Gary A. Dodge (0897)
Phillip J. Russell (10445)
HATCH, JAMES & DODGE
10 West Broadway, Suite 400
Salt Lake City, UT 84101
Telephone: 801-363-6363
Facsimile: 801-363-6666
Email: gdodge@hjdlaw.com
prussell@hjdlaw.com

Attorneys for the Utah Association of Energy Users

William J. Evans (5276)
Vicki M. Baldwin (8532)
Chad C. Baker (14541)
PARSONS BEHLE & LATIMER
201 South Main Street, Suite 1800
Post Office Box 45898
Salt Lake City, UT 84145-0898
Telephone: (801) 532-1234
Facsimile: (801) 536-6111
Email: bevans@parsonsbehle.com
vbaldwin@parsonsbehle.com
cbaker@parsonsbehle.com

Attorneys for UIEC, an Intervention Group

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of Rocky Mountain Power for Approval of a Significant Energy Resource Decision and Request to Construct Wind Resource and Transmission Facilities	Docket No. 17-035-40

DIRECT TESTIMONY AND EXHIBITS OF BRADLEY G. MULLINS

The Utah Association of Energy Users ("UAE") and the Utah Industrial Energy Consumers ("UIEC") hereby submit the Direct Testimony of Bradly G. Mullins in this docket.

DATED this 5th day of December 2017

/s/ *Phillip J. Russell*
Gary A. Dodge
Phillip J. Russell
HATCH, JAMES & DODGE
Attorneys for the Utah Association of Energy Users

/s/ *William J. Evans*
William J. Evans
Vicki M. Baldwin
Chad C. Baker
PARSONS BEHLE & LATIMER
Attorneys for UIEC, an intervention group

Certificate of Service
Docket No. 17-035-40

I hereby certify that a true and correct copy of the foregoing was served by email this day 5th day of December 2017, on the following:

ROCKY MOUNTAIN POWER

Jeff Richards	robert.richards@pacificorp.com
Yvonne Hogle	yvonne.hogle@pacificorp.com
Bob Lively	bob.lively@pacificorp.com
datarequest@pacificorp.com	

DIVISION OF PUBLIC UTILITIES

Patricia Schmid	pschmid@agutah.gov
Justin Jetter	jjetter@agutah.gov
Chris Parker	chrisparker@utah.gov
William Powell	wpowell@utah.gov

OFFICE OF CONSUMER SERVICES

Steven Snarr	stevensnarr@agutah.gov
Robert Moore	rmoore@agutah.gov
Michele Beck	mbeck@utah.gov
Cheryl Murray	cmurray@utah.gov

UTAH CLEAN ENERGY

Sophie Hayes	sophie@utahcleanenergy.org
Kate Bowman	kate@utahcleanenergy.org

INTERWEST ENERGY ALLIANCE

Mitch M. Longson	mlongson@mc2b.com
Lisa Tormoen Hickey	lisahickey@newlawgroup.com

NUCOR STEEL-UTAH, A DIVISION OF NUCOR CORPORATION

Peter J. Mattheis	pjm@smxblaw.com
Eric J. Lacey	elacey@smxblaw.com
Jeremy R. Cook	jcook@cohnekinghorn.com

WESTERN RESOURCE ADVOCATES

Jennifer E. Gardner	jennifer.gardner@westernresources.org
Nancy Kelly	nkelly@westernresources.org

/s/ *Phillip J. Russell*
Phillip J. Russell

BEFORE THE

PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of Rocky Mountain Power for Approval of a Significant Energy Resource Decision and Request to Construct Wind Resource and Transmission Facilities	Docket No. 17-035-40

DIRECT TESTIMONY OF BRADLEY G. MULLINS

ON BEHALF OF

THE UTAH ASSOCIATION OF ENERGY USERS

AND

THE UTAH INDUSTRIAL ENERGY CONSUMERS

December 5, 2017

REDACTED VERSION

TABLE OF CONTENTS TO THE CONFIDENTIAL DIRECT TESTIMONY OF BRADLEY G. MULLINS

EXHIBIT LIST

I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Bradley G. Mullins, and my business address is 333 SW Taylor Street, Suite 400, Portland, Oregon 97204.

Q. PLEASE STATE YOUR OCCUPATION AND ON WHOSE BEHALF YOU ARE TESTIFYING.

A. I am an independent energy and utilities consultant representing large energy consumers throughout the United States, with a focus in the West. I am testifying on behalf of the Utah Association of Energy Users ("UAE") and the Utah Industrial Energy Consumers ("UIEC"). UAE and UIEC, as more specifically stated in their respective petitions for intervention in this docket, represent large electric customers served by Rocky Mountain Power ("PacifiCorp") in Utah.

Q. PLEASE SUMMARIZE YOUR EDUCATION AND WORK EXPERIENCE.

A. I have a Master of Accounting degree from the University of Utah. After obtaining my Master's degree, I worked at Deloitte in San Jose, California, where I specialized in performing research and development tax credit studies. I later worked at PacifiCorp as an analyst involved in power supply cost forecasting and began working independently as an energy and utilities consultant in 2013. I currently provide services to utility customers on matters such as revenue requirements, power costs, utility planning, rate spread, and rate design. I have sponsored testimony in regulatory jurisdictions throughout the United States, including before the Public Service Commission of Utah

("Commission"). A list of cases in which I have submitted testimony can be found in UAE-UIEC Exhibit 1.1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to respond to PacifiCorp's request for approval of a significant energy resource decision to procure 860 MW of wind resources (collectively, the "Wind Projects").[1] I also respond to PacifiCorp's voluntary request for approval of resource decisions concerning its proposal to construct the "Aeolus-to-Bridger/Anticline Line" and associated network upgrades (collectively, the "Transmission Projects").[2] I refer to the Wind Projects and Transmission Projects collectively as "Energy Vision 2020."[3]

As a threshold matter, there is uncertainty as to what precisely the Company is requesting the Commission approve in this docket because the Company's request has been something of a moving target, as discussed below. For example, while PacifiCorp's filing has proposed the Wind Projects and the Transmission Projects as largely inseparable investments, since filing testimony in this matter, PacifiCorp modified its ongoing request for proposal ("RFP") for the Wind Projects, pursuant to the Commission's September 22, 2017 Order in Docket No. 17-035-23.[4] One of the

---

1 Application at 1-2.

2 *Id.*

3 The "Energy Vision 2020" name is sometimes used in a broader sense to describe the Wind Projects, the Transmission Projects, and the Repowering Projects (currently under discussion in Docket No. 17-035-039). In this testimony, I use the name more narrowly to describe just the Wind Projects and Transmission Projects.

4 *Application of Rocky Mountain Power for Approval of Solicitation Process for Wind Resources*, Docket No. 17-035-23, Order Approving RFP with Suggested Modification at 7 (Sep. 22, 2017).

modifications was to allow the RFP to consider procuring wind resources in geographic locations that do not require construction of the associated Transmission Projects.[5] In addition, PacifiCorp's application in this matter contemplates addition of only 860 MW of new wind resources.[6] The RFP, however, is seeking cost-competitive bids for up to 1,270 MW of wind resources.[7] These are sources of ambiguity in PacifiCorp's application, since it is unclear how one might determine whether Energy Vision 2020 is in the public interest if it is possible that PacifiCorp might procure resources other than the Wyoming wind and transmission assets described and analyzed in its application. I am aware of nothing presented in this matter that would demonstrate whether these other potential alternatives might be in the public interest.

Q. WHAT WAS THE SCOPE OF YOUR REVIEW?

A. I reviewed the confidential, and non-confidential, filing and workpapers of PacifiCorp. I also conducted discovery, and reviewed PacifiCorp's responses to discovery requests submitted in this matter. Responses to data requests relevant to my testimony may be found in UAE-UIEC Exhibit 1.2. Finally, I conducted supplemental analytics surrounding the economics of the Energy Vision 2020 assets, such as an analysis reviewing of the accuracy of previously issued official forward price curves.

---

5 *Id.*

6 Application at 1-2.

7 PacifiCorp, *Renewable Request for Proposals (2017R RFP)* at 1 (Sep. 27, 2017). Some, but not all, of the difference between the quantity of wind in the Application and in the RFP appears to be a result of 240 MW of committed qualifying facility resources. *See* Direct Testimony of Rick T. Link at 479-494.

Q. WHAT ARE YOUR PRIMARY CONCLUSIONS AND RECOMMENDATIONS?

A. Based on my review, I have concluded the following:

- The Energy Vision 2020 assets are not necessary for reliability purposes or to meet a demonstrated capacity need.
- Rather, the Energy Visions 2020 assets are being justified in comparison to PacifiCorp's forecasts of future power, natural gas, and carbon prices.
- I demonstrate that the forward prices in PacifiCorp's Official Forward Price Curve ("OFPC") have historically overestimated actual spot market prices for wholesale electricity and natural gas.
- I also demonstrate how that the potential for any ratepayer benefits from the Energy Vision 2020 assets will be eliminated upon the potential resolution of H. Res. 1, the Tax Cuts and Jobs Act of 2017—which, at the time of preparing this testimony, had passed the Senate and was in committee.
- Finally, I demonstrate the degree of uncertainty surrounding capital costs, as well as a number of other speculative, unjustified assumptions, embedded in PacifiCorp's economic case for acquiring the Energy Vision 2020 assets.

Based on the conclusions reached above, I believe it is unlikely that the acquisition of the Energy Vision 2020 assets will provide any financial benefit to Utah ratepayers. Accordingly, I recommend that the Commission not approve of the resource decisions underlying the proposed Energy Vision 2020 assets and find that it would not be in the public interest to proceed with such a significant, $[redacted] billion investment using ratepayer monies.

II. BACKGROUND ON THE PROPOSAL

Q. IS THE CONCEPT BEHIND ENERGY VISION 2020 NEW?

A. No. The concept behind Energy Vision 2020, of building new transmission facilities into Wyoming in order to access low cost wind resources there, has been under discussion for a long time. The Transmission Projects proposed in this matter include sub-segment D2 of Energy Gateway, a proposed transmission project discussed at least as far back as PacifiCorp's 2008 Integrated Resource Plan ("IRP").[8] The idea behind the Energy Gateway was to rely on a 'hub and spoke' configuration, to efficiently integrate transmission lines with resources and load centers. When it proposed Energy Gateway, PacifiCorp claimed that it was designed to "facilitate needed infrastructure to integrate and deliver large volumes of renewable energy in the west."[9] Subsequent to the Energy Gateway proposal, however, many stakeholders have questioned the need to make such significant transmission additions.

Q. HAVE PARTS OF THE ENERGY GATEWAY BEEN CONSTRUCTED?

A. Yes. Both the 'Populous to Terminal' and 'Sigurd to Red Butte' Energy Gateway segments have been constructed. Both were expensive and controversial. In a docket before the Idaho Public Utility Commission, the record established that the Populous to Terminal line was originally estimated to cost $78 million, but in fact cost $801 million, the amount requested by PacifiCorp for inclusion in rate base.[10] The Idaho Commission found that 27% of those costs—equaling $216.4 million of the $801 million PacifiCorp sought to rate base—was not used and useful, and was plant held for future use.[11]

[8] *See* PacifiCorp, 2008 Integrated Resource Plan at 60-66 (May 28, 2009).

[9] *Id*. at 63.

[10] Id.PUC Case No. PAC-E-10-07, Direct Testimony of Randy Lobb at 20:12-22.

[11] *In re the Application of PacifiCorp dba Rocky Mountain Power For Approval of Changes to Its Electric Service Schedules*, Id.PUC Case No. PAC-E-10-07, Order No. 32196 at 35.

Q. WHEN DID PACIFICORP FIRST ANNOUNCE ITS INTENTION OF PROCEEDING WITH ENERGY GATEWAY SUB-SEGMENT D2?

A. The idea was introduced late in the public process leading up to the 2017 IRP. Over the course of the 2017 IRP process, parties were given the impression that no further Energy Gateway segments would be proposed to be built in the 2017 IRP action plan. In the January 26-27, 2017 General Public Meeting, for example, the preferred regional haze portfolio did not include any Energy Gateway additions, and there was no discussion indicating that PacifiCorp was still considering the inclusion of additional Energy Gateway segments in the 2017 IRP.

It was not until the very last General Public Meeting on March 2-3, 2017, held approximately one month before PacifiCorp submitted the 2017 IRP filing, when PacifiCorp announced its intention to include construction of Energy Gateway sub-segment D2 in the action plan, in conjunction with 1,100 MW of new wind resources.

Q. WHY WAS THIS TIMING SURPRISING?

A. This timing was surprising to many because PacifiCorp apparently made much of the financial commitment underlying the newly proposed wind resources in December 2016, to qualify for the production tax credit. It wasn't until March 2017, however, that PacifiCorp disclosed this financial commitment to stakeholders, which raises questions as to the purpose for the delay in disclosure.

Q. DID PACIFICORP UPDATE ITS ANALYSIS OF ENERGY VISION 2020 AFTER FILING THE 2017 IRP?

A. Yes. On or around July 28, 2017, PacifiCorp updated its analysis of Energy Vision 2020. The July update contained supplemental studies that further considered the economic benefits of Energy Vision 2020, using the System Optimizer ("SO") and Planning and-Risk ("PaR") dispatch models. PacifiCorp filed an Energy Vision 2020 Update with this Commission on August 31, 2017 in Docket No. 17-035-23 as Exhibit RMP___(RTL-S1) along with the Supplemental Testimony of Rick T. Link, which contained the results of its July Update. Table 4.1 of Exhibit RMP___(RTL-S1) summarized the results of the July update for the Wind Projects and Transmission Projects.

Q. WHAT CHANGES DID PACIFICORP MAKE IN ITS UPDATED ANALYSIS?

A. In its update, PacifiCorp filed a summary that detailed the specific changes in the July 28, 2017 analysis, relative to the 2017 IRP.[12] These changes included incorporating new modeling adjustments designed to improve the forecast economics of Energy Vision 2020, which were claimed to account for energy imbalance market ("EIM") benefits, line losses benefits, and reliability benefits.[13] PacifiCorp confirmed in discovery in the Oregon docket that, in the 2017 IRP, it had previously made these additional adjustments outside of the models in a way that increased the projected benefits of Energy Vision 2020, but has since incorporated those adjustments into the SO and PaR models.[14]

Q. WHAT WERE THE RESULTS OF PACIFICORP'S SUPPLEMENTAL STUDIES?

A. The supplemental studies suggested that the Energy Vision 2020 projects might produce a wide range of economic outcomes, depending on uncertain future natural gas and

---

[12] Docket No. 17-035-23, Exhibit RMP___(RTL-S1) at 16-17.

[13] *Id*.

[14] UAE-UIEC Exhibit 1.2 at 3-4 (PacifiCorp's Response to PacifiCorp Idaho Industrial Customers ("PIIC") 2nd Set Data Request ("DR") 10).

electric market prices and carbon price assumptions. The analysis suggested there was a $530 million range of potential economic outcomes, between (-)$121 million and $409 million, depending on the natural gas market price and carbon assumptions used.[15] After considering some of the speculative modeling assumptions that went into developing these studies, however, and as discussed later in my testimony, it is clear that the likelihood for a detrimental outcome is much greater than PacifiCorp represents.

Q. HOW MUCH CAPITAL WOULD PACIFICORP DEPLOY FOR ENERGY VISION 2020?

A. PacifiCorp's proposal would represent a staggering commitment of ratepayer capital of over $[redacted] billion. Confidential Table 1, below, details the projected capital cost of the respective aspects of the Energy Vision 2020 projects, based on my review of the Company's confidential workpapers. These expenditure amounts are inclusive of an allowance for funds used during construction.

---

15 Direct Testimony of Rick T. Link at 36, Table 2.

CONFIDENTIAL TABLE 1

Energy Vision 2020 Capital Investment Detail ($000)

[redacted]

Q. DOES PACIFICORP HAVE AN INCENTIVE TO DEPLOY THIS CAPITAL?

A. Yes. It has been widely documented that utilities subject to rate of return regulation have an incentive to over-invest in capital in order to increase earnings.[16] This phenomenon is often referred to as the Averch-Johnson Effect—based on the economists who first developed the model to describe it back in the 1960s—and has a real and significant impact on how utility operations are managed. As the saying goes, the utility earns on what it builds. Accordingly, when considering the capital investments identified in

16 *See* Harvey Averch & Leland L. Johnson, *Behavior of the Firm Under Regulatory Constraint*, 52 AM. ECON. REV. 996, 1052 (1962).

Confidential Table 1, it is important to recognize that the shareholder has the potential to benefit hugely if it is deployed.

In addition, the shareholder benefits associated with the proposed Energy Vision 2020 capital investment accrue without regard to whether the alleged ratepayer benefits materialize. Thus, with economic investments such as Energy Vision 2020, there is a fundamental asymmetry in that ratepayers bear all of the risks associated with the investment while the shareholder receives financial benefits that would be practically guaranteed from a ratemaking perspective.

Q. DO YOU KNOW WHETHER AND WHY MOST RATEPAYER ADVOCATES OPPOSE THE PROJECT?

A. The renewable aspects of Energy Vision 2020 are appealing to many. Notwithstanding those potential environmental benefits, comments and testimony filed by ratepayer advocates throughout the PacifiCorp system show that they almost uniformly view Energy Vision 2020 as a very risky investment proposal that is likely to be detrimental to ratepayers. It is clear that there might be some limited scenarios in which Energy Vision 2020 might produce some ratepayer benefits. From a ratepayer perspective, however, Energy Vision 2020 appears more likely to harm ratepayers than to benefit them. If Energy Vision 2020 were based on a demonstrated resource or reliability need, it might provide a better justification for taking on the additional risks of the investment. However, the Energy Vision 2020 project is discretionary and not necessary, based largely on speculative assumptions of future prices meant to benefit shareholders rather than ratepayers. In the past, bets like Energy Vision 2020 have harmed ratepayers, and I believe it is for that reason that most ratepayer advocates, including myself, recommend against approval of the proposed investment.

III. THE NEW WIND AND TRANSMISSION RESOURCES ARE NOT NECESSARY

Q. WHY IS THE ISSUE OF RESOURCE NEED CENTRAL TO DETERMINING WHETHER ENERGY VISION 2020 IS IN THE PUBLIC INTEREST?

A. Fundamental to public utility regulation is the concept that ratepayers should be required to pay only for utility investments necessary to provide utility services. It was recognized more than 25 years ago "that the basis of all calculations as to the reasonableness of rates to be charged … must be the fair value of the property being used by it for the convenience of the public."[17]

Q. HOW HAS THE NOTION OF RESOURCE NECESSITY BEEN EMBODIED IN PUBLIC UTILITY REGULATION IN UTAH?

A. My understanding is that Utah has a relatively strong used and useful standard that must be met in order to include investments in utility plant. In many other states, used and useful standards have been established explicitly through statute.[18] In Utah, however, the used and useful standards have primarily been implemented in the courts. In *Terra Utilities, Inc. v. Public Serv. Com'n*, for example, the Utah Supreme Court affirmed the Commission's decision to exclude from rate base costs related to the portions of a water and sewer plant that the Commission found not to be used and useful.[19]

---

18 *See, e.g.*, Revised Code of Washington § 80.4.250.
19 575 P.2d 1029 (Utah 1978).

Q. IS ENERGY VISION 2020 PROPERLY CHARACTERIZED AS ADDRESSING A RESOURCE NEED?

A. No. Table 5.14 of the 2017 IRP shows—without the Energy Vision 2020 investments—available front office transactions of 1,670 MW exceed the system requirements by a wide margin through the first ten years of the study period.[20] In 2026, PacifiCorp expects that currently available resources and front office transactions will exceed total system requirements, including a 13% planning reserve, by approximately 447 MW. This means that, without acquiring any new generating resources or transmission lines, PacifiCorp will continue to be capable of providing adequate services to customers in Utah, inclusive of a material reserve margin. As such, the proposal cannot reasonably be characterized as addressing a resource need. Rather, the proposal is more reasonably characterized as an economic opportunity based on the current relationship between projected forward prices and the projected costs of the new resources.

In addition, the Company has confirmed on the record in Oregon that "there is no reliability need to put [the Transmission Projects] in place absent the wind."[21] The Company also confirmed that it is "currently compliant with North American Electric Reliability Corporation reliability standards and expect[s] to be going forward"[22]

---

20 *PacifiCorp 2017 IRP*, Volume I at 91.

21 Or.PUC Docket No. LC 67, Staff Final Comments at 19 (Oct. 6 2017).

22 *Id*.

Q. WHY IS THE ISSUE OF RESOURCE NEED IMPORTANT WHEN CONSIDERING SUCH SIGNIFICANT UTILITY INVESTMENTS?

A. When a legitimate reliability-based resource need has been established, a resource must be acquired whether or not the resource produces financial benefits to ratepayers or increases overall financial risk to ratepayers. Thus, when a reliability need has been established, the pertinent inquiry is to determine which type of resource best fulfills the resource need at the least cost and least risk to ratepayers. In the case of a project justified on the basis of such a resource need, ratepayers appropriately take on the risk that the project might be uneconomic, since the project must be completed in order for the utility to continue to provide adequate utility service.

I am not a lawyer and I do not know whether or under what circumstances a discretionary investment justified, not on the basis of a reliability need, but rather on a purely economic basis, can or should properly be approved under Utah's Resource Procurement Act. From an economic and policy perspective, however, in the absence of a resource need, a potential resource acquisition might appropriately be considered as a utility investment, but only to the degree that it can be clearly and unambiguously shown to produce significant economic benefits or rents to ratepayers through reduced rates, in a manner commensurate with the risk of the investment. From this ratepayer perspective, the decision of whether to proceed with a resource acquisition is fundamentally different, depending on whether or not a clear resource reliability need has been established. In the case of an investment justified on the basis of economic benefits, the threshold for proceeding with the investment has to be sufficiently higher and—to ensure ratepayers will recognize positive economic rents associated with the project—should not be risky or speculative.

Q. CAN YOU PROVIDE AN ANALOGY TO ILLUSTRATE YOUR POINT?

A. The distinction between a resource constructed to fulfill a clear resource need, versus a project justified on the basis of economics, can be analogized to the considerations one might make when deciding whether to acquire a home as a primary residence, versus acquiring a home as a rental property. When making the decision to acquire a home as a primary residence, there are many risks that are not necessary to consider, simply because one needs a place to live. In contrast, when considering whether to invest in a rental property, one performs a fundamentally different analysis. One must determine, for example, whether the rents forecasted to be received are sufficient to cover the costs and risks, with a reasonable margin to justify the investment. In addition, one would only proceed with investing in a rental property if one has sufficient capital, the timing is right, and if other relevant factors support the investment. An investment in a rental property would also only occur if the investor had strong confidence in its rent forecast. Moreover, when an investment is being made with funds that will be provided or guaranteed by others, there is a compelling fiduciary-type obligation to ensure that those ultimately bearing the risk of the investment will reap clear benefits, and not just those promoting the acquisition.

Q. PACIFICORP CLAIMS THAT THESE RESOURCES WILL DISPLACE FRONT OFFICE TRANSACTIONS. DOES THAT REPRESENT FILLING OF A RESOURCE NEED?

A. No. Front office transactions are market resources to which customers have access today, without capital risk. Moreover, existing access to market resources is not without significant ratepayer cost. Customers have invested significantly in PacifiCorp's extensive transmission system in order to have access to bilateral markets. The fact that these markets exist demonstrates that there is surplus power in the West. Surplus power is derived from load diversity among utilities, allowing them to buy and sell power and energy among each other. Also, a large amount of energy from independent power and qualifying facilities contributes to surplus power available in bilateral markets. These markets are viable and should not be ignored when evaluating whether a utility has a "need" to make significant capital investments.

When accessing these bilateral markets, no incremental ratepayer supplied capital is required. For that reason, it is generally preferred from a ratepayer perspective that PacifiCorp rely on front office transactions when available, rather than making significantly more risky capital investments. Finally, to the extent PacifiCorp ceases to rely on the supply of energy in bilateral markets, and instead acquires its own resources, it will have the effect of increasing regional supply, thus reducing market prices and further reducing the likely economic benefits of its proposed acquisitions.

Q. IS THERE RISK IN RELYING ON FRONT OFFICE TRANSACTIONS?

A. Reliance on front office transactions is not without risk. It is possible that markets may change in the future making front office transactions more, or less, expensive. The same sort of risks, however, are present with all of PacifiCorp's resources. Hydro resources bear risks associated with hydrological conditions. Gas plants bear risks associated with gas prices. Coal plants are subjected to coal price and environmental risks. This is why PacifiCorp's system has been built over the years as a diverse portfolio, so that the risks of these different types of resources are combined to make an overall less risky system than if any one type of resource were relied upon too heavily. Relying on front office transactions is a key part of this diverse portfolio and that resource, and the diversity it represents, should not be minimized in an effort to justify the investment in the proposed Energy Vision 2020 assets.

Q. COULD THE ENERGY VISION 2020 ASSETS BE VIEWED AS A HEDGE?

A. The cost of a wind resource is relatively fixed, meaning that a wind resource becomes more expensive to ratepayers if market prices decline, and less expensive if market prices increase. From this perspective, a wind plant could be viewed as a hedge against market prices. Whether the Energy Vision 2020 might appropriately be justified for inclusion in utility rates on the basis that it constitutes a long-term hedge, however, is a separate discussion. When selecting portfolios of resources necessary to provide services, it is appropriate for the utility to consider the impact of new resource additions on the overall risk of its portfolio. It is not appropriate, however, for a utility to begin making discretionary investments in unneeded facilities that are acquired solely for hedging value. PacifiCorp already has complex policies and strategies designed to hedge the impacts of changing market prices, and constructing a resource on the sole basis that it constitutes a hedge, would upset the controversial hedging framework that is already in place.

Q. IS THE IRP AN APPROPRIATE FRAMEWORK FOR EVALUATING ECONOMIC RESOURCE ACQUISITIONS?

A. No. While an IRP analysis may be useful for selecting among available resources when a clear resource need has been established, it is not useful in evaluating potential economic investments. Since the IRP process is designed to identify the best resource to fill an identified resource need, it can and does ignore many of the risks associated with acquiring new resources. When a resource is necessary from a reliability or supply perspective, many risks must be assumed without regard to the resource acquired. When dealing with a discretionary, economic investment, however, many additional risks must be considered.

IV. THERE ARE MANY RISKS PACIFICORP HAS NOT CONSIDERED

Q. WHAT ADDITIONAL RISKS ASSOCIATED WITH ENERGY VISION 2020 HAS PACIFICORP NOT ADEQUATELY CONSIDERED?

A. Among specific risks that I have identified with the Energy Vision 2020 investments that PacifiCorp has not adequately addressed are 1) the current status of the Multi-State Protocol; 2) forecasted regional oversupply conditions; 3) movement towards regionalized transmission; and, 4) changes to the tax law. This is not meant to be an exhaustive list, as there are many more of these types of risks which are not normally considered in the context of an IRP analysis, but are appropriately considered in the context of a discretionary economic investment.

Q. WHAT IS THE CURRENT STATUS OF THE MULTI-STATE PROCESS?

A. The 2017 Multi-State Protocol will expire on December 31, 2019, and stakeholders are currently in the process of trying to develop a replacement interjurisdictional allocation methodology. In place of the current framework, PacifiCorp has proposed sweeping changes to the way that the cost of generation will be allocated amongst the states. PacifiCorp's current proposal is to effectively split up the system, assign each state a fixed allocation of existing resources, move to a subscription-based method for assigning new resources to each state, and utilize locational marginal pricing for valuing transfers and transactions among the jurisdictions.

Q. HOW WOULD A FIXED-SLICE/SUBSCRIPTION FRAMEWORK IMPACT THE ECONOMICS OF ENERGY VISION 2020?

A. It is far from clear how the Energy Vision 2020 resources would fit within a fixed allocation/subscription framework, and this source of uncertainty is a serious risk to ratepayers. Indeed, in my view, the very fact that PacifiCorp is attempting to cram down the Energy Vision 2020 resources despite widespread opposition and skepticism from ratepayer advocates and regulators creates significant doubt and uncertainty about the viability of PacifiCorp's proposed Multi-State Process "solutions."

Q. MIGHT ENERGY VISION 2020 CREATE DISPARATE IMPACTS AMONGST THE STATES IN A SUBSCRIPTION FRAMEWORK?

A. Yes. What is clear, with respect to a subscription framework, is that there is the potential for disparate impacts amongst the states if the Energy Vision 2020 investment is made. The new generation and transmission would influence locational marginal pricing in a subscription framework, which in turn would impact how generation costs would be allocated to each state under PacifiCorp's Multi-State Process proposal. Needless to say, it can hardly be considered wise, from a ratepayer perspective, to begin making significant, irreversible financial decisions immediately prior to splitting up the system into a fixed slice/subscription model. It is akin to a couple buying an expensive house after they have decided to divorce. It makes the allocation of assets and risks much more complicated.

Q. YOU ALSO MENTIONED THE RISK OF OVERSUPPLY CONDITIONS IN THE WEST. PLEASE EXPLAIN.

A. One of the more pressing issues currently affecting electric utilities in the West has to do with persistent oversupply conditions. Most in the industry are aware of the implications of the "duck curve," and the impact that surplus renewables are having on supply, including reduced prices in bilateral markets. Faced with this influx of renewables on the system, PacifiCorp is not the only entity in the West aware of the low cost of renewable resources, and giving thoughts to building them.

Q. ARE OVERSUPPLY CONDITIONS LIKELY TO PERSIST?

A. Given current price trajectories for renewables, it is reasonable to expect that oversupply conditions will get worse, not better. For example, PacifiCorp has indicated in presentations to large customers that it is already experiencing negative EIM prices in Wyoming. There is no reason not to expect that this negative pricing caused by oversupply conditions will persist, and likely worsen, particularly if PacifiCorp constructs the Wind Projects. PacifiCorp has not considered this risk associated with oversupply of renewables. At a minimum, the potential that current conditions may persist is a reason to put greater weight on the low gas price scenarios in the economic analyses.

Q. DO CURRENT QUALIFYING FACILITY DEVELOPMENTS INFLUENCE THE OVERSUPPLY CONDITIONS?

A. Yes. In its Q2 2017 avoided-cost update filing with this Commission, PacifiCorp indicated that potential qualifying facility ("QF") resources in its pricing queue include total nameplate capacity of approximately 5,775 MW, with total contribution to capacity of approximately 2,920 MW.[23] When added to the approximately 860 MW of new wind proposed in this docket, Utah ratepayers might be looking at paying for several thousand megawatts of renewable and QF resource additions. Despite this, PacifiCorp's analyses in this docket do not consider how the dramatic influx of QF contracts and other sources of supply might impact the economics of its proposal—another risk that weighs against approval of the Energy Vision 2020 resources at this time.

Q. HOW MIGHT FURTHER REGIONALIZATION OF THE TRANSMISSION SYSTEM IMPOSE RISKS WITH RESPECT TO ENERGY VISION 2020?

A. The recent regionalization efforts undertaken through the CAISO appear to have ended suddenly, and might be forgotten as quickly as was Grid West. Notwithstanding, it is reasonable to expect continued movement towards regionalization of the transmission system. The Energy Gateway was a controversial aspect of recent regionalization efforts, as PacifiCorp insisted on being able to complete the projects outside of CAISO's regional transmission planning process. Many parties were not supportive of PacifiCorp's

---

[23] *Rocky Mountain Power's 2017 Avoided Cost Input Changes Quarterly Compliance Filing*, Docket No. 17-035-37, Rocky Mountain Power Q2 Compliance Filing at 6.

proposal to build Energy Gateway outside of the regional planning process, which would otherwise require competitive bidding with respect to new transmission investments.[24]

Under Order 1000, FERC has expressed a preference for utilities to perform inter-regional transmission planning. Moreover, Section K of PacifiCorp's own OATT contemplates regional and sub-regional planning efforts to inform transmission expansion. From an inter-regional perspective, segment D2 of the Energy Gateway may not be the best solution for addressing transmission needs in the West. Ratepayer capital is limited and would be better deployed for the purpose of improving reliability throughout the West, not for the purpose of pursuing transmission investments driven by speculative economic investment opportunities.

Q. WHAT RISKS MIGHT CHANGES TO THE TAX CODE POSE FOR THE ENERGY VISION 2020 INVESTMENT?

A. Changes to the tax code have the potential to produce dramatic impacts on the purported ratepayer benefits of the Energy Vision 2020 project. Much of the ratepayer benefit purported by the Company with respect to Energy Vision 2020 comes in the form of tax benefits. Yet, we know that in the long run, the availability of these tax benefits can be moderated or eliminated through changes in the tax code and regulations. Accordingly, it is inherently risky to rely on particularities of the tax code as the primary basis for justifying a long-lived investment, as those benefits can disappear overnight.

24 *In re Transmission Access Charge Options*, California Independent System Operator, ICNU Comments on Revised Straw Proposal at 2-3.

In fact, it is becoming increasingly likely that this risk might materialize. At the time of drafting of this testimony, H. Res. 1, the Tax Cuts and Jobs Act of 2017, had passed both the House and Senate and was in conference to resolve disparities between the resolutions passed by the House and by the Senate. The proposed tax changes would more than eliminate the potential for any ratepayer benefits with respect to Energy Vision 2020 by reducing corporate tax rates and eliminating inflationary escalators on the production tax credit. The impacts of these potential changes will be discussed further below.

Q. AFTER CONSIDERING THESE RISKS, DO YOU BELIEVE THE ENERGY VISION 2020 PROJECTS ARE IN THE PUBLIC INTEREST?

A. No. Since the Energy Vision 2020 project is driven solely by economic, not reliability or resource concerns, it needs to be shown with relative certainty that the investment will produce ratepayer benefits, through reduced rates. PacifiCorp has failed to make such a showing. In fact, after one considers the speculative nature of many of PacifiCorp's assumptions, including those related to projected market prices, it is likely that Energy Vision 2020 will result in great harm to ratepayers in the long-run.

V. IMPACT OF FORECAST MARKET PRICES

Q. WHAT IMPACT DOES MARKET PRICE ASSUMPTIONS HAVE ON PACIFICORP'S ANALYSES?

A. The economic case underlying the proposed Energy Vision 2020 investment is dependent, almost entirely, on PacifiCorp's assumptions related to future natural gas and power prices. Under PacifiCorp's analyses, if future gas and electric prices are high, the

Energy Vision 2020 project could prove to be economical. If prices do not increase to the extent projected by PacifiCorp, however, Energy Vision 2020 will not be economical. As a result, the case for Energy Vision 2020 can be viewed largely as a speculative investment of ratepayer money on PacifiCorp's bet as to future market prices. Because market prices are a key assumption in PacifiCorp's proposal, it is important to have a clear understanding of the likely accuracy of PacifiCorp's forecast.

Q. HOW ACCURATELY HAS PACIFICORP FORECAST MARKET PRICES IN THE PAST?

A. PacifiCorp has not done a very good job in the past at predicting future prices. In fact, the analysis I discuss below demonstrates that the forward prices used in PacifiCorp's price curve have systematically over-forecast market prices in the past. While there should be little expectation that anyone can predict future market prices with any degree of accuracy, particularly as far as 20 or 30 years into the future, the significant inaccuracy of PacifiCorp's past projections provides a convincing case why unnecessary, speculative investments based on those projections would be unwise.

Q. DO THE SAME CONCERNS ABOUT THE FORWARD PRICE CURVE APPLY TO A PROJECT BUILT BASED ON A RELIABILITY NEED?

A. No. When a project is constructed to meet a demonstrated reliability need, the accuracy of the long-term price forecast is less important. The price forecast may affect which specific types of resource will be selected, but not whether a resource should be acquired at all. Thus, the accuracy of forward price curves is of greater importance in the case of an investment driven by economic factors.

Q. WHAT ANALYSES HAVE YOU PERFORMED SURROUNDING PACIFICORP'S PRICE FORECASTING?

A. PacifiCorp issues periodic Official Forward Price Curves ("OFPCs"). These OFPCs are usually issued on a quarterly basis, although at times they are issued at more frequent intervals. The OFPCs contain a schedule of escalating forecast gas and electric market prices sometimes more than forty years into the future. I have performed an analysis to consider the accuracy of previously issued OFPCs. My analysis demonstrates that PacifiCorp's forecast has tended to overstate future prices, and by significant margins. In addition, I also performed some analysis on PacifiCorp's 2012 long term gas hedge, a contract that—like Energy Vision 2020—PacifiCorp sought to justify based on forecast market prices, but which has since proved to be detrimental to ratepayers compared to actual market prices.

Q. HOW DOES PACIFICORP DEVELOP ITS OFPC?

A. In the first six years of the OFPC, the forecast prices are based on current forward market prices based on quotes obtained from power and natural gas brokers. Beyond six years, prices transition to a fundamental analysis, with some blending of current forward market rates and broker quotes over a short transition period. For natural gas prices, the fundamental analysis used beyond six years is developed by a third party. For electricity prices, PacifiCorp develops the fundamental analysis using the AuroraXMP model.

a. **<u>PacifiCorp's Forward Price Curves Systematically Overstate Future Market Prices</u>**

Q. PLEASE PROVIDE AN OVERVIEW OF THE ANALYSIS YOU PERFORMED WITH RESPECT TO PACIFICORP'S PREVIOUSLY ISSUED OFPCS.

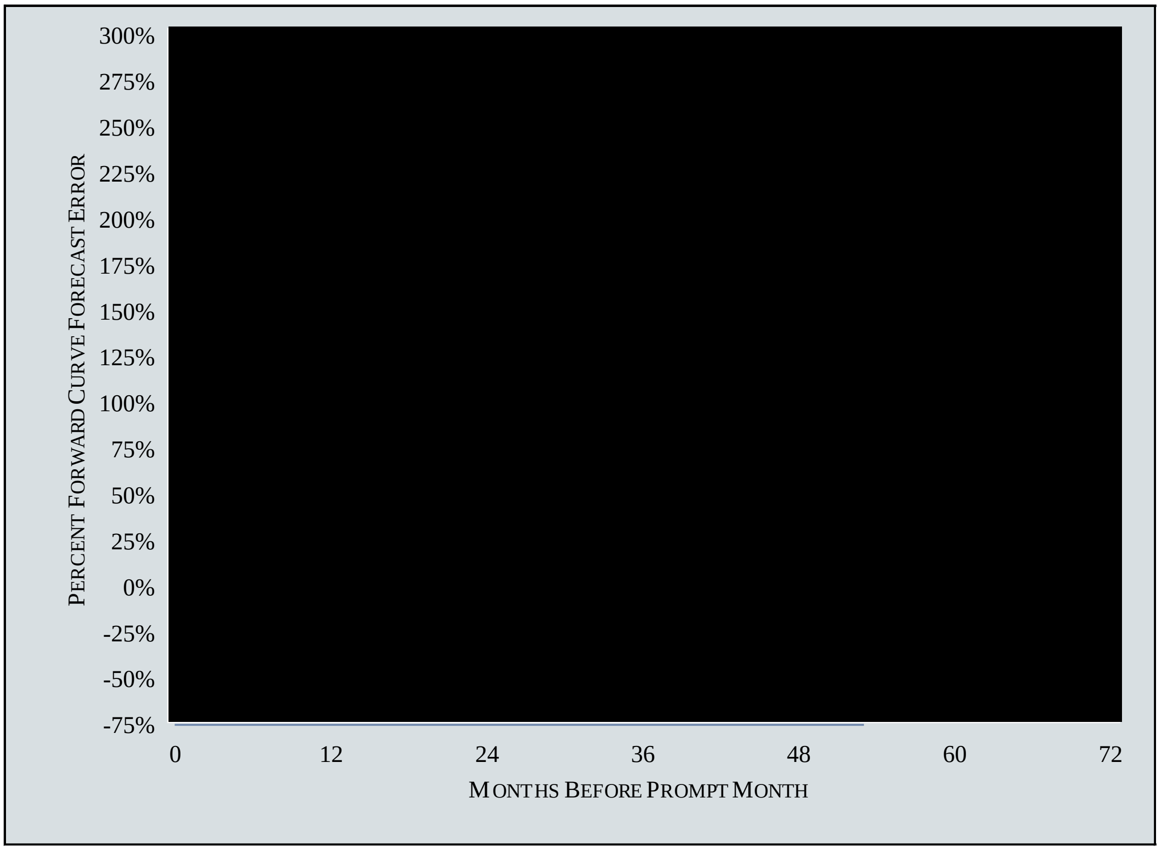
A. In UAE-UIEC Exhibit 1.3 and UAE-UIEC Exhibit No. 1.4, I present an analysis exploring the accuracy of PacifiCorp's previously issued OFPCs. UAE-UIEC Exhibit 1.3 examines the accuracy of OFPCs issued over the period 2007 through 2016. UAE-UIEC Exhibit No. 1.4 examines the accuracy of OFPCs issued over the period 2010 through 2016. UAE-UIEC Exhibit 1.4 considers a shorter period of 2010 through 2016 in order to determine whether structural changes in natural gas and power markets—which occurred generally in the period 2008 through 2010, as a result of advances in directional drilling and fracking technologies and other factors—might have contributed to the over-forecasting observed in the longer-term analysis presented in UAE-UIEC Exhibit 1.3.

Q. WHAT DOES YOUR ANALYSIS SHOW?

A. The analysis in UAE-UIEC Exhibit 1.3 shows that, over the period 2007 to 2016, PacifiCorp historically overestimated future forward prices, and that the magnitude of the overestimation tended to be greater the further out the forecast was made. In addition, the same pattern of overestimation can be observed in UAE-UIEC Exhibit 1.4, when considering only the curves issued over the shorter period of 2010 through 2016. This indicates that PacifiCorp's over-forecasting cannot be explained by the unexpected, rapid decline in natural gas prices that occurred between 2008 and 2010.

The analysis for the Henry Hub market has been reproduced in Confidential Figure 1, below, based on OFPCs issued over the period 2007 through 2016.

CONFIDENTIAL FIGURE 1
Henry Hub Forecast Error
For OFPCs Issued 2007 to 2016



Similar figures may be found in UAE-UIEC Exhibit 1.3 for other power and gas markets over this same 2007 to 2016 time period. In addition, UAE-UIEC Exhibit 1.4 contains similar figures over the shorter 2010 to 2016 time period.

Q. PLEASE DESCRIBE THE DATA PRESENTED IN CONFIDENTIAL FIGURE 1.

A. Confidential Figure 1 is a plot of the percentage forecast error associated with forward prices included in forward price curves issued by PacifiCorp over the period 2007 to the end of 2016. Each dot in the figure represents the percentage difference between a price that was forecast in a forward curve and the ultimate spot price for the given prompt month. To the extent that the error is positive, it means that the price in the forward curve exceeded the ultimate spot price. To the extent that the error is negative, it means that the price in the forward curve was less than the ultimate spot price. Along the x-axis, the set of forecast errors was separated by the number of months before the prompt month for which the forward price was calculated. Thus, a forecast error further to the right indicates the forecast error associated with a price that was forecast further in advance of the prompt month. Similarly, a forecast error on the left side of the x-axis represents a price that was forecast nearer to the prompt month. Overlaid on the figure is the median forecast error based on the number of months in advance of the prompt month that the forward prices were calculated, as well as the interquartile range of the forecast errors.

Q. HOW CAN THE DATA PRESENTED IN CONFIDENTIAL TABLE 1 ABOVE BE USED TO DETERMINE PACIFICORP'S ABILITY TO PREDICT FORWARD PRICES?

A. If the OFPCs are reasonably accurate, one would expect PacifiCorp's price forecast to be an unbiased expectation of future spot prices. That is, forward prices would exceed the ultimate spot price 50% of the time and be less than the spot price 50% of the time. That, however, is clearly not the case. Rather, PacifiCorp's projected forward prices have exceeded the ultimate spot price approximately 90% of the time in Confidential Figure 1, above.

Q. COULD THE ABOVE ANALYSIS ALSO BE USED TO DETERMINE IF THERE IS A RISK PREMIUM EMBEDDED IN THE FORWARD PRICE CURVE?

A. Yes. In the first six years of the OFPC, the market prices are based on broker quotes for current forward market prices. Accordingly, another way to look at PacifiCorp's propensity to over-forecast is as a risk premium, an additional cost above the spot market price that PacifiCorp is willing to pay, and that the counterparty demands, in order to lock in a fixed price. If there is no risk premium embedded in the OFPC, the median forward curve forecast error over the six-year period of the OFPC relying on broker quotes should be zero. If, however, the median forecast error exceeds zero, then that is an indication of a risk premium in the broker quotes that PacifiCorp relies on to develop its OFPC. It makes sense that there might be a risk premium built into forward prices, based on the fact that the curves are always upsloping, having the attributes of a contango market.

Q. WHAT DOES THE DATA IN YOUR ANALYSIS CONFIRM ABOUT THE EXISTENCE OF RISK PREMIUMS IN PACIFICORP'S FORECASTS?

A. The empirical analysis underlying Confidential Figure 1 indicates that risk premiums have been embedded in the forward curves and that those risk premiums have been substantial. For a transaction executed more than one year in advance of the prompt month, the expected forecast error for Henry Hub was approximately [redacted]%. This means that each time PacifiCorp purchases a financial gas swap more than one year in advance of the prompt month, ratepayers should statistically expect to pay an amount that is [redacted]% greater than the actual spot price of natural gas.

Similar risk premiums may be observed in power markets. As can be identified in UAE-UIEC Exhibit 1.3, the risk premium observed in PacifiCorp's Palo Verde market forecast was approximately [redacted]% for transactions executed more than one year in advance. For transactions executed more than 5 years in advance, the observed risk premium rose to approximately [redacted]%—meaning that, if a transaction were executed more than five years in advance based on the Palo Verde Market, ratepayers would be required to pay nearly [redacted] of the spot rate for power. These are considerable premiums, with many troubling implications, particularly with respect to the speculative economics of the proposed Energy Vision 2020 investment.

Q. HOW SHOULD THE ABOVE ANALYSIS BE CONSIDERED WHEN EVALUATING THE ECONOMIC CASE FOR ENERGY VISION 2020?

A. In the case of Energy Vision 2020, the economic case relies on forward prices extending, 20-40 years into the future. The analyses in UAE-UIEC Exhibit 1.3 and UAE-UIEC Exhibit 1.4 only detail forecast errors for prices forecast five to seven years in advance of the prompt month, due to the availability of data. Based on the analysis, however, it is reasonable to expect that PacifiCorp will over-estimate forward prices by even greater magnitudes when estimated 20 or 40 years into the future. Simply put, ratepayers throughout PacifiCorp's system have a sound basis to be uncomfortable taking on the significant risks associated with Energy Vision 2020 if PacifiCorp's price forecast might be overstated. Since PacifiCorp has historically overstated market prices—and by significant margins—little weight should be given to the economics in PacifiCorp's medium and high-priced gas scenarios. In fact, even the prices in the low-priced scenario may well be overstated based on the magnitude of risk premium observed in PacifiCorp's historical curves.

Q. WHAT IS THE IMPACT OF THE ABOVE FORECAST ERRORS ON THE COMPANY'S ANALYSIS?

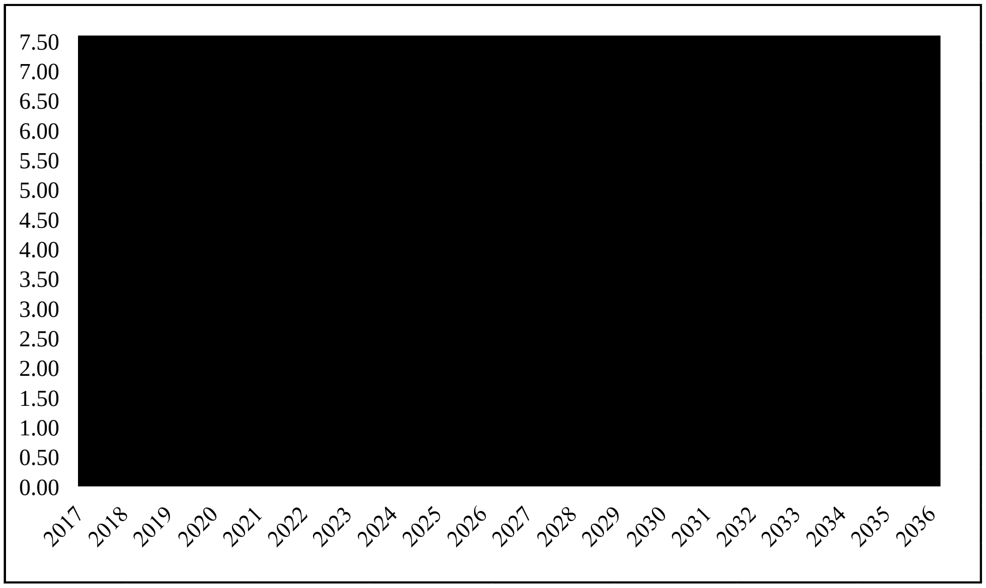
A. If one assumes that PacifiCorp will continue to over estimate prices, as by the same degree as it has done in the past, it will significantly reduce the economics of the proposed Energy Vision 2020 investment, making the prospect of any rate reduction resulting from the investment highly unlikely. Based on the above analysis over the period 2010 through 2016, and using the median historical forecast error associated with the Palo Verde market, I estimate that the economics of the project will decline by approximately $411.2 million on an NPVRR basis over the 20-year study period as a result of PacifiCorp's over-forecasting. At a minimum, this degree of over forecasting is a reason to rely on the price curves based on the low gas price scenario, which shows the Energy Vision 2020 investment not to be beneficial to ratepayers.

Q. HOW DO PACIFICORP'S MEDIUM GAS PRICE CURVES COMPARE TO THE LOW GAS PRICE CURVES, IF ADJUSTED FOR THE HISTORICAL LEVEL OF OVER FORECASTING?

A. In Confidential Figures 2 and 3, below, I have performed an analysis adjusting PacifiCorp's medium price forecasts based on the observed forecast errors over the period 2010 through 2016.

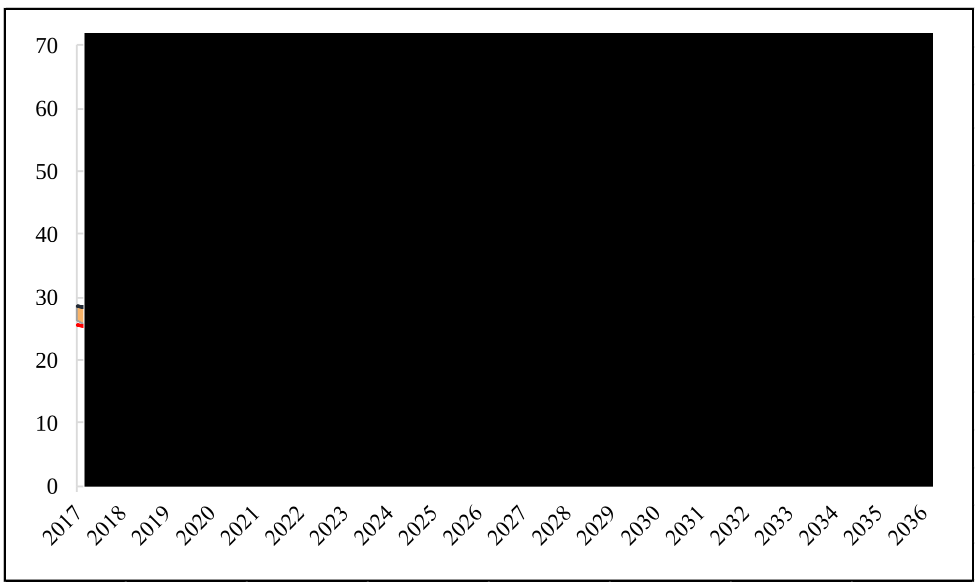
CONFIDENTIAL FIGURE 2

<u>Medium Henry Hub Price Forecast Adjusted for Historical Forecast Errors</u>
<u>Based on Forecast Errors Observed Over the Period 2010 -2016</u>
<u>$/MMBtu</u>



CONFIDENTIAL FIGURE 3

<u>Medium Palo Verde Price Forecast Adjusted for Historical Forecast Errors</u>
<u>Based on Forecast Errors Observed Over the Period 2010 -2016</u>
<u>$/MMBtu</u>



Q. PLEASE PROVIDE AN OVERVIEW OF CONFIDENTIAL FIGURES 2 AND 3.

A. Confidential Figures 2 and 3 show that PacifiCorp's medium forecast adjusted for the historical level of forecasting error produces a result that is lower than the low gas case PacifiCorp has used in its sensitivity analysis. The dark, solid line in the respective charts shows the medium price forecast for the Henry Hub and Palo Verde markets. The shaded area under the medium price forecast represents an expected level of risk premium based on the data from 2010 to 2016 presented in UAE-UIEC Exhibit 1.4.[25] Overlaid on the figure is the low price forecast for the respective markets. Since the shaded area extends below the low price forecast, that is an indication that even PacifiCorp's low price forecast overstates expected future prices after adjusting for a risk premium.

Q. HAS THE COMMISSION RECOGNIZED THE INHERENT DIFFICULTY ASSOCIATED WITH LONG-TERM PRICE FORECASTING?

A. Yes. One example of which I am aware is the Commission's recent skepticism regarding long-term price forecasts used to develop QF avoided prices. In a recent docket, the Commission reduced the maximum length of QF contracts from 20 years to 15 years. PacifiCorp proposed that the QF term be reduced to just three years, in large part due to perceived "fixed price risk" stemming from long-range price forecasts. Moreover, PacifiCorp claimed a clear distinction between QF resources acquired because of a must-buy obligation and resources determined in an IRP process to be necessary. Notwithstanding PacifiCorp's aggressive testimony in that docket, and the Commission's

[25] One caveat is that my analysis here applies the forecast error using the natural log difference rather than the absolute difference presented in UAE-UIEC Exhibit 1.4.

concurrence, at least in part, by reducing the term of QF contracts to 15 years, PacifiCorp in this docket is asking ratepayers to bear the risk of 30-year fixed prices for 860 MW of unnecessary wind resources. The Energy Vision 2020 investment would clearly not be economic if the new wind projects were based on only a 15 year term.

In addition, as discussed below, there are recent examples in which previous attempts to execute long term transactions in which PacifiCorp's OFPC forecasts provided the economic justification have not worked in ratepayers' favor due to forecast errors. There should be little expectation that Energy Vision 2020 might produce any different result.

b. <u>Recent Bets on PacifiCorp's Forward Price Curve Have Not Provided Financial Benefits for Ratepayers.</u>

Q. HAS PACIFICORP ENTERED INTO ANY RECENT LONG-TERM TRANSACTION JUSTIFIED ON THE BASIS OF ITS PRICE FORECAST?

A. Yes. In 2012, PacifiCorp entered into a pair of long-term gas hedging contracts. The execution of those contracts was discussed in Docket No. 12-035-102. Execution of the long-term contracts was subject to a provision that the levelized price of each contract must not exceed the forward market prices in PacifiCorp's forecast. Specifically, the stipulation in that matter required that "refreshed pricing yields a market ratio below 100 percent calculated from PacifiCorp's most current forward price curve at the time bid prices are refreshed"[26] This means that the hedging contract was only to be executed if it was estimated to be neutral, or beneficial, in relation to PacifiCorp's forward price curve.

Q. DID PACIFICORP EXECUTE GAS HEDGING CONTRACTS?

A. Yes, PacifiCorp entered into two contracts with J. Arron, the Commodities trading division of Goldman Sachs. I have reviewed the terms of those contracts, and previously contested them in a Wyoming proceeding on the basis that they constituted affiliate transactions. At the time of the transaction, Berkshire Hathaway possessed warrants on Goldman Sachs equating to beneficial ownership of about 8.4%. I do not contest the transactions in this matter, but merely point out that they have been financially detrimental to ratepayers, and that they were justified on the basis of PacifiCorp's official forward price curve projections in a manner similar to the proposed Energy Vision 2020 investment.

Q. WHAT HAVE BEEN THE FINANCIAL IMPACTS OF THE LONG-TERM GAS HEDGING CONTRACTS?

A. From a ratepayer perspective, the contracts have resulted in payment of significant risk premiums. Confidential Figure 2, below, details the historical settlements, as well as the future mark-to-market costs, associated with the long-term gas hedging contracts. The data underlying Confidential Figure 2 was obtained through UAE Data Request 2.2

---

26 *In the Matter of the Voluntary Request of Rocky Mountain Power for Approval of Resource Decision to Acquire Natural Gas Resources,* Ut.PSC Docket No 12-035-102, Settlement Stipulation, ¶ 5

CONFIDENTIAL FIGURE 4
Benefit / (Cost) of J. Arron Long-term Gas Hedging Contracts ($millions)
2013 - 2023

[redacted]

Q. WHAT DOES CONFIDENTIAL FIGURE 4 SHOW?

A. Confidential Figure 4 shows that PacifiCorp has a record of losing when making long-term bets on its official forward price curve. Based on RMP's current Official Forward Price Curve forecasts, which themselves may be overstated due to the over-forecasting described above, ratepayers are poised to incur approximately $[redacted] million in costs with respect to the above long-term gas hedging contracts.

Q. WHAT IS YOUR CONCLUSION REGARDING FORECASTING RISKS ASSOCIATED WITH ENERGY VISION 2020?

A. In total, I believe the Energy Vision 2020 proposals will likely cost ratepayers billions of dollars in the long-term. As with the long-term gas hedging contracts discussed above, PacifiCorp purports to justify the Energy Vision 2020 investment primarily based on its future market price projections. Yet, PacifiCorp's price projections have historically failed to reflect a reasonable estimate of future prices, and the long-term gas hedging contracts demonstrates how significant the impact of inaccurate assumptions can be. In my view, it is not reasonable for PacifiCorp to make long-term bets with billions of dollars of ratepayer money predicated on the accuracy of its forward price curve for unnecessary, speculative investments of the magnitude contemplated for Energy Vision 2020.

VI. THE ECONOMIC CASE IS NOT COMPELLING

Q. WHY DO YOU BELIEVE THAT PACIFICORP HAS OVERSTATED THE POTENTIAL FOR BENEFITS ASSOCIATED WITH ENERGY VISION 2020?

A. Even if one were to ignore PacifiCorp's pattern of over-forecasting future prices, the economic case for Energy Vision 2020 is not compelling. Upon examination of the assumptions PacifiCorp used to inform its analysis, it is apparent that there is not an overwhelming economic case for deploying the significant amount of capital underlying Energy Vision 2020. In fact, the data suggests that it is more likely that these projects will end up costing Utah ratepayers greatly in the long run. In Confidential Table 2, below, I detail the impact of peeling away some of the speculative assumptions in PacifiCorp's analysis. Due to PacifiCorp's history of over forecasting, the analysis begins with the low gas price scenario in PacifiCorp's filing.

CONFIDENTIAL TABLE 2
Net Present Value Revenue Requirement ("NPVRR")
Impact of Speculative Assumptions ($million)

NPVRR Benefit / (Cost), Low Gas Med CO2		**$**	**(72,606)**
Impact of Speculative Assumptions:			
Tax Reform (Tax Rate)	(139,500)		
Tax Reform (PTC Escalation)	[redacted]		
Supplemental GRID Studies	(62,196)		
Wholesale Transmission Revenues	[redacted]		
Transmission Costs Estimates	[redacted]		
Transmission Levelized Fixed Costs	[redacted]		
Wind Integration Costs	(57,054)		
Subtotal			**(1,042,113)**
Likely Benefit / (Cost) to Ratepayers		**$**	**(1,114,718)**

With a forecasted ratepayer NPVRR *cost* of $32 million to $73 million under the low gas price scenario,[27] the potential for Energy Vision 2020 to result in harm to ratepayers is great. After considering these speculative assumptions, Energy Vision 2020 could end up costing ratepayers approximately $1.1 billion on an NPVRR basis. Even if PacifiCorp is wrong on just one of these speculative assumptions, that would be enough to effectively eliminate all of the purported economic benefits in its medium gas price scenario. These are not the characteristics of an economic project that PacifiCorp should be pursuing as a utility investment.

[27] *See* Direct Testimony of Rick T. Link at 36, Table 2.

a. <u>Impacts of Tax Reform</u>

Q. WHAT IS THE CURRENT STATUS OF TAX REFORM?

A. At the time of developing this testimony the Tax Cuts and Jobs Act of 2017 had passed both houses of congress and was in conference. It is unclear how the legislation might develop from this point on. Notwithstanding, there are many provisions with the bill that will further diminish the economic case for making the Energy Vision 2020 investment.

Q. WHAT IMPACT MIGHT TAX REFORM HAVE ON THE PROJECT ECONOMICS?

A. As discussed above, much of the projected benefits of PacifiCorp's proposed Energy Vision 2020 investment come in the form of expected tax benefits. Notwithstanding, the tax reform legislation currently being discussed would diminish, if not entirely eliminate, the benefits of favorable tax provisions purported in the Energy Vision 2020 investment proposal.

There are at least three aspects of the tax reform legislation that would negatively impact the economics of the proposed investment. First, the tax reform legislation reduces corporate income tax rates from 35% to 20%. Second, the legislation would also modify the way that inflationary assumptions are applied to the production tax credit rate. Third, the legislation would impose restrictions on the ability of entities to utilize general business credits, including the production tax credit.

Q. HOW DO REDUCED CORPORATE TAX RATES REDUCE THE PURPORTED BENEFIT ASSOCIATED WITH THE ENERGY VISION 2020 PROPOSAL?

A. Reducing the corporate tax rate will have the effect of reducing the revenue requirement impact of production tax credits. It will also diminish the impact of other tax benefits associated with the renewable resource addition, such as the benefit of bonus and accelerated depreciation. This is a significant risk associated with the project. In response to a data request, PacifiCorp estimated that, if tax reform is approved, it will reduce the project economics by approximately $93 million.[28] PacifiCorp's estimate, however, assumed the corporate tax rate would be reduced to 25%. Assuming the tax rate declines to 20%, using simple extrapolation, the impact could grow to approximately $139.5 million.

Q. WHAT CHANGES ARE BEING CONTEMPLATED WITH RESPECT TO THE INFLATIONARY ESCALATOR APPLIED TO THE PRODUCTION TAX CREDIT RATE?

A. The proposed House Resolution would eliminate the inflationary escalator applied to production tax credits for facilities where construction begins after the date of the enactment of the resolution. Currently, production tax credit rates are approximately $24.00/MWh, with annual adjustments corresponding to inflation. Absent the inflationary escalation, the production tax credit rate is $15.00/MWh.

Moving from escalating production tax credit rates of $24.00/MWh down to fixed production tax credit rates of $15.00/MWh obviously will have extreme impacts on the overall case for making the Energy vision 2020 investment. PacifiCorp's analysis, however, begins with a credit rate of $24.00/MWh and assumes 2% per year inflationary escalation for production tax credits for ten years. Replacing PacifiCorp's assumption with a fixed $15/MWh production tax credit rate would reduce the NPVRR economics of

[28] *See* UAE-UIEC Exhibit 1.2 at 9-10 (PacifiCorp's Response to PIIC DR 13).

Energy Vision 2020 by approximately $[redacted] million. Just removing the inflationary escalation, and keeping the $24.00/MWh production tax credit rate, has a lesser impact of $[redacted] million on an NPVRR basis.

There are many questions about how the termination of the inflationary escalation might be applied. The proposed language contains special rules for determining the beginning of construction, which could be subject to various interpretations and it is not clear how the Internal Revenue Service might implement the provision surrounding the termination of the production tax credit inflationary escalator. Such uncertainty further undermines the speculative economics and increases the risks to ratepayers that no economic benefits will ever be realized.

Q. HOW DOES WOULD THE TAX REFORM LEGISLATION IMPACT THE WAY PRODUCTION TAX CREDITS GET UTILIZED?

A. The Senate version of the tax reform legislation included series of provisions replacing the Alternative Minimum Tax called the Base Erosion Anti-Abuse Tax ("BEAT") provision.[29] I have not reviewed the specific language behind these provisions, but my understanding is that the BEAT tax would impose a minimum tax equal to 10% of taxable income, meaning that production tax credits would only be eligible to offset 90% of taxable income in any given year.

[29] See https://www.utilitydive.com/news/last-minute-provision-in-senate-tax-bill-could-devastate-renewable-energy/511923/

Q. BASED ON YOUR REVIEW, WHAT IS THE TOTAL POTENTIAL IMPACT OF TAX REFORM ON THE ECONOMIC CASE FOR ENERGY VISIONS 2020

A. In total, tax reform has the potential to reduce the already questionable economics of the Energy Vision 2020 project by $[redacted] million on a NPVRR basis. This demonstrates how risky a resource strategy justified based on tax savings can be.

b. <u>Supplemental GRID Studies</u>

Q. WHAT SUPPLEMENTAL GRID STUDIES DID PACIFICORP PERFORM WHEN DEVELOPING THE ECONOMIC CASE FOR ENERGY VISION 2020?

A. As a part of the initial economic analyses surrounding Energy Vision 2020, PacifiCorp performed supplemental GRID studies where it quantified additional projected benefits of approximately $62.2 million, on a NPVRR basis, over a 20-year period. The studies were used to quantify certain aspects of PacifiCorp's proposal related to reduced line losses, reliability benefits, and EIM benefits, which PacifiCorp believed would be additive to the economics calculated using the IRP models.

Q. HAVE THESE MODELING ADJUSTMENTS BEEN INCORPORATED INTO THE IRP MODELS?

A. Yes. PacifiCorp confirmed that it has subsequently incorporated the adjustments underlying the supplemental GRID studies into the System Optimizer and Planning and Risk models. For the reasons discussed below, however, those adjustments have little basis in reality, yet are a key driver in the economic benefits that PacifiCorp projects with respect to Energy Vision 2020.

Q. WHAT ADDITIONAL CLAIMED BENEFITS DID PACIFICORP INCLUDE WITH RESPECT TO LINE LOSSES?

PacifiCorp believes that the new transmission line will have a positive impact on line losses, and modeled the line losses by quantifying the power cost impacts of reducing loads in Wyoming. In reality, I believe that the addition of new resources in remote areas of Wyoming would actually increase line losses, in contrast to resources at locations nearer to loads. While the lines themselves may have improved loss ratings, adding more resources in remote locations on PacifiCorp's system will cause more power to flow over long distances, subjecting more power to transmission level losses. For example, a study performed by Steve Knudson in the Utah proceeding on the ongoing RFP showed that locating new resources in Wyoming far from load would result in materially higher real system power losses in critical winter and summer peak conditions.[30] In addition, ratepayers have no way to ensure that any line loss reductions will actually be achieved.

Q. WHAT IS YOUR REACTION TO ADDITIONAL CLAIMED BENEFITS WITH RESPECT TO THE EIM?

A. I am concerned with PacifiCorp's analysis regarding the additional claimed EIM benefits, because the benefits associated with the EIM are being modeled in a way that is completely different than the way that EIM benefits are established when setting power costs in general rate cases and other similar dockets. In its economic analysis of Energy Vision 2020, PacifiCorp modeled the entrance of Idaho Power into the EIM by increasing the transfer capability between Jim Bridger and Walla Walla by 300 MW, even though

---

30 *In re the Application of Rocky Mountain Power for Approval of Solicitation Process of Wind Resources*, Docket No 17-035-23, Prefiled Testimony of F. Steven Knudsen at 12:245-247.

no actual increase to transfer capability will occur as a result of the EIM. Thus, PacifiCorp's models were configured to allow additional phantom transfers of power from Jim Bridger into the Northwest, even though PacifiCorp does not have transmission rights to accommodate those transfers. Such an assumption has no basis in the way that the EIM actually operates, since based on my understanding, the EIM does not allow a utility to rely on the system of another utility in order to effectuate firm transfers of power in excess of firm rights. As I understand it, attempting to use the EIM to effectuate firm transfers in the manner contemplated by PacifiCorp is a prohibited practice and would appear to violate many provisions of the EIM, such as the requirement to enter into the hour with a balanced forecast of loads and resources. To accomplish the additional firm transfers, PacifiCorp would basically have to manipulate its hour-ahead schedules, with the expectation that EIM would redispatch its resources in order to serve loads in the Northwest.

In contrast, the EIM will likely represent an additional cost associated with the Wind Projects, which PacifiCorp has not considered in its economic analysis. The Wind Projects will be subject to uninstructed imbalance charges, and the cost of those charges is not reflected in PacifiCorp's analysis. Due to transmission constraints in eastern Wyoming, I expect the uninstructed imbalance charges to be significant, as PacifiCorp is already experiencing negative EIM pricing in eastern Wyoming due to the uninstructed imbalance associated with wind facilities located in the transmission area.

Q. ARE THESE MODELING ADJUSTMENTS APPROPRIATELY USED TO JUSTIFY SUCH MAJOR RESOURCE ADDITIONS?

A. No. These supplemental analyses are hardly a sound basis to justify such significant resource additions and ratepayer risks. Notwithstanding, these modeling adjustments would comprise nearly the entirety of the benefits forecast in the medium gas and CO2 scenario in PacifiCorp's analysis. Effectively, ratepayers are dealing with a risky marginal project that would clearly not be forecast to be economic in the absence of these modeling adjustments. Ratepayers and regulators should not be comfortable making significant resource additions based solely on these types of aggressive modeling assumptions.

c. <u>Wholesale Transmission Revenues</u>

Q. WHAT HAVE YOU IDENTIFIED WITH RESPECT TO PACIFICORP'S ASSUMPTIONS SURROUNDING WHOLESALE TRANSMISSION REVENUES?

A. PacifiCorp assumes that, in connection with the Aeolus to Bridger segment, it will receive about $[redacted] million, on a NPVRR basis, of associated incremental transmission revenues over the 20-year period.[31] In response to discovery requests in the docket before the Idaho Commission regarding these claimed incremental benefits, PacifiCorp described these additional claimed benefits as the amount by which projected incremental revenue received from other transmission customers will offset the revenue requirement for these transmission investments.[32]

---

[31] Calculated from PacifiCorp's confidential workpaper "Energy Gateway GM 2017 03 13 w Bonus", Tab "Gateway", Column "G."

[32] UAE-UIEC Exhibit 1.2 at 5-6 (PacifiCorp's Response to PIIC DR 11).

Q. DO YOU AGREE WITH PACIFICORP'S ASSUMPTION?

A. No. PacifiCorp's analysis was highly simplified, and does not represent the way that the formula rates will actually work. PacifiCorp simply assumed that 12% of the new investment would be funded by Open Access Transmission Tariff ("OATT") customers, based upon the historical percentages of transmission revenue requirement that has been funded by OATT customers in the past. But, PacifiCorp did not perform a rigorous analysis of how the amount of costs allocated to OATT customers will change as a result of the project.

Q. IS IT POSSIBLE THAT OATT CUSTOMERS WILL NOT BE REQUIRED TO PAY FOR ANY OF THE ENERGY VISION 2020 TRANSMISSION INVESTMENT?

A. OATT customers will likely not be pleased to pay for an investment driven entirely by economics benefits that cannot possibly accrue to them. In Attachment K of PacifiCorp's OATT the process for making investments in new transmission facilities is identified. Based on the fact that the Energy Vision 2020 project is being driven by economics, rather than reliability concerns, it would seem more likely to me that all of the cost of the investment in the Transmission Projects would be allocated to PacifiCorp merchant and not shared by OATT customers.

Q. DOES PACIFICORP PROPERLY ACCOUNT FOR THE WAY THAT THE PROJECT MIGHT FLOW THROUGH FORMULA RATES?

A. No. Even if the cost of the Transmission Projects is unfairly socialized to other OATT customers, PacifiCorp's analysis fails to account for the fact that if Energy Vision 2020 project is constructed, PacifiCorp's merchant operations will likely be required to maintain additional transmission capacity in order to utilize the wind facilities. When this additional capacity is acquired, it will dilute the percentage of costs allocated to OATT customers, resulting in additional cost being allocated to retail customers.

PacifiCorp's 12% assumption was made with little rigor and is fundamentally inconsistent with how the new project will impact the costs borne by retail customers. Moreover, MSP uncertainty, discussed above, makes reliance on projected transmission benefits even less supportable. This assumption, like others, does not provide a basis to justify the significant investment and ratepayer risk proposed by PacifiCorp, yet the preponderance of alleged benefits could be attributed solely to this assumption.

d. <u>Transmission Cost Assumptions</u>

Q. HOW MUCH CERTAINTY DO RATEPAYERS HAVE WITH RESPECT TO PACIFICORP'S COST ASSUMPTIONS?

A. At this point, the cost assumptions are just projections. The total capital required for the Aeolus to Bridger/Anticline transmission project is forecast to be about $[redacted] million.[33] Given the magnitude of the proposed transmission investment in this case, even small changes to this cost assumption can have the effect of eliminating the claimed positive economics of the project.

---

[33] <u>See</u> PacifiCorp's confidential workpaper "Energy Gateway GM 2017 03 13 w Bonus", Tab "Summary", Cell "G26"

Q. DOES PACIFICORP RECOGNIZE THAT THERE IS A GREAT DEAL OF UNCERTAINTY SURROUNDING ITS COST ASSUMPTIONS?

A. Yes. In response to PIIC Data Request 15 in the docket before the Idaho Commission, PacifiCorp estimated the accuracy of its transmission cost assumption to be within plus or minus 15% of actual cost.[34] That is a range of approximately $[redacted] million above and below PacifiCorp's estimate. On an NPVRR basis over the life of the Transmission Projects, that equates to approximately $[redacted] million in additional ratepayer costs. That magnitude of error could eliminate any claimed favorable economics associated with the project, under the medium price scenarios. As was seen in the case of the Populous to Terminal Energy Gateway segment, the line ultimately cost more than ten times the amount that was originally forecast.

Q. HAS PACIFICORP MADE OTHER QUESTIONABLE COST ASSUMPTIONS?

A. PacifiCorp also makes some assumptions regarding operating expenses. In response to PIIC Data Request 14 for example, PacifiCorp identifies an assumption in its model to include $1 million of incremental operations and maintenance expenses associated with the new transmission project.[35] When asked to substantiate this estimate, PacifiCorp noted that it had no supporting workpapers for the estimate, and therefore, no basis to refute that incremental operating expenses might be substantially higher than its estimate.

[34] UAE-UIEC Exhibit 1.2 at 12-13 (PacifiCorp's Response to PIIC DR 15).

[35] UAE-UIEC Exhibit 1.2 at 11 (PacifiCorp's Response to PIIC DR 14).

e. <u>Transmission Levelized Fixed Costs</u>

Q. HOW DOES THE COMPANY MODEL THE COST OF THE TRANSMISSION PROJECTS IN ITS ECONOMIC ANALYSIS?

A. The analysis presented in Table 2 of Mr. Link's testimony is based on a 20 year study period. PacifiCorp assumes, however, that the Transmission Project assets will have a 62 year life. To analyze the Transmission Project assets within the 20 year period, PacifiCorp used a levelized fixed cost calculation, which spread the cost of the Transmission Project assets over their assumed 62 year life and assigned only a portion of the cost to the 20 year study period. Levelized fixed costs are often used in IRP analysis for the purpose of comparing the cost of different resources, with differing lives extending beyond the end of the study period.

Q. IS THE LEVELIZED FIXED COST TECHNIQUE APPROPRIATE FOR EVALUATING TRANSMISSION INVESTMENTS?

A. No. While the use of levelized fixed costs is fine to be used when comparing generation assets with differing lives, it is not appropriate to be used for analyzing transmission investments. By using the levelized fixed cost calculation for transmission, PacifiCorp's analysis only considered about one-third—or, 20 of 62 years—of the ratepayer cost associated with the Transmission Project investment. Unlike generation, the transmission assets do not produce electricity, and therefore are not comparable to other resources on a levelized fixed cost basis.

Q. WHAT IS THE IMPACT OF USING LEVELIZED FIXED COSTS TO CONSIDER THE TRANSMISSION PROJECT INVESTMENTS?

A. The NPVRR of the Transmission Project investments over the 62 year life is approximately $[redacted] million. In contrast, by using a levelized fixed costs over a 20 year period, PacifiCorp assumes the NPVRR of the Transmission Project investment is only $[redacted] million. Thus, PacifiCorp has excluded approximately $[redacted] million NPVRR cost associated with the Transmission Projects from its analysis. Ratepayers will still be required to pay for the Transmission Project investment after the 20 year period, and for that reason, it is appropriate to consider the impact of the transmission investment over the full life of the Transmission Project assets.

f. Wind Integration Cost

Q. WHAT LEVEL OF WIND INTEGRATION COSTS DID PACIFICORP INCLUDE IN ITS ANALYSIS?

A. PacifiCorp includes wind integration costs of approximately $0.63/MWh.

Q. WHAT WIND INTEGRATION VALUES HAS PACIFICORP USED PREVIOUSLY?

A. Based on its 2014 Wind Integration Study, PacifiCorp estimated intra-hour wind integration costs of approximately $2.35/MWh—almost four times as much as is assumed for the new wind in this docket.[36] In addition, PacifiCorp has previously

---

36/ See e.g., In The Matter of the Application of Rocky Mountain Power for Authority of a General Rate Increase in Its Retail Electric Utility Service Rates in Wyoming of $32.4 Million Per Year or 4.5 Percent, Wy.PSC, Docket No. 20000-469-ER-15, Direct Testimony of Bradley G. Mullins at 63, Table BGM-6.

identified inter-hour wind integration costs of approximately 0.75/MWh,[37] yet the economic analysis for Energy Vision 2020 includes no inter-hour wind integration costs.

Q. WHAT IS THE IMPACT OF USING THE PREVIOUS WIND INTEGRATION ASSUMPTION?

A. I estimate that if the 2014 Wind Integration Study results were used, including inter-hour wind integration, it would reduce PacifiCorp's claimed economics of the Energy Vision 2020 project by approximately $57.1 million on a 20-year NPVRR basis.

Q. IS IT POSSIBLE TO VERIFY THAT SAVINGS IN WIND INTEGRATION COSTS WILL BE ACHIEVED?

A. No. Generally, it is not possible in actual operations to determine the amount of actual wind integration costs that PacifiCorp might incur with respect to the Wind Projects. If the actual wind integration costs are higher than PacifiCorp projects, it will reduce the economics of the project, yet it will not be possible to verify whether wind integration costs will ultimately be in line with PacifiCorp's assumptions in this matter.

g. <u>Summary of Economic Case</u>

Q. PLEASE SUMMARIZE WHY YOU BELIEVE THE ECONOMIC CASE FOR ENERGY VISION 2020 IS NOT COMPELLING.

A. Taking all of PacifiCorp's speculative assumptions into consideration, it is clear that the Energy Vision 2020 project is far riskier than PacifiCorp suggests. If these speculative assumptions are stripped away, the project cannot be viewed as being economic for ratepayers, nor in the public interest. Based on these assumptions, it is clear that there are

[37] UAE-UIEC Exhibit 1.2 at 7-8 (PacifiCorp's Response to PIIC DR 12).

a great number of risks associated with the project that cannot be reasonably captured in the probabilistic analyses that PacifiCorp performed. Risks such as the possibility of changing tax provisions make economic projects inherently more risky to ratepayers than a project justified based on a demonstrated reliability need. For that reason, this type of economic project should not be pursued absent an overwhelming showing of benefits. In this case, there is no overwhelming economic showing and, in fact, it appears more likely that the project would cost ratepayers significantly.

VII. SINGLE ISSUE RATEMAKING SHOULD BE AVOIDED

Q. HOW HAS PACIFICORP PROPOSED TO RECOVER THE COSTS OF ENERGY VISION 2020?

A. The ratemaking proposal of PacifiCorp in this matter was described in the Direct Testimony of Mr. Larsen. Prior to PacifiCorp's next general rate case, PacifiCorp proposes to use a Resource Tracking Mechanism ("RTM") to recover costs associated with the New Wind and New Transmission investments.[38]

Q. IS PACIFICORP'S RATEMAKING PROPOSAL APPROPRIATE?

A. No. PacifiCorp's proposal would constitute single issue ratemaking, which is inherently unfair to ratepayers and should generally be avoided.

Q, WHY IS SINGLE ISSUE RATEMAKING UNFAIR TO RATEPAYERS?

A. When utility regulatory commissions determine the appropriateness of a cost that a utility seeks to recover from its customers, the standard practice is to review and consider all

[38] Direct Testimony of Jeffrey K. Larsen at 30-49.

relevant factors as part of a general rate case, rather than just certain factors in isolation. Isolation of a single issue, as PacifiCorp requests with respect to the RTM, is disfavored as a matter of policy because it distorts a fundamental "matching principle" of traditional ratemaking. While under traditional ratemaking, revenues and costs are balanced at a common point in time, single issue ratemaking often isolates only those costs expected to increase, without recognizing counterbalancing savings in another area. As a result, single issue ratemaking often results in over-earning by the utility and over-paying by the customer. Accordingly, the Commission should view the ratemaking proposal surrounding the RTM with great caution.

Q. If ENERGY VISION 2020 WERE APPROVED, HOW SHOULD THE INVESTMENTS BE INCORPORATED INTO RATES?

A. From a ratepayer perspective, it is more appropriate to consider investments of the scope contemplated with Energy Vision 2020 in a general rate case. This will allow all aspects of the utility's costs to be considered. In a general rate case, ratepayers can be assured to receive credit from other aspects of PacifiCorp's results, which might have trended favorably.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of Rocky Mountain Power for Approval of a Significant Energy Resource Decision and Request to Construct Wind Resource and Transmission Facilities	Docket No. 17-035-40

UAE-UIEC Exhibit 1.1

Q. PLEASE PROVIDE A LIST OF YOUR REGULATORY APPEARANCES.

A. I have sponsored testimony in the following regulatory proceedings:

- In re the Application of PacifiCorp dba Rocky Mountain Power For A Certificate of Public Convenience and Necessity and Binding Ratemaking Treatment for New Wind and Transmission Facilities, Id.PUC Case No. PAC-E-17-07.
- In re Avista Corporation Request for a General Rate Revision, Wa.UTC, Docket No. UE-170485 (Cons.).
- In re the Application of Nevada Power Company d/b/a NV Energy for Authority to Adjust its Annual Revenue Requirement for General Rates Charged to All Classes of Electric Customers and For Relief Properly Related Thereto, Nv.PUC, Docket No. 17-06003 (Cons.).
- In re PacifiCorp, dba Pacific Power, 2016 Power Cost Adjustment Mechanism, Or.PUC, Docket No. UE-327.
- In re the 2018 General Rate Case of Puget Sound Energy, Wa.UTC, Docket No. 170033 (Cons.).
- In re PacifiCorp, dba Pacific Power, 2018 Transition Adjustment Mechanism, Or.PUC, Docket No. UE 323.
- In re Portland General Electric Company, Request for a General Rate Revision, Or.PUC, Docket No. UE 319.
- In re Portland General Electric Company, Application for Transportation Electrification Programs, Or.PUC, UM 1811.
- In re Pacific Power & Light Company, Application for Transportation Electrification Programs, Or.PUC, Docket No. UM 1810.
- In re the Public Utility Commission of Oregon, Investigation to Examine PacifiCorp, dba Pacific Power's Non-Standard Avoided Cost Pricing, Or.PUC, Docket No. UM 1802.
- In re Pacific Power & Light Co., Revisions to Tariff WN U-75, Advice No. 16-05, to modify the Company’s existing tariffs governing permanent disconnection and removal procedures, Wa.UTC, Docket No. UE-161204.
- In re Puget Sound Energy’s Revisions to Tariff WN U-60, Adding Schedule 451, Implementing a New Retail Wheeling Service, Wa.UTC, Docket No. UE-161123.

- 2018 Joint Power and Transmission Rate Proceeding, Bonneville Power Administration, Case No. BP-18.

- In re Portland General Electric Company Application for Approval of Sale of Harborton Restoration Project Property, Or.PUC, Docket No. UP 334 (Cons.).

- In re An Investigation of Policies Related to Renewable Distributed Electric Generation, Ar.PSC, Matter No. 16-028-U.

- In re Net Metering and the Implementation of Act 827 of 2015, Ar.PSC, Matter No. 16-027-R.

- In re the Application of Rocky Mountain Power for Approval of the 2016 Energy Balancing Account, Ut.PSC, Docket No. 16-035-01

- In re Avista Corporation Request for a General Rate Revision, Wa.UTC, Docket No. UE-160228 (Cons.).

- In re the Application of Rocky Mountain Power to Decrease Current Rates by $2.7 Million to Recover Deferred Net Power Costs Pursuant to Tariff Schedule 95 and to Increase Rates by $50 Thousand Pursuant to Tariff Schedule 93, Wy.PSC, Docket No. 20000-292-EA-16.

- In re PacifiCorp, dba Pacific Power, 2017 Transition Adjustment Mechanism, Or.PUC, Docket No. UE 307.

- In re Portland General Electric Company, 2017 Annual Power Cost Update Tariff (Schedule 125), Or.PUC, Docket No. UE 308.

- In re PacifiCorp, Request to Initiate an Investigation of Multi-Jurisdictional Issues and Approve an Inter-Jurisdictional Cost Allocation Protocol, Or.PUC, UM 1050.

- In re Pacific Power & Light Company, General rate increase for electric services, Wa.UTC, Docket No. UE-152253.

- In The Matter of the Application of Rocky Mountain Power for Authority of a General Rate Increase in Its Retail Electric Utility Service Rates in Wyoming of $32.4 Million Per Year or 4.5 Percent, Wy.PSC, Docket No. 20000-469-ER-15.

- In re Avista Corporation, General Rate Increase for Electric Services, Wa.UTC, Docket No. UE-150204.

- In re the Application of Rocky Mountain Power to Decrease Rates by $17.6 Million to Recover Deferred Net Power Costs Pursuant to Tariff Schedule 95 to Decrease Rates by $4.7 Million Pursuant to Tariff Schedule 93, Wy.PSC, Docket No. 20000-472-EA-15.

- Formal complaint of The Walla Walla Country Club against Pacific Power & Light Company for refusal to provide disconnection under Commission-approved terms and fees, as mandated under Company tariff rules, Wa.UTC, Docket No. UE-143932.

- In re PacifiCorp, dba Pacific Power, 2016 Transition Adjustment Mechanism, Or.PUC, Docket No. UE 296.

- In re Portland General Electric Company, Request for a General Rate Revision, Or.PUC, Docket No. UE 294.

- In re Portland General Electric Company and PacifiCorp dba Pacific Power, Request for Generic Power Cost Adjustment Mechanism Investigation, Or.PUC, Docket No. UM 1662.

- In re PacifiCorp, dba Pacific Power, Application for Approval of Deer Creek Mine Transaction, Or.PUC, Docket No. UM 1712.

- In re Public Utility Commission of Oregon, Investigation to Explore Issues Related to a Renewable Generator's Contribution to Capacity, Or.PUC, Docket No. UM 1719.

- In re Portland General Electric Company, Application for Deferral Accounting of Excess Pension Costs and Carrying Costs on Cash Contributions, Or.PUC, Docket No. UM 1623.

- 2016 Joint Power and Transmission Rate Proceeding, Bonneville Power Administration, Case No. BP-16.

- In re Puget Sound Energy, Petition to Update Methodologies Used to Allocate Electric Cost of Service and for Electric Rate Design Purposes, Wa.UTC, Docket No. UE-141368.

- In re Pacific Power & Light Company, Request for a General Rate Revision Resulting in an Overall Price Change of 8.5 Percent, or $27.2 Million, Wa.UTC, Docket No. UE-140762.

- In re Puget Sound Energy, Revises the Power Cost Rate in WN U-60, Tariff G, Schedule 95, to reflect a decrease of $9,554,847 in the Company's overall normalized power supply costs, Wa.UTC, Docket No. UE-141141.

- In re the Application of Rocky Mountain Power for Authority to Increase Its Retail Electric Utility Service Rates in Wyoming Approximately $36.1 Million Per Year or 5.3 Percent, Wy.PSC, Docket No. 20000-446-ER-14.

- In re Avista Corporation, General Rate Increase for Electric Services, RE, Tariff WN U-28, Which Proposes an Overall Net Electric Billed Increase of 5.5 Percent Effective January 1, 2015, Wa.UTC, Docket No. UE-140188.

- In re PacifiCorp, dba Pacific Power, Application for Deferred Accounting and Prudence Determination Associated with the Energy Imbalance Market, Or.PUC, Docket No. UM 1689.

- In re PacifiCorp, dba Pacific Power, 2015 Transition Adjustment Mechanism, Or.PUC, Docket No. UE 287.

- In re Portland General Electric Company, Request for a General Rate Revision, Or.PUC, Docket No. UE 283.

- In re Portland General Electric Company's Net Variable Power Costs (NVPC) and Annual Power Cost Update (APCU), Or.PUC, Docket No. UE 286.

- In re Portland General Electric Company 2014 Schedule 145 Boardman Power Plant Operating Adjustment, Or.PUC, Docket No. UE 281.

- In re PacifiCorp, dba Pacific Power, Transition Adjustment, Five-Year Cost of Service Opt-Out (adopting testimony of Donald W. Schoenbeck), Or.PUC, Docket No. UE 267.

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of Rocky Mountain Power for Approval of a Significant Energy Resource Decision and Request to Construct Wind Resource and Transmission Facilities	Docket No. 17-035-40

UAE-UIEC Exhibit 1.2
Redacted Version

PIIC Data Request 9

Please provide the Company's best estimate of the impact of updating its analysis regarding the economics of its propose projects to be based on the September 30, 2017 official forward price curve, and provide work papers supporting the Company's estimate.

Response to PIIC Data Request 9

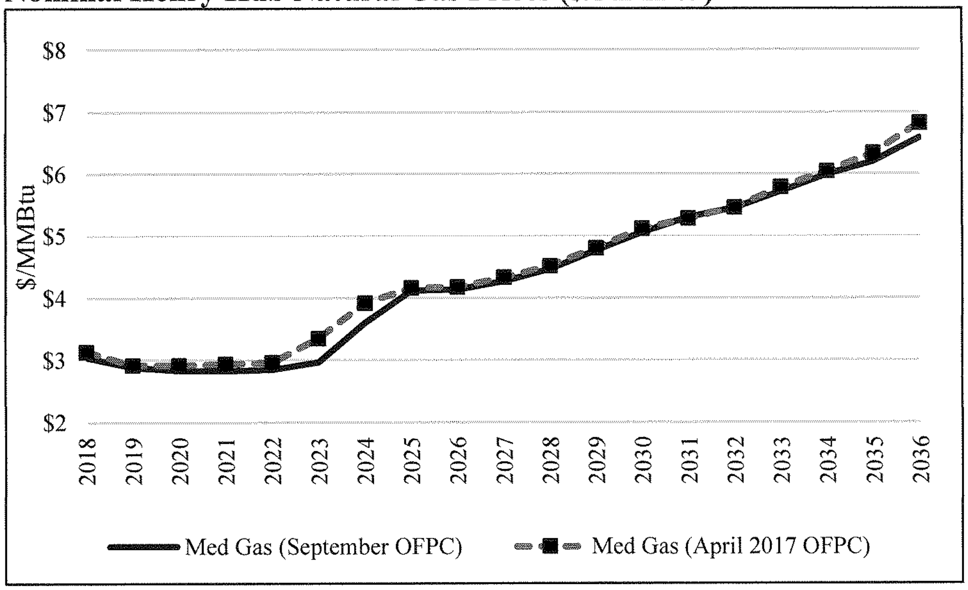
The Company objects to this request on the basis that it is vague, speculative, requiring development of a special study or information not maintained in the ordinary course of business, and not reasonably calculated to lead to the discovery of admissible evidence.

PacifiCorp assumes the PacifiCorp Idaho Industrial Customers' (PIIC) reference to "proposed projects" is to Energy Vision 2020 as defined in the Company's 2017 Integrated Resource Plan (IRP) – Energy Vision 2020 Update, filed with the Idaho Public Utilities Commission (IPUC) on July 28, 2017. Based on this assumption, the Company responds as follows:

The Company has not produced an updated economic analysis of Energy Vision 2020 isolating the impact of updating to the September 2017 official forward price curve (OFPC). The Company refreshed its economic analysis of its proposed wind repowering project, one element of Energy Vision 2020, with several modeling updates, including updated market price assumptions that are based on the September 2017 OFPC. This analysis was prepared in support of the Company's rebuttal testimony filed with the Public Service Commission of Utah (UPSC) on October 19, 2017, in Docket No. 17-035-39. In this filing, the updated economic analysis, which includes updated assumptions beyond the OFPC (*i.e.*, cost-and-performance updates for repowered wind facilities) shows that the present-value revenue requirement (PVRR) benefits of the wind repowering project have increased from \$359 million as reported in the July 28, 2017 Update (Table 3.2) to \$471 million assuming medium natural gas prices and medium carbon dioxide (CO_2) prices through 2050.

The Company has not completed a similar update for its proposed new wind and transmission projects, which are also elements of Energy Vision 2020.
Based on the relatively minor changes between the September 2017 OFPC and the April 2017 OFPC, as shown in the figure below, the updated OFPC assumptions would not materially alter the present value of revenue requirements differential benefits of Energy Vision 2020.

Nominal Henry Hub Natural Gas Prices ($/MMBtu)



Recordholder: Dan Swan

Sponsor: Rick Link

PIIC Data Request 10

Reference the GRID studies provided to Mr. Mullins in response to ICNU Data Request 10 in Oregon Docket No. LC 67: Please identify how the results of those studies are incorporated into the economics of the Company's proposal as developed using the IRP work papers.

Response to PIIC Data Request 10

The line loss, transmission system derate, and energy imbalance market (EIM) transfer benefit adjustments identified in the Company's response to ICNU Data Request 0010 (inserted below for other parties' reference) are incorporated into the 2017 Integrated Resource Plan (IRP) results. These adjustments are made out of the model and input into the "SO Model Summary Report" on tab "New FOM Adjustments". Please refer to pages 220 and 221 of Volume I of the 2017 IRP, Chapter 8 (Modeling Results).

The Company's 2017 IRP is publicly available and can be accessed by utilizing the following website link: http://www.pacificorp.com/es/irp.html

For the economic analysis supporting the new wind and transmission projects proposed in this proceeding, the line loss, transmission derate, and EIM transfer benefits were incorporated into the System Optimizer model and the Planning and Risk model. Please refer to the Direct Testimony of Company witness Mr. Rick T. Link (pg. 24 line 19 through pg. 26 line 12).

ICNU Data Request 0010

Please provide ICNU consultant, Brad Mullins, with access to all Generation and Regulation Initiative Decision Tools (GRID) model studies and analysis that the Company has performed with respect to new wind resources in the Company's 2017 Integrated Resource Plan, including:

(a) The GRID project files;

(b) The GRID model conversion wizard;

(c) Any GRID input files in Excel format;

(d) Any GRID model work papers, with the same level of detail as provided in Transition Adjustment Mechanism filing;

(e) Any GRID model scenario files, fully intact, with all functioning macros;

(f) Any subsequent analysis performed using the GRID model scenarios; and

A narrative description of all the major GRID molding assumptions, using a format similar to the quarterly report that the Company files in Utah, documenting its avoided cost pricing methodology.

Recordholder: Dan MacNeil

Sponsor: Rick Link

PIIC Data Request 11

Reference the incremental wholesale transmission volumes and revenues that the Company has assumed in connection with completing the Aeolus to Bridger transmission segment:

(a) Please identify the amount of the referenced incremental transmission revenues assumed in the Company's analysis.

(b) Please provide work papers supporting the referenced incremental wholesale transmission volumes and revenues.

(c) Please explain how the referenced transmission segment will allow the Company to make more wholesale wheeling transactions.

(d) Does the Company have any existing requests for wholesale transmission service that it is unable to fulfill in the absence of the referenced transmission segment. If yes, please identify all such requests.

Response to PIIC Data Request 11

The Company objects to this data request on the basis that it is unduly vague to the extent it fails to mention which document PacifiCorp Idaho Industrial Customers (PIIC) is referencing in its statement in its first sentence, starting with "the Company has assumed …". The Company does not know whether PIIC is referencing the testimony in the current case or some other document. Without waiving the objection, based on the assumption that Mr. Mullins copied this set of data requests from those data requests he issued in the Oregon docket as a representative of the Industrial Customers of Northwest Utilities (ICNU), PacifiCorp assumes the PIIC reference to "wholesale transmission volumes and revenues" is to the Company's discussion of transmission-revenue credits related to the proposed Aeolus-to-Bridger/Anticline transmission line as discussed in the Company's 2017 Integrated Resource Plan (IRP) – Energy Vision 2020 Update filed with the Idaho Public Utilities Commission (IPUC) on July 28, 2017 (pages 12-13). Based on this assumption, the Company responds as follows:

(a) Please refer to Attachment E to the 2017 IRP – Energy Vision 2020 Update, specifically the rows "Incremental Transmission Revenue," which are the same for each price-policy scenario.

(b) Please refer to Attachment PIIC 0011, which provides the derivation of the range of percentages that served as the basis for the Company assuming transmission revenue credits tied to 12 percent of transmission revenue requirement. The calculation of revenue credits based the 12 percent assumption is provided in the confidential work papers supporting the 2017

IRP – Energy Vision 2020 Update, specifically folder "Transmission Projects", file "Energy Gateway GM 2017 03 13 w Bonus.xlsm", tab "Gateway".

(c) The Company has not assumed the Aeolus-to-Bridger/Anticline line will allow the Company to make more wholesale wheeling transactions nor does the Company anticipate that the proposed line will increase wheeling transactions.

(d) No, the Company does not have any pending third-party requests for wholesale *transmission service* that rely on the new transmission segment. There are, however, third-party requests for *interconnection service* that cannot be accommodated without significant investments in the transmission system, including the proposed Aeolus-to-Bridger/Anticline transmission line.

Recordholder: Shay LaBray / Randy Baker

Sponsor: Rick Vail

PIIC Data Request 12

Reference the integration costs assumed with respect to the Company's new wind proposal:

(a) Please identify the integration costs that the Company assumed in its analysis on a $/MWh basis.

(b) Please provide work papers supporting the integration cost assumptions used in the Company's analysis.

(c) Please identify the $/MWh cost of inter-hour wind integration included in the Company's July update in Docket UE 323, the 2018 Transition Adjustment Mechanism Filing, before the Oregon Public Utility Commission.

(d) Please identify the $/MWh cost of intra-hour wind integration included in the Company's July update in Docket UE 323, the 2018 Transition Adjustment Mechanism Filing, before the Oregon Public Utility Commission.

Response to PIIC Data Request 12

The Company objects to this request on the basis that it is vague to the extent it fails to identify which document it references when it says "reference the integration costs assumed with respect to the Company's new wind proposal." Without waiving the objection and assuming Mr. Mullins copied this set of data requests from the set that he issued on behalf of the Industrial Customers of Northwest Utilities (ICNU) in the Oregon Integrated Resource Plan (IRP) docket which are nearly identical to this set, the Company assumes Mr. Mullins is referring to the integration costs assumed in the 2017 IRP and states as follows:

(a) The wind integration cost is $0.57 per megawatt-hour ($/MWh), as reported in Volume II of PacifiCorp's 2017 IRP, Chapter F (Flexible Resource Study), page 133, Table F.22 (2017 FRS Flexible Resource Costs as Compared to 2014 WIS Costs, $/MWh).

(b) Please refer to the public data disks that accompanied the 2017 IRP, specifically: Data Disk 1_PUBLIC\Chapters Appendix - Public.zip\Chapters Appendix\Appendix F - Flexible Reserve Study\, file "2017 Flexible Reserve Study Results.xlsx", which provide the supporting work papers.

(c) In Oregon Docket UE 323 (2018 Transition Adjustment Mechanism (TAM)), the inter-hour wind integration cost is $0.75/MWh, based on Volume II of PacifiCorp's 2015 IRP, Chapter H (Wind Integration Study), page 100, Table H.3 (Wind Integration Cost, $/MWh), then adjusted for inflation rate.

(d) The Company is not able to explicitly calculate intra-hour wind integration cost. The Generation and Regulation Initiative Decision Tool (GRID) reflects perfectly optimized costs for an hourly period assuming load net of wind and solar generation remains unchanged at a single level for the whole hour. The GRID result does not include these additional within-hour costs because it does not include the within-hour variation in requirements or the constrained set of resources available to accommodate those changes.

Recordholder: Dan Swan / Teresa Tang

Sponsor: Rick Link

PIIC Data Request 13

Has the Company performed any analysis to quantify the potential impacts of tax reform on the economics of its resource proposal? If yes, please provide all work papers supporting its analysis. If no, please explain why the Company believes that it is not necessary to consider such impacts.

Response to PIIC Data Request 13

The Company performed a tax-policy sensitivity that is summarized in the rebuttal testimony of Company witness, Rick T. Link, in Utah Docket No. 17-035-39. The sensitivity study assumes the current federal tax corporate income tax rate is reduced from 35 percent to 25 percent. Assuming a marginal state income tax rate of 4.54 percent less a federal deductibility benefit of 1.135 percent, the assumed net state tax rate is 3.405 percent. Based on these inputs, the effective combined federal and state income tax rate assumed for this sensitivity is 28.405 percent.

The table below summarizes the results of the sensitivity relative to an updated benchmark case, which reflects updated transmission, load forecast, price curve, and cost-and-performance assumptions. To assess the potential impact of a change in the federal corporate tax rate, the present-value revenue requirement differential (PVRR(d)) results were calculated through 2036 based on the System Optimizer model (SO model) and the Planning and Risk (PaR) model results. The sensitivity results reflect updated medium natural gas and medium carbon dioxide (CO_2) price-policy assumptions.

Tax Policy Sensitivity
(Benefit)/Cost of Wind Repowering ($ million)

Model	Sensitivity PVRR(d)	Benchmark PVRR(d)	Change in PVRR(d)
SO Model	($45)	($138)	$93
PaR Stochastic Mean	($23)	($115)	$93
PaR Risk Adjusted	($24)	($121)	$97

Although the overall benefit of the wind repowering project is reduced by between $93 million to $97 million, the wind repowering project still produces net economic benefits for customers.

Please refer to Confidential Attachment PIIC 13, which provides the SO and PaR study results related to this sensitivity.

Confidential information is provided subject to the protective agreement in this proceeding.

Recordholder: Dan Swan

Sponsor: Rick Link

PIIC Data Request 14

Please identify the amount of incremental operations and maintenance expense that the Company has assumed with respect to the new transmission segment, and provide work papers supporting the assumed amounts.

Response to PIIC Data Request 14

The Company assumes incremental operations and maintenance (O&M) expense for the Aeolus-to-Bridger/Anticline transmission line of $1 million per year in 2017 dollars. The Company does not have supporting work papers as this estimate is based on management judgment. Maintenance activities include:

- Line safety inspections
- Line detail inspections
- Corrective line maintenance
- Tower inspections
- Substation inspections
- Substation equipment maintenance: relay testing, breaker inspections
- Corrective substation maintenance

Recordholder: Mark Paul

Sponsor: Rick Link

PIIC Data Request 15

Reference the capital cost of the proposed Aeolus to Bridger transmission segment:

(a) Please identify the total amount of capital cost that the Company has assumed with respect to the referenced transmission segment.

(b) Please provide an explanation of how the Company derived its capital cost estimate.

(c) Please provide work papers supporting its capital cost estimate, including itemization of each identified component of the estimated capital costs.

(d) Please identify any contingency that the Company has included in its estimate.

(e) Please identify any risks that the Company has considered which might cause the actual capital costs associated with building the referenced transmission segment to exceed the estimates the Company used in its analysis.

Confidential Response to PIIC Data Request 15

(a) The Company estimates a total capital cost of **[CONFIDENTIAL BEGINS]** [redacted] **[CONFIDENTIAL ENDS]** for the Aeolus-to-Bridger/Anticline 500/345 kilovolt (kV) transmission line.

(b) The Company developed the estimate using quantity models from the preliminary transmission-line design with historical unit pricing from previous projects (adjusted for inflation as necessary). Substation estimates were derived from models of substation components and equipment based on conceptual one-line diagrams. Construction costs were estimated using historical unit prices and major equipment prices were evaluated by requesting budgetary quotes from manufacturers.

(c) The cost studies for the project contain commercially sensitive information and are considered highly confidential. The Company requests special handling. Public disclosure of this information before completion of the competitive bidding process in 2018 could negatively impact the responses from bidders with potential for the company to not secure the most cost-efficient proposal. Please contact Ted Weston at (801) 220-2963 to make arrangements for review.

(d) The Company has presented the transmission cost estimate with a plus or minus 15 percent accuracy given the early nature of the estimate and pending finalization of the scope and approach. The estimate values used historical pricing from previous projects (adjusted for inflation as necessary), and the historical pricing units were from engineer, procure and construct (EPC) contracts and contained contractor contingencies representing such risks as soils, production rates, weather, environmental constraints. In addition, the Company prepared a risk evaluation to determine potential cost and schedule risks; the values determined from this process identified that the risk profile was within the overall accuracy of the project cost estimate.

(e) The risk/uncertainty assessments correlate closely to the cost study data and therefore could also impact the competitive bidding process if made public at this time. The Company considers this information commercially sensitive and highly confidential. The Company requests special handling. Please contact Ted Weston at (801) 220-2963 to make arrangements for review.

Confidential information is provided subject to the terms of the protective agreement in this proceeding.

Recordholder: Todd Jensen

Sponsor: Rick Vail

UAE Data Request 2.1

Reference the accuracy of Company's Official Forward Price Curve (OFPC):

(a) Has the Company ever performed an analysis to quantify the forecast error associated with previously-issued long-term official forward price curves? If yes, please provide any such analyses.

(b) Please provide each OFPC the Company issued over the period December 2006 through January 2017 (inclusive), including all power and natural gas hubs where the Company transacts. Please include forward prices for each month and year for which the forecast was prepared. Please provide this data in format similar to the Company's response to ICNU Data Request 001 in OR.PUC Docket No. UE 307.

(c) Please provide actual spot market prices, on a monthly basis over the period January 2007 through September 2017 (inclusive), including all power and natural gas hubs where the Company transacts.

(d) When evaluating the forecast error associated with previously issued Official Forward Price Curves, does the Company agree that such an analysis may be reasonably performed using price curves issued over the period 2007 through 2017? If no, please identify the period which the Company believes would provide the most reasonable basis for measuring the forecast error associated with previously issued OFPCs.

(e) If the Company believes that the forecast error associated with its OFPCs would be more reasonably measured over a longer period of time than 2007 through 2017, please provide each OFPC issued and monthly spot market prices, in the same manner as identified subparts (b) and (c) to this request, over the period the Company believes would be more reasonable for measuring the forecast error of previously issued OFPCs.

Response to UAE Data Request 2.1

(a) No, PacifiCorp has not conducted this type of analysis.

(b) The Company objects to this request on the basis that it is overly broad and unduly burdensome. Without waiving the objection, the Company generally issues its official forward price curve (OFPC) on a quarterly basis. In addition, for the Oregon transition adjustment mechanism (TAM) indicative and final filings, the Company develops two 10-year forward price curves (starting in Oregon Docket UE 296) or three-year forward price curves. These 10-year curves or three-year curves are then used to supersede the initial years of the most recent quarterly OFPC.

Please refer to Attachment UAE 2.1-1, which provides the quarterly OFPCs and the final TAM OFPCs covering December 2006 through January 2017.

(c) The Company objects to this request on the basis that it is overly broad and unduly burdensome. Without waiving the objection, please refer to Attachment UAE 2.1-2, which provides the monthly average market prices derived from the day-ahead price from archived proprietary sources (where available) for each month covering January 2007 through September 2017.

(d) The Company objects to the request on the basis that it assumes facts not in evidence. Please refer to the Company's response to subpart (a) above.

(e) Please refer to the Company's response to subpart (d) above.

17-035-40 / Rocky Mountain Power
November 17, 2017
UAE Data Request 2.2

UAE Data Request 2.2

Reference the long-term gas contracts executed pursuant to the Company's 2012 Gas RFP, as discussed in UT.PSC Docket 12-035-102:

(a) Does the Company agree that it ultimately executed two gas transaction pursuant to the referenced 2012 Gas RFP? If yes, please provide a brief overview of these transactions.

(b) Please identify the counterparty associated the referenced transactions.

(c) Does the Company agree that the referenced transactions were subject to a requirement that the levelized price of the gas contracts not exceed the levelized market price in the Company's forward price curve (just as the economics of the Company's Energy Vision 2020 project are highly dependent upon the prices in the Company's OFPC)?

(d) How accurate has the OFPC that the Company relied upon when executing the referenced transactions been?

(e) Please identify the OFPC the Company relied upon when executing the referenced transactions, and if not already provided in response to another request, please provide a copy of the OFPC.

(f) Please provide the actual monthly settlements data associated with the referenced transactions over the period 2013 (including the earliest month where settlements were made) through the most recent month with available settlement data. Please provide the settlement data in the same format as provided in "Attach ECAM MFR 3 -3 CONF" in the ongoing Energy Cost Adjustment Mechanism Proceeding before the Wyoming Public Service Commission (Docket No. 20000-514-EA-17).

(g) Please provide the deal tracking data from the Company's energy trading system over the period August 2017 through the term of the referenced agreements (based on a ten-year term, approximately 2023). Please provide the deal tracking data in a manner substantially similar to the Company's GRID modeling Gas Swaps work paper (See e.g. "ORTAM18w_Gas Swaps (1612) FEB17 CONF").

(h) If not readily apparent from the data provided in response to this request please identify the monthly fixed prices associated with the referenced transactions over the term of the transactions.

Confidential Response to UAE Data Request 2.2

The Company objects to this request on the basis that the requested information will not likely lead to the discovery of admissible evidence and is beyond the scope of this case. Without waiving the objection, the Company states as follows:

(a) **[CONFIDENTIAL BEGINS]** [redacted] **[CONFIDENTIAL ENDS].**

(b) Please refer to the Company's response to subpart (a) above.

(c) Please refer to Attachment UAE 2.2-1 for the order in the referenced docket. The order provides requirements ordered by the Public Service Commission of Utah (UPSC).

(d) The Company's official forward price curve (OFPC) is updated and validated by the Company's risk management group within the energy supply management (ESM) business unit against other published price curves at the end of each quarter (with the exception of the two OFPCs issued specifically for the Company's annual Oregon Transition Adjustment Mechanism (TAM)) to assure its accuracy at that given point in time. The OFPC is an indication to where parties could reasonably trade for a specific term and price as of the date the OFPC is produced. In addition to the quarterly OFPC, the Company produces a daily forward price curve (FPC) that is an indication of where parties could reasonably trade for a specific term and price as of the date the FPC is produced. The Company monitors the daily exposure of all fixed price deals against a daily produced FPC, which is an accurate representation of forward prices at a given point in time.

(e) At the time of the transaction execution, the Company relied on the daily FPC of August 12, 2013 and the daily FPC of August 22, 2013 for the two identified transactions executed as a result of the 2012 Natural Gas RFP. Please refer to Confidential Attachment UAE 2.2-2.

(f) Please refer to Confidential Attachment UAE 2.2-3, which provides actual monthly settlements data from September 1, 2013 through September 30, 2017 for transaction 1250444 and transaction 1256734 (the natural gas swap transactions executed as a result of PacifiCorp's 2012 Natural Gas RFP).

(g) Please refer to Confidential Attachment UAE 2.2-4, which provides the deal tracking data from the Company energy trading system (ETS) record over the period August 2017 through August 2023.

(h) **[CONFIDENTIAL BEGINS]**

[redacted]

[redacted]

[CONFIDENTIAL ENDS]

Confidential information is provided subject to Public Service Commission of Utah (UPSC) Rule 746-1-602 and 746-1-603.

UAE Data Request 2.3

Reference the Company's wind shaping methodology:

(a) When modeling the new wind resources in the System Optimizer and PaR models, did the Company use the same hourly wind shaping methodology that it uses in the GRID model for forecasting net power costs in general rate case, and other related, proceedings?

(b) Please provide a description of how the hourly wind profiles for the new wind resources were modeled in the SO and PaR models.

(c) Please provide the hourly wind profiles for each of the new wind resources as input into the System Optimizer and PaR models.

Response to UAE Data Request 2.3

(a) In general rate cases (GRC), the Company uses a wind shaping methodology based on a single calendar year of hourly energy output from each owned and purchased wind facility. The actual generation levels are scaled up or down so that the average output over the course of a day and a month is the same as the forecasted level. This methodology is applied to all wind resources for which data is available during the historical period. The proposed wind resources do not have historical data so this methodology would not apply.

The Company recognizes that a reasonably correlated hourly shape is important to evaluate wind resources, particularly when they are constrained areas. To this end, an hourly shape for new wind resources is prepared based on a blend of the hourly output of two existing wind projects. The two existing projects which are closest to the new resource's location are used, but smaller existing projects are excluded as the reported hourly output is rounded to the nearest megawatt (MW) and thus has less precision. This also eliminates duplicative results, as many of the small existing resources are next to larger existing resources.

The historical hourly shapes of the two closest existing wind resources are blended together, with the hourly shape of the closer resource receiving a higher weighting, based on their relative distances. The un-repowered shapes are used because repowering capacity and large generator interconnection agreement (LGIA) limits may not be aligned. The adjusted rather than actual shape is used because it has been aligned with the characteristic week used in the Planning and Risk (PaR) model. The resulting hourly shape is adjusted such that the result matches the 12-month by 24 hour (12x24) generation profile of the future wind resource. This adjustment is comparable to that performed to align historical hourly shapes with median generation forecasts for existing resources.

(b) The wind profiles for new wind resources are modeled in the System Optimizer model (SO model) and the PaR model as an index, using annual hourly pattern data (365 days by 24 hours). The annual pattern represents the hourly capacity factor.

The SO model internally calculates "time of day" blocks from the hourly data, representing summer and winter peak, off-peak and super-peak patterns. SO model generation is reported in gigawatt hours (GWh).

PaR is similar to SO except a sample week is selected each month to determine wind generation levels, which is then scaled within PaR for the relevant month. To eliminate the unintended distortion of monthly wind shapes due to relying on a sample week, the PaR inputs are recast such that every week of a given month has the same pattern but preserves the expected monthly and annual generation. PaR generation is also reported in GWh.

(c) Please refer to Confidential Attachment UAE 2.3, which provides the hourly new wind profiles referenced in the Company's response to subpart (b) above.

Confidential information is provided subject to Public Service Commission of Utah (UPSC) Rule 746-1-602 and 746-1-603.