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

Counsel for Utah Association of Energy Users

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

PacifiCorp's 2019 Integrated Resource Plan	Docket No. 19-035-02

INITIAL COMMENTS OF THE UTAH ASSOCIATION OF ENERGY USERS

The Utah Association of Energy Users ("UAE") hereby submits its initial comments on PacifiCorp's 2019 Integrated Resource Plan ("IRP").

Commission review of the IRP is important primarily for the following issues: (i) determining whether the IRP is sufficiently consistent with the Commission's published Standards and Guidelines to warrant acknowledgment; (ii) providing feedback on how the IRP process can be improved in the future; (iii) providing specific "review" and "guidance" to the utility under Utah Code §§ 54-17-101, et seq., on the proposed action plan; and (iv) evaluating the reasonableness of the timing and character of the next deferrable resource for avoided cost pricing purposes.

UAE appreciates the efforts of PacifiCorp ("PacifiCorp" or "Company") and others in developing this IRP. UAE has concerns about portions of this IRP, which represents a significant potential for increased risks and rates for captive Utah ratepayers stemming from proposed new resource additions, including transmission and battery storage resources. UAE also has concerns regarding the Company's failure to use a true benchmark in evaluating potential portfolios, which obscures the costs associated with the preferred portfolio. Each of these concerns is addressed in further detail, below, with references to the Commission's IRP Standards and Guidelines ("Guidelines") adopted in Docket No. 90-2035-01.[1]

As a result, and for the reasons set forth more fully below, UAE recommends the Commission partially decline to acknowledge the IRP.

I. THE PROPOSED ENERGY GATEWAY SOUTH TRANSMISSION PROJECT HAS NOT BEEN PROPERLY EVALUATED RELATIVE TO LOWER COST OPTIONS

UAE has several concerns about the Company's inclusion of the Energy Gateway South Transmission Project ("Gateway South") in the preferred portfolio, each of which is discussed in detail in this Section.

A. PacifiCorp has failed to provide a robust analysis of potential economic transmission alternatives to Gateway South

PacifiCorp has been developing its Energy Gateway transmission expansion projects for over a decade, yet it has not been able to provide any publicly available transmission planning studies or analyses that have provided a robust evaluation of potential lower cost transmission alternatives. Recently, due to this lack of a robust analysis, and at the request of multiple stakeholders, the Northern Tier Transmission Group ("NTTG") initiated an Economic Study Request as part of the study process to develop its biennial 2018-2019 Regional Transmission

[1] *See In the Matter of Analysis of an Integrated Resource Plan for PacifiCorp*, (Report and Order on Standards and Guidelines, issues June 18, 1992), Docket No. 90-2035-01. Future references to Guidelines contained in that order will be referred to by the Guideline number. For example, "Guideline 3" will refer to Guideline 3 from page 19 of that order, without referencing the 1992 order each time the Guideline is referred to in these comments.

Plan. NTTG's Economic Study Request Report ("NTTG Report") identified an alternative transmission configuration to the Gateway West and Gateway South transmission projects that could provide reliable system performance in all of NTTG's test cases[2] at a capital cost savings of over $1.9 Billion.[3] The NTTG Report identified an alternative transmission configuration that "showed acceptable performance" and "demonstrated reduced capital costs" when compared to PacifiCorp's Gateway South proposal.[4]

Despite this strong evidence of a reliable and lower cost alternative transmission configuration, PacifiCorp has been unwilling in this 2019 IRP process to evaluate whether the proposed transmission alternative could more economically meet the needs of its customers. In fact, in response to an OCS discovery request, PacifiCorp specifically refused to run a case that would evaluate the proposed NTTG economic alternative based on PacifiCorp's unsubstantiated claim that it believed the requested case was not feasible.[5] It should be noted that PacifiCorp was able to run other similar cases in response to discovery.

B. **The NTTG Report identified an alternative transmission configuration that would result in significant cost savings for customers**

According to the NTTG Report, the capital cost savings of the alternative transmission configuration were estimated to be over $1.9 Billion, which was estimated to result in an annual revenue requirement savings to customers of $271 million per year.[6] While the NTTG Report

[2] NTTG 2018-2019 Draft Final Regional Transmission Plan, September 18, 2019, Appendix E: NTTG 2019 Economic Study Request Report, p. 92.
[3] Id, p. 107. EGW and EGS estimated capital cost $4.5 Billion – alternative configuration estimated capital cost $2.6 Billion = $1.9 Billion capital cost savings.
[4] Id, p. 92.
[5] *See* PAC response to OCS Data Request 2.1, attached hereto as Exhibit A.
[6] NTTG 2018-2019 Draft Final Regional Transmission Plan, September 18, 2019, Appendix E: NTTG 2019 Economic Study Request Report, p. 108.

did identify the potential for $17 million per year in transmission congestion costs,[7] and up to $71 million per year in "bottled energy" costs,[8] the capital cost savings benefit exceeded these identified costs by $183 million per year.[9]

C. <u>A robust analysis of economic transmission alternatives requires further evaluation of the transmission configuration identified in the NTTG Report</u>

The NTTG Report provides substantial evidence that a lower cost and reliable transmission alternative may exist. A robust analysis of an economic transmission alternative such as the one identified in the NTTG Report requires additional analysis to properly evaluate whether it might be a preferable alternative to some or part of the Gateway West and Gateway South transmission development proposals, and some of the critical issues that require further evaluation have been highlighted through NTTG stakeholder comments and NTTG's responses to those comments.[10] However, PacifiCorp has refused to run a single test case for the transmission configuration using its System Optimizer (SO) model in this 2019 IRP planning process. Similarly, PacifiCorp has not provided a publicly available transmission study or evaluation of economic alternatives during the past decade during which it has been developing the Energy Gateway transmission expansion projects. Given the magnitude of the potential savings for customers and PacifiCorp's inability to date to provide a robust analysis of transmission alternatives, UAE recommends that the

[7] Id, p. 102.
[8] Id, p. 103.
[9] $271 million per year in capital cost savings - $17 million congestion costs - $71 million "bottled energy" = $183 million per year of estimated savings. NTTG stakeholders including Utah Association of Energy Users, Utah Associated Municipal Power Systems, Deseret Power, Utah Office of Consumer Services, and the Utah Municipal Power Agency submitted comments contending that the $71 million estimate of "bottled energy" costs were significantly overstated. *See,* <u>Joint Parties' Comments on the 2018-2019 NTTG Revised Draft Final NTTG Regional Transmission Plan</u>, October 2, 2019.
[10] <u>NTTG 2018-2019 Revised Draft Final Regional Transmission Plan Stakeholder Comments and NTTG Response</u>, October 2, 2019.

Commission decline to acknowledge the portion of the IRP that includes or relies on the inclusion of Gateway South in the preferred portfolio.

D. The Extension of the PTC Affects the Timing and Potential Benefits of Gateway South

In addition to the fact that PacifiCorp has failed to adequately consider alternatives to Gateway South, PacifiCorp's inclusion of Gateway South in its preferred portfolio is based on an outdated assumption about the expiration of production tax credits ("PTCs"). The timing of the availability of PTCs in the IRP process was a key assumption in the selection of Gateway South as an IRP resource. In the initial IRP System Optimizer (SO) runs, the earliest available in-service date for Gateway South was at the end of 2024. In these runs the Gateway South transmission was not chosen as an economic resource until much later in the forecast period, if at all.

Subsequent to these initial SO runs, the IRP team was told to assume that the in-service date for Gateway South could be expedited to the end of 2023. At the time that PacifiCorp assumed that the construction of Gateway South could be expedited to be completed before the end of 2023, federal tax laws permitted wind projects could be eligible for some level of PTCs if they came online prior to the end of 2023. As a result of PacifiCorp's assumption that Gateway South could be completed in time to qualify interconnected wind projects to claim PTCs, the SO model selected Gateway South in most portfolios.

Given this sequence of events, the timing of PTC availability has an obvious effect on the timing of transmission resources such as Gateway South. As this Commission is likely aware, the Taxpayer Certainty and Disaster Tax Relief Act of 2019 (the "Act")[11] extended the PTC expiration

[11] A link to the text of the Act can be found here: https://www.congress.gov/bill/116th-congress/house-bill/3301/text.

date by one year, such that projects that begin construction in 2020 and come online prior to the end of 2024 remain eligible for 60% of the PTC.[12] Prior to passage of the Act, the PTC for wind facilities phased down to 40% for facilities for which construction began in 2019 and to 0% for facilities for which construction began in 2020. While this extension of the PTC was not known at the time PacifiCorp performed the later SO model runs that advanced the construction of Gateway South into 2023, the extension is a key development in IRP transmission planning.

This extension of the PTC to 2024 provides PacifiCorp additional time to more fully consider alternatives to Gateway South in the context of the 2021 IRP. UAE recommends that the Commission not acknowledge the selection of Gateway South in the 2019 IRP and that the Commission instead instruct PacifiCorp to move forward with 2021 IRP transmission planning with updated PTC assumptions.

II. THE 2019 IRP PLACES MUCH RELIANCE ON BATTERY ENERGY STORAGE SYSTEMS, ABOUT WHICH NOT ENOUGH IS KNOWN

PacifiCorp's proposal to advance the retirement of numerous coal generation resources and to integrate thousands of new megawatts of intermittent renewable resources during the planning period places great reliance on utility-scale battery energy storage systems ("BESS"), the capabilities and costs of which are not yet fully understood. While UAE acknowledges that BESS is, at least for now, the most likely technology to integrate intermittent renewable generation resources onto the PacifiCorp system while shifting away from a reliance on coal-fired resources, UAE nonetheless is concerned about the scale of PacifiCorp's proposed reliance on those BESS resources. The 2019 IRP Preferred Portfolio proposes to add 600 MW of battery storage capacity

[12] Interestingly, the Act did not extend PTC eligibility for projects that begin construction in 2019 and, as a result, a project that begins construction in 2019 and comes online prior to 2023 are eligible only for 40% PTCs.

(all located alongside new solar resources) by the end of 2023.[13] Over the 20-year planning horizon of the 2019 IRP, PacifiCorp proposes to add some 2,800 MW of battery storage capacity.[14] This is a significant amount of new battery storage for a utility that, as of the filing of the IRP, did not have any BESS resources operating on its system.[15]

PacifiCorp's battery storage plans are ambitious, and it is unclear exactly how the batteries will interact with the rest of the system or how much they will cost to operate. For example, PacifiCorp's PaR model, which it has used for numerous IRP cycles to optimize dispatch of generation resources, was unable to adequately optimize dispatch of BESS resources during IRP model runs.[16] To address this shortcoming in the PaR model and seek to integrate BESS technology into its IRP planning, PacifiCorp created a methodology to approximate an optimized system utilizing BESS that exists outside of the PaR model.[17] While PacifiCorp discussed this new methodology with stakeholders, the fact that it is necessary to work around the limitations of PacifiCorp's own IRP planning models to evaluate BESS demonstrates PacifiCorp's lack of familiarity with the technology and the uncertainty associated with integrating large volumes of BESS resources.

In addition to these modeling concerns, UAE also has concerns related to the costs of operating BESS projects. PacifiCorp acknowledges in its IRP filing that O&M costs for BESS are

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[13] *See* 2019 IRP Vol. 1 at 6-7.
[14] *Id*. at 7.
[15] *See* 2019 IRP Vol. 1 at 155 ("PacifiCorp has two BESS projects in development, one in Utah and one in Oregon."). UAE is informed that the storage project in Utah is now online and operating, but UAE could not corroborate this information prior to filing these comments.
[16] *See* 2019 IRP Vol. 1 at 194-95 ("[T]he PaR model experienced difficulty optimizing the dispatch for battery storage resources.").
[17] *Id*. ("To improve upon this shortcoming in the PaR model, PacifiCorp developed and tested a method to produce an optimized peak-shave/valley-fill profile for these resources outside of PaR that is based on load net of wind, solar, energy efficiency resources, and private generation resources in any given portfolio.").

"uncertain."[18] While PacifiCorp will gain some knowledge of the O&M costs to operate utility-scale battery storage projects with its battery storage projects in Utah and Oregon, those programs will be on a much smaller scale than is proposed in the IRP. For example, the Utah project is a combined solar and battery project, in which "[t]he total battery storage system will be approximately five (5) megawatt-hours, [and] the solar system size will be approximately 650 kilowatts."[19] The battery storage systems—and combined solar and battery storage systems—that are contemplated in the 2019 IRP are much larger and may represent much greater O&M costs than are currently contemplated.

This uncertainty regarding integration of BESS into the PacifiCorp system and its ongoing O&M costs—particularly given the volume of BESS resources to be added in the short term—represents a risk for PacifiCorp's customers, and calls into question the certainty with which PacifiCorp can claim that it (or this Commission) can fully analyze the "tradeoffs" between "reliability and dispatchability and the acquisition of lowest cost resources."[20]

Despite these risks and the concerns raised herein, UAE does not (at this point) recommend that the Commission decline to acknowledge the 2019 IRP because of the risks associated with PacifiCorp's proposal to deploy large volumes of BESS in its planning period. UAE does, however, request that the Commission require the Company to provide regular updates about the integration and operating costs of the battery storage systems as they become more well defined. Specifically UAE requests that the Commission order PacifiCorp to provide quarterly updates with

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[18] *See* 2019 IRP Vol. 1 at 155 ("Due to the complexity and maturity of the battery market, O&M costs continue to be an area of some uncertainty.").
[19] *Application to Implement Programs Authorized by the Sustainable Transportation and Energy Plan Act*, Docket No. 16-035-36, dated September 12, 2016.
[20] *See* Guideline 3.j. (requiring PacifiCorp to conduct "[a]n analysis of tradeoffs; for example, between such conditions of service as reliability and dispatchability and the acquisition of lowest cost resources.").

sufficient information to allow stakeholders to determine the accuracy of PacifiCorp's assumptions about the O&M costs of the battery storage systems in its preferred portfolio and to assess whether PacifiCorp's modeling workaround of the PaR model properly integrates and optimizes the dispatch of the battery storage systems, or if additional modeling work must be done.

III. PACIFICORP DID NOT IDENTIFY A MEANINGFUL BENCHMARK IN ITS 2019 IRP, MAKING IT DIFFICULT TO EVALUATE RESOURCES ON A CONSISTENT AND COMPARABLE BASIS

While PacifiCorp evaluated numerous potential portfolios against each other during its 2019 IRP stakeholder process, it never compared those potential portfolios against a *status quo* benchmark for existing operations and, therefore, failed to properly evaluate resources on a consistent and comparable basis. This Commission's IRP Guidelines require PacifiCorp to "evaluate[] all known resources on a consistent and comparable basis."[21] For the reasons set forth below, UAE is concerned that PacifiCorp's failure to use a *status quo* benchmark portfolio—and, instead, its use of a "benchmark" portfolio that purports to include some of the most expensive new resource additions identified in the preferred portfolio—fails to evaluate resources on a "consistent and comparable basis."

As part of its IRP, PacifiCorp must identify revenue requirement impacts of various portfolios,[22] which it develops by "comput[ing] the percentage change in nominal annual revenue requirement from top performing resource portfolios . . . relative to a benchmark portfolio selected during the final preferred portfolio screening process."[23] A true *status quo* benchmark—even if it

[21] Guideline 3.b. (requiring PacifiCorp to conduct "[a]n evaluation of all present and future resources, including future market opportunities (both demand-side and supply-side), on a consistent and comparable basis.").
[22] *See, e.g.*, Guideline 3.g. (requiring PacifiCorp to conduct "[a]n evaluation of the cost-effectiveness of the resource options from the perspectives of the utility and the different classes of ratepayers.").
[23] PacifiCorp 2019 IRP Vol. 1 at 195.

does not represent a viable portfolio—can provide a baseline for understanding the scope of modifications proposed in the portfolios evaluated throughout the IRP process, as well as the potential rate impacts of the preferred portfolio. Unfortunately, the benchmark that PacifiCorp utilized in the 2019 IRP was not a true *status quo* benchmark.

The *status quo* benchmark should be the preferred portfolio from the most recent acknowledged IRP.[24] In this case the *status quo* benchmark should have been the preferred portfolio from the 2017 IRP Update. While the Utah and Oregon Commissions declined to acknowledge all or portions of the 2017 IRP Update, both Commissions approved or acknowledged the EV 2020 resource additions that were the subject of the Commissions' acknowledgement decisions regarding the 2017 IRP Update. Thus, the *status quo* benchmark in this docket would have been the preferred portfolio from the 2017 IRP Update, which included the EV 2020 resources.

There are several differences between the "benchmark" used in the 2019 IRP and the 2017 IRP Update that are important to highlight. First, the 2019 IRP "benchmark," which PacifiCorp labeled as portfolio P-01,[25] incorporates assumptions about capital additions and retirement dates for Jim Bridger Units 1 and 2 that were discussed in the 2017 IRP process, but which not incorporated into the 2017 IRP Update preferred portfolio. For example, in the 2017 IRP Update, PacifiCorp selected a preferred portfolio that assumed the retirement of Jim Bridger Units 1 and 2 in 2028 and 2032, respectively. This assumption was compared to a scenario in which SCRs would be installed on Jim Bridger Units 1 and 2 in 2022 and 2021, respectively, and both units would be

[24] Updates to include regulatory and legal obligations might also be incorporated.
[25] *See* 2019 IRP Vol. 1 at Table 7.9 (p. 198); *id*. at Vol. 2 at 280-281.

retired in 2037. In its 2017 IRP Update, PacifiCorp determined that advancing the retirement dates for Jim Bridger Units 1 and 2, rather than installing SCRs and operating the units until 2037, would result in PVRR savings of $83 million when using the PaR model, and of $179 million when using the SO model.[26]

Despite the conclusions of the 2017 IRP Update, the 2019 IRP "benchmark" P-01 does not utilize the preferred portfolio from the 2017 IRP Update. Instead, P-01 assumes that SCRs would be installed on Jim Bridger Units 1 and 2 in 2022 and 2021, respectively, and both units would be retired in 2037. That is, the "benchmark" for the 2019 IRP incorporates the very same, more expensive, scenario that PacifiCorp rejected in developing its 2017 IRP Update preferred portfolio.[27]

While PacifiCorp's decision to utilize a benchmark scenario that it had previously rejected is curious, the other assumptions it included in its "benchmark" scenario in its 2019 IRP are, perhaps, more problematic. For example, P-01 assumes the addition of the Gateway South transmission project in 2024, along with various other transmission and generation projects—including more than 1900 MW of wind generation projects slated to interconnect to the Gateway South transmission project—that were not included in its 2017 IRP Preferred Portfolio.[28] Including these expensive and transformational resources in the benchmark portfolio prevents a fair or accurate comparison of the modifications that PacifiCorp is proposing to make to its system in its 2019 IRP preferred portfolio over what it proposed just two years ago, and prevents any meaningful analysis of the potential revenue requirement impacts of its 2019 IRP proposal.

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[26] *See* 2017 IRP Update at Table 6.3 (pp. 73-75). Both numbers use the Medium Gas and Medium CO_2 price policy scenarios.
[27] *See* 2019 IRP Vol. 2 at 280-281.
[28] *Id*.

UAE requests that the Commission decline to acknowledge the 2019 IRP unless and until PacifiCorp offers a comparison of the 2019 IRP Preferred Portfolio with the 2017 IRP Preferred Portfolio. This comparison should include the full comparative Cost and Risk Analysis as described in the 2019 IRP, Vol. 1, Chapter 7.

DATED this 4th day of February, 2020.

Respectfully submitted

By: ______________________________

Phillip J. Russell
HATCH, JAMES & DODGE, P.C.

Attorneys for UAE

Certificate of Service
Docket No. 19-035-02

I hereby certify that a true and correct copy of the foregoing was served by email this 4th day of February, 2020 on the following:

ROCKY MOUNTAIN POWER

Yvonne Hogle	yvonne.hogle@pacificorp.com
Jana Saba	jana.saba@pacificorp.com
	Datarequest@pacificorp.com
	irp@pacificorp.com

DIVISION OF PUBLIC UTILITIES

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

OFFICE OF CONSUMER SERVICES

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

UTAH CLEAN ENERGY

Hunter Holman	hunter@utahcleanenergy.org
Kate Bowman	kate@utahcleanenergy.org

STADION LLC

R. Bryce Dalley	rbd@fb.com
Richard Lorena	rlorenz@cablehuston.com
John Lucas	johnlucas@fb.com

INTERWEST ENERGY ALLIANCE

Lisa Tormoen Hickey	lisahickey@newlawgroup.com

WESTERN RESOURCE ADVOCATES	
Sophie Hayes	sophie.hayes@westernresources.org
Nancy Kelly	nkelly@westernresources.org
Steven S. Michel	smichel@westernresources.org

SIERRA CLUB	
Gloria Smith	gloria.smith@sierraclub.org
Julian Aris	julian.aris@sierraclub.org
Ana Boyd	ana.boyd@sierraclub.org

/s/ *Phillip J. Russell*

EXHIBIT A

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

1407 W. North Temple
Salt Lake City, UT 84116

December 4, 2019

Cheryl Murray
Office of Consumer Services
160 East 300 South
Salt Lake City, Utah 84111
cmuray@utah.gov (C)

RE: UT Docket No. 19-035-02
OCS 2nd Set Data Request (1-2)

Please find enclosed Rocky Mountain Power's Responses to OCS 2nd Set Data Requests 2.1-2.2. Also provided is Attachment OCS 2.1.

Sincerely,

___/s/___
Jana Saba
Manager, Regulation

Enclosures
C.c. DPU dpudatarequest@utah.gov (C)
Hunter Holman/UCE hunter@utahcleanenergy.org (C)

OCS Data Request 2.1

Case P-45CNW without Gateway South. Please run a case based on the parameters of P-45CNW but remove Gateway South as a resource selection. Please provide the resulting resource portfolio, stochastic mean PVRR (benefit)/cost and risk adjusted PVRR versus P-45CNW.

Response to OCS Data Request 2.1

Throughout the 2019 Integrated Resource Plan (IRP) modeling process, Energy Gateway Segment F (Gateway South or GWS) was endogenously selected by the System Optimizer model (SO model) in nearly every resource portfolio. In the preferred portfolio, the year-end 2023 in-service date enables 1,920 megawatts (MW) of new wind capable of qualifying for 40 percent of the full value of production tax credits (PTC) before they expire. The persistence of the SO model selection of GWS in nearly every portfolio obviated the need for a counterfactual case that eliminates GWS from the preferred portfolio. Nonetheless, PacifiCorp recognizes there is broad stakeholder interest in understanding how the preferred portfolio and system costs might be impacted if GWS is assumed to be removed from the preferred portfolio. Consequently, in response to this data request, PacifiCorp has produced a range of cases to evaluate portfolio and system cost impacts when GWS is removed as a resource option.

<u>Case 1 (Counterfactual with Third-Party Firm Transmission):</u>
The first counterfactual case eliminates GWS as a resource option. However, even if GWS is not constructed, it is unrealistic to assume that PacifiCorp transmission would not be obligated to construct *any* transmission system upgrades out of eastern Wyoming to accommodate Federal Energy Regulatory Commission (FERC) jurisdictional requests for open access transmission tariff (OATT) interconnection service and transmission service. Indeed, both PacifiCorp's interconnection queue and its separate transmission service queue currently contain requests for service that are contingent upon GWS being constructed. Even conservatively examining only the transmission service (not interconnection service) queue, only third-party requests for service out of eastern Wyoming, and assuming no additional third-party request for transmission service will be submitted, PacifiCorp transmission would need to identify a non-GWS alternative to granting a request for 500 MW of FERC-jurisdictional OATT firm point-to-point (PTP) transmission service. Based on preliminary, high-level estimates only, granting that PTP request without GWS would trigger the need for a 230 kilovolt (kV) transmission line by the end of 2023, at a minimum. Therefore, this counterfactual case includes the cost of a 230 kV transmission line at the end of 2023, net of incremental wheeling revenue.

PacifiCorp has conservatively been assuming that 12 percent of system transmission costs are recovered by third-party transmission customers. A review of PacifiCorp's transmission usage relative to the usage of third-party transmission customers since 2012 shows that third-party usage has been increasing each year. In 2018, third-party usage was nearly 19 percent of the total. The table below shows the present value revenue requirement differential (PVRR(d)) for the counterfactual case, inclusive of the estimated transmission upgrades to accommodate the queued 500 MW PTP request. Results are shown assuming 12 percent and 19 percent of system transmission costs are recovered by third-party customers. Please refer to Attachment OCS 2.1 for the counterfactual resource portfolio.

Study	Stochastic Mean ($m)			Risk Adjusted ($m)		
	Pref. Port. PVRR	Case 1 (No GWS) PVRR	(Benefit)/ Cost of GWS PVRR(d)	Pref. Port. PVRR	Case 1 (No GWS) PVRR	(Benefit)/ Cost of GWS PVRR(d)
12% Third-Party Revenue	$23,207	$23,474	($267)	$24,376	$24,657	($282)
19% Third-Party Revenue	$23,018	$23,369	($350)	$24,178	$24,548	($371)

<u>Case 2 (No New Natural Gas Resources):</u>
The counterfactual case described above accelerates the addition of new natural gas-fired capacity. Considering the risk that future policy developments such as a price on carbon emissions may increase the costs of operating these resources in the future, PacifiCorp developed an additional counterfactual case that assumes no new natural gas-fired resources can be added to the portfolio. As described above, this case also includes estimated transmission service request (TSR)-driven costs associated with a queued 500 MW request for firm PTP transmission service. This counterfactual is compared to Case P-29, which includes GWS but similarly eliminates new natural gas-fired capacity as a resource option. The table below shows the PVRR(d) for the second counterfactual case relative to Case P-29. Results are shown assuming 12 percent and 19 percent of system transmission costs are recovered by third-party customers. Please refer to Attachment OCS 2.1 for the counterfactual resource portfolio.

Study	Stochastic Mean ($m)			Risk Adjusted ($m)		
	P-29 PVRR	Case 2 (No GWS) PVRR	(Benefit)/ Cost of GWS PVRR(d)	P-29 PVRR	Case 2 (No GWS) PVRR	(Benefit)/ Cost of GWS PVRR(d)
12% Third-Party Revenue	$23,328	$24,077	($750)	$24,503	$25,293	($791)
19% Third-Party Revenue	$23,145	$23,958	($813)	$24,311	$25,170	($859)

<u>Case 3 (Alternative Renewables):</u>
Considering that the level of renewable energy is reduced in the first counterfactual case and considering strong customer interest in ensuring more renewable resources are added to the system, PacifiCorp also conducted a counterfactual case that includes renewable energy at levels that are similar to those in the preferred portfolio. Note: PacifiCorp was unable to include renewable energy levels that match the preferred portfolio, because without GWS, there are insufficient transmission upgrades available across the system to achieve a comparable level of renewable resources as the 2019 IRP Preferred Portfolio.

Consequently, this counterfactual case includes renewable resources that represent just 74 percent of the renewable nameplate capacity and just 77 percent of the renewable energy in the preferred portfolio. As described above, this case also includes estimated TSR-driven costs associated with a queued 500 MW request for firm PTP transmission service. The table below shows the PVRR(d) for the third counterfactual case relative to the preferred portfolio. Results are shown assuming 12 percent and 19 percent of system transmission costs are recovered by third-party customers. Please refer to Attachment OCS 2.1 for the counterfactual resource portfolio.

Study	Stochastic Mean ($m)			Risk Adjusted ($m)		
	P-29 PVRR	**Case 2 (No GWS) PVRR**	**(Benefit)/ Cost of GWS PVRR(d)**	**P-29 PVRR**	**Case 2 (No GWS) PVRR**	**(Benefit)/ Cost of GWS PVRR(d)**
12% Third-Party Revenue	$23,207	$24,186	($979)	$24,376	$25,403	($1,027)
19% Third-Party Revenue	$23,018	$24,057	($1,038)	$24,178	$25,269	($1,092)

Conclusions:

The results above show that quantified benefits from GWS and associated new wind range between $267 million and $1.09 billion. These benefits are conservative as they do not include the non-quantified benefits associated with the new transmission line, which include (also listed at page 75, Volume I of the 2019 IRP):

- Adding a parallel path to the Gateway West Sub-Segment D.2 project (Aeolus-to-Bridger/Anticline), which will improve the reliability of the 230 kV system in Wyoming for the loss of either 500 kV line.

- Strengthens the PacifiCorp transmission system (increased fault duty) by interconnecting the geographically drivers areas of eastern Wyoming and southern Utah together, allowing additional generation resources to be connected.

- Improves grid reliability by providing better operational control of the backbone transmission system by interconnecting two areas of the PacifiCorp transmission system that are abundant in two different forms of renewable resources, specifically wind rich eastern Wyoming with the solar rich areas of southern Utah.

- Provides anticipated improvements in eastern Utah reliability by providing a potential future high voltage source and power delivery option to meet the projected oil expansion and corresponding load growth (Ashley, Vernal).

- Improves the southern Utah transmission system reliability by providing congestion relief on the 345 kV lines during outage conditions.

- Supports PacifiCorp's North American Electric Reliability Corporation's (NERC) TPL-001-4 transmission system reliability efforts, which are necessary to improve grid reliability performance.

- Assists PacifiCorp in meeting its OATT obligations to identify and construct the transmission system upgrades necessary to accommodate FERC-jurisdictional requests for interconnection service and transmission service.

19-035-02 / Rocky Mountain Power
December 4, 2019
OCS Data Request 2.2

OCS Data Request 2.2

Case P-45CNW without Gateway South but allowing selection of additional 345 kV lines as outlined in the August 2019 NTTG Economic Study Request (ESR) report. Please run a case based on the parameters of P-45CNW but remove Gateway South as a resource selection and add the transmission facilities from the referenced NTTG report as potential resources. Assume these additional transmission resources would have the same in-service date as assumed for Gateway South. From the NTTG ESR report, these resources are:

(1) Two 345 kV circuits between Aeolus and Anticline (154 Miles) [or an alternate could be using the Gateway West line at 500 kV already under construction and add second 345 kV],

(2) A single 345 kV circuit from Anticline to Bridger,

(3) Two series compensated 345 kV circuits between Anticline and Populus (203 Miles),

(4) A single series compensated 345 kV circuit between Populus and Midpoint (153 Miles),

(5) A single series compensated 345 kV circuit between Midpoint and Hemingway (130 miles),

(6) With two Hemingway 345/500 kV transformers (700 MVA each).

(7) Line shunt reactors to balance 90% the line charging of each circuit and bus shunt reactors for the remaining 10%.

A link to the NTTG ESR report is here:
https://www.nttg.biz/site/index.php?option=com_docman&view=download&alias=3243-nttg-2019-economic-study-request-report-draft-08-27-2019&category_slug=2019-esr-study-report-development&Itemid=31

For convenience, a copy of the report is also attached.

Please provide the resulting resource portfolio, stochastic mean PVRR (benefit)/cost and risk adjusted PVRR versus P-45CNW.

Response to OCS Data Request 2.2

Based on the conclusion in the Northern Tier Transmission Group (NTTG) economic study report that determined the proposed solution was not a better solution for the region due to added congestion, project timing and other issues, PacifiCorp does not believe the requested case is feasible, and consequently, the company has not produced the requested analysis. For a full read of the results from the NTTG economic study and stakeholder comments, please refer to NTTG's website at the following link:

https://nttg.biz/site/index.php?option=com_docman&view=list&slug=nttg-committees&Itemid=31