BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR APPROVAL OF THE 2017 PROTOCOL	DOCKET NO. 15-035-86 EXHIBIT NO. DPU 1.0 DIR

DIRECT TESTIMONY OF ARTIE POWELL, PHD

ON BEHALF OF THE

DIVISION OF PUBLIC UTILITIES

DEPARTMENT OF COMMERCE

March 16, 2016

Q: Will you please identify yourself for the record?

A: My name is Artie Powell. I am the manager of the Energy Section in the Division of Public Utilities and my business address is in the Heber Wells Building, Fourth Floor, 160 East 300 South, Salt Lake City, Utah. I will be testifying on behalf of the Division in this case.

Q: Would you please summarize your educational and professional experience?

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 dealing with a variety of regulatory issues including, the NARUC Annual Regulatory Studies Program (1996) and IPU Advanced Regulatory Studies Program (2005). 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, qualifying facility pricing, and the cost of capital. For the past several years, I have, along with other Division staff, represented the Division during various meetings or discussions on inter-jurisdictional allocations.

Q: What is the purpose of your testimony?

A: On behalf of the Division, I offer supporting testimony for the 2017 Protocol and recommend that the Commission adopt the method as defined in the 2017 Protocol documents including the appendices for purposes of cost allocation for the interim period described in Section II, Effective Period and Expiration. I also provide historical context for Utah's Equalization Adjustment.

Q: The 2017 Protocol is defined as a two-year agreement, is that correct?

A: Yes. Despite three years of discussions among the various representatives participating in the multi-state process or MSP Workgroup, the participants were unable to come to a consensus for a longer-term allocation method. Thus, the 2017 Protocol agreement expires December 31, 2018 unless a one-year extension is approved by all of the state commissions that approve the agreement.

Q: Do you believe the 2017 Protocol is an improvement over previous allocation methods?

A: Yes. Despite the reference to "Protocol" in the title, the 2017 Protocol is a fully Rolled-In allocation method with a fixed lump sum, jurisdictional-specific adjustment. An exception is the Oregon adjustment, which is allowed to vary as described in Section XIV, Additional State-Specific Terms, of the agreement.

Q: Is it important that the 2017 Protocol is a fully Rolled-In method?

A: Yes. Reaching a fully Rolled-In, one-system allocation method has been the stated goal of the Utah Commission since the 1989 merger and has been repeated in numerous dockets since. For example, in its report and order in Docket No. 02-035-04, dated February 3, 2012, the Commission states: "for the reasons we have stated consistently since the Utah Power and Pacific Power merger, we find the principle-based, Rolled-In method and its current, rather than historical, cost-causation rationale, for determining Utah's revenue requirement in the public interest." (pp. 18-19)

Q: Are the issues preventing a longer-term consensus on an allocation method new?

A: Not entirely. While there may be some new issues or at least nuances to old issues, the current inter-jurisdictional allocation issues began with the 1989 merger of two utilities with differing cost structures: the relatively lower cost hydro-based Pacific Power and the higher cost coal-based Utah Power. Although the merger was approved, the Utah Commission did not determine as part of the merger case, Docket No. 87-035-27, an inter-jurisdictional allocation method. While the Commission had concerns about approving the merger prior to determining inter-jurisdictional allocations, the Commissioned noted that, "Applicants assert that developing detailed allocations prior to the merger is not essential because the Merged Company's shareholders will assume the risk that differing allocation methods employed by the various jurisdictions could result in less than full cost recovery." (Merger Order: Report and Order, Docket No. 87-035-27, September 28, 1988, p. 62). Furthermore, the Commission concluded that, "net positive benefits will result from the merger and that a reasonable allocation plan can be worked out after the merger to assure that Utah ratepayers receive their appropriate share of these benefits." (Merger Order p. 67)

Q: How were allocations determined after the merger?

A: As part of the merger order, the Commission directed the Company to "convene multi-jurisdictional meetings within six weeks of the merger to discuss allocation issues."

(Merger Order, p. 96) The Company convened the PacifiCorp Interjurisdictional Task Force on Allocations or PITA, which met several times from February 1989 through February 1990. (Report and Order, Docket No. 90-035-06, pp. 9-10) The taskforce developed two allocations methods: Rolled-In, which was described as a method based on cost causation, and the Consensus. The Consensus method differed from Rolled-In in a series of ten steps, "principle among which were direct assignment (instead of allocation) of pre-merger plant to divisions of the merged Company, i.e., the former Pacific Power and the former Utah Power; establishment of a hydro endowment favoring the Pacific Division; and establishment of a transmission endowment favoring the Utah Division." (Doug Kirk, Draft White Paper, Utah Power & Light and Pacific Power & Light Merger/Allocations, May 15, 2002, footnote 3)

Over the intervening years from 1990 through 1997, several additional allocation methods, each of which retained the hydro endowment in one form another as well as other departures from Rolled-In, were developed by PITA. However, as the Commission concluded in the 1990 rate case, "The analysis of single-system, rolled-in costs of service provides the only acceptable benchmark or standard by which alternative allocation approaches, such as the Consensus Method, may be judged" and "would best promote a single-system planning and operation." (Report and Order, Docket No. 90-035-06, Phase I, December 7, 1990, p. 12, 13)

Q: Did the Commission adopt the Consensus Method for allocation purposes?

A: No. However, the Commission did recognize that an immediate application of a Rolled-In method would result in an unfair cost shift to the Pacific Division. The Commission, therefore, adopted a non-cost based lump sum transfer as a means to achieve merger fairness. To estimate the merger fairness premium, the Commission adopted the results of the Consensus Method to establish the maximum departure from Rolled-In that it would allow for merger fairness. (1990 Order, Phase I, p. 13) The Commission set the merger fairness premium at an approximate $72 million addition to Utah's annual revenue requirement.[1] (Report and Order, Docket No. 90-035-06 Phase II, April 10, 1992, pp. 11, 14-15)

In addition to establishing the maximum merger fairness premium, the Commission also stated as its goal to transition to "a rolled-in method for interjurisdictional allocations process within ten years," with a caveat that "meeting the fairness objective . . . may continue to require some modification of full roll-in . . . over a transitional period no longer than the depreciation schedules and contract renewals and terminations," of pre-merger plant and contracts. (1990 Order Phase I, p. 14)

Finally, as part of the Phase I order in the 1990 rate case, the Commission established eight rebuttable presumptions "to guide all further considerations of allocation methods." (Phase I, p. 15) Those presumptions are:

[1] The Commission's 1990 order does specify "approximately." However, as discussed below, subsequent calculations from Docket No. 97-035-01 appear to use exactly $72 million.

1. A fully Rolled-In allocation method will be the standard of comparison by which alternative allocation methods will be judged.
2. Future allocation methods will not diverge further from Rolled-In cost of service than does the Consensus method.
3. Future allocation methods must promote progress toward the fully Rolled-In standard.
4. With the noted caveat, ten years is a reasonable goal for the transition to inter-jurisdictional allocations based on a fully Rolled-In method.
5. The opportunity to lower future system cost of service due to the Arizona Public Service contracts will be weighed against the divisional endowments.
6. In the absence of a least-cost plan, it could not be presumed that the Utah Power stand-alone company would have a higher future resource cost than the Pacific Power stand-alone company.
7. System rather than divisional allocations should be used for all production and transmission operations and maintenance expense.
8. All post-merger costs and non-retail revenues should be allocated system wide.

Q: Did the merger fairness premium make it into rates at the conclusion of the 1990 rate case?

A: Yes. The premium was in rates effective with the April 10, 1992 rate case order (Docket No. 90-035-06) and remained in rates until the Commission authorized an end to the premium with the final order in Docket No. 97-035-01, dated March 4, 1999. The premium, therefore, was in rates approximately 7 years.[2] Thus, from April 1992 through

[2] More accurately, since the Company collects its revenue on a monthly basis, one-twelfth of the premium, or $6 million, was in rates for approximately 83 months, 9 months in 1992, 2 months in 1999, and 72 months from 1993 through 1998. Although, future and present values would, because of compounding, be somewhat different if considered on a monthly basis, I present the following analysis for 1992 through 1999 using annual values. This makes the comparison between the merger fairness premium and the 1997 rate case “buy-out” discussed below simpler.

February 1999 Utah ratepayers payed on a nominal basis approximately $498 million in merger fairness premiums.

Q: Was that the total of the merger fairness premiums paid by Utah ratepayers?

A: No. As part of the 1997 rate case, Docket No. 97-035-01, the Commission authorized that part of a pending rate refund would be used to "buy-out" the remaining value of the merger premium. On a present value basis—that is, in "1999" dollars—the buy-out was equal to $71.24 million.

As part of the 1997 rate case, the Commission determined that the 1996 premium amount was $43.2 million,[3] which was to be amortized over five years: $43.2 million for 1996, $34.56 million for 1997, $25.92 million for 1998, $17.28 million for 1999, $8.64 million for 2000, and zero thereafter. The present value of the amounts for 1997 through 1999, on a monthly basis at the Company's authorized weighted average cost of capital, 8.84%, yields the $71.24 million.[4] (See DPU Exhibit 1.1 DIR for details).

[3] The $43.2 million for 1996 is the average of the value for a ten year and thirty year straight-line amortization of the $72 million merger fairness premium.

[4] Two adjustments are necessary to arrive at the Commission's buy-out value. First, the Commission appears to have used $34.76 and not the $34.56 for the 1997 premium value. Second, the 1997 premium is assumed to be in rates only 10 months. Thus, for calculation purposes, the 1997 total remaining premium appears to be $28.97 million or $2.897 million per month.

If the premium from 1992 through 1999 is restated in 1999 dollars then the total premium for that period is $543.56 million. Thus, from 1992 through 1999, the total premium in 1999 dollars, including the buy-out, totaled approximately $614.80 million.[5]

Q: Since the 1997 rate case, have there been other cases where above Rolled-In costs have been included in rates?

A: Yes. Since the 1997 rate case, there have been 12 rate cases in Utah. Some of these cases used Rolled-In or an equivalent method (i.e., the Utah application of the 2010 Protocol) as the basis of cost allocation. Other cases used earlier variations of the 2010 Protocol, namely, Protocol or Revised Protocol. Under the Protocol and Revised Protocol, the above Rolled-In costs that the Company could seek recovery of was capped. While I have not calculated the exact amounts for this later group of cases, some amount of above Rolled-In costs were included in the final rates approved by the Commission.

Q: Is the 2017 Protocol consistent with the Commission's rebuttable presumptions?

A: Yes, with the exception of the fifth presumption, the 2017 Protocol is consistent with those presumptions. Since the divisional endowments are not used for Utah's revenue

[5] There is somewhat of a mismatch in arriving at the $614.80 million. The present value of the remaining premium, $71.24 million, was calculated using the Company's weighted average cost of capital (WACC), 8.84%, whereas the nominal premium of $498 million for the years 1992 through 1999 was restated in 1999 dollars using the consumer price index or CPI. If instead, the Company's WACC were used to restate that amount, the future value would be considerable higher. For example, using the Commission authorized WACC from the 1990 rate case, 10.188%, the restated total premium for 1992 through 1999 would be $733.53 million. And the total premium paid by Utah rate payers, including the buy-out, would be $804.77 million.

requirement allocation under either the 2010 Protocol or under the 2017 Protocol, the fifth presumption does not appear to be relevant at this time.

Q: The second presumption states that future allocations will not depart from Rolled-In by more than the Consensus Method. How does the Equalization Adjustment satisfy this presumption?

A: As I previously discussed, the Commission adopted the results of the Consensus Method in the 1992 rate case to establish the merger fairness premium, $72 million. There are three factors to consider with regard to the Equalization Adjustment. First, the Equalization Adjustment serves a different purpose than did the merger fairness premium. Second, even though it is intended to address a different issue, the Equalization Adjustment is less than the 1992-projected value of the merger fairness premium for 2017 and 2018. Third, the Equalization Adjustment is similar in magnitude to a range of potential outcomes under plausible applications of a Rolled-In method.

Q: Would you please briefly explain the purpose of the Equalization Adjustment?

A: The purpose of the Equalization Adjustment is explained in Section IV.C of the 2017 Protocol. In summary, the Equalization Adjustment addresses the issue of different jurisdictional applications of the embedded cost differential or ECD, which reflects the hydro endowment in its current configuration, and the resulting cost allocation hole. In contrast, the merger fairness premium was intended as a mechanism of gradualism to lessen the impact of the adoption of a Rolled-In allocation method.

Q: What was the 1992-projected merger fairness premium for 2017 and 2018?

A: In the 1992 rate case, the Commission stated as a goal to transition to Rolled-In allocations over ten years with the caveat that a longer time may be required for fairness, the longer period corresponding to the time needed to depreciate pre-merger plant, approximately 30 years. If the original merger fairness premium were amortized over ten years, the 2017 value would be zero. However, under a 30-year amortization, the 2017 and 2018 values would respectively be $7.2 million and $4. 8 million. (See Exhibit No. DPU 1.1 DIR). In comparison, Utah's Equalization adjustment is $4.4 million.

Q: Would you please explain your third condition that the Equalization Adjustment is similar in magnitude to the outcome of potential Rolled-In applications?

A: Yes. A Rolled-In method can be defined in numerous ways, and much of the discussions and work of the MSP Workgroup centered on defining alternative allocation methods, primarily variations of Rolled-In and divisional allocations. As part of the MSP Workgroup meetings, the Company performed numerous studies and provided a model to simulate various Rolled-In allocation assumptions including weighting the classification of costs and the coincident peaks used in defining capacity.

For the most part, the divisional allocation methods proposed by various parties relied on unrealistic simplifying assumptions and were never fully defined. Consequently, the workgroup members were unable to come to a consensus on how a divisional allocation method might work or perform. Additionally, the Division views the divisional allocation proposals to be a movement away from a Rolled-In, single-system allocation method[6] and, thus, inconsistent with the Commission's stated long-term goal for allocations.

Rolled-In allocation can be defined in numerous ways by including different classification weights or the number of coincident peaks. For both the 2010 and 2017 Protocols the weighting is 75% demand and 25% energy, and both utilize all 12 coincident peaks. Generally speaking, emphasizing energy in the weighting reduces Utah's revenue requirement while reducing the number of coincident peaks increases Utah's revenue requirement. DPU Exhibit 1.2 DIR, compares several combinations of different weights and coincident peaks to a Rolled-In allocation that uses the current 75/25 weighting with 12 coincident peaks, identified as the Foundational Study.[7]

For example, if the demand weight is reduced for generation only from 75% to 60%, Utah's annual revenue requirement decreases by approximately 0.05 percent. If we also increase the weight on demand to 100 percent for transmission, then Utah's revenue requirement would decrease by only 0.02 percent. If the weighting is reset at

[6] Several parties including the Division raised the question of whether the Company could or would continue to plan and operate a single system under a divisional allocation scheme. In the Division's view, the proponents of divisional allocation never satisfactorily addressed this issue. Interestingly, at the request of the Washington Commission, PacifiCorp included in its 2015 IRP a divisional planning study. The IRP results indicate that a two-system approach could potentially add as much as $2 billion to system costs over the IRP planning horizon. (PacifiCorp's 2015 IRP, Volume I, pp. 202-203)

[7] The Foundational Study uses as a base 2013 actual data with forecasts of seven years, 2017 through 2022 and 2027. As shown in DPU Exhibit 1.2 DIR, the comparisons reported herein are relative to the present value of the annual revenue requirement for the years 2017 through 2022. Other scenarios can be run using the model submitted in DPU witness Artie Powell's CONFIDENTIAL work papers. The weighting inputs are found on the worksheet "Variables," and the CP inputs are in worksheet "Factor Inputs 1," starting in cell AQ12, and are chosen relative to the 2017 monthly coincident peaks.

75/25 for both generation and transmission, moving to an 8CP, four summer months and 4 winter months, Utah's revenue requirement increases by approximately 0.23 percent. Further restriction on the coincident peaks will further increase Utah's revenue requirement. A 2CP, for example, would increase Utah's revenue requirement by approximately 2.86%.

In summary, different definitions of Rolled-In will produce different revenue requirements for each of the Company's jurisdictions. For a group of plausible but non-exhaustive combinations of weighting and coincident peaks, Utah's revenue requirement could decrease by as much as 0.05 percent or increase by as much as 3.0 percent. By comparison, the 2017 Equalization Adjustment for each state or jurisdiction, except California, was originally designed as approximately 0.20% to 0.25% of the jurisdiction's annual revenue requirement. According to the Company's June 2015 results of operations, Utah's 2017 Equalization Adjustment, $4.4 million, is approximately 0.22 percent of Utah's revenue requirement at its authorized rate of return.

Q: What other aspects did the Division factor in its conclusion to support the 2017 Protocol Agreement?

A: The Division fully participated in the discussions and meetings of the MSP Workgroup over the past three years. Due to differing and often conflicting objectives, the participating parties were unable to come to a consensus on a long-term allocation method. However, as I noted earlier, the 2017 Protocol is a fully Rolled-In method, and is based on the current 75/25 weighting and uses a 12CP to define capacity requirements. This is consistent with the oft stated Commission goal of transitioning to a single-system dynamic allocation method that reflects current cost causation. This was a priority concern for the Division from the start of the current round of MSP meetings. Other aspects or specific elements include:

- Nothing in the agreement is meant to abrogate the Commission's or another parties legal obligations in establishing fair, just, and reasonable rates. (Agreement, pp. 2-3);
- The 2017 Protocol is a short-term solution to the allocation issues. (Section II);
- States continue to be insulated from incremental costs above what the Company would otherwise incur for state specific resources to comply with resource portfolio standards and other jurisdiction-specific initiatives. (Section IV.A.2, 4); and
- The 2017 Protocol describes a process for addressing issues arising from State-specific actions related to "Access to Alternative Electricity Suppliers." (Section X).

Q: Do you have any final comments regarding the 2017 Protocol?

A: Yes. There are several changes to the allocation factors found in Appendix B. I have highlighted these changes in Exhibit No. DPU 1.3 DIR, which is adapted from an exhibit in Docket No. 02-035-04. These changes include additions to accounts or allocations, eliminating factors that are obsolete, or changing a factor. For example:

- Peaking Plants and Cholla are no longer allocated on a seasonal factor as they were under former allocation methods and have been removed from Appendix B attached to the 2017 Protocol. See for example Steam Generation, Accounts 500, 501, and 503. A footnote to the original exhibit, which I have left in DPU 1.3 DIR, indicates these resource costs are included in other accounts.

- Removal of the embedded cost differential endowments and certain Klamath Dam costs. See Account 557, Other Expenses.
- Added allocation factors for PMI (PacifiCorp Minerals Inc.) and Foreign Tax Credit, Account 40910, Renewable Energy Tax Credit.
- Added a factor for pensions, Account 128, Pensions.

Finally, to reiterate the Division recommends that the Commission approve the 2017 Protocol for use of allocating costs and establishing Utah's revenue requirement. The 2017 Protocol is a fully Rolled-In allocation method and, thus, is consistent with cost causation principles and the Commission's goal of achieving an allocation method consistent with the planning and operation of a single system; Utah's Equalization Adjustment is reasonable; and the 2017 Protocol is short-lived and insulates Utah ratepayers from specific actions of the other states.

Q: Does that conclude your direct testimony?

A: Yes it does.