAL COSTS, SHORT-RUN OR LONG-RUN, DOES THE DIVISION ADVOCATE THAT THE COMMISSION LOOK TO FOR INSIGHT?

A: There is no simple answer to that question; both short-run and long-run marginal costs have their strengths and weaknesses. Professor Bonbright concludes that long-run marginal costs—at least those qualified estimates of long-run marginal costs I previously discussed—are more significant than short-run marginal costs for establishing utility rates and rate relationships.[25] This does not mean that short-run marginal costs need be or should be ignored. It does mean, however, that short-run marginal costs "should be used with caution, and with special warnings of the liability of rates based thereon to cancellation or revision on short notice."[26]

Q: WHAT ARE THE STRENGTHS OR ARGUMENTS FOR USING SHORT-RUN MARGINAL COSTS?

A: In a competitive market, "prices are supposed to tend to come much more quickly into accord with short-run marginal costs than into accord with long-run marginal costs."[27] That is, under competition, current costs reflect current market conditions. As I previously explained, a utility's short-run marginal costs will depend on the current relationship between output and capacity. If capacity is redundant, then marginal costs are likely to be relatively low. On the other hand, if capacity is constrained, short-run marginal costs could be quite high. This is, according to some advocates of short-run marginal costs, as it should be. If capacity is redundant, then prices or rates should reflect that condition to encourage ratepayers to use the excess capacity efficiently for as long as the excess capacity exists. If capacity is constrained, then rates should rise to the short-run marginal cost to ensure again that the existing limited plant is used efficiently and, thus, avoid overt rationing.

Q: WHAT ARE SOME WEAKNESSES OF OR ARGUMENTS AGAINST THE USE OF SHORT-RUN MARGINAL COSTS?

A: As indicated in the previous discussion on short-run marginal costs, attempting to match rates with the utility's short-run marginal cost could produce unacceptable volatility in rates. Some critics argue it is this volatility (among other things) that makes short-run marginal costs impractical as a guide for setting rates. Advocates of long-run marginal

[25] Bonbright, p. 336.

[26] Bonbright, p. 336.

[27] Bonbright, p. 332.

costs argue that long-run marginal costs promote greater stability in rates and, it is exactly these longer-lived rates that are expected to be in place for a considerable time (say several years) that really "play the major role in controlling the types and amounts of use of public utility services."[28] Thus, a strong argument for long-run marginal costs is better rate stability.

Q: WHAT ARE THE WEAKNESSES OF LONG-RUN MARGINAL COSTS?

A: Consider the definition I provided for long-run marginal costs: a period long enough for all productive inputs to vary. The length of time necessary for "all" inputs to vary is likely to be so long that basing rates on estimates of these costs may be impractical, or worse, speculative. However, unless this "limiting case" definition of long-run marginal costs is accepted, the distinction between short-run and long-run marginal costs becomes blurred.[29] For example, some advocates of long-run marginal costs propose a compromise in which some inputs are allowed to vary but others are held constant. Which costs fall into which category is a matter of informed judgment and may be controversial.

COMMISSION QUESTIONS DEALING WITH CERTAIN ISSUES

Q: IN YOUR SUMMARY, YOU INDICATED THAT YOU WOULD ADDRESS CERTAIN QUESTIONS POSED BY THE COMMISSION TO THE DIVISION. WOULD YOU EXPLAIN THE NATURE OF THOSE QUESTIONS?

A: Yes, I will explain my understanding of the Commission's questions. Further responses to the Commission's questions are in Ms. Smith's testimony.

On May 10, 2012, the Commission issued an Action Request to the Division directing the Division to investigate several cost of service issues related to the Company's treatment of certain items in the Company's filed case. On May 17, 2012,

[28] Bonbright, p. 333.

[29] See Bonbright, pp. 318-327.

the Commission issued a Revised Action Request (Action Request) to the Division wherein the Commission clarified several of those questions. The Action Request was issued under this docket with a due date of June 25, 2012; the deadline for direct testimony on cost of service issues was scheduled as part of this docket as June 22, 2012. Given the proximity of the two due dates, the Division is incorporating its response to the Action Request as part of its direct testimony. The Division may have follow up comments and recommendations in subsequent rounds of testimony depending on the response of other parties in this docket.

According to the Action Request, in the preparation of its integrated revenue requirement and class cost of service model (Commission Model), the Commission identified what it perceived as inconsistent treatment of several items between the Company's inter-jurisdictional and class cost of service models or studies. As specified in the Action Request, these items included, "1) [the] relationships among cash working capital, interest expense, and income taxes; 2) the determination of state income taxes; and 3) use of the income to revenue multiplier."

The Commission held a technical conference on June 4, 2012. Prior to the technical conference, the Commission made its model available as part of the docket. At the technical conference, Commission staff explained the nature of the perceived inconsistencies, potential impacts or implications for the apportionment of costs to the classes, and their location using the Commission Model. Parties attending the technical conference were given an opportunity to ask clarifying questions.

Cash Working Capital, Interest Expense, and Income Taxes

Q: WHAT SPECIFIC QUESTIONS HAS THE COMMISSION ASKED THE DIVISION TO ADDRESS WITH RESPECT TO THE RELATIONSHIP AMONG CASH WORKING CAPITAL, INTEREST EXPENSE, AND INCOME TAXES?

A: The Commission directed the Division to investigate the apparent differences in the way these three variables are treated in the Company's JAM model and the Company's class cost of service model, the need for these differences, and the advantages or disadvantages of eliminating these differences with respect to the fair statement of the class cost of service. Specifically, the Commission asked whether "a direct calculation of cash working capital, interest expense, and income taxes by rate schedule, without assumptions or imputation, [would] be simpler and result in a fair statement of cost of service by rate schedule?"

Q: DOES THE DIVISION BELIEVE THAT THE THREE VARIABLES ARE TREATED INCONSISTENTLY BETWEEN THE TWO COMPANY MODELS?

A: Yes.

Q: WOULD YOU EXPLAIN THE RELATIONSHIP BETWEEN THE THREE VARIABLES?

A: The three variables form a system of three equations which yield a closed form solution. That is, cash working capital (CWC) is a function of, among other things,[30] income taxes; interest expense is a function of CWC; and income taxes are a function of interest expense.[31] Given this relationship, it is possible to solve the system of equations to arrive at a solution that is consistent with the initial relationship but avoids any circularity in the solution. In other words, although the variables are dependent on one another, the solution makes it possible to calculate a value for each variable independent of the calculation of the other two and yet preserve the underlying relationship. Perhaps a simple example would be useful.

[30] For example, CWC is a function of O&M expense. However, since O&M is an exogenous variable—a variable whose value is determined outside the instant system of equations—its value is treated as a constant or given in so far as the relationships among CWC, interest expense, and income taxes are concerned.

[31] This relationship was discussed at the June 4, 2012, technical conference.

Suppose we have two unknown variables, X and Y, and two equations that define their relationship where a, b, c, and d are known parameters (values):

$$\begin{aligned} Y &= a + b * X \\ X &= c + d * Y \end{aligned} \tag{7}$$

To solve the system we can substitute the value of Y from the first equation into the second and solve the resulting expression for X. The resulting solution for X can be substituted into the first equation to yield the solution for Y. The final expressions yield formulas (or values) for X and Y in terms of the known parameters consistent with the original relationship defined in Equation 7. That is,

$$\begin{aligned} Y &= \frac{a + b * c}{1 - d * b} \\ X &= \frac{c + d * a}{1 - d * b} \end{aligned} \tag{8}$$

Although a little more complicated, the relationships among CWC, interest expense, and income taxes can be solved in a similar fashion so that their values for a given level of revenues can be calculated directly. This is in essence what the Company’s jurisdictional allocation model (JAM) does and what the Commission’s model does explicitly in the JAM tab.

In summary, the JAM allocates the revenue requirement to Utah and solves for the jurisdictional earned return consistent with the relationship among CWC, interest expense, and income taxes.

Q: DOES THE COMPANY USE THIS RELATIONSHIP IN ITS CLASS COST OF SERVICE MODEL TO ARRIVE AT VALUES FOR THE THREE VARIABLES FOR THE SCHEDULES?

A: No, it does not. In the functional allocation model or FAM tab in the Commission’s model, Utah’s revenue requirement is allocated to each function—production (P), Transmission (T), Distribution (D), Customer (C), and Miscellaneous (M)—except for CWC and income taxes. To assign a value for CWC and income taxes to each function, the Company imputes a level of revenue to each function assuming each function achieves the jurisdictional earned rate of return. In this process, interest expense is treated as a constant and is allocated to each function using a gross plant factor. Thus, the Company's treatment of interest expense in the FAM introduces an inconsistency—the relationship among CWC, interest expense, and income taxes that was preserved in the JAM is no longer true for each of the functions. Thus, the level of interest expense allocated to each function is likely not the same level that would have been assigned to the functions if the underlying relationship had been preserved in the calculations of all three variables directly.

In the function tabs, each function's result is allocated to the schedules. The imputed CWC from the FAM tab for each function is allocated to the schedules on an O&M factor; interest expense is allocated on a rate base factor; and income taxes are allocated on an income before taxes factor. Again, this process will not maintain the same relationship among CWC, interest expense, and income taxes that was present in the JAM.

Finally, in the schedule allocation model or SAM tab, each schedule's assignment of these three variables is the sum of that schedule's amounts previously determined in the function tabs. For example, each schedule's CWC is the sum of the amounts allocated to the functions.

Determination of State Income Taxes

Q: ARE STATE INCOME TAXES DETERMINED IN THE SAME MANNER IN BOTH THE JURISDICTIONAL COST STUDY AND CLASS COST STUDY?

A: No. In the JAM tab, state income taxes for each jurisdiction are determined using a blended state tax rate applied to that jurisdiction's taxable income. In the FAM tab, state income taxes are imputed to the functions as part of the iteration process imputing revenues to the functions assuming each function earns the Utah earned return, although in each iteration the level of taxes is calculated using the blended state tax rate. However, in the function tabs, state taxes are allocated to the schedules using an income before taxes factor. The difference introduced in the FAM to determine each schedules state income taxs does not appear warranted.

The Income to Revenue Multiplier

Q: THE COMMISSION'S ACTION REQUEST ALSO ASKED THE DIVISION TO LOOK AT THE USE OF THE INCOME TO REVENUE MULTIPLIER BETWEEN THE COMPANY'S MODELS. WOULD YOU EXPLAIN HOW THE INCOME TO REVENUE MULTIPLIER IS USED IN THE JAM?

A: For each jurisdiction the JAM calculates the revenue deficit given the allowed rate of return. However, a change in revenues will generate a change in taxes.[32] The income to revenue multiplier grosses up the change in revenues necessary to cover or collect the additional taxes. Thus, the final change in revenues for each jurisdiction is sufficient to recover the additional taxes brought about the change in revenues.

Q: DOES THE COMPANY USE THE SAME APPROACH IN THE CLASS COST OF SERVICE STUDY?

A: No. In the SAM, the Company first determines the revenue deficit for each schedule based on the schedule's earned return compared to the jurisdictional earned return. It adds to this deficit an amount grossed up for taxes necessary to bring each schedule to the allowed return. In essence, in the first step to bring the schedule to the jurisdiction earned return, the Company assumes the multiplier is equal to one—it does not gross

[32] The change in revenues will also change the level of uncollectibles assuming the uncollectible rate remains the same.

up the first revenue change for taxes. In the second step, the additional revenue change is grossed up for taxes.

This means that the revenue change necessary to bring a schedule from its earned return to the allowed return is understated. For those schedules earning less than the jurisdictional average return, their change in revenues will be understated; for those earning more than the jurisdictional average return, their change in revenues will be overstated.

Recommendation Regarding Commission Issues

Q: WHAT ARE THE DIVISION'S RECOMMENDATIONS REGARDING THE ISSUES RAISED IN THE COMMISSION'S ACTION REQUEST?

A: With respect to these issues, the Division recommends that the Commission direct the Company to modify its class cost of service study in this and future cases to be consistent with its jurisdictional cost of service study. Specifically, the class cost of service study should treat consistently the determination of CWC, interest expense, and income taxes for each schedule as is done for each jurisdiction in the JAM. Additionally, the class cost of service should apply the income to revenue multiplier in a consistent manner. The Division believes these changes are necessary to help fairly apportion the Utah revenue requirement to the various schedules and customers.

CONCLUSIONS AND RECOMMENDATIONS

Q: WOULD YOU SUMMARIZE THE DIVISIONS RECOMMENDATIONS?

A: In addition to those recommendations on cost of service, revenue spread, and rate design presented by Ms. Smith, the Division recommends that,

(1) The Company update its stress factor analysis study prior to the next rate case;
(2) Wind resources be classified as primarily energy and allocated accordingly; and

(3) The Company treat cash working capital, interest expense, and income taxes in its class costs of service study consistent with the treatment of these variables in the jurisdictional cost of service study.

These last two recommendations are reflected in the Division's rate spread and design recommendations in Ms. Smith's testimony.

Q: DOES THAT CONCLUDE YOUR DIRECT TESTIMONY IN THIS PHASE OF THE CASE?

A: Yes it does.