BEFORE THE PUBLIC SERVICE COMMISSION OF WYOMING

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR A MODIFICATION OF AVOIDED COST METHODOLOGY AND REDUCED TERM OF PURPA POWER PURCHASE AGREEMENTS	))))))	DOCKET NO. 20000-545-ET-18 RECORD NO. 15133

REC Exhibit 600
RMCRE Exhibit 700

Direct Testimony of Dr. Marc Hellman and Dr. Lance Kaufman

NON-CONFIDENTIAL PUBLIC VERSION

On Behalf of

Renewable Energy Coalition &
Rocky Mountain Coalition for Renewable Energy

April 19, 2019

I. INTRODUCTION AND SUMMARY

Q. Please state your names and business addresses.

A. My name is Dr. Marc Hellman. My business address is 2760 Eagle Eye Ave NW, Salem, Oregon.

A. My name is Dr. Lance Kaufman. My business address is 2623 NW Bluebell Place, Corvallis, Oregon.

Q. Dr. Hellman, please describe your education, background and experience.

A. My education, background and experience is provided in the Qualification Statement attached hereto as REC-RMCRE/Q1.

Q. Dr. Kaufman, please describe your education, background and experience.

A. My education, background and experience is provided in the Qualification Statement attached hereto as REC-RMCRE/Q2.

Q. On whose behalf are you testifying?

A. We are testifying on behalf of the Renewable Energy Coalition ("REC") and the Rocky Mountain Coalition for Renewable Energy ("RMCRE").

REC was established in 2009, and is comprised of nearly forty members who own and operate, or are in the process of developing, small renewable energy generation qualifying facilities ("QFs") in Oregon, Idaho, Montana, Washington, Utah, and Wyoming. Several types of entities are members of the Coalition, including irrigation districts, waste management districts, water districts, electric cooperatives, corporations, and individuals. Most projects are small hydroelectric projects, but the membership also includes biomass, geothermal, solid waste, and solar projects.

RMCRE is an unincorporated, informal coalition formed for the purpose of opposing the efforts of Rocky Mountain Power ("RMP") in Wyoming to limit the maximum term of QF power purchase agreements ("PPAs") to seven (7) years and to modify the Partial Displacement Differential Revenue Requirement ("PDDRR") methodology that the Company uses to set avoided costs, as well as other proposals set forth in RMP's application in this docket. Current RMCRE supporters include owners and developers of renewable energy projects in the Western United States and elsewhere, including developed projects in Wyoming. These supporters include Sustainable Power Group ("sPower"), VK Clean Energy Partners, LLP ("VK Clean Energy"), and Chevron Power and Energy Management Company ("Chevron").

Q. How is your testimony organized?

A. Our testimony is organized into the following sections:

Q. Please summarize RMP's proposed changes.

A. In its Application, Rocky Mountain Power ("RMP") proposes the following changes to QF contracts pursuant to the Public Utility Regulatory Policies Act of 1978 ("PURPA") contracts, Schedule 37, and Schedule 38:

1. Set the maximum qualifying facility ("QF") power purchase agreement ("PPA") term length to 7 years.[1]
2. Modify the Partial Displacement Differential 23 Revenue Requirement ("PDDRR") methodology currently used for Schedule 38 to reflect "same type" displacement.[2]
3. Modify the method used to calculate Schedule 37 to mirror the PDDRR methodology proposed for Schedule 38.
4. Change the On-Peak and Off-Peak definitions of Schedule 37.
5. Differentiate a pro-forma PPA from a PPA negotiation for Schedule 37.[3]

[1] See Direct Testimony of Mark P. Tourangeau, page 1, lines 15 through 17.
[2] See Direct Testimony of Daniel J. MacNeil, page 7, lines 11 to 21.
[3] See Direct Testimony of Mark P. Tourangeau, page 2, line 20 through page 3 line 1.

6. Modify Schedule 38 to allow RMP to update pricing any time prior to RMP executing and filing a PPA with the Commission.[4]
7. Limit the time between the Commercial Operation Date and execution of a PPA to 30 months.[5]
8. Require that QFs provide project development security within 30 days of the PPA being filed with the Commission.[6]
9. Modify the treatment of Schedule 37 rates after 10 megawatts ("MW") of Firm Power have been acquired under Schedule 37.[7]
10. Modify Schedule 37 negotiation process to mirror Schedule 38 negotiation process.[8]

Q. What are the interests of the parties you are representing?

A. The interests of the parties in this docket are to ensure that QF rates offered by RMP are fair and reasonable in that the rates reflect the costs RMP customers would avoid but for the purchase of QF power. If avoided costs are set too low, as is the case with RMP's filing, then development of cost-effective QF projects will be impeded and RMP's rates to its retail customers will be higher than otherwise necessary.

RMP appears to treat PURPA and design the PDDRR to be constrained to match or be compliant with the specific resources that RMP is planning to acquire in its

[4] See Direct Testimony of Mark P. Tourangeau, page 3, lines 1 and 2.
[5] See Direct Testimony of Mark P. Tourangeau, page 3, lines 3 through 5.
[6] See Direct Testimony of Mark P. Tourangeau, page 3, lines 5 through 7.
[7] See Direct Testimony of Mark P. Tourangeau, page 3, lines 8 through 13.
[8] See Direct Testimony of Mark P. Tourangeau, page 3, lines 13 through 15.

Integrated Resource Plan (“IRP”). Such a constraint leads to the like-for-like treatment of renewable resources. RMP is proposing that, if a QF developer is proposing a renewable resource different than the selected IRP renewable resource, then the QF developer’s project is not eligible for capacity payments associated with the IRP resource. But that is not consistent with PURPA. PURPA requires QFs to be offered prices equal to the *costs* that would be avoided but for the purchase of QF power. This concept is discussed in more detail below. We do not view PURPA as a contingent price offering, namely that QF developers are paid only in circumstances where the QF supplies the type of resource that the utility would otherwise build.

Q. Please summarize your recommendations?

A. Our recommendations are as follows:

1. Deferral of Front Office Transactions (“FOT”) should be priced using monthly capital cost of a simple cycle combustion turbine (“SCCT”). Months of deferred FOTs should include all months with loss of load probability absent FOTs.
2. Generation resource deferral should allow for deferral across resource types. In years where no renewable resource deferral is included in QF rates, green tags should remain with the QF.
3. For determining levels of RMP need for capacity and amounts met by QFs that have executed contracts but not yet operating, RMP should only assume 75 percent of executed QFs will operate.
4. The 20-year contract term should be retained.

5. For Schedule 37: If the Commission is inclined to have Schedule 37 Customers over 100 kW revert to Schedule 38 when a threshold of new QFs MW amount is reached, the RMP recommended 10 MW threshold should be revised to 100 MW.
6. The RMP proposed tariff language on Page 37-3 should be revised to read "After the Company acquires those 10 megawatts of system resources and files for updated Schedule 37 rates, ... until the Commission takes final action on any Company filing to revise Schedule 37 pricing."
7. RMP recommended changes to the definition of peak/off peak and seasons should not be adopted.
   a. If the Commission is inclined to address this issue it should be addressed in a separate proceeding
8. The GRID model used in PDDRR should be modified to:
   a. Remove the Foote Creek replacement project from both base and avoided cost GRID runs
   b. Allow coal units to cycle
   c. Escalate coal prices consistent with historic increases
   d. Allow sales to entities in Wyoming and east of Wyoming

Q. Before going further, if you do not address a change that RMP proposes in this docket, does that mean you support the RMP proposal?

A. No. Lack of discussion on any of RMP's proposed changes does not signify support for the proposal.

Q. What standard does this Commission use to evaluate PURPA issues?

A. This Commission considered issues similar to the ones raised in this docket in Docket No. 20000-481-EA-15. In its Order concluding that Docket, this Commission found:

1. "(QF) rates must be just and reasonable to consumers and in the public interest, but must not discriminate against QFs."[9]
2. "QF rates are set at a utility' s 'full avoided cost.' ... In other words, a utility must purchase energy and capacity from QFs at the same price it would have to pay if it otherwise purchased or generated the energy or capacity on its own."[10]
3. The Commission must exercise its discretion to establish QF contract terms that "advances the policy interests and goals underlying PURPA of encouraging development, while not discriminating against QFs in Wyoming, and without unduly burdening Wyoming ratepayers with excessive price risk."[11]
4. RMP has the "burden to show that the solutions proposed in its application ... will reasonably address the system-wide problems it alleges give rise to the application."[12]

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[9] *In the Matter of the Application of Rocky Mountain Power for Modification of Contract Term of PURPA Power Purchase Agreements with Qualifying Facilities*, Docket No. 20000-481-EA-15 (Record No. 14220), June 23, 2016 Memorandum Opinion, Findings of Fact, Decision and Order ("2015 Wyoming PSC QF Docket Order") at ¶ 93.
[10] *Id*.
[11] *Id*. ¶ 95.
[12] *Id*. ¶ 96.

Q. How does the standard applied by RMP in this application differ from that set out by the Commission in Docket No. 20000-481-EA-15?

A. The Commission’s stated standard correctly articulates a balanced consideration of the interests of ratepayers, QFs, and PURPA objectives. While RMP repeatedly cites the “customer indifference standard,” its proposals in this docket would drive the price of power purchased from a QF project well below RMP’s actual avoided costs. RMP’s justifications for its proposed changes are one-sided, in that they focus on downside risks and costs to ratepayers without addressing upside risks or benefits and without addressing the impact of the proposed changes to PURPA goals.

This testimony identifies numerous RMP proposals that contain this one-sided approach. As an example, RMP’s proposes that any QF project may only receive a capacity payment if it displaces a project of the same generation type in the IRP preferred portfolio (i.e., wind-for-wind, or tracking solar for tracking solar, etc.) (the “like-for-like” proposal). This like-for-like proposal leads to the incorrect result that a baseload renewable resource defers no new resources over the next 20 years. However, RMP is planning to add generation resources to meet capacity needs in 2030, and a baseload QF PPA will in fact defer these planned additions. This is a simple fact of the need-based nature of IRP modeling.

By offering no capacity value for baseload QF PPAs, RMP is undervaluing the avoided cost of the QF, and providing rates that are lower than those that would satisfy the customer indifference principle. These lower prices will discourage QF development contrary to the objectives of PURPA. The Commission's PURPA objectives and standards are not being met because QF rates are below RMP's avoided costs, discouraging the development of cost effective QFs for Wyoming ratepayers.

Q. How is RMP's one-sided approach consistent with RMP's incentives?

A. RMP's primary source of net income is the equity component of its return on rate-base. Resources deferred by QFs have a direct impact on RMP's future income potential. RMP is, therefore, economically motivated to limit or eliminate QF development.

As just one example, RMP's recently received approval to invest in 1,150 MW of new wind generation in Wyoming, which will increase RMP's rate-base by $3.1 billion.[13] This equates to $149 million of after-tax profit in the first year of service and $2.3 billion dollars of profit over the life of the project.[14] QFs displace RMP's profit because QFs displace rate-based generation. RMP can reduce QF displacement by making QFs more difficult to develop. Therefore, RMP has an incentive to make the PPA terms available to QFs less generous than those that would result from a fair and unbiased approach.

Q. The RMP testimony discusses risk. How should risk be evaluated in the context of this case?

A. RMP's testimony discusses risk incorrectly. Risk is simply another word for uncertainty. An uncertain positive event is as risky as an uncertain negative event. The main relevance of risk in the context of this docket is the effect of risk on RMP customers. RMP customers experience more risk if there is more variation in future revenue requirements.

[13] http://www.pacificorp.com/es/energy-vision-2020.html
[14] Assuming RMP's 2018 authorized rate of return, 50/50 capital structure, and a 30-year life.

For example, Table 1 presents potential outcomes under a high-risk utility plan and a low risk utility plan. The high-risk plan (i.e. utility ownership and short-term purchases) is highly sensitive to energy prices. The low risk plan relies on long term market purchase and is less sensitive to energy prices. The long-term market purchases have low risk, because the cost to consumers is less variable, or has lower "Variance".

Table 1: Low Risk Plan has Smaller Variance

	$/MWh	
	High risk	Low Risk
Low energy prices	$20	$25
High energy prices	$40	$35
Expected Price	$30	$30
Statistical Varience	100	25

In general, consumers are risk averse, or prefer outcomes with less variation over outcomes with more variation.[15] This means that ratepayers prefer a long-term purchase plan over a short-term purchase plan because, as illustrated in Table 1, a long-term purchase plan produces an outcome with less variation. Long-term QF PPAs are generally less risky than either short-term market purchases or utility-owned generation. With short-term market purchases ratepayers are exposed to volatile market prices. With utility-owned generation, ratepayers are exposed generation risk, capital cost risk, maintenance cost risk, and operating cost risk, all of which affect the $/MWh paid by ratepayers. With long-term QF PPAs, ratepayers pay according to a fixed price schedule, have no variation in the $/MWh paid, and thus have no price variation risk. The primary source of risk from QF PPAs arises when the term of the PPA differs from the life of a

[15] This is in accordance with a standard economic theory, Expected Utility Theory.

utility-owned asset. A secondary risk is the focus of RMP's discussion regarding must-take power purchases when QF output is variable. However, even this risk is overstated as discussed later in this testimony.

Q. Given that QF PPAs reduce risk, and that ratepayers prefer less risky options, how can ratepayers be made indifferent to QFs?

A. Ratepayers can be made indifferent to risk by either reducing the cost of the riskier options or increasing the cost of the less riskier option. This difference in cost is referred to as the "risk premium" and is readily apparent in competitive markets, such as financial markets where riskier investments have lower prices and higher potential returns, or insurance markets where insurance premiums exceed the expected insurance payouts.

Q. Do you propose to add a risk premium to the rates paid to QFs such that the avoided cost payments are higher?

A. No, but it is worth keeping in mind that if avoided costs are accurately estimated, and if the PPA QF term is sufficiently long, ratepayers will prefer QF PPAs to other resource options because ratepayers avoid price risk and the utility risks identified above.

Q. Are QF rates currently calculated accurately by RMP?

A. No, under the current methodology QF rates are not calculated accurately. This is highlighted by the fact that, under the current method, QFs receive no capacity payment during years in which RMP plans to add capacity resources. Our testimony will show that QF rates should include a capacity component in all years, regardless of RMP's next capacity addition. In section VI we recommend that QFs be recognized as deferring any type of IRP capacity resource. In section V we recommend that deferred front office transactions, which RMP provides a de minimis value, should be priced based on the monthly fixed cost of RMP's least expensive IRP capacity resource. At a minimum, this approach should be applied to Schedule 37. For Schedule 38, capacity payments should apply over much of the contract term.

II. RMP's PROPOSAL DISCOURAGES DEVELOPMENT OF QFs

Q. Please discuss RMP's proposal regarding the dramatic reductions in payments to QF developers.

A. This Commission has previously found that it must advance "the policy interests and goals underlying PURPA of encouraging development, while not discriminating against QFs in Wyoming, and without unduly burdening Wyoming ratepayers with excessive price risk."[16] RMP's proposal in this docket would result in dramatic reductions in payments for MWh produced by QF projects. Table 2, below, illustrates the large reduction in prices that would be offered to QFs if this Commission were to adopt all of RMP's proposals in this docket.

[16] 2015 Wyoming PSC QF Docket Order, ¶ 95.

Table 2: RMP Proposes Large Reduction In QF Rates

	Current Method	New Method	Percentage Reduction
Baseload	31.01	17.61	-43.21%
Wind	27.18	9.44	-65.27%
Tracking Solar	24.49	15.25	-37.73%

This substantial reduction in avoided cost prices will discourage the development of independent power production in Wyoming. As a consequence, it will reduce the competitive pressure on RMP to maintain efficient operations and will cause RMP customers to lose the economic opportunities afforded by Wyoming QF development.

The RMP methodology and recommendations such as the seven-year contract term appears designed to significantly reduce the avoided-cost prices offered to QFs. The seven-year term length coincides with RMP's forecasted period of resource sufficiency, effectively eliminating all capacity costs from the calculation of QF prices. This "like-for-like" capacity deferral proposal compartmentalizes resources to such a degree that even baseload resources are assumed to have no capacity value during periods of resource deficiency when RMP lacks sufficient generation resources to meet its load requirements.

Even the energy-cost payments are artificially and incorrectly reduced. The redefinition of peak period results in a five percent reduction in expected payments, despite RMP's false claim that the change in definitions is revenue neutral. All of these changes reduce the payments made to QFs. RMP makes these changes without providing any factual evidence that the changes will allow an environment that continues to appropriately encourage the development of Wyoming QFs.

Q. How does a reduction in avoided-cost rates impact the development of QFs in Wyoming?

A. All else equal, a reduction in avoided-cost rates would lower the QF developer's internal rate of return. This makes the project appear riskier from the perspective of lenders, and less valuable to equity investors. This will make the project more difficult to finance and less likely to be completed.

Q. How does a reduction in contract term impact the development of QFs in Wyoming?

A. As discussed later in this testimony, the reduction in contract term makes it less likely that the QF will receive avoided capacity costs. This lowers the internal rate of return for the project. In addition, the reduction in the term makes project revenues after the term expires less certain, increasing the project risk to investors and making it harder to finance. Both factors make a project less likely to be completed.

III. QF PPAS EXPOSE CUSTOMERS TO LESS RISK THAN ALTERNATIVES

Q. How does RMP's relate the risk of QFs to non-QF resources?

A. RMP focuses on three differences between QF and non-QF resources:

1. QFs do not go through the same planning process as IRP resources.[17]

[17] Direct Testimony of Mark P. Tourangeau at page 4 lines 14-16.

2. QFs do not go through a competitive process.[18]
3. QFs are not economically dispatched.[19]

Q. Are these concerns actually risks?

A. No, from a ratepayer standpoint these are not risks. QFs are priced consistent with the IRP least-cost least-risk plan, so the impact on ratepayers is consistent with the least-cost resource. QF avoided capacity costs are informed by RMP's competitive bidding process. The GRID modeling used to price QFs accounts for the fact that QFs are not dispatched economically, and the QF energy is priced accordingly. All three of the risk concerns raised by RMP are moot.

Q. Will a shorter contract term affect any of RMP's observations about risk?

A. No, even under a seven-year contract the three QF characteristics identified by RMP will persist.

Q. How does the risk of QF PPAs compare to the risk of market purchases?

A. When evaluating risk from a traditional economic and financial perspective, QF PPAs are less risky for customers than market purchases. Again, we are focusing on the risk that relates to the variation in expected outcomes (i.e., $/kWh) for customers. Risk is reduced by reducing the variation in expected $/kWh. QF PPAs are fixed price contracts and tend to reduce variation in $/kWh, while market purchases tend to increase risk.

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[18] Direct Testimony of Mark P. Tourangeau at page 4 lines 18-20.
[19] Direct Testimony of Mark P. Tourangeau at page 4 lines 21-23.

Q. Why do QF PPAs reduce variation in $/kWh?

A. QF PPAs reduce variation in $/kWh because they are fixed-price power-purchase agreements. This means that for the term of the PPA, RMP will pay a known price regardless of how markets change. RMP models avoided costs for a QF PPA based on the best-known forecast of future energy prices. RMP's ratepayers then pay that avoided-cost price whether actual prices end up higher or lower than that forecast. If actual prices end up higher than was predicted in setting the avoided cost for that QF PPA, RMP ratepayers save money. If actual prices end up lower than forecast, RMP ratepayers end up paying more money. By fixing prices with a PPA, RMP ratepayers experience less variation in prices, and thus experience less risk.

Q. Can you illustrate this using the GRID model?

A. To illustrate this, we performed four runs using RMP's Generation and Regulation Initiative Decision Tools ("GRID") model. We performed four total GRID runs—two runs at low fuel-price scenarios and two at high fuel-price scenarios. We ran each scenario with and without a 50 MW QF PPA. The results are provided in REC Exhibit 600.1/RMCRE Exhibit 700.1, attached hereto. The variance in cost across fuel prices and within years is provided in Table 3. The variance in cost was lower with the QF than without the QF in seven of eight years. This shows QFs reduces fuel price risk for RMP customers.

Table 3: QF PPAs Have Lower Cost Variance from Fuel Price Changes

	Variance		Lower
	Without QF	With QF	Variance
2029	0.062	0.061	With QF
2030	0.103	0.102	With QF
2031	0.158	0.157	With QF
2032	0.238	0.237	With QF
2033	0.220	0.221	Without QF
2034	0.315	0.313	With QF
2035	0.438	0.435	With QF
2036	0.625	0.621	With QF

Q. How does the risk of a QF PPA compare to the risk of a utility-owned generation resource?

A. QF PPAs are less risky than utility resource ownership. This is because utility resource ownership still results in significant variation in $/kWh, while QF PPAs provide a known and fixed $/kWh.

Q. Why does utility resource ownership result in uncertain $/kWh?

A. Like QF PPAs, utility ownership reduces the sensitivity of rates to electric market prices. However, the regulatory mechanisms through which utility-owned resource costs are recovered result in highly variable $/kWh. Some of the factors that contribute to this are:

- Actual capital cost;
- Actual operation and maintenance;
- Fuel prices;
- Future environmental requirements;
- Legal liability;
- Plant efficiency;

- Annual variation in weather;
- Early retirement.

Q. How does actual capital cost contribute to risk?

A. Actual capital cost contributes to risk because capital costs vary in two ways. First the cost of capital changes as the authorized return on equity changes due to interest rate fluctuations and general investor interests in utility stock ownership. Second, capital costs vary as refurbishments are required on the generation plant to maintain operations.

Q. How does actual operation and maintenance expense contribute to risk?

A. Actual operation and maintenance expense contribute to risk as these costs change over time. Operation and maintenance costs will change as labor costs change and the prices for inputs to operate the plant change.

Q. How do fuel prices contribute to risk?

A. Fuel prices can vary widely due to the market for fuel, transportation of fuel costs change, or the costs of utility-owned fuel change due to effort required to gather the fuel changes.

Q. How do future environmental requirements contribute to risk?

A. The costs change as government regulations require new investments to meet environmental emission standards or change the operation of the plant to limit power production and resulting emitting of pollutants. The costs of the investments such as scrubbers can be monetarily significant.

Q. How does legal liability contribute to risk?

A. Legal liability can contribute to risk as legal challenges are raised in the siting and building of utility generation or operation of resources.

Q. How does variation in plant efficiency affect rates?

A. For facilities with low operating costs, such as wind and solar, there is an inverse relationship between efficiency and $/kWh. To see this, consider two plants Solar Stud IV and Solar Dud XI. These hypothetical facilities have the same annual levelized capacity cost ($1 million) and same capacity (10 MW) but different capacity factors (0.25 vs. 0.30). Table 4 on the following page shows the cost per kWh for these two plants. As the table demonstrates, the plant with the lower capacity factor is less efficient and, therefore, more expensive.

Table 4: Cost Per MWh For Rate-based Resource Depends on Generation

		Solar Stud IV	Solar Dud XI
(a)	Capacity	10	10
(b)	Capacity Factor	0.35	0.3
(c) = (a) * (b) * 24 * 365	Annual Energy (MWh)	30660	26280
(d)	Levelized Annual Cost	$1,000,000	$1,000,000
(e) = (d) / (c)	Cost per MWh	$32.62	$38.05

RMP's owned wind plants tend to be less efficient than planned. Table 5 shows expected capacity factor and actual capacity factor for several RMP wind facilities. There is significant variation in this, however. Sometimes RMP plants are as efficient as planned. This variation in performance translates into variation in rates, and increased customer risk.

Table 5: Actual Generation Differs from Expected Generation[20]

Project Name	Expected P50 Net Capacity Factor (NCF) at Time of Decision*	Actual Net Capacity Factor (NCF) Since Inception	Expected NCF less Actual NCF
Dunlap I	36.4%	40.0%	-3.6%
Glenrock I	38.6%	34.9%	3.7%
Glenrock III	31.0%	33.0%	-2.0%
Goodnoe Hills	32.4%	27.0%	5.4%
High Plains	35.7%	34.9%	0.8%
Marengo I	32.0%	28.7%	3.3%
Marengo II	30.5%	26.9%	3.6%
Mcfadden Ridge I	34.5%	37.0%	-2.5%
Rolling Hills	31.0%	31.5%	-0.5%
Seven Mile Hill I	41.3%	38.7%	2.6%
Seven Mile Hill II	39.3%	41.7%	-2.4%
Average	**34.8%**	**34.0%**	**0.8%**

Q. How does annual variation in weather affect customer risk?

A. Continuing the rational from the efficiency example, if the energy output for a single plant varies from year to year, the cost per kWh for that plant will also vary from year to year. Table 6 illustrates annual generation for an actual wind farm and compares how rates vary under utility ownership and QF PPA.

[20] *See* REC Exhibit 600.2/RMCRE Exhibit 700.2 (RMP Response to RMCRE 3.1 and Attach RMCRE 3.1-1).

Table 6: Annual Generation Varies by Year

	Name Plate	Annual Capacity Factor			
	Capacity (MW)	**2014**	**2015**	**2016**	**2017**
Foote Creek I	41.1	31%	29%	38%	35%
Glenrock	138	34%	33%	36%	30%
Goodnoe Hills	94	26%	23%	27%	23%
Leaning Juniper	100.5	24%	21%	23%	18%
Marengo Wind Plant	210.6	29%	24%	29%	25%
McFadden Ridge	28.5	39%	31%	38%	34%
Rolling Hills	99	31%	30%	33%	27%
Seven Mile Hill	118.5	39%	35%	40%	39%

Q. How does early retirement contribute to risk?

A. RMP has committed to early retirement of major components of nearly all wind resources as part EV 2020 wind repowering. This early retirement will reduce the expected lifetime generation of the components by 66 percent; however, ratepayers are still expected to pay the full original cost of these components. RMP is also contemplating early retirement of many coal units. Had these resources been operating under a PPA ratepayers would not be exposed to these cost escalations.

Q. For all the examples above, how do the variations for QF owners affect RMP rates?

A. QF owners bear all the risk associated with these variations. Because RMP pays fixed price contracts, none of this risk is passed on to ratepayers.

Q. How does a shorter QF contract term limit impact QF PPA risk?

A. A shorter QF contract term increases customer exposure to market risk. As explained above, QFs reduce variation in customer rates, and therefor reduce risk. When the QF PPA expires, the customer becomes exposed once again to the risks that the QF mitigates. Even if the QF renews the PPA for another term, customers still experience greater risk.

Q. Why are a series of short QF PPA's not as effective as one longer PPA in terms of risk?

A. Each time a QF renegotiates a PPA, RMP recalculates the QF rates based on current avoided costs. If the utility's prospective actual costs are higher than originally expected when the first PPA was set, the renewed PPA will have higher rates. Similarly, the renewed PPA could have lower rates. This increases the variation in rates and adds risk. RMP's proposed seven-year term would result in three separate PPAs over the same period as the current 20-year term limit.

Q. What kind of quantitative risk analysis does RMP perform to evaluate the risk of QF PPAs?

A. The only quantitative risk analysis provided by RMP is a comparison of avoided costs across different periods in time. This analysis does not support a conclusion that QF PPAs are risky because RMP does not include accurate interpretation of the results. RMP finds that avoided costs have changed substantially over the last few years. This means that absent fixed price contracts, RMP and its ratepayers are exposed to highly variable market fuel and energy prices for power costs.

RMP's narrative instead focuses on whether recent QF contracts are "in-the-money" or "out-of-the-money". RMP finds that recent QF contracts are out-of-the-money, meaning that RMP is paying more for the energy than the avoided cost at the time the QF delivers the power. RMP then asserts that QF PPAs are risky because they are out-of-the-money at the time power is delivered. For various reasons discussed below, this claim is misleading. It is true that fixed price contracts can be different than market at the time energy is delivered. It is easy to determine whether a fixed price contract is above or below the market price at any given time by comparing the market price to the levelized price in the contract. For fixed plant investments, however, it is not as easy to compare rate-based resources to market prices. We note in this testimony that overall RMP resources are "out-of-the-money".

We find the RMP discussion is far too limited in its analysis of risk as there are a host of risks besides pricing risk. And, what if the contracts were in the money? Does that mean having fixed-priced contracts are not risky? Our testimony discusses many risks beyond the limited scope of RMP's analysis and finds that there are many benefits to the QF contract fixed price format.

Q. Beginning on Page nine of Tourangeau Direct Testimony, he compares differences in resource procurement between QFs and company IRP resources. Do you have any comments on this discussion?

A. Yes. We think the discussion is one-sided in the sense of downplaying other types of risks that put QF supply in a better light as compared to the Tourangeau testimony, and specifically, as compared to utility-owned generation acquired through an IRP.

Q. Please explain.

A. For example, there are different economic risks to customers when comparing a utility-owned generating resource and a QF. If the utility builds a resource and places it in rate-base, the plant remains in rate-base over the life of the plant, which is longer than even the existing 20-year contract term, and significantly longer than the seven-year term RMP is proposing. Further, customers could be responsible for all the Company investment regardless of whether the generation plant continues to operate. For example, in the short-run, a plant might not operate because of an equipment failure or other reasons. And, the generation plant might cease operations altogether due to a new environmental regulation or because economic conditions have changed that have made the cost of fuel supply prohibitive as compared to other sources of power. Therefore you can think of rate-based generation investment as a long-term fixed plant-investment commitment.

This contrasts with QF supply. QFs are paid on actual production. If the QF ceases to operate because of plant failure for example, the QF is not paid. The Company's retail customers are not responsible for this economic risk. You could think of this as a performance-based ratemaking concept where costs are recovered when the plant operates.

Q. Did you ask RMP whether it is entitled to cost recovery of its fixed generation plant if the plant stopped operating prior to the end of its depreciation life?

A. Yes. RMP's response to RMCRE DR 2.22 stated that recovery of costs would be up to the public service commission. We are not aware of a utility voluntarily offering, or a regulatory Commission concluding, absent some prudence finding, the ratepayers are not required to pay the costs of the remaining fixed generation plant. A copy of RMP's response to RMCRE DR 2.22 is attached as REC Exhibit 600.3/RMCRE Exhibit 700.3.

The Wyoming PSC has agreed to allow RMP to continue recovery of un-depreciated plant removed from service as part of the EV2020 wind repowering projects.[21] RMP also recently filed for updated depreciation rates to accelerate the depreciation of the Cholla plant associated with an unexpected early closure date.[22] RMP is closing Cholla 4 before the end of its functional life because it is no longer economic. The accelerated closure results in an increase in depreciation expense from $15,449,657 to $71,831,775 per year.[23] This is an increase of $56.4 million per year that affects RMP ratepayers under utility ownership but would not affect ratepayers if the energy was provided through a PPA.

Q. Is it possible that a QF contract could allow RMP to avoid purchasing a more expensive resource in the future or unexpectedly higher-priced power in the future?

A. Yes. QF rates are fixed based on forecasted costs for market power, fuel, and new generation capital requirements. If fuel prices or capital requirements are higher than forecast, the PPA rates will be avoiding higher priced power in the future. The impact of higher fuel prices is illustrated in REC Exhibit 600.1/RMCRE Exhibit 700.1, attached hereto. This table shows that if QF rates are set using low fuel costs, and actual fuel costs are higher than expected, the QF rates will be lower than avoided cost, thus saving ratepayers money.

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[21] WPSC Memorandum Opinion, Findings, and Order Approving Stipulation Docket No. 20000-519-EA-17
[22] Docket No. 20000-539-EA-18.
[23] Docket No. 20000-539-EA-18 Exhibit RMP JJS-2 Page 1395 (page A2 of study).

Q. Are there other differences between QFs and utility generation that reflect an advantage of QFs over utility generation?

A. Yes. Consider the case of equipment failure or new environmental regulations that cause additional investment in the generation resource. In that case, for QFs, the prices are set and the QF owner bears any investment costs. It cannot be passed on to RMP retail customers. This contrasts with RMP-owned generation. Where RMP must make capital investments, or reduce operations to stay within emissions limits, those costs can be requested by the utility to be included in rates.

Q. Do you have another example?

A. Yes. Consider a wind project where the investment pencils out at a projected capacity factor based on wind studies, but after the project is built the actual capacity factor is lower than was projected in those studies. If the wind project is a QF, the QF is paid based on actual generation and will receive less compensation as the project produces fewer MWh than was projected. If the project is utility owned, however, the utility will likely continue to recover all the fixed costs incurred to build the project and ratepayers will suffer the consequences from the actual capacity factor being lower than was forecast. The only way the utility would not recover all of its fixed costs is if consumer groups can demonstrate to the regulatory commission that the utility acted imprudently in relying on the wind studies, or on some other basis, to have the utility not get full recovery of the plant capital investment costs or from purchased power costs.

Several examples of this appear in Table 5 on page 20. Goodnoe Hill was expected to have a capacity factor of 32.4 percent but has only achieved a capacity factor of 27 percent. This means that the project was expected to produce 20 percent more energy than it actually does. Because ratepayers are still paying the full cost of construction, ratepayers are paying 20 percent more per kWh than was expected when the project was approved.

IV. RMP HAS INCENTIVES TO IMPEDE QF ENTRY

Q. Explain how RMP has incentives to impede QF entry.

A. RMP's main incentive to impede QF entry is that RMP earns a profit on resources RMP owns. RMP profits when the Commission approves new rates that include RMP's capital investments in rate-base, where the utility earns a return on and a return of its plant investment.

Q. Does RMP earn a return on power purchased from QFs?

A. No. Like any power supply purchase that RMP may enter into, RMP does not earn a return on that category of costs, as it is an expense, not a capital investment. RMP has an opportunity to recover the expense in rates but does not have an opportunity to profit through the rate of return for rate-base investments.

Q. Is RMP's incentive to impede QF entry evidenced in this docket?

A. Yes. Most of the changes that RMP proposes in this docket would, if adopted, impede QF entry. RMP's proposal to reduce QF PPA terms from 20 years to 7 years, to reduce capacity contribution payments to like-for-like resources, and other changes in this docket will impede QF entry by drastically reducing the financial incentive to develop a QF project. These changes are consistent with RMP's incentives.

Q. Do you have any other examples that show utility incentives influencing its behavior?

A. Whenever a utility chooses a self-build option rather than a power purchase, which is common in utility RFP decisions, it is reasonable to suspect that one of the incentives driving this decision is the Averch-Johnson effect. [24]

Q. Is ratemaking treatment another incentive with regard to this issue?

A. Yes. The other incentive at play in this issue is the ratemaking treatment of rate-based generation versus PPA purchases. For example, with a generating plant, or any rate-based item, the capital revenue requirements are generally front-loaded, meaning that rates are highest in the first year and decline over time as the plant depreciates. This is especially true for low variable-cost generation or variable costs that vary only slightly over time.

Q. How does declining rate-base also provide incentive?

A. This method of front-loading capital revenue requirements provides an incentive to impede QF development because a utility's rates apply to the rate-base approved in the previous rate case. The rate-base investment is highest when it is placed in service. Over time, the level of rate-base declines (absent new capital refurbishments) as depreciation occurs. It is the net plant--gross plant minus depreciation--that is placed in rates.

[24] In 1962, an American Economic Review article was published that became known as the Averch-Johnson effect. The Averch-Johnson effect essentially says that regulated utilities have the incentive to add to its rate-base so that the utility has the opportunity to earn a return on that investment— "a profit". The greater the utility rate-base, the greater its profits. The utility would have the disincentive to enter into PPAs because the utility does not earn a return on power purchases.

Therefore, the incentive for the utility is to time its rate-change applications around the placement in service of major capital investments. With those rates in place, the utility will continue to charge customers its authorized rates established in the first year of the power plant operation even though later years the plant net-plant balance is declining. The utility does not have to make or submit any regulatory filing with the Commission after rates are set. Regulation will automatically result in higher profits with respect to that major plant investment as the rate-base declines and rates charged to retail customers remains set on the initial higher rate-base value. This is one factor that has helped RMP earn a return on equity higher than its authorized ROE in both 2017 and 2016.[25]

Q. How does that contrast with a QF power purchases?

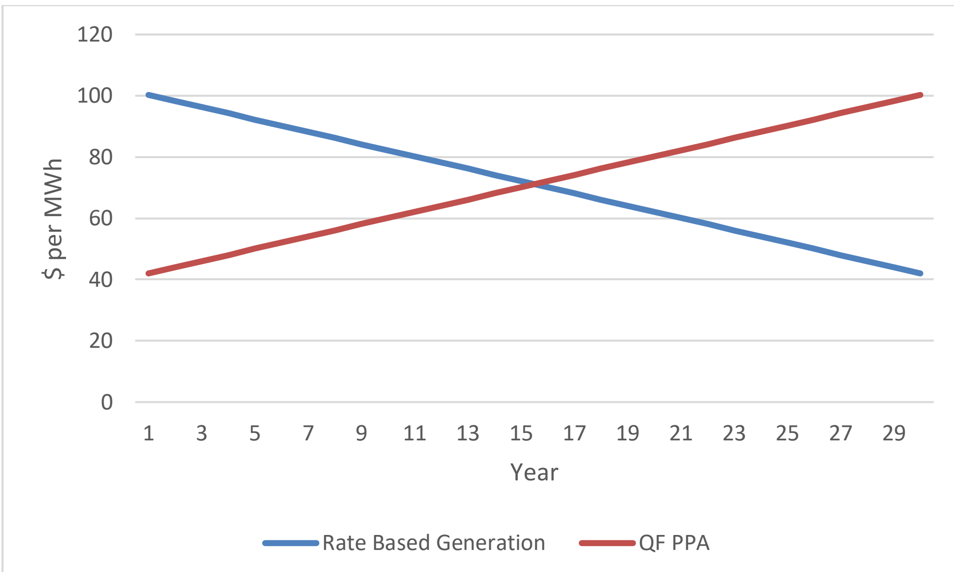
A. The RMP purchase of a QF power purchase has two relative drawbacks from the perspective of utility shareholders. First, RMP does not earn a return on the power purchases, as there is only the power purchase expense and nothing associated with the QF in RMP rate-base.

Second, the stream of avoided-cost prices typically starts very low and then rises over time so that the avoided-cost price is the levelized average price throughout the term of a QF contract. Absent any regulatory mechanism, RMP would see reduced earnings once retail rates are set inclusive of the QF power purchase. The Commission-authorized retail rates (inclusive of the QF power purchase) that are established at an “initial” power-

[25] *See* REC Exhibit 600.4/RMCRE Exhibit 700.4 (Pages 18,25, and 58 from Berkshire Hathaway Energy 2018 Fixed-Income Investor Conference. Retrieved from https://www.berkshirehathawayenergyco.com/assets/pdf/2018-fiic-presentation.pdf.).

purchase expense would not reflect the higher power-purchase expense that the utility pays to the QF in the form of higher avoided cost-based prices in subsequent years. This difference is illustrated in Figure 1.

Figure 1: Customers Pay for Rate-based Generation Up Front, Increasing Risk of Overpayment



Q. How else have you seen RMP activity that shows an incentive to add to its rate-base?

A. The most recent example of this is the EV 2020 project which adds several billion dollars to rate-base with no demonstrated capacity need.

Q. Does the Company receive capacity payments when the Company adds generation plant even when the Company is not resource deficient?

A. Yes. This is the case whenever the Company adds generation plant to rate-base, and has rates adjusted to reflect the added plant. The capacity payments are made in the form of recovery of fixed costs through inclusion of the generation plant in rate-base. The capacity payments last as long as there is net plant in rate-base. This could be the expected economic life of the resource assuming that is how the regulatory depreciation lives are set. And again these "payments" are front-loaded as the return on rate-base (and federal income-tax payments) are the greatest as the highest net-plant balance is when the plant is first placed in service.

Q. Do QFs have a similar opportunity to receive capacity payments RMP's framework?

A. No. QFs, under the current PDDRR framework, at best do not receive capacity payments unless, at the time of the contract, the Company is projected to be resource deficit or have a need for a specific renewable resource. That is how, in part, the Company is effectively proposing to exclude any capacity payments in its avoided cost streams. The Company is not projected to be resource deficient until 2030, but the Company is proposing to limit QF contract terms to seven years.

In RMP's PDDRR methodology, baseload QFs do not have an opportunity to receive any capacity payments because of RMP's like-for-like approach and restricting QFs to receive capacity payments only if RMP has a like-powered resource that is deferrable.

Q. Is there an option available to the QF so that they could get capacity payments if RMP unexpectedly became capacity short?

A. Yes. In response to RMCRE Data Request 2.14, RMP stated that if the QF had selected "As-Available" pricing, the QF would receive capacity payments. A copy of RMP's response to RMCRE DR 2.14 is attached as REC Exhibit 600.5/RMCRE Exhibit 700.5.

Q. What is "As-Available" pricing?

A. In that same response to 2.14, RMP stated "As-Available" pricing is, "pricing calculated at the time of delivery,..." QFs have the choice of a fixed price stream or pricing calculated at time of delivery. The QF chooses the pricing option when executing the PPA.

Q. Is the "As-Available" pricing a reasonable alternative for QFs sufficient to dismiss your capacity payment recommendations, given that it provides QFs capacity payments if and when RMP is resource deficit?

A. No. We doubt many (if any) QFs would choose the "As-Available" pricing alternative because RMP will rarely have a capacity deficit at the time the QF delivers power. RMP typically adds sufficient capacity such that it is not resource deficit for several years out in every year it operates. Therefore, there is little likelihood of ever getting capacity payments under the "As Available" pricing option.

Q. Does RMP properly recognize the capacity contribution of existing QFs?

A. No. There are two aspects to this question. One is the extensive reliance on FOTs and, in doing so, eliminating need for a capacity resource for several years. The second aspect to this question is whether QFs are fairly compensated for the capacity value they provide.

Q. Please discuss the first aspect.

A. In its IRP, RMP assumes that it will purchase a large amount of FOTs to meet its capacity needs. There is no demonstration that the level of FOTs will be available into the future as the amount of power available in the region changes. For example, if the region is in a capacity load/resource deficit position, RMP cannot be assured that FOTs will be available to meet its capacity needs. While there may be capacity in the market for sale, demand for that capacity will out-strip supply. That is, there could be several utilities seeking to purchase the same capacity RMP is identifying as available for RMP to purchase. We recommend that regional load/resource balances be examined to determine the likelihood of FOT being available. We have identified publications that conclude that the region will be capacity deficit such that there is no assurance that current reliance on FOTs can continue long-term in the future.

Q. Please discuss the second aspect.

A. The second aspect is recognizing the capacity contribution that current QFs make to RMP’s system. Table 7 below displays RMPs capacity deficit position and the impact existing QFs provide to RMP and its ratepayers.

Table 7: RMP Load and Resource Balance Shows Capacity Deficiency Starting 2019

RMP Capacity Deficit After EV2020

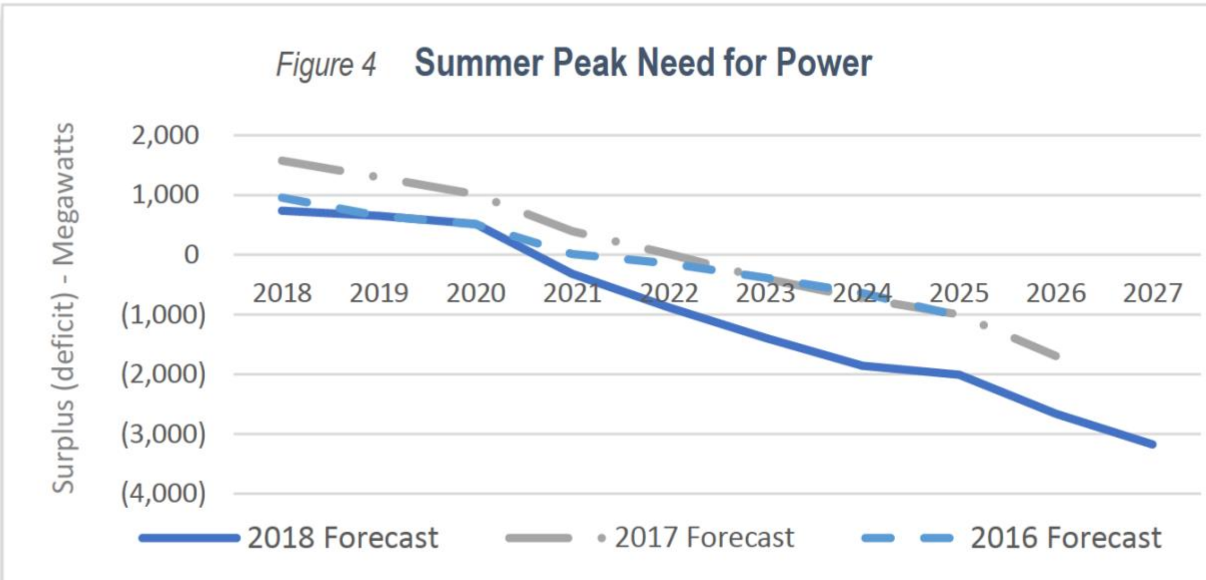
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Non QF Resources	9,647	10,150	10,264	10,151	10,101	10,126	10,133	10,027	9,999	9,976
Non-Wyoming QF Resources	634	645	684	655	648	638	603	599	594	559
Wyoming QF Resources	249	266	286	283	284	282	261	259	258	256
Obligation	9,594	9,544	9,495	9,497	9,513	9,526	9,541	9,550	9,490	9,469
Reserves	1,273	1,266	1,260	1,260	1,262	1,264	1,266	1,267	1,259	1,256
Obligation + Reserves	10,867	10,811	10,755	10,757	10,775	10,790	10,807	10,817	10,749	10,725
System Position	(337)	(661)	(490)	(606)	(675)	(664)	(674)	(790)	(749)	(750)
New EV2020 Wind	0	0	0	207	207	207	207	207	207	207
EV2020 System Position	(337)	(661)	(490)	(399)	(468)	(457)	(467)	(583)	(542)	(543)
System Position w/o Wyoming QF	(586)	(927)	(776)	(682)	(752)	(739)	(728)	(842)	(800)	(799)
System Position w/o System QF	(1,220)	(1,572)	(1,460)	(1,337)	(1,400)	(1,377)	(1,331)	(1,441)	(1,394)	(1,358)

Wyoming QFs provide 266 MW of capacity to RMP's system. We note that while RMP's load obligations are flat, total resources decline over time from loss of resources such as coal plant retirements.

Q. Absent QF capacity RMP appears highly reliant on FOTs. Is the regional power system capable of meeting RMP's FOT needs?

A. No, it is not. Two recent regional studies find that the region will soon be capacity deficit in the summer. The Pacific Northwest Utilities Conference Committee ("PNUCC") current ten-year forecast finds the region will become summer capacity deficient beginning in 2021. The forecasted regional load and resource balance is reproduced in Table 8.

Table 8: PNUCC Regional Load and Resource Balance[26]



A recent regional resource adequacy study by Energy Environment and Economics ("E3") finds that the Northwest region will be capacity deficit by 8 GW in 2030.[27] If we assume that FOTs cannot be assured beyond 2021 and that FOTs of 750 MW is the maximum that can prudently be relied on, absent Wyoming QFs RMP will be capacity short beginning in 2025. Absent system QFs, RMP is capacity short today. Yet the Wyoming QFs overall are not receiving capacity payments that adequately compensate them for their contribution of capacity to RMP's system.

[26] *See* REC Exhibit 600.6/RMCRE Exhibit 700.6 (Northwest Regional Forecast of Power Loads and Resources 2019 through 2028 (relevant pages)) at p. 3.
[27] REC Exhibit 600.7/RMCRE Exhibit 700.7 (Resource Adequacy in the Pacific Northwest, January 2019 (relevant pages)) at p. 30.

Q. You noted previously that RMP receives fixed payment recovery akin to capacity payments. Does this capacity load resource balance analysis say that QFs should receive capacity payments as well?

A. New QFs should receive capacity payments prior to the 2030 deferral of IRP generation resources. This issue is discussed in more detail in Section V. We recommend that the avoided capacity cost associated with deferred FOTs be valued based on the percent of months RMP is capacity deficient per year times the annual carrying cost of the least expensive IRP capacity resource.

Q. On Page six of Mr. Tourangeau's testimony, he states that the conditions that prompted the passage of PURPA no longer exist. Do you agree?

A. No. Many things have changed. But at least one condition has not. RMP is still a vertically integrated monopoly operating distribution, transmission and generation business functions to serve customers in its exclusive service territory. RMP is also a vertically integrated generation company in the sense that it owns, or is affiliated with, fuel, mining operations and electrical generation. Retail customers have limited ability to purchase generation services from other suppliers. Retail customers have even less ability to choose a different distribution company absent takeover of utility facilities. The retail customer options for consumers are dependent on the specific state statutes that allow for choice.

PURPA provided an opening for some competitive entry into the generation market by requiring investor-owned utilities to buy power from qualifying facilities at state-commission established prices. Otherwise, this level of generation supply might not exist or be severely limited.

V. RMP UNDERVALUES THE CAPACITY CONTRIBUTION OF QFs PRIOR TO RESOURCE DEFERRAL

Q. What is RMP's current load resource balance?

A. RMP's 2017 IRP Update load and resource balance shows a capacity deficit, even after adding new generation in the preferred portfolio, in all years of the planning horizon. Table 8 summarizes RMP's resources inclusive of EV2020 Wind.

Table 8: RMP Resources in 2017 IRP Update inclusive of EV2020 Wind

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Total Resources	10,530	10,150	10,264	10,151	10,101	10,126	10,133	10,027	9,999	9,976
Obligation	9,594	9,544	9,495	9,497	9,513	9,526	9,541	9,550	9,490	9,469
Reserves	1,273	1,266	1,260	1,260	1,262	1,264	1,266	1,267	1,259	1,256
Obligation + Reserves	10,867	10,811	10,755	10,757	10,775	10,790	10,807	10,817	10,749	10,725
System Position	(337)	(661)	(490)	(606)	(675)	(664)	(674)	(790)	(749)	(750)
New EV2020 Wind	0	0	0	207	207	207	207	207	207	207
System Position w/ New Wind	(337)	(661)	(490)	(399)	(468)	(457)	(467)	(583)	(542)	(543)

Q. How does RMP plan to meet this capacity deficit?

A. RMP plans to acquire FOTs in every year of the planning horizon.

Q. How does RMP value capacity contribution of QFs prior to resource deferral?

A. RMP's first deferrable resource is added in 2030. Prior to the 2030 resource deferral date, RMP values QF capacity by removing FOTs from GRID. RMP models FOTs in GRID as month-long high-load hour contracts. When RMP runs GRID to calculate a QF's avoided costs, it reduces FOTs equal to the capacity contribution of the QF resource.

Q. How are FOTs priced in GRID?

A. Energy from FOTs is priced to be, on average, $1/MWh higher than system balancing transactions over the same period. This premium is constant over the 20-year study period. The $1 per MWh premium that RMP places on FOTs translates into $0.41/kW-year.

Q. Using RMP's PDDRR methodology, what months do QF resources defer FOTs?

A. QF resources defer FOTs in July and December.

Q. How does RMP make firm market transactions?

A. RMP makes [redacted]

Q. Does RMP experience capacity deficits only in July and December?

A. Not necessarily. RMP evaluates the capacity contribution of facilities with seasonal variation by weighting capacity contribution in each month based on loss of load probability in each month.[29] This process provides capacity value in months outside of July and December when RMP experiences loss of load probability outside the months of July and December. RMP expects to [redacted]

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[28] Calculated from RMP Response to RMCRE DR 2.10 and Confidential Attachment RMCRE 2.10.
[29] Direct Testimony of Daniel J. MacNeil, page 10 lines 5 to 15.
[30] *See* CONFIDENTIAL REC Exhibit 600.8/CONFIDENTIAL RMCRE Exhibit 700.8 (RMP Response to REC 3.7 and Confidential Attachment REC 3.7).

Q. What are your concerns with how RMP values the capacity contribution of QFs prior to generation resource deferral?

A. We have two concerns. First, QFs defer FOTs in more months than RMP claims. Second, at $0.41/kW-year, RMP undervalues the long-term avoided capacity value of a QF. The annual carrying cost for RMP's least expensive capacity resource is $55.39/kW-year in 2019 and escalates to $85.13 by 2039.[31] The cost of RMP's least expensive capacity resource far exceeds the RMP capacity payment offered to QFs.

RMP has [redacted]

Q. Why should RMP acknowledge more months of deferred FOTs?

A. Both Loss of Load Probabilities and actual market transactions show RMP relies on market capacity fo[redacted] rather than two months. By only deferring FOTs in July and December RMP underrepresents how many months of FOTs are actually deferred by QF capacity.

Q. Can you explain why RMP's preferred portfolio only includes FOTs in July and December, while RMP is capacity deficient in [redacted]?

A. RMP's planning models are only designed to create portfolios that meet the coincident summer and winter peak. This means that System Optimizer, RMP's model for

[31] *See* REC Exhibit 600.9/RMCRE Exhibit 700.9 (Annual Carrying Cost of Frame SCCT)

generating capacity expansion portfolios, will only select FOTs for the two months containing system peaks, rather than for all months with capacity deficits. However, RMP does experience near-peak loads in other months, and in actual operations RMP acquires FOTs to meet capacity needs in other months.

Q. Why does $0.41/kW-year undervalue the avoided capacity cost of a QF?

A. RMP fails to account for the avoided risk associated with relying on FOTs to meet capacity needs. Unlike FOTs, QFs provide long term security for both price and availability. RMP's current plan of relying on FOTs to meet capacity assumes that a large quantity of FOTs will be available from the Mid-Columbia market over an extended period at an economical price. However, the FOTs that RMP is relying on to meet capacity needs may not be available or may be available but at uneconomically high prices. The capacity value of deferred FOTs needs to account for the long-term stability and certainty that QF capacity provides.

Q. How much reliance does RMP place on FOTs to meet capacity?

A. RMP's 2017 IRP update indicates RMP plans to acquire 624 MW of summer capacity through FOTs in 2019. This escalates to 1,575 MW of FOTs by 2029. RMP relies on market purchases to meet 15 percent of the 2029 system peak load.[32] However, recent regional planning studies show that absent new generation, the Northwest power system,

[32] Calculated as 1,575 / 10,500. See the 2017 IRP Update Figure 1.1.

which includes Mid-Columbia and all RMP states except California, will be capacity deficit by eight GW in 2021.[33]

Q. How can RMP rely on 1.5 GW of FOTs when the Northwest is expected to be 8 GW deficient?

A. This plan will only work if new capacity resources are added. However, capacity will only be added if market prices support new capacity. For market prices to support new capacity, they must include a capacity component that recovers the *annual* fixed capital costs of new generation. Yet RMP proposes to only acknowledge $0.41/kW-year in capacity value. This is less than one percent of the capacity value needed to support RMP's cheapest capacity resource, a SCCT.

Q. What approach do you propose to properly recognize the capacity value that QFs bring by deferring FOTs?

A. The capacity premium should reflect the cost of new capacity, because the Northwest needs to add capacity to meet near term load demands. However, RMP only relies on FOTs for capacity in [redacted] out of the year. In other filings, RMP calculates a monthly capacity cost based on an SCCT, and only values avoided capacity for the number of months that FOTs are avoided.[34] This seems like a reasonable approach for RMP to apply to Wyoming, as well. Thus, we recommend that during years where a QF defers FOTs, QF rates include avoided capacity

[33] *See* REC Exhibit 600.6/RMCRE Exhibit 700.6 (Northwest Regional Forecast of Power Loads and Resources 2019 through 2028 (relevant pages)) at p. 3.
[34] *See* REC Exhibit 600.10/RMCRE Exhibit 700.10 (Washington Utilities and Transportation Commission, Docket No. UE-144160, Order 04 dated November 12, 2015) at ¶ 31.

costs equal to the monthly fixed costs for an SCCT times the number of months that require market transactions to meet reserve requirements.[35] Table 9 illustrates the impact of this on Schedule 37 wind rates.

Table 9: Correctly Valued FOT Deferral Increases Schedule 37 Wind Rates

	On Winter	On Summer	Off Winter	Off Summer
2019	$ 1.58	$ 2.54	$ 0.90	$ 1.18
2020	$ 1.62	$ 2.49	$ 0.94	$ 1.18
2021	$ 1.76	$ 2.20	$ 1.00	$ 1.11
2022	$ 1.78	$ 2.35	$ 1.00	$ 1.19

Q. Has RMP implemented this proposed approach for Wyoming QF rates in the past?

A. Yes. Prior to 2016, RMP included three months of capacity costs based on the cost of a SCCT in Schedule 37 rates. RMP filed updated Schedule 37 rates in 2014 that eliminated capacity payments prior to resource deferrals. In that testimony, RMP referred to this period as the "Sufficiency Period," even though RMP was resource deficient. The term Sufficiency Period is a misnomer because it implies that RMP has sufficient resources to meet its peak load. The Commission approved RMP's elimination of capacity costs prior to resource deferrals for Schedule 37 QFs in Docket No. 20000-458-EA-14, Record No. 14021 Order Issued August 26, 2015. However, no intervening parties filed responsive testimony in that docket and the Commission did not have a chance to review a fully developed record with respect to the changes proposed by RMP.

[35] This could be determined by calculating the number of months with loss of load probability greater than zero absent market purchases. As noted earlier, the two months of FOTs shown in the IRP preferred portfolios do not represent actual annual capacity needs because the IRP only tests for resource sufficiency in July and December. Therefore, the IRP FOTs should not be relied on to determine the number of months that RMP is capacity deficient or the number of months that QFs defer FOTs.

VI. RMP UNDERVALUES QF DEFERRAL OF GENERATION RESOURCES

Q. How do QFs help RMP defer generation resources?

A. RMP regularly invests capital in generation facilities. The energy provided by QFs reduces the need for RMP investment in generation facilities, which in turn reduces RMP's capital investment in those resources.

For example, if RMP signs a Wyoming QF PPA for a baseload resource (such as hydropower), RMP experiences higher planning reserves, greater reliability, and increased market sales. All of these changes impact RMP's future resource acquisitions. The higher planning reserves and lower loss of load probability will reduce RMP's need to acquire capacity resources during the term of that QF PPA.

Q. How does RMP's proposal undervalue deferral of generation resources?

A. RMP's proposal undervalues avoided capital costs because:

- RMP seeks to restrict the type of resources that can be deferred;
- RMP's proposed seven-year term eliminates credit for avoided capacity costs;
- RMP does not appropriately apply avoided capital costs to renewing QFs.

Q. How does RMP restrict the type of resources that can be deferred?

A. Both the current and proposed methodology limits the type of generation resource that qualify to defer a RMP-planned resource. For example, with the current methodology, solar resources can only defer thermal resources. As RMP now acknowledges, this results in the currently illogical situation where RMP plans to add solar resources, but the current methodology provides no capacity credit to solar QFs that would defer RMP's planned solar investments.

In this docket, RMP proposes to address this problem by modifying the PDDRR methodology to only allow a QF to defer resources of the same type. This does not accurately represent RMP's avoided capacity costs. It results in the illogical situation where a baseload resource with a flat generation profile is considered not to be the same type of resource as a solar or wind project[36] and, therefore, receives no credit for avoided capital costs, even when it is likely to displace the planned wind or solar generation. Under the Company's proposal, a baseload QF defers no generation resources, only front-office transactions. As a result, the avoided cost calculations assume that RMP avoids no long-term capacity costs.[37]

Q. How can a baseload renewable resource displace a solar resource?

A. Other than EV 2020, RMP's first solar and wind additions are planned for 2030. These additions occur in the first year that RMP experiences significant summer capacity deficits. These 2030 resources are added to satisfy RMP's capacity and energy deficiencies. A baseload QF PPA would reduce the capacity and energy deficiencies that cause the 2030 renewable acquisitions. If RMP were to add a baseload QF to the existing resources and re-run all the 2017 IRP Update models with this additional resource, the preferred portfolio would have fewer intermittent resource additions in 2030.

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[36] See Direct Testimony of Daniel J. MacNeil, page 2, lines 2 to 11.

[37] Front office transactions do not reflect the cost of long-term purchase agreements. RMP limits the number of FOTs that can be relied on in IRP modeling

Q. Have you performed any IRP modeling to illustrate how this works?

A. REC Data Request 5.8 asks RMP to provide System Optimizer portfolio results with and without a generic QF resource as an existing resource. RMP declined to perform such modeling.[38] The same request also asked for access to the programs necessary to perform the modeling. RMP also declined to provide such access.[39]

Q. What is your experience with RMP's IRP planning?

A. Our experience includes working extensively on RMP's 2013 IRP. Our work experience involved exploring alternative compliance scenarios for regional haze requirements. Through this work, we have become familiar with the primary tools that RMP uses to construct and evaluate capacity expansion portfolios, the System Optimizer and Planning and Risk models. Based on this experience, we are confident that the addition of a base load QF would defer at least one of the 2030 wind and solar resource additions identified in the 2017 IRP Update preferred portfolio.

RMP objected to REC Data Request 5.8 because RMP claimed that it was not appropriate to only make a single change to the model, without updating any of the other parameters.[40] However, our proposed analysis requires holding all else constant, in order to isolate the impact of the addition of a QF from the other types of updates that may go into the 2019 IRP.

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[38] *See* REC Exhibit 600.11/RMCRE Exhibit 700.11 (RMP Response to REC Data Request 5.8)
[39] *Id*.
[40] *Id*.

Q. Based on your familiarity with the IRP planning models, what would happen if the System Optimizer model used in creating the 2017 IRP Update were re-run with an additional 50 MW of existing baseload QF resources

A. The additional baseload resource would reduce capacity needs in all years by 50 MW. However, the 2017 IRP Update preferred portfolio did not include any baseload generation resources. What would likely happen is that FOTs would be reduced by 50 MW until the portfolio adds a generation resource.[41] This means that the baseload resource would defer 2030 wind or solar, or a combination of wind and solar.[42]

Q. What rationale does RMP provide for limiting deferrable resources to the same type?

A. RMP states "Limiting deferral to QFs of the same type helps ensure reasonable alignment between the operating characteristics of a QF and the preferred portfolio resources it is assumed to defer, which in turn helps ensure that the least-cost, least-risk outcomes achieved by the preferred portfolio are maintained."[43]

Q. If a baseload QF resource does indeed defer a wind resource in the IRP planning framework, is it reasonable to ignore the avoided capital costs of the deferred wind resource for the sake of preserving the characteristics of the "preferred portfolio"?

A. No, this is not consistent with RMP's concept of customer indifference. Customer indifference requires that the QF be paid RMP's avoided capital costs, even though the replacement resource may have different operating characteristics. What is important is

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[41] The EV2020 resources would likely not be deferred because they are not need-based resources.
[42] Assuming the term of the PPA is 20 years, or the QF renews to provide energy past 2030.
[43] The Direct Testimony of Daniel J. MacNeil, page 11 lines 8 to 12.

that when avoided costs are calculated, the differences in operating characteristics be accounted for.

Q. Can the PDDRR methodology accurately model the avoided cost of a baseload resource deferring a wind or solar resource, while still accounting for the differences in operating characteristics?

A. Yes. The PDDRR method can capture most of the cost impacts associated with different operating characteristics between a baseload resource and a wind resource. For example, the PDDRR method accounts for transmission constraints, integration costs, trapped energy, and system balancing transactions.

Q. Does RMP propose to allow wind resources to defer baseload resources?

A. Yes. RMP states that, "If no renewable resources of the same type (as a QF) remain in the IRP preferred portfolio, the QF would be assumed to defer thermal resources, and avoided capacity costs would be based on the capital costs of the next deferrable thermal resource in the IRP preferred portfolio."[44]

Q. How is it that RMP can account for the differences in operating characteristics when a wind resource displaces a thermal resource, but cannot account for the differences in operating characteristics when a baseload resource defers a wind resource?

A. We did not see any RMP testimony explaining this and have no independent explanation.

[44] See Direct Testimony of Daniel J. MacNeil, page 7, lines 17 through 20.

Q. How would you implement the PDDR model to reflect a baseload resource deferring a wind resource?

A. We would implement the PDDRR model in a similar manner as wind deferring wind. However, we would adjust the size of the deferred wind resource to match the capacity contribution of the baseload resource. For example, a 50 MW baseload QF has a 50 MW contribution to system peak. A 50 MW eastern wind resource only has a 7.9 MW contribution to system peak. In order to model the correct deferred capacity, the deferred wind resource needs to be scaled up to 316 MW.

Q. How would you treat green tags or renewable energy credits in periods where the QF rate defers FOTs or non-renewable generation?

A. To maintain the customer indifference principle, the green tags should remain with the QF if the QF does not receive compensation calculated using the cost of deferred renewable resources.

Q. What are the PDDRR analysis results of baseload QF deferring a wind resource?

A. REC Exhibit 600.1/RMCRE Exhibit 700.1 contains the PDDRR results when Schedule 37 baseload rates are calculated with a deferred wind resource. The impact on avoided cost rates is relatively minor, despite the avoided capital costs of 316 MW of wind. This is because energy costs increase with the deferral of that much wind capacity, and the increased energy costs largely offset the deferred capital costs. Table 10 summarizes the increase in Schedule 37 baseload rates when allowing baseload to defer 2030 wind additions.

Table 10: Baseload QF Deferral of Wind Resource Increases Schedule 37 Baseload Rates

	On Winter	On Summer	Off Winter	Off Summer
2030	$ 12.99	$ 18.58	$ 7.18	$ 9.71
2031	$ 7.04	$ 9.79	$ 3.88	$ 5.12
2032	$ 0.77	$ 1.07	$ 0.42	$ 0.56
2033	$ 2.37	$ 3.32	$ 1.31	$ 1.75
2034	$ 4.91	$ 6.79	$ 2.70	$ 3.57
2035	$ 2.09	$ 2.94	$ 1.15	$ 1.54
2036	$ 0.41	$ 0.59	$ 0.23	$ 0.31
2037	$ 0.97	$ 1.37	$ 0.53	$ 0.72
2038	$ 0.98	$ 1.37	$ 0.54	$ 0.72
2039	$ 0.99	$ 1.39	$ 0.54	$ 0.73
2040	$ 1.00	$ 1.40	$ 0.56	$ 0.74

Q. How do these prices account for differences in resource performances, risk, and resource cost?

A. These prices are calculated using the PDDRR methodology. This methodology returns RMP rates to those that would exist absent the QF. As a result, the expected costs are in line with the least-cost least-risk deferred wind resource. As discussed in Section III, QFs are less risky than utility owned resources. If RMP were to compare the variance in rates for the baseload QF and with the variance of the displaced wind using the IRP's Planning and Risk model, we expect the baseload QF to have lower variance. Furthermore, the Planning and Risk model does not account for many of the ratepayer risks associated with utility ownership, such as generation risk, construction cost risk, and early retirement risk.

VII. RMP'S PROPOSED SEVEN-YEAR CONTRACT TERM IS TOO SHORT

Q. Do you agree with RMP's proposal to reduce the contract term length to seven years?

A. No. The Commission should not adopt RMP's proposal to reduce the contract term for both Schedule 37 and 38 QFs to seven years. We have the following concerns with a seven-year contract term:

1. A shorter contract adds to QF project risk and makes QF development less likely.
2. Customers receive less certainty with a seven-year contract.
3. RMP models no deferrable resources during the next seven years.

We recommend that the Commission maintain the current 20-year term limit.

Q. Why do you think a seven-year contract will make QF development less likely?

A. RMP is proposing a 65 percent reduction in term length. QF developers, like any business operation, need to assess the economic feasibility of its power generating facility including a risk assessment. A key component of the analysis is the price paid for the power supplied to RMP. The shorter the time period of assured pricing, the greater the risk. A reduction of the current 20-year contract term to seven years is huge and would greatly add to the level of uncertainty a project developer would have in assessing the economic viability of going forward.

Q. Do you have any RMP information regarding what may be the relationship between contract length and the viability of QFs to operate under shorter terms and resulting prices?

A. Yes. In response to RMCRE Data Request 2.25, RMP provided information for QFs in all the states the Company serves. Below, we compare Table 1 in Mr. Tourangeau's Direct Testimony, which identified QF information in only a portion of RMP's states, with a new table based on the information provided in response to RMCRE's DR No. 2.25:

Original Table 1, Page 7, Direct Testimony of Mark Tourangeau

Table 1

	QFs In Operation (MW)	QFs Under Contract not yet in Operation (MW)	QFs in the Pricing Queue (MW)
Utah	1,001	174	441
Wyoming	398	458	1,518
Oregon	382	115	952
Other States	206	0	80
Total	**1,987**	**747**	**2,991**

RMP's Response to RMCRE Data Request 2.25:

Table 1

	Qualifying Facilities (QF) In Operation (megawatts (MW))	QFs Under Contract not yet in Operation (MW)	QFs in the Pricing Queue (MW)
Utah	1,001	174	441
Wyoming	398	458	1518
Oregon	382	115	952
California	9	0	0
Washington	3	0	80
Idaho	194	0	0
Total	**1,987**	**747**	**2,990**

As shown in RMP's Response to RMCRE Data Request 2.25, Idaho has no new QFs under contract or in the queue. In Idaho, the RMP QF contract term is three years. This indicates that the short contract term allowed in Idaho is not long enough to attract QF development.

Q. Did you ask RMP if they were willing to build and construct large generation projects if RMP was only guaranteed prices for the first seven years?

A. Yes. RMP objected to the request, asserting that it was not relevant and was not reasonably calculated to lead to discovery of admissible evidence.[45] We asked the question because our experience working with regulated electric utilities leads us to believe the obvious answer is, "no." Yet, this is exactly what RMP is proposing for QFs in this application. RMP's response is also contrary to the Commission's stated that it must exercise its discretion to establish QF contract terms that "advance the policy interests and goals underlying PURPA of encouraging development, while not discriminating against QFs in Wyoming, and without unduly burdening Wyoming ratepayers with excessive price risk."[46]

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[45] *See* REC Exhibit 600.12/RMCRE Exhibit 700.12 (RMP's response to RMCRE DR 2.31)
[46] 2015 Wyoming PSC QF Docket Order, ¶ 95.

Q. On Page 19 of Mr. Tourangeau's Direct Testimony beginning at line 8, he provides an example of a wind project in Carson County, Texas that was financed without a PPA. Does RMP know how the prices applicable to that project compare to the proposed wind prices in this filing?

A. It does not. Mr. Tourangeau references a 182 MW wind project in Carson County, Texas that was "built and financed using a 13-year, fixed-for-float swap with Morgan Stanley that only covers 80 percent of the expected output of the facility."[47] This project in Texas is irrelevant to the requirements of financing a QF project in Wyoming for several reasons. First, the Texas project is more than 100 MW larger than the 80-MW threshold for a QF, so it is more efficient to build and can be financed over a shorter term. Second, the project is in Texas, which has deregulated markets for generation resources, meaning that the project has a very good chance of finding a buyer for energy at the conclusion of the 13-year term of the swap. This enables the project to be financed with a swap for only 13 years and for less than the full expected output of the facility.

Moreover, in response to RMCRE Data Request 2.33, RMP stated that it has not sought to determine how the prices applicable to the Texas project compare to the prices that would be applicable to a wind project that interconnects to RMP's system, either currently or if RMP's proposals in this docket are adopted. A copy of RMP's response to RMCRE DR 2.33 is attached as REC Exhibit 600.14/RMCRE Exhibit 700.14.

[47] Tourangeau Direct Testimony at p. 19, lines 8-11.

Q. On Page 18 of Mr. Tourangeau's Direct Testimony, beginning at line 6, he states that there is a five-year trend of shorter contract terms. What evidence is there for a trend?

A. There is no evidence in Mr. Tourangeau's testimony of any such trend. The term trend implies a change from past practices; however Mr. Tourangeau does not show that average contract terms have decreased.

Q. On Page 18 of Tourangeau's Direct Testimony beginning at line 6, he asserts that renewable projects are getting done with short contract terms. For the examples he cites, what percentage of MW is for terms seven years of less?

A. Less than 1.5 percent of the PPAs that Mr. Tourangeau cites are for terms of seven years or fewer.[48] This 1.5 percent of short term renewable PPAs may have extenuating circumstances that explain how they were able to develop under such short contract terms. The evidence Mr. Tourangeau cites is simply to point out the term length of PPAs. This does not support his assertion that projects are being financed with those PPAs. That is, a renewable project that has been producing energy for 20 years can sign a new PPA for 3, or 5, or 7 years, but this does not mean that the project is being "financed" with this PPA. Moreover, the projects cited by Mr. Tourangeau may be in unregulated jurisdictions with more liquid markets that would give the developer confidence that it can sell power from the project even after the conclusion of the PPA term. Wyoming and Texas operate under different market structures and so Mr. Tourangeau's claims are not well-founded.

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[48] Calculated as (4,500MW * 8 %) / (4,500 MW + 20,000 MW). *See* REC Exhibit 600.13/RMCRE Exhibit 700.13 (RMP Response to RMCRE DR 2.32).

Q. Does the RMP's proposed seven-year contract term eliminate avoided capital cost payments to QF developers?

A. Yes. The seven-year contract term, combined with RMP's pattern of "committing" near-term resources and adding non-IRP resources, will effectively eliminate avoided capital costs from QF avoided cost rates. Under the current 2017 IRP Update, all deferrable resources have been pushed outside the seven-year time horizon. If RMP maintains its practice of shifting resource acquisitions early enough to "commit" to, or late enough to be outside of the seven-year term length, then RMP will have succeeded in preventing avoided capital costs from entering the QF renewal price.

Q. How would QF capacity payments fare from a historical perspective, under RMP's seven-year term?

A. In response to RMCRE DR 2.18, RMP provided timeframes over which it would make capacity payments for contracts beginning in each of the years 2010 through 2019. In that response, RMP stated that a Schedule 38 QF would be eligible to receive capacity payments differentiated by Wind and non-Wind. Table 11 shows the year-by-year eligibility of capacity payments for wind.

Table 11: Schedule 38 Wind Receives No Capacity Payment Under Seven-Year Term

	Schedule 38 Percentage of Full Wind Capacity Payment Available																			Average Capacity
Year	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Payment
2011	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	0.632
2012		0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	0.611
2013			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.000
2014				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.000
2015					0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.000
2016						0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.000
2017							0	0	0	0	0	0	0	0	0	0	0	0	0	0.000
2018								0	0	0	0	0	0	0	0	0	0	0	0	0.000
2019									0	0	0	0	0	0	0	0	0	0	0	0.000

Notes: Values for year reflect IRP findings so 2011 IRP applies to 2011.
Updates are assumed to apply the following year so 2011 Update are values beginning 2012.

A wind resource signing a seven-year PPA in 2011 would receive no capacity payments during an initial seven-year PPA 2011 to 2017. If it were to sign a new seven-year PPA in 2018, the wind resource would receive no capacity payments during that second PPA term from 2018 to 2024. If the developer were to sign a third seven-year PPA starting in 2025 and concluding in 2031, it would receive two years of capacity during that term (assuming the 2017 IRP Update remains the preferred portfolio). This equates to capacity payments in one out of the first 20 years. On the other hand, under a 20-year term the wind facility would receive capacity payments in 13 of those 20 years. Over that same time period, RMP added a major thermal capacity resource in 2014 and plans to acquire new wind and solar resources in 2020. Customers would pay RMP for new capacity in 17 out of the 20 years.

Q. How does this affect the prices offered to QFs?

A. It significantly reduces the prices offered to QFs. This reduction in price not only makes customers prefer QF energy to utility energy, it also discourages the development of QFs and new QF supply.

Q. Do you believe the supply of QFs depends in part of the price offered for its power?

A. Yes, that is a basic principle of economics. Therefore, we do not believe it is meaningful to discuss the supply of QFs in other regions and allude to its applicability to Wyoming without also addressing a discussion of prices being offered in other regions as compared to Wyoming, along with other factors affecting the market for power.

Q. Is the current twenty-year contract term comparable to what the company obtains when it adds resources?

A. No, the QF is treated worse than how the utility is treated when it acquires or constructs generation resources. When the utility adds a resource, absent a disallowance, the utility will receive capacity payments as soon as the resource is included in rates, or in some account that is recoverable in rates later (such as through deferred accounting). The number of years that a utility receives capacity payments is typically much longer than 20 years.

Here, we are referring to fixed-cost recovery. For example, if the utility added a resource with large fixed costs and very little variable costs, such as a solar facility, once the resource is in rate-base, the utility recovers the fixed costs. In this case, timing the filing of a rate case to coincide with the on-line date of the solar resource would provide the Company with twenty-five years of fixed cost recovery, assuming the depreciation life is 25 years. Dividing 25 by the 25 years of expected life of the resource yields 100 percent capacity payments.

Q. Page 24 of the Direct Testimony of Mark P. Tourangeau, lines 12 to 18, says that the intent of the seven-year term is to place QFs on a level playing field. Does it?

A. While we support the objective of fair play and level playing fields, reducing QF PPA terms to seven years would place QF developers at a severe disadvantage. In response to a data request, RMP asserts that Mr. Tourangeau's "level playing field" comment was intended to mean that it wanted to place QFs in Wyoming on a "level playing field" in relation to other large QF developers in other parts of the country.[49] The response shows that RMP does not intend to place Wyoming QF developers on a level playing field with RMP. Rather, RMP claims that Wyoming QF developers have an advantage over QF developers elsewhere. This statement makes little sense. The regulatory environment in Wyoming is the same for all renewable developers. No law or regulation places some QF developers at an advantage over other QF developers in Wyoming. Moreover, RMP does not advocate changing the regulatory environment in Wyoming to match the regulatory environments in other states that have more liquid markets.

Q. Does RMP add resources only when it is capacity deficit?

A. RMP regularly acquires resources without capacity need. For example, RMP acquired Chehalis in 2008 even though the PacifiCorp 2007 IRP update had no action item related to acquiring thermal generation and the corresponding preferred portfolio through FOTs and renewable resource additions until 2012.[50] RMP is acquiring $3.1 billion worth of new Wyoming wind generation and transmission resources without any demonstrated capacity need.[51] There are many other instances where a RMP or any other utility might add resources ahead of need.[52] In these cases, the RMP can recover its fixed costs beginning with the first day of generation. At the same time, RMP's proposal does not provide QFs capacity payments even when RMP is capacity deficient.

[49] *See* RMP response to RMCRE DR 2.32, attached as REC Exhibit 600.13/RMCRE Exhibit 700.13.
[50] See PacifiCorp 2007 IRP Update Tables 12 and 13.
[51] See http://www.pacificorp.com/es/energy-vision-2020.html and PacifiCorp 2017 IRP Update Figure 4.4.
[52] For example, to reduce fuel cost, reduce market purchase, lower integration costs, or acquire distressed assets.

Q. Please continue your discussion on contract term and likelihood of receiving capacity payments.

A. The discussion regarding contract term and reduced likelihood of capacity payments means that the prospect of a higher stream of avoided cost prices is reduced significantly. A QF project that breaks even with a price of 3.5 cents per kWh will lose money if the price is 2.0 cents per kWh. It does not matter how robust financing markets are, or how many people support renewable power. If a project is clearly not economically viable, a fund that provides project financing and is aware of the project economics will likely not provide financing.

Q. On Page 24, lines 5 through lines 11, Mr. Tourangeau, states that PURPA does not require the Wyoming Commission to set the term of contracts to be that required to minimize the cost of financing. Do you agree?

A. Yes. But that does not mean that the Wyoming Commission should adopt the RMP seven-year term proposal. It is reasonable that the QF PPA term should meet the PURPA requirement that says QF avoided costs should reflect the costs the utility avoids but for the purchase of the QF power. If the purchase of power allows for the deferral of a long-lived resource, then the avoided costs should reflect those long-lived set of costs. Generation plants are long-lived and hence the avoided cost should reflect a long term. We view 20 years as on the low end of a contract term and any reduction as even further apart from the life of any planned utility generation plant life.

Q. Why do you view the 20-year term on the low end of the spectrum?

A. Because most of RMP's generation resource supply such as wind and natural gas generation have economic lives more than 20 years, with natural gas generation much more than 20 years. Table 12 summarizes the PacifiCorp 2017 IRP resource design life.

Table 12: PacifiCorp 2017 IRP Resource Design Life Exceeds 20Years

Fuel	Resource	Design Life (Years)
Natural Gas	sCCT Aero x3, IsO	30
Natural Gas	Intercooled sCCT Aero x2, IsO	30
Natural Gas	sCCT Frame "F" x1, IsO	35
Natural Gas	IC Recips x 6, IsO	35
Natural Gas	CCCT Dry "G/H", 1x1, IsO	40
Natural Gas	CCCT Dry "G/H", DF, 1x1, IsO	40
Natural Gas	CCCT Dry "G/H", 2x1, IsO	40
Natural Gas	CCCT Dry "G/H", DF, 2x1, IsO	40
Natural Gas	CCCT Dry "J/HA.02", 1x1, IsO	40
Natural Gas	CCCT Dry "J/HA.02", DF, 1x1, IsO	40
Natural Gas	CCCT Dry, "J/HA.02" 2X1, IsO	40
Natural Gas	CCCT Dry "J/HA.02", DF, 2X1, IsO	40
Coal	SCPC with CCs	40
Coal	IGCC with CCs	40
Coal	PC CCS retrofit @ 500 MW	20
Geothermal	Blundell Dual Flash 90% CF	40
Geothermal	Greenfield Binary 90% CF	40
Geothermal	Generic Geothermal PPA 90% CF	20
Wind	2.0 MW turbine 38% CF WA	30
Wind	2.0 MW turbine 38% CF OR	30
Wind	2.0 MW turbine 38% CF ID	30
Wind	2.0 MW turbine 31% CF UT	30
Wind	3.3 MW turbine 43% CF WY	30
Solar	pV poly-si Fixed Tilt 26.8% AC CF (1.35 MWdc/Mwac) UT	25
Solar	pV poly-si single Tracking 31.1% AC CF (1.25 MWdc/Mwac) UT	25
Solar	pV poly-si Fixed Tilt 24.9% AC CF (1.35 MWdc/Mwac) OR	25
Solar	pV poly-si single Tracking 28.8% AC CF (1.25 MWdc/Mwac) OR	25
Solar	Csp Trough w Natural Gas	30
Solar	Csp Tower 24% CF	30
Solar	Csp Tower Molten salt 30% CF	30
Biomass	Forestry Byproduct	30
Storage	pumped storage 1 (3,800 MWh)	50
Storage	pumped storage 2 (12,000 MWh)	50
Storage	pumped storage 3 (7,000 MWh)	50
Storage	CAEs (15,360 MWh)	30
Nuclear	Advanced Fission	40
Nuclear	small Modular Reactor x 12	40

Q. Mr. Tourangeau states on Page 31 of his direct testimony that maintaining the current 20-year term places an unfair burden on Wyoming ratepayers. Do you agree?

A. No. When the utility builds a resource and it is added to rate-base, the customers are responsible for the costs of the plant over the expected life (depreciation life) of the plant, whether or not the plant runs or even if it is prematurely retired. The depreciation life is typically thirty years or more for thermal plant generation and clearly 20 years or more for renewable generation. Moving from a 20-year contract stream to 7 years is unfair in relation to treatment for Company resources. Such a policy would harm customers by removing competitive generation supply, which incentivizes RMP to keep net power costs low.

Q. If utility generation turned out to be uneconomic on a prospective basis, do customers still have to pay for the costs?

A. Yes. This can be clearly seen where states have direct access opportunities for its retail customers. In states where retail generation supply choice is available, RMP has stranded cost charges that apply to departing customers. This means that the "freed-up" generation of Company resources have costs higher than market and the departing customers must pay a fee to the utility for purposes of holding other customers harmless.

Q. Does RMP or PacifiCorp have stranded cost charges?

A. Yes. We are aware of such stranded costs for departing customers in Oregon.

Q. On that same Page 31, Mr. Tourangeau testifies that by changing to a seven-year contract term the risk is balanced. Do you agree?

A. No. However, we do agree that there should be protections to customers if, at stated avoided-cost prices, a significant number of QFs are likely to fully complete the contracting process and commence operation.

Q. What customer protections do you support given your recommendation to maintain the 20-year contract term?

A. We support the Company having the right to request the Commission adopt revised avoided-cost values and get timely Commission decisions. The Company has somewhat included such an option on page 37-3 of its proposed tariff. The tariff states that, when the Company acquires 10 MW of system resources, QFs over 100 kW will need to follow the procedures under Schedule 38 until such time prices are updated and approved by the Commission.

VIII. RMP SHOULD NOT ASSUME ALL QFS WITH EXECUTED PPAS WILL BEGIN COMMERCIAL OPERATION WHEN CALCULATING AVOIDED COSTS

Q. How does the number of QFs that have executed power purchase agreements affect the calculation of avoided cost?

A. Presumably, those QFs that have executed PPAs with RMP (or PacifiCorp) would be counted as meeting any resource need, on a like-for-like basis, and hence would impact the evaluation as to whether any capacity payment would be available.

Q. Do you take issue with accounting for the number of QFs that RMP has signed contracts?

A. Yes, as it is applied in this docket. RMP overstates the available supply of QFs offsetting the need for a renewable resource.

Q. Why is that?

A. The reasoning is straight forward. Just because a QF has executed a contract to deliver power that does not guarantee that the QF will begin operation on the scheduled of commercial-operation date, or ever.

Q. Has the Wyoming Commission made a determination previously as to the percent of QFs that executed contracts eventually began commercial operation?

A. Yes. On June 23, 2016, the Wyoming Commission issued Final Order 20000-481-23451, (Record No. 14220), and in Paragraph 52 of that Order, found from RMP's own data that only 75 percent of QFs with executed PPAs reached commercial operation.

Q. Did you attempt to verify the continued reasonableness of the 75 percent value?

A. Yes. RMCRE DR 2.19 asked for information for the time period beginning in 2010 with regards, in part, to QFs that have executed PPAs and commercial operation dates. From reviewing that information, we found that roughly 9 percent of QFs with executed PPAs formally terminated their projects after executing the PPA. We also found that 36.7 percent of QFs that have executed PPAs have yet to commence operations. Given this wide range of results, we recommend the Commission's prior determination of 75 percent remains reasonable. This is further supported by the fact that the Wyoming order is less than three years old.

Q. What is your recommendation?

A. We recommend the Commission adopt its 75 percent value cited above and direct RMP to use that finding in calculating whether there is capacity deferrable assuming the Wyoming Commission does not adopt our related capacity-payment obligations found elsewhere in this testimony.

Q. If the Wyoming commission wanted to update its 75 percent value, how do you recommend it be calculated?

A. Assuming the PDDRR paradigm, we recommend the historic percentage of QFs that have begun operation relative to those that have executed contracts, for each respective resource type, be used to derive the future expected amount of QF supply in meeting RMP needs for capacity. This percentage, if then applied to the QFs that have executed contracts but not yet commenced operating, would reasonably reflect the likely actual additional supply of power expected from QFs. Even this is slightly optimistic in that it assumes the QF will continue deliveries for the full term of its PPA and not shut down or stop delivery early for any reason.

Q. Could you be more specific in the calculation that you are recommending?

A. Yes. The calculation we are recommending is a weighted-average calculation by type of resource. To get the divisor of the calculation, by type of resource, take the total number of MWH that the Company has executed contracts with QFs beginning in 2010 and ending in 2018. To get the numerator, by type of resource, take the total number of MWH of QFs that have commenced production during this same time period. The ratio of the total MWH that have begun production divided by the total MWH that have signed contracts yield the percentage of signed QFs that can be expected to produce power.

This percentage would then be multiplied to the current number of contractually signed QFs that have not commenced operation to yield the total expected MWH meeting the targeted need for new resources.

If the PDDRR is maintained with like-for-like requirement, then the calculation discussed above would need to be calculated separately for each “fuel” type of QF.

IX. SCHEDULE 37 – 10 MW TRIGGER

Q. Do you support the language proposed on Page 37-3 of the proposed tariff that begins with, "after the Company acquires those 10 megawatts of system resources, …." and ends with, "...until schedule 37 prices are updated and approved by the Commission"?

A. No. As written, the language assumes that RMP will file for updated prices, and that the Commission eventually adopts updated prices. The language should be changed to reflect the possibility that RMP does not make a timely filing and to reflect the possibility that the Commission does not approve the updated rates. Therefore, we recommend the proposed tariff text be changed to read:

> "After the Company acquires those 10 megawatts of system resources and files for updated Schedule 37 rates, ...until the Commission takes final action on any Company filing to revise Schedule 37 pricing."

Q. Do you support having the triggering event for shifting Schedule 37 customers onto Schedule 38 be 10 MW of Company system acquisition?

A. No. The 10 MW trigger is not consistent with the way the Schedule 37 rates are calculated. Schedule 37 rates are calculated using 50 MW of incremental Wyoming QF resources. The size and location of the QF resources have a meaningful impact on the QF rate.

The avoided costs associated with QFs decrease as total QF resources increase. Because of this, it does make sense to have a trigger for re-calculating Schedule 37 rates. However, Schedule 37 QFs are substantially smaller than the 50 MW resource modeled.

This means that the first QFs that sign up on Schedule 37 after each update will actually be under-compensated. Triggering an update at 10 MW means that the Schedule 37 QF resources will never actually reach the 50 MW modeled, and therefore Schedule 37 QFs will always be undercompensated. The trigger should be 100 MW, which allows symmetry around the 50 MW modeled in the rate calculations. This will allow the under-compensation for initial QFs to be balanced by over-compensation for later QFs.

The location of modeled QF resources is important because the incremental resources are in Wyoming, and Wyoming is transmission constrained. QF additions outside Wyoming will not have the same impact as QF additions inside Wyoming. The trigger should refer to Wyoming Schedule 37 resource acquisition and not system resources. The tariff is a Wyoming tariff not a total Company tariff. It seems inequitable that activities ongoing in other Company states could harm or affect Wyoming operations.

X. <u>ON PEAK OFF PEAK</u>

Q. Please discuss RMP's proposal to revise the definition of peak and off-peak loads as well as seasons do not reflect RMP costs.

A. RMP has proposed to make substantive changes to its definition of the summer and winter seasons as well as on- and off-peak hours. These changes are shown in the redlined version of Tariff 37-9 of RMP's application. We disagree with RMP's proposal for the following reasons:

1. RMP does not use the correct hourly prices to select on-peak periods and shape avoided costs.
2. Accepting RMP's hourly price inputs, the methodology is not revenue neutral within summer and winter months; hence they are not calculated correctly.
3. RMP's methodology is not consistent with hourly and seasonal pricing offered to cost of service customers.
4. RMP's methodology does not achieve the stated goal of providing correct incentives to QF developers.

Q. What are the proposed changes to the definitions of the seasons?

A. The Winter Season is currently defined as the months of November through April, a total of six months. RMP proposes to expand that definition to include the months of October through May, a total of eight months. The Summer Season is proposed to be correspondingly shortened by two months, to June through September.

Q. What are the proposed changes to peak and off-peak hours?

A. The On-Peak Hours definitions currently are 6:00 am to 10:00 pm, except for Sunday and NERC holidays. The proposed definition for the Winter Season eliminates from the peak hour definition the hours from 8:00 am to 5:00 pm and adds 10:00 pm to 11:00 pm. The Summer Season eliminates from the peak hour definition the hours 6:00 am to 3:00 pm. Also, on page 23, lines 21-23, of Mr. MacNeil's Direct Testimony, holidays and weekends are no longer excluded from the peak-hours' time-frames.

Q. Did RMP explain why it was changing the peak hour definitions?

A. Yes. RMP states in Paragraph 15 of its Application that the new definitions purportedly better align with high and low-cost periods that RMP experiences. Page 3 of Mr. MacNeil's Direct Testimony, lines 5 through 19, speaks of the "proliferation of solar generation on the Company's system and across the West." Mr. MacNeil addresses this issue more fully beginning on page 23 of his Direct Testimony. Beginning on page 24, line 14, Mr. MacNeil states that the peak hours were based in part on the Official Market Price and hourly market price scalers.

Q. Please explain your finding that RMP does not use the correct hourly prices.

A. The hourly prices used by RMP to define peak hours are not be representative of RMP's marginal (or avoided) costs. Avoided costs should reflect the cost avoided but for the output of the QF. Instead, RMP used its Forward Market Price Forecast for Palo Verde to establish the peak hours and seasons. There are two problems with using the Palo Verde prices. First, the QF resources modeled in Schedule 37 largely impact [redacted]

[53] *See* MacNeil Workpaper "336 - WY Sch 37 - 1a - GRID AC Study CONF _2018 09 25 Thm.xlsm" sheet "Delta".

[redacted]

[redacted]	[redacted]
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[redacted]	[redacted]

[redacted]

The second problem with RMP's prices is that they do not reflect transmission constraints, market liquidity, thermal dispatching, and many other factors involved in power costs. Therefore, market prices are unrepresentative of the hourly avoided cost of Wyoming QF generation. Actual GRID avoided cost results are more appropriate sources for hourly prices. Different hourly prices result in different definitions of season and peak hours because RMP selects peak hours based on hourly price curves. Furthermore, even using the same definition of season and peak hours, actual GRID avoided costs result in different on- and off-peak pricing. Table 14 compares RMP's proposed prices for Schedule 37 thermal avoided cost with those calculated using GRID hourly avoided costs.

Table 14: Shaping QF Rates According to Hourly Avoided Cost Results in Different Rates

	On Winter	On Summer	Off Winter	Off Summer
2019	$ (3.86)	$ (4.35)	$ 1.81	$ 2.68
2020	$ (4.26)	$ (5.37)	$ 2.08	$ 3.04
2021	$ (1.88)	$ (4.81)	$ 0.90	$ 2.38
2022	$ (2.15)	$ (3.41)	$ 1.04	$ 1.83

Q. Is RMP's methodology revenue neutral within seasons?

A. No. Even if RMP were using the correct hourly prices (which they are not), RMP's methodology is not revenue neutral within seasons. RMP uses hourly pricing to reshape the annual PDDRR avoided costs across all months. This reshaping pushes a substantial amount of avoided costs experienced in summer months into winter months. Table 15 illustrates this for Schedule 37 thermal QFs. The total Summer 2019 avoided costs are $3.8 million. RMP's reshaping results in only $3.1 million paid out in summer months. This means that RMP's method is not revenue neutral and does not represent expected avoided costs.

Table 15: RMP Peak Price Shaping Methodology Is Not Revenue Neutral

	Avoided Energy Costs			
Month	PDDRR	On	Off	Total
Jun-19	474,667	301,838	342,980	644,818
Jul-19	1,782,595	383,686	465,509	849,196
Aug-19	882,558	432,139	448,054	880,193
Sep-19	660,662	317,473	372,436	689,909
Summer-19	3,800,482	1,435,136	1,628,979	3,064,115

This issue would be remedied by using correct prices because it is a mechanical problem with RMP's model, not with the inputs to the model.

Q. How is RMP's model not consistent with prices offered to cost of service customers

A. RMP uses on-peak pricing for some Wyoming cost of service customers. For example, Schedule 46 includes an on-peak definition. However, RMP does not use or plan to use the proposed hours for any other filings or schedules.[54]

Q. Why does RMP's proposal not achieve the stated goal?

A. RMP states that the goal of the new definition is to provide QFs with incentives that are more consistent with RMPs needs. However, RMP's method does not calculate the correct values because it uses the wrong prices and because it shifts costs across seasons.

Q. What is your recommendation regarding RMP's changes to season and peak definitions?

A. We recommend the Commission maintain the current definitions. RMP has not shown that the new definitions will provide accurate signals to QFs, nor has RMP shown that the new definitions will not harm the development of QFs. Furthermore, RMP should utilize similar peak price definitions across all filings. The definition of peak price is an issue that is relevant to all customers involved in time of use. If the Commission is inclined to improve RMP's price signals, the Commission should do so in a separate docket that invites participation by all interested parties impacted by peak hour definitions.

[54] See REC Exhibit 600.15/RMCRE Exhibit 700.15. (RMP Response to REC Data Request 5.2).

XI. GRID MODEL CHANGES

Q. Summarize the GRID model changes that you recommend

A. We recommend the following changes be made to the GRID modeling to more accurately reflect avoided costs:

1. Remove the Foote Creek replacement project from both base and avoided cost GRID runs
2. Allow coal units to cycle
3. Escalate coal prices consistent with historic increases
4. Allow sales to entities in Wyoming and east of Wyoming.

Q. Why do you recommend removing the Foote Creek replacement project from the GRID runs?

A. The Foote Creek replacement project appears to be a response to the Commission's decision to exclude the Uinta wind facility from the EV2020 CPCN. RMP had not even filed for the Foote Creek CPCN at the time of the Schedule 37 update, yet the update includes Foote Creek power through to 2040, ten years past the current retirement date of Foote Creek. Table 16 avoided cost rates calculated with and without Foote Creek for Schedule 37 thermal QFs.

Table 16: Removing Foote Creek Repower Increases Avoided Cost Rates

	On Winter	On Summer	Off Winter	Off Summer
2030	$ 0.31	$ 0.44	$ 0.17	$ 0.23
2031	$ 0.37	$ 0.51	$ 0.20	$ 0.27
2032	$ 0.16	$ 0.22	$ 0.09	$ 0.11
2033	$ (0.05)	$ (0.07)	$ (0.03)	$ (0.04)

Q. Why do you recommend that coal units be allowed to cycle?

A. Transmission congestion in Wyoming limits the ability to move economic wind energy out of Wyoming. Allowing coal units to cycle will free up transmission capacity to allow trapped renewable energy to leave the Wyoming transmission area. This is also more reflective of RMP's future expectations for coal unit dispatch.

Q. Why do you recommend that coal prices escalate consistent with historic increases?

A. RMP shows Jim Bridger fuel costs [redacted] RMP provides no evidence that the historic pattern will change. Furthermore, as coal deliveries decrease and the Bridger Coal Company mines become depleted, the cost of mining should increase.

Q. Why do you recommend that GRID allow sales to entities east of Wyoming?

A. We understand that transmission from Wyoming east is less congested than from Wyoming south and west. RMP has transmission connections from Wyoming east to the Craig and Hayden units. Allowing GRID to move energy east would reduce trapped energy and renewable curtailment. If RMP could avoid curtailment associated with Wind QFs, the QF rate would increase from 50 to 100 percent. Table 17 below illustrates the impact of eliminating curtailment on Schedule 37 rates.[55]

[55] See REC Exhibit 600.1/RMCRE Exhibit 700.1 for full PDDRR results.

Table 17: Reducing Wind Curtailment Increases Avoided Cost Rates

	On Winter	On Summer	Off Winter	Off Summer
2019	$ (0.53)	$ (0.85)	$ (0.30)	$ (0.40)
2020	$ (0.57)	$ (0.88)	$ (0.33)	$ (0.42)
2021	$ 8.34	$ 10.46	$ 4.73	$ 5.29
2022	$ 5.96	$ 7.89	$ 3.38	$ 3.99

Q. Does this conclude your direct testimony?

A. Yes.

BEFORE THE PUBLIC SERVICE COMMISSION OF WYOMING

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR A MODIFICATION OF AVOIDED COST METHODOLOGY AND REDUCED TERM OF PURPA POWER PURCHASE AGREEMENTS	))))))	**Docket No. 20000-545-ET-18** **(Record No. 15133)**

AFFIDAVIT, OATH AND VERIFICATION FOR DIRECT TESTIMONY

STATE OF OREGON)
) SS:
COUNTY OF MARION)

Dr. Marc Hellman, being first duly sworn, on his oath states:

1. My name is Dr. Marc Hellman. I am the President of MH Energy Economics, LLC. I have been asked by Intervenors Renewable Energy Coalition ("REC") and Rocky Mountain Coalition for Renewable Energy ("RMCRE") to testify in this docket on their behalf.

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony, which has been prepared in written form for introduction into evidence in Docket No. 20000-545-EA-18.

3. I hereby swear and affirm that my answers contained in the testimony are true and correct.

Marc Hellman, Ph.D.
MH Energy Economics, LLC
2760 Eagle Eye Ave. NW
Salem, OR 97304

Subscribed and sworn to before me this 18TH day of April, 2019.

Notary Public

My Commission Expires: 10/03/2020

OFFICIAL STAMP
HANS LEO ANDRESEN
NOTARY PUBLIC-OREGON
COMMISSION NO. 955038
MY COMMISSION EXPIRES OCTOBER 03, 2020

BEFORE THE PUBLIC SERVICE COMMISSION OF WYOMING

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR A MODIFICATION OF AVOIDED COST METHODOLOGY AND REDUCED TERM OF PURPA POWER PURCHASE AGREEMENTS	))))))	**Docket No. 20000-545-ET-18 (Record No. 15133)**

AFFIDAVIT, OATH AND VERIFICATION FOR DIRECT TESTIMONY

STATE OF COLORADO)
) SS:
COUNTY OF DENVER)

Dr. Lance Kaufman, being first duly sworn, on his oath states:

1. My name is Dr. Lance Kaufman. I am a Principle Economist with Aegis Insight. I have been asked by Intervenors Renewable Energy Coalition ("REC") and Rocky Mountain Coalition for Renewable Energy ("RMCRE") to testify in this docket on their behalf.

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony, which has been prepared in written form for introduction into evidence in Docket No. 20000-545-EA-18.

3. I hereby swear and affirm that my answers contained in the testimony are true and correct.

Lance Kaufman, Ph.D.
Aegis Insight
4801 W. Yale Ave.
Denver, CO 80219

Subscribed and sworn to before me this 18th day of April, 2019.

Notary Public

My Commission Expires:
05-16-22

OFFICIAL STAMP
RONALD PAUL CORNELISON
NOTARY PUBLIC - OREGON
COMMISSION NO. 974425
MY COMMISSION EXPIRES MAY 16, 2022

CERTIFICATE OF SERVICE

I hereby certify that on this ____ day of April, 2019, the **DIRECT TESTIMONY OF DR. MARC HELLMAN AND DR. LANCE KAUFMAN ON BEHALF OF ROCKY MOUNTAIN COALITION FOR RENEWABLE ENERGY** was e-filed with the Wyoming Public Service Commission and a true and correct copy was sent via electronic mail addressed to the following:

Yvonne R. Hogle
Jacob A. McDermott
Assistant General Counsel
Rocky Mountain Power
1407 W. North Temple, Suite 320
Salt Lake City, UT 84116
yvonne.hogle@pacificorp.com
jacob.mcdermott@pacificorp.com

Christopher Leger
Wyoming Office of Consumer Advocate
2515 Warren Avenue, Suite 304
Cheyenne, WY 82002
Christopher.leger@wyo.gov

Irion A. Sanger
Sanger Law, P.C.
1117 SE 53rd Avenue
Portland, OR 97215
irion@sanger-law.com
marie@sanger-law.com

Crystal J. McDonough
Callie Capraro
McDonough Law LLC
1635 Foxtrail Drive
Loveland, CO 80538
crystal@mcdonoughlawllc.com
callie@mcdonoughlawllc.com

Michelle Brandt King
Abigail C. Briggerman
Holland & Hart LLP
6380 South Fiddlers Green Circle, Suite 500
Greenwood Village, CO 80111
mbking@hollandhart.com
acbriggerman@hollandhart.com
aclee@hollandhart.com

Renewable Energy Coalition
Attn: John Lowe
P.O. Box 25576
Portland, OR 97298
jravenesanmarcos@yahoo.com

Stacy Splittstoesser
Wyoming Regulatory Affairs Manager
Rocky Mountain Power
315 West 27th Street
Cheyenne, WY 82001
stacy.splittstoesser@pacificorp.com

Data Request Response Center
PacifiCorp
825 NE Multnomah, Suite 2000
Portland, OR 97232
datarequest@pacificorp.com

/s/ Dale Cottam