Montana Public Service Commission
Docket No. 2024.05.053
Electric and Natural Gas Rate Review

DIRECT TESTIMONY

OF JOSEPH M. STIMATZ

ON BEHALF OF NORTHWESTERN ENERGY

TABLE OF CONTENTS

Description	Starting Page No.
Witness Information	2
Purpose of Testimony	3
PCCAM Base Update	3
Calculation of Bridge Amount for YCGS	11
Regional Market Activities	13
Ancillary Services Jurisdictional Study	14
Effect of New Resources on FERC Rates	20
Conclusion	20
Verification	21

Exhibits

PowerSIMM™ PCCAM Base	Exhibit JMS-1
PowerSIMM Inputs	Exhibit JMS-2
PowerSIMM Outputs	Exhibit JMS-3

Witness Information

Q. Please identify yourself, your employer, and your job title.

A. My name is Joseph M. Stimatz. I am NorthWestern Corporation d/b/a NorthWestern Energy's ("NorthWestern") Director of Market Operations in the Energy Supply group.

Q. Please provide a description of your relevant employment experience and other professional qualifications.

A. I have over 25 years of experience in the areas of electricity and natural gas trading and marketing, hedging strategy, and asset valuation. I joined NorthWestern in March of 2011 and now lead NorthWestern's electric and natural gas wholesale market operations. Prior to joining NorthWestern, I co-founded Highland Energy, an energy trading firm that participated in electricity markets throughout the Western Electricity Coordinating Council region. I also worked for Montana Power Trading & Marketing Company and PPL Energy Plus in various positions related to trading, marketing, and portfolio management. I hold a Bachelor's degree in Finance, a Master's in Business Administration, and a Chartered Financial Analyst designation.

Purpose of Testimony

Q. What is the purpose of your testimony in this docket?

A. The purpose is to present an update to the Base Power Costs and Credits for NorthWestern's Power Costs and Credits Adjustment Mechanism ("PCCAM"). This baseline of costs and credits is referred to as the PCCAM Base. I also describe NorthWestern's participation in regional initiatives for the benefit of our customers, and describe the "units most likely" methodology used as part of the jurisdictional cost of service study as it relates to ancillary services.

PCCAM Base Update

Q. Please provide an overview of the PCCAM Base.

A. The PCCAM Base is a forecast of costs and credits used to develop the rates through which NorthWestern recovers power costs such as fuel and purchased power expenses incurred to serve electric customers. NorthWestern also recovers Demand Side Management ("DSM") costs, Montana Public Service Commission ("MPSC" or "Commission") taxes, and Montana Consumer Counsel ("MCC") taxes pursuant to PCCAM tariff, Schedule No. EPCC-1. As that tariff describes, however, those costs are not included in the PCCAM Base that I present in my testimony.

Q. What PCCAM Base did the Commission approve in the last rate review?

A. The Commission approved a PCCAM Base of $208,282,098 in Order No. 7860y, ¶ 233, Docket No. 2022.07.078 (Oct. 27, 2023). This PCCAM Base included $130,761,159 of non-Qualifying Facility ("QF") costs and credits and $77,520,939 of QF costs.

Q. What categories of costs and credits are included in the PCCAM Base?

A. The costs include items such as market purchases, fuel for thermal units such as Colstrip Unit 4 ("CU4") and the Dave Gates Generating Station ("DGGS"), and contract costs for Judith Gap and Basin Creek. The credits include revenue from market sales and production tax credits for the hydroelectric generation and wind facilities. A more specific listing of costs and credits is included in Exhibit JMS-1.

Also, see the Direct Testimony of Elaine A. Rich, explaining NorthWestern's proposed change to the PCCAM tariff to explicitly provide for reagent costs, such as CU4 limestone costs and DGGS ammonia costs, to be included in the PCCAM instead of base rates. The cost of ammonia, used as a fuel treatment at DGGS, is included in Exhibit JMS-1 row 22, "DGGS Fuel, Transportation, and Reagents." The ammonia cost is $955,744. Related to Colstrip, the cost of mercury reduction ($986,616) and limestone ($995,347) are both included in row 20, "Colstrip Unit 4 Total Fuel Cost." For the Yellowstone County Generating Station ("YCGS"), the reagent costs are included in row 24.

Q. Why should the Commission approve an update to the PCCAM Base?

A. The PCCAM Base that the Commission approved in 2023 was the result of NorthWestern's 2022 Electric and Natural Gas General Rate Review and was based on a forecast of market prices that is now two years old. The forecast needs to be updated to include more recent electric market and fuel prices. In addition, there have been changes in NorthWestern's portfolio of resources that should be reflected in the PCCAM Base. These changes together have the result of substantially reducing the PCCAM Base from the previous level.

Q. How does the current market for future delivery of electricity compare to the market prices that were used to determine the current PCCAM Base?

A. Today's Mid-Columbia trading hub wholesale forward prices are lower in some months and higher in other months, but overall higher on average. Table 1 below shows the forward curve for July of 2022 through June of 2023 from the Intercontinental Exchange ("ICE"), which was used to set the current PCCAM Base, and the current forward prices for July of 2024 through June of 2025.

Table 1

	Forward Curve from 2022 PCCAM Base Update	Current Forward Market
July	$ 79.73	$ 76.36
August	$ 140.15	$ 116.16
September	$ 99.69	$ 95.31
October	$ 71.18	$ 60.37
November	$ 69.45	$ 66.86
December	$ 91.91	$ 94.92
January	$ 82.44	$ 110.22
February	$ 73.02	$ 88.77
March	$ 48.26	$ 58.59
April	$ 31.43	$ 53.69
May	$ 29.36	$ 41.49
June	$ 38.57	$ 34.47
Mid-Columbia all hours price, $/MWh		

Q. How does the current market for future delivery of natural gas fuel compare with the market prices that were used to determine the current PCCAM Base?

A. The current market is significantly lower than the market in 2022. Table 2 below shows the forward curve for July of 2022 through June of 2023 compared with the current forward curve for July of 2024 through June of 2025 at the Alberta Energy Company ("AECO") hub.

Table 2

	Forward Curve from 2022 PCCAM Base Update	Current Forward Market
July	$ 5.556	$ 1.285
August	$ 5.367	$ 1.318
September	$ 5.409	$ 1.315
October	$ 5.351	$ 1.455
November	$ 5.673	$ 2.093
December	$ 5.889	$ 2.397
January	$ 5.921	$ 2.500
February	$ 5.917	$ 2.487
March	$ 5.196	$ 2.286
April	$ 3.751	$ 2.197
May	$ 3.498	$ 2.131
June	$ 3.493	$ 2.169
AECO Natural Gas Prices, $/MMBtu		

Q. How has NorthWestern's supply portfolio changed since the Commission approved the PCCAM Base in the 2022 rate review?

A. The most significant change has been the addition of YCGS. The plant will provide significant capacity and energy for NorthWestern's customers. Also, two 80-MW solar QF facilities, MTSun and Apex, came on-line in 2023. Finally, two capacity contracts with Morgan Stanley for a total of 75 MW expired on March 31, 2024.

Q. What YCGS costs are included in the PCCAM Base?

A. The YCGS costs included in PCCAM Base are the cost of fuel purchases, reagents, and fuel transportation and storage costs. The fuel purchase costs include the cost for NorthWestern to purchase natural gas on the market for delivery to NorthWestern's system using the Colorado Interstate Gas ("CIG") Pipeline. Transportation costs include costs on both CIG and on NorthWestern's gas transportation system. Fuel storage costs include the cost of storing and withdrawing natural gas in storage facilities owned by NorthWestern. Reagent costs are the costs of ammonia, limestone, or other consumables where usage varies with the consumption of fuel and power generation.

Q. Please describe how NorthWestern provides YCGS with fuel.

A. We procure the majority of the fuel needed for YCGS in the Rockies region, typically at the Cheyenne Hub. We also have the ability to procure additional natural gas delivered by counterparties using CIG, and we can withdraw fuel from storage on NorthWestern's system for delivery to YCGS. NorthWestern's system is used to deliver the natural gas from the interconnection with CIG to the plant. We have a long-term transportation contract with CIG for up to 25,000 MMBtu per day for this purpose.

Q. How does the addition of YCGS to NorthWestern's portfolio affect the PCCAM Base?

A. Adding YCGS reduces the need for energy purchases and increases market sales, which provide credits for customers. The lower cost of purchases and increased credit for sales are partially offset by the cost of fuel to generate, but since YCGS is dispatchable and will only generate energy when its variable generation costs are lower than the market price, the net effect is a significant reduction in the PCCAM Base.

Q. What PCCAM Base amount does NorthWestern propose for approval in this case?

A. NorthWestern proposes a PCCAM Base of $119,007,402. The total includes forecasted non-QF Base Power Costs and Credits of $24,192,691, which are subject to 90/10 sharing and forecasted QF costs of $94,814,711, which are not subject to the 90/10 sharing.

Q. How did you develop the proposed PCCAM Base?

A. NorthWestern retained Ascend Analytics, LLC to use the PowerSIMM software to help forecast some of the expected costs and credits on our system. PowerSIMM is an analytical software package that combines market dynamics with physical characteristics in power system modeling. PowerSIMM simulates weather, load, renewable generation, and market prices. The simulations flow into a dispatch model where the physical parameters of the power system (generators, transmission, ancillary services, etc.) are used to simulate the operation of the power system. PowerSIMM was used in a similar fashion to set the PCCAM Base in the 2022 rate review, and NorthWestern has used PowerSIMM for over a decade for services including resource planning, avoided cost modeling, evaluation of Requests for Proposals ("RFP"), and other supply planning activities.

Note that PowerSIMM is used to forecast or estimate energy purchase costs, sales credits, fuel costs, and payments for deliveries under PPAs. Some costs and credits included in the total PCCAM Base, such as the fixed costs of capacity purchases, renewables forecasting costs, and production tax credits, are forecasted outside of PowerSIMM. The PCCAM Base also includes an estimate of market purchase costs that NorthWestern incurs during cold snaps and heat waves, when capacity in the region is very tight and market prices rise to extreme levels, often at or near $1,000 per MWh. This estimate is included in the Energy Market Purchases, line 9, in Exhibit JMS-1.

Q. What assumptions and inputs are included in the PowerSIMM forecast?

A. The key assumptions in the PowerSIMM base forecast are:

1. the forward price of electricity;
2. the forward price of natural gas;
3. the expected supply load; and
4. the resources in the supply portfolio

Further details regarding the PowerSIMM inputs and other assumptions are included in Exhibit JMS-2.

Q. Do you have an exhibit of the resulting PowerSIMM outputs used to develop the proposed PCCAM Base?

A. Yes. Exhibit JMS-3 illustrates the PowerSIMM outputs.

Calculation of Bridge Amount for YCGS

Q. Does NorthWestern propose a bridge amount related to YCGS?

A. Yes. NorthWestern is proposing a bridge amount of $58,470,142. Ms. Fang's testimony describes the need for the bridge amount and how it will be implemented. I describe the calculation of the amount below.

Q. How did you determine the bridge amount?

A. First, I estimated the effect that YCGS has on the PCCAM Base I presented in my testimony above. As I described, YCGS is included in the proposed PCCAM Base presented in my testimony. The inclusion of YCGS reduces the amount of the base compared to what it would have been had YCGS not been included. YCGS affects both the energy costs and the capacity costs in the PCCAM Base.

Q. How did you determine the effect on energy costs?

A. If YCGS was not included in the PowerSIMM modeling, there would have been additional market purchases needed, and there would also have been fewer market sales. I calculated the combination of additional market purchases and reduced market sales by multiplying the modeled output of

YCGS for each hour by the modeled market price in that hour and summing the results. The total for the modeled year is $84,150,240, which represents the gross energy market benefit of YCGS in the PCCAM Base. I subtracted the $34,756,496 of YCGS generation costs from the gross market benefit to arrive at a net energy benefit of $49,393,743.

Q. How did you determine the effect on capacity costs?

A. To determine the YCGS effect on capacity costs, I estimated the additional capacity we would need to purchase in the market each month if we did not have YCGS in the portfolio. I then multiplied the lower of the shortfall or the qualifying capacity of YCGS by the estimated market price of capacity of $14/kW-month. The result for the year is a capacity benefit of YCGS of $9,076,398.

Q. What would be the total effect of removing YCGS from the PCCAM Base?

A. The total benefit is the sum of the energy benefit and the capacity benefit, which is $58,470,142. Put another way, this means that without YCGS, the PCCAM Base would have been higher by that amount. Instead of $119,007,402, it would have been $177,477,543.

Regional Market Activities

Q. Please provide an update on regional market activities.

A. There are two major regional market initiatives underway. First, the California Independent System Operator ("CAISO") is developing the Extended Day-ahead Market ("EDAM"). This market will expand the Western Energy Imbalance Market ("WEIM"), in which NorthWestern participates, to include day-ahead unit commitment and transactions. Second, the Southwest Power Pool ("SPP") is developing Markets +, a competitor to EDAM and WEIM.

Q. Will NorthWestern join one of these markets?

A. We believe that these markets will provide significant customer benefits and that most if not all of the utilities in the region will join one or the other. We expect to join either EDAM or Markets +, though we have not yet determined which market will be a better choice for NorthWestern and our customers. Though there are other considerations, the decision largely depends on our transmission connectivity to each market and the entities that participate. Thus, our decision will depend in large part on what our neighboring utilities decide.

Q. If NorthWestern decides to join a day-ahead market, when will it begin participating?

A. We could begin participating as early as 2027. It is possible that we could begin incurring costs for the implementation later this year.

Ancillary Services Jurisdictional Study

Q. Did NorthWestern prepare a jurisdictional study for ancillary services?

A. Yes. In paragraph 6 of the Stipulation and Settlement agreement approved in Docket No. 2022.07.078 ("2023 Settlement"), NorthWestern agreed to provide a comprehensive jurisdictional study of all costs associated with providing wholesale service concurrently with its next electric rate review. NorthWestern agreed to provide supporting workpapers and inputs (including variability analysis used to estimate units most likely), the outputs used to set current FERC-regulated rates, and refreshed outputs based on updated data.

Q. How was the ancillary services jurisdictional study presented in this filing developed?

A. NorthWestern took the same approach to the ancillary services analysis that we did in our 2019 Federal Energy Regulatory Commission ("FERC") rate review. That approach resulted in the ancillary service rates that are currently in effect for third-party customers under our Open Access Transmission Tariff ("OATT"). There are four ancillary service products or schedules in our OATT: Schedule 3,[1] Regulation and Frequency Response; Schedule 5, Operating Reserve – Spinning Reserve Service; Schedule 6, Operating

[1] Schedules 3 and 3A of NorthWestern's OATT both cover Regulation and Frequency Response service; Schedule 3 applies to load in NorthWestern's Balancing Authority ("BA") and generation in the BA that serves that load. Schedule 3A applies to generation that is exported on point-to-point transmission. For simplicity, my references to Schedule 3 encompass both schedules.

Reserve – Supplemental Service; and Schedule 11, Flex Reserve Service. There are three major steps to determine the rates for each service.

First, we estimate the amount of each type of reserves that were needed on NorthWestern's system during the test year. Although there are only four ancillary service schedules in NorthWestern's OATT, there are five types of reserves needed. We engaged Eugene Shlatz of Green Mountain Solutions to perform the detailed study work to estimate the volume of Fast-Moving Reserves and Following Reserves that comprise Schedule 3 and the Flex Reserves used to provide Schedule 11. Mr. Shlatz performed the same anlysis for our 2019 FERC rate review. His testimony in this docket describes the methodology in detail. The percentage of load and generation needed for Schedules 5 and 6 is specified by reliability standards. The quantities needed for Schedules 5 and 6 during the test year were determined by NorthWestern based on that standard.

Second, we used the "units most likely" or "UML" methodology to allocate the quantity of each ancillary service to the generating units that are capable of providing the reserves. My testimony below describes this allocation process.

Third, we used the results of Mr. Shlatz's study and the UML analysis, along with the fixed cost of the generating units, to derive rates for the ancillary services, and we use those rates to estimate the revenue credit that might result from those rates, if we were to go through a FERC rate review to change the existing rates. This portion of the analysis is presented in the Direct Testimony of Glenda J. Gibson.

This analysis is intended to provide information as agreed to in the 2023 Settlement. NorthWestern attempted to use methodologies consistent with those used in its 2019 FERC rate review, and the results are presented in this filing. The 2019 FERC rate review resulted in a settlement, which included agreement on quantities of Schedules 3 and 11, which were lower than the amounts calculated by Mr. Shlatz in his analysis for that case. NorthWestern estimated similar adjustments to the quantities in the current analysis in order to be consistent with the outcome of that FERC rate review. NorthWestern has no plans to initiate a FERC rate review at this time, and the rates that result from any such FERC rate review could differ from what is presented in this filing.

Q. How did NorthWestern identify the units that provide the reserves?

A. We used a two-step process to identify the units. This approach had been accepted by FERC in several proceedings prior to NorthWestern's use of it in 2019 and was accepted by FERC in our case. First, we used historical data to identify the available capacity from the units that are able to provide any of the five types of reserves that are needed on our system: Fast-Moving Reserves, Spinning Reserves, Supplemental Reserves, Following Reserves, and Flex Reserves. This includes both generation plants owned by

NorthWestern and a plant under a long-term PPA for which NorthWestern has dispatch control. Second, to account for the fact that the same resources can provide multiple types of reserves, we used an iterative allocation process to ensure that the same capacity is not double-counted or used twice to serve the same regulation need.

Q. How did you determine the amount of capacity available to provide reserves for each plant?

A. We calculated each plant's available capacity during the test year (2023)[2] by multiplying the Net Maximum Capability by the difference between the Equivalent Availability Factor ("EAF") and the Net Capacity Factor ("NCF") — i.e., Net Maximum Capability x (EAF – NCF). A plant's Net Maximum Capability is its gross maximum capacity less any capacity used for station service. EAF is a plant's total service hours, less planned and unplanned outage hours and derate hours, expressed as a percentage of the total hours in the period. NCF is calculated as the net generation of the plant, divided by the product of the Net Maximum Capacity and the number of hours in the period. Table 1 in Exhibit JMS-4 summarizes these calculations for each resource that provides reserves.

[2] Since YCGS was not online in 2023, we used estimates based on modeling during the 2020 RFP process.

Q. How does NorthWestern account for the possibility that some units may be used primarily to serve load?

A. The Available Capacity calculation addresses this possibility and ensures that capacity used to serve base load is not double-counted as capacity utilized in ancillary services. As can be seen in Table 1 of Exhibit JMS-4, facilities such as CU4 have relatively low available capacities for purposes of providing ancillary services because they have high capacity factors and are used primarily to serve retail base load. Thus, these types of facilities have less capacity available to provide reserves. Conversely, facilities such as DGGS have lower capacity factors, so their available capacity to provide ancillary services is relatively higher.

Q. Please describe the allocation of capacity to Reserves.

A. In order to determine the amount of capacity that is available to provide Fast-Moving Reserves, there are considerations in addition to the Available Capacity. First, the ability to provide the reserves may be limited by a unit's ramp range. That is, the amount that a unit can ramp in ten minutes might be less than its Available Capacity. Second, Fast-Moving Reserves must be provided by resources that are online and able to respond to an Automatic Generation Control ("AGC") signal. The quantity of Fast-Moving reserves is allocated among the resources that can provide it, based on each resource's Available Capacity. Table 2 in Exhibit JMS-4 shows the allocation of Fast-Moving Reserves.

Q. Please describe the allocation of capacity to Spinning Reserves.

A. The first step in this part of the process is to subtract the quantity of Fast-Moving allocation from the Available Capacity for each unit, which leaves the amount of Available Capacity for potential allocation to Spinning Reserves. Again, this ensures that a resource's capacity is not double-counted. In order to provide Spinning Reserves, a resource must be online and capable of providing energy within ten minutes; however, the unit does not need to be on AGC. This means that most of the resources in the pool are capable of providing Spinning Reserves. The quantity of Spinning Reserves needed on the system is allocated among the resources that can provide that product. Table 3 in Exhibit JMS-4 shows the allocation of Spinning Reserves.

Q. Please describe the allocation of capacity to the other reserves.

A. The quantity needed for each product is allocated in turn similar to the process for Spinning Reserves. In each case, the amount of capacity allocated in previous steps is subtracted from the Available Capacity in order to ensure that the resource's capacity is not double-counted. The necessary amount of each product is then allocated on a pro-rata basis among the resources that can provide it, based on each resource's remaining Available Capacity.

Q. Please describe the results of the ancillary services jurisdictional study.

A. Table 4 in Exhibit JMS-4 summarizes the results of the allocation to each reserve type. The percentage allocations are used to determine rates for each service, which in turn are used to estimate the revenue that would result from providing service at those rates to third-party customers. This part of the process is discussed in Ms. Gibson's testimony.

Effect of New Resources on FERC Rates

Q. Will the inclusion of YCGS change the FERC rates?

A. No, the FERC rates will not change with the addition of YCGS or the resulting UML. Our FERC-approved OATT allows us to charge certain rates for ancillary services based on the cost of a defined mix of resources that provides the services. We cannot change the mix of resources that was used to calculate ancillary service rates without making a Section 205 Filing with FERC to request the change, initiating a contested process.

Conclusion

Q. Please summarize your testimony.

A. Because the current PCCAM Base does not reflect NorthWestern's current supply portfolio or the current forward markets for electricity and natural gas, NorthWestern requests that the Commission approve a decrease of the PCCAM Base from $208,282,098 to $119,007,402. NorthWestern expects to join one of the regional day-ahead markets as early as 2027, and may begin incurring costs related to joining as early as 2024. Finally, NorthWestern performed a jurisdictional study related to ancillary services. I presented the portion of that study known as the Units Most Likely, which allocates the provision of ancillary services to the generating units that provide them. Other portions of the study are presented in the Direct Testimonies of Glenda Gibson and Eugene Shlatz.

Q. Does this conclude your direct testimony?

A. Yes, it does.

<u>Verification</u>

This Direct Testimony of Joseph M. Stimatz is true and accurate to the best of my knowledge, information, and belief.

<u>/s/ Joseph M. Stimatz</u>
Joseph M. Stimatz