Office of the Secretary
Service Date
January 21, 2022

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF IDAHO POWER COMPANY'S ANNUAL COMPLIANCE FILING TO UPDATE THE LOAD AND GAS FORECASTS IN THE INCREMENTAL COST INTEGRATED RESOURCE PLAN AVOIDED COST MODEL	)))))))	**CASE NO. IPC-E-21-35** **ORDER NO. 35294**

On October 15, 2021, Idaho Power Company ("Company") filed its annual update ("Filing") to its updated load forecast, natural gas price forecast, and contracts used as inputs to calculate its incremental cost Integrated Resource Plan ("IRP") avoided cost rates. The Company must update these inputs annually by October 15. *See* Order Nos. 32697 and 32802. IRP avoided cost rates are available to qualifying facilities ("QFs") that are above the resource-specific project eligibility cap for published avoided cost rates under Idaho's implementation of the Public Utility Regulatory Policies Act of 1978 ("PURPA").

On November 5, 2021, the Company filed a supplement ("Supplement") to its Filing which updated the Peak Hours and Premium Peak Hours used to calculate capacity payments for battery storage resources in the incremental cost IRP avoided cost model.

On November 19, 2021, the Commission issued a Notice of Filing and established a December 21, 2021, public comment deadline and a December 28, 2021, Company reply deadline. Order No. 35228.

On November 22, 2021, the Company filed a second supplement ("Second Supplement") correcting an error that the Company discovered with the natural gas price forecast it initially submitted in its Filing.

Staff filed comments to which the Company filed a reply.

Having reviewed the record in this case, including Staff's comments, the Commission approves the Company's annual update to its load forecast, contract changes, Peak Hours and Premium Peak Hours as filed. The Commission declines to adopt the natural gas price forecast filed in the Second Supplement.

BACKGROUND

Under PURPA and the Federal Energy Regulatory Commission's ("FERC") implementing regulations, this Commission has approved the IRP Method to calculate avoided cost rates for QFs that are above the resource-specific project eligibility cap. QFs below the project eligibility cap are eligible to receive published avoided cost rates calculated using the surrogate avoided resource ("SAR Method"). *See* Order No. 32697 at 7-8. The avoided cost rate is the purchase price paid to QFs for the energy and capacity that the QF provides to the utility. 18 C.F.R. § 292.101(b)(6) (defining "avoided cost"). To ensure that avoided costs most accurately reflect the utility's marginal cost of energy and capacity, the Commission has directed utilities to "update fuel price forecasts and load forecasts annually – between IRP filings," and to update the Commission about the utility's "long-term contract commitments because of the potential effect that such commitments have on a utility's load and resource balance." *See* Order No. 32697 at 22.

THE FILING

The Company proposed to update the peak and energy load forecast, natural gas forecast, and QF contract additions used as inputs in the Company's IRP Method. The Company's proposed update to its natural gas price forecast was developed using the most recent Henry Hub and Sumas Basis Annuals from S&P Global Platt's Long-term Forecast[1], which was published in July 2021. Filing at 4.

The Company stated it currently had three non-PURPA long-term power purchase agreements ("PPA") online with a combined megawatt ("MW") capacity of 136 MW as well as a long-term PPA scheduled to be online in December 2022 with a 120 MW capacity. *Id.* at 5. The Company further stated that it currently had 129 contracts with PURPA QFs with a total nameplate capacity of 1,137.8 MW. *Id.* The Company also represented that it had two new signed Energy Sales Agreements ("ESA") with Oregon solar QF ESAs totaling approximately 71.3 MW that were not yet online, and ten replacement ESAs for existing Idaho QF projects totaling 24.95 MW. *Id.*

STAFF COMMENTS

A. Load Forecast, Contract Changes, and Peak Hours and Premium Peak Hours

Staff believed the change to the load forecast and the resulting increased load forecast were reasonable. *Id.* Staff reviewed the contract changes listed in Attachment 2 of the Application

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[1] The Company represented that, since "the Platts forecast is subscription based and proprietary", information from the forecast was included as a confidential attachment to the Filing.

and noted that the changes were correct. *Id.* (citing Order No. 32697). Staff noted that it had learned from a recent IRP meeting that there has been some uncertainty associated with the Jackpot Holdings, LLC (120 MW) project scheduled to be online in December of 2022. *Id.* Staff thus recommended the Company remain vigilant in updating the IRP model to reflect any changes that occur to the project. *Id.*

Staff recommended approval of the proposed Peak Hours and Premium Peak Hours used to calculate capacity payments for energy storage qualifying facilities in the IRP Methodology and approval of the proposed Peak Hours used to calculate capacity payments for energy storage qualifying facilities in the SAR Methodology. *Id.* at 8.

The Company used the same method to determine the Peak Hours and the Premium Peak Hours as it did in the Compliance Filing in Case No. IPC-E-20-02. Staff believed the result in this case was reasonable and complied with the requirements of Order No. 34913.

Staff corroborated the Preliminary Premium Peak Hours with the Loss of Load Probability ("LOLP") data from the most recent IRP (2019) and the most recent Locational Marginal Pricing ("LMP")[2] data. *See Id.* at 9. Staff noted the LOLP in the 2019 IRP was based on an analysis of the likelihood of unique loss-of-load events in year 2025. Staff believed that using year 2025 for the LOLP analysis was reasonable.

Staff stated that Order No. 34913 requires an annual update of the Peak Hours used to calculate capacity payments for energy storage QFs in the SAR Methodology. Staff stated that the current update shifts the peak hours one hour later for July and for August from the current peak hours approved in Order No. 34913. Staff further stated that, because the update does not change the total number of Peak Hours in a year (434 hours), the SAR Model does not need to be updated, and the published avoided cost rates for energy storage will not be affected. However, Staff indicated that the timeframe that the avoided cost of capacity is applied shifts by one hour.

B. The Corrected Natural Gas Price Forecast

Staff noted that the Company provided a nominal price forecast ("July Forecast") in the Second Supplement to correct the errors it made in the natural gas price forecast submitted with the Filing. Staff Comments at 3. Staff focused on the first few years of the July Forecast time horizon as, due to the limited term length of two years, this is the only portion of the forecast that

[2] The LMP data is weighted average hourly prices based on all pricing nodes in the Company's Balancing Area from four fifteen-minute market price intervals and twelve real-time five-minute price intervals.

affects pricing in new IRP-based contracts. *Id.* (citing Order No. 33357.) Staff was concerned with the July Forecast after (1) comparing it to an earlier forecast the Company submitted in IPC-E-21-15 ("March Forecast"), and (2) comparing the Company's Henry Hub forecast to the Henry Hub forecasts recently filed by the two other Idaho electric utilities in their annual updates. *Id.* Based on these comparisons, Staff ultimately believed that the natural gas forecast filed in the Second Supplement should be rejected. *Id.*

Staff started by comparing the Company's July Forecast to the March Forecast. Both forecasts were Henry Hub annuals from S&P Global Platts long-term forecasts adjusted for Sumas basis and transport costs for Idaho City Gate delivery. *Id.* Staff stated that the July Forecast was published in July 2021 and the March Forecast was published in March 2021. Staff noted that Figure No. 3 and the confidential natural gas updates provided to Staff by the other Idaho utilities demonstrated that changes in natural gas market fundamentals between March and July 2021 caused an upswing in natural gas spot market prices and in future prices. *Id.* at 4. However, Staff pointed out that the Company's March and July Forecasts were almost identical. *Id.* (citing Figure No. 2). Staff believed that the lack of change between the two forecasts indicated that Platts may not have been responsive to short-term market changes.

Staff then compared the Company's S&P Global Platts Henry Hub forecast to the Henry Hub forecasts used by the other two utilities—Avista Corporation dba Avista Utilities ("Avista") and Pacificorp dba Rocky Mountain Power ("RMP")—without including an adjustment for Sumas basis and transport costs for Idaho City Gate delivery. Staff noted that the Company's near-term forecast was significantly lower than the other two utilities' forecasts, especially during the first few years. *Id.* at 5.

Staff further noted that the main difference between Avista's and RMP's forecasts and the Platts forecast is that the former forecasts use New York Mercantile Exchange ("NYMEX") futures prices exclusively over the first few years. *Id.* at 6.

Staff stated that Avista used a blend of two national price forecasting consultant's most recent forecasts, the Energy Information Administration's ("EIA") Annual Energy Outlook forecast, and forward market prices. *Id.* at 6. Staff further stated that the first 12 months of Avista's forecast was based entirely on the NYMEX forward prices and the weight of forward prices given to subsequent years decrease over time. *Id.*

Staff stated that RMP's Official Forward Price Curve ("OFPC") was developed using 36 months of natural gas forward prices. Staff Comments at 6. Staff observed that the 12 months following the first 36 months use a blend of forwards and market fundamentals, while the remaining months of the forecast transition to a pure fundamentals-based forecast starting in month 49. *Id.* Staff represented that RMP believed that market forwards (from broker quotes and / or settled forward prices) for the first 36 months are observable and represent a consensus view of the market. *Id.* at 6-7.

Staff noted through discovery that the Company specifically discussed the Platts methodology which the Company uses. *Id.* at 7. Based on the Company's discussion, Staff came to two conclusions.

First, Staff did not believe the near-term discrepancy was due to the different timing of the three forecasts. *Id.* As Staff noted, the Platts forecast used by the Company was published in July 2021 and Avista's NYMEX data was obtained on August 13, 2021. *Id.* Staff believed that, given the similarity between the two datasets, notwithstanding the fact that RMP's final OFPC was finalized on September 30, 2021, RMP obtained the forward prices around the same time as Avista. *Id.*

Second, Staff believed that the Platts forecast failed to capture the changes in the natural gas market occurring in the months before October 15, 2021, while Avista and RMP's forecasts—which rely on NYMEX forward prices for the near term—did. *Id.* Staff explained that it had previously supported the Company's use of the Platts forecast as Platts was an improvement from EIA and, being published in March 2021, was comparable to the two other utilities' Commission-approved forecasts. *Id.* (citing Case Nos. AVU-20-10 and PAC-E-20-16). However, Staff noted that the Platts forecast did not capture the changes in the market and that this lack of responsiveness was not revealed in the March Forecast because the Market was "relatively stable at that time." *Id.* at 7.

For the above reasons, Staff recommended rejecting the Company's July Forecast. *Id.* Staff recommended that the Company use the first three years of the latest NYMEX forwards prices for contracts signed after January 1, 2022, and continue to use these prices until the effective date of the next annual update. In addition, Staff recommended that the Company reevaluate the forecast methodology it uses to determine next year's annual update, especially for the first three years of the forecast time horizon.

C. January 1, 2022, Effective Date

Finally, Staff recommended that the Company, as well as the other two electric utilities in Idaho, continue to file its annual natural gas and load forecast IRP Method updates by October 15 as required by Order No. 32802, but establish a fixed effective date of January 1st, of the following year. *Id.* at 8. Staff recommended this effective date should apply in this case and in all future update cases for all three Idaho electric utilities. *Id.* Staff stated that having an effective date after the filing deadline would provide more time to review the utilities' filings and prevent having an identical filing deadline and effective date. *Id.*

COMPANY REPLY COMMENTS

A. Load Forecast, Contract Changes, and Peak Hours and Premium Peak Hours

The Company replied that it appreciated and accepted Staff's recommendations to approve the Load Forecast, Contract Changes, and Peak Hours and Premium Peak Hours. Company Reply Comments at 2.

B. Natural Gas Price Forecast

The Company replied that Staff's recommendation to change the forecast source was inconsistent with Commission precedent. *Id.*. The Company further replied that Staff's recommendation to change the forecast source was not supported by the evidence. *Id.* at 5. The Company also observed that the Platts updated December 2021 forecast corresponded to RMP's and Avista's forecasts and, therefore, proposed updating its forecast with the Platts December 2021 update rather than utilizing the NYMEX. *Id.* at 8.

1. Commission Precedent

The Company stated that the Commission previously determined that the load forecast and the natural gas forecast used as inputs for the Incremental Cost Integrated Resource Plan ("ICIRP") avoided cost methodology were to be updated annually by October 15 of each year. *Id.* at 3. (citing Order No. 32697).

The Company explained that "[h]istorically, the October 15 update to the natural gas price forecast has been an update to the ***vintage*** of the natural gas price forecast, not to the ***source*** of the forecast or the ***methodology*** for calculating it." *Id.* (emphasis in the original). The Company explained that the "update has incorporated the most-recent version of the forecast used in the most recently acknowledged IRP." *Id.* The Company explained that "[a]ny changes to the source or calculation of the forecast have been primarily reviewed and vetted through the IRP itself – not through changes to the October 15 annual update." *Id.* As the Company further explained, this process "is consistent with the intent and language of Order No. 32697 – the gas price forecasts used in the IRP are updated between IRP cycles, but other IRP variables and assumptions remain the same." *Id.*

The Company summarized that it is important "that the gas forecast methodology used for avoided cost pricing remains consistent with that used by the utility in its Integrated Resource Planning - but [allow for] the data (vintage) to be updated on an annual basis, rather than every two years with the IRP." *Id.* at 4. The Company contended that "to use the NYMEX forward prices as the natural gas price forecast in the near-term, rather than the Platts forecast used in the most recently acknowledged IRP . . . would be a stark departure from this precedent on the annual gas price forecast and would lead to the use of a forecast that has not been adequately considered in the IRP process." *Id.* at 4. In sum, the Company explained that changing the forecast source would "inappropriately create a disconnect between the gas price forecast source in the 2019 IRP and the forecast used in the ICIRP methodology between IRPs [and would be] inconsistent with the intent of this proceeding." *Id.* at 4.

The Company reiterated that changing from the Platts forecast, which was substantially reviewed and vetted by the Commission, the public and the Company's own IRP process, to the NYMEX, which was not, would be improper. *Id.* at 4-5.

2. Evidence for the Change

The Company stated that Staff's recommendation to reject the Company's Platts forecast was "based on two analyses it conducted: (1) a comparison of the nominal forecast in this case (July Forecast) to an earlier forecast submitted in IPC-E-21-15 (March Forecast); and (2) a comparison of the Company's Henry Hub forecast to RMP's and Avista's Henry Hub forecasts recently filed through their annual updates." *Id.* at 5. The Company disagreed with Staff's conclusion that the Platts forecast failed to respond to near term market shifts. *Id.* The Company explained that it "believed that the differences identified by Staff [were] solely due to the timing differences of when Platts and Avista's and RMP's forecast data was obtained relative to the upswing in market prices referenced by Staff." *Id.* at 5-6.

The Company explained that it used "the information from both Avista's and RMP's filings, [and] was able to back into the pull-date for the Henry Hub pricing contained in their forecasts: September 30, 2021, for RMP; and October 13, 2021, for Avista." *Id.* at 6. The Company pointed out that "Figure No. 3: U.S. Historical Natural Gas Prices" demonstrated "that the difference in timing between the data utilized by the different forecast corresponds to the differences in near term prices seen by Staff." *Id.* at 6-7 (citing Staff Comments at 5.). The Company further explained that Figure No. 3 graph demonstrated why there would "be little difference between a Platts forecast from March 2021 to June 2021." *Id.* at 7.

The Company summarized that "the difference between the Henry Hub (NYMEX) forecasts is due to the timing." *Id.* at 7. The Company explained that the "timing difference explains the disparity between the updated Platts long-term July forecast which does not capture the volatile price run-up that occurred from the end of July through the end of November." *Id.*

The Company further explained that "the spot market is different than the forward market." *Id.* As the Company elucidated, changes in the spot or daily cash market are often driven by a number of factors including seasonality, weather, and short-term pipeline events and do not affect the long-term market fundamentals; therefore, such changes should not be factored into a long-term (6+ years) forecast which shows one price annually. *Id.*

To illustrate the volatility of the markets, the Company explained that the "Henry Hub/NYMEX annual price for 2022 increased by 39% from June 4, 2021, (the time when the Platts July forecast was developed), to September 30 (when RMP pulled pricing) and 41% from June 4, 2021, to October 13, 2021 (when Avista pricing was updated in the 12/14/21 filing)." *Id.* at 8. However, as the Company stated, from "October 13 to December 23, that price decreased by 19%." *Id.* at 8.

3. Platts Correspondence

The Company stated that "the Platts updated December 2021 Forecast corresponded to RMP's and Avista's forecasts." *Id.* The Company stated that "Platts published an updated Platts Long-Term Gas Forecast in December, 2021, which does factor in increased prices and the first 5 years of the forecast show a 22% increase over the July, 2021 forecast." *Id.* The Company explained that this "reinforces the effect of the timing of the relative forecasts in relation to the run-up in gas pricing referenced by Staff, which occurred from approximately late July through November 2021." *Id.* The Company further explained that it was limited to using the July Platts forecast—which did not capture the run-up in pricing reflected in the other utility's forecast—as this was the most recent Platts forecast available to make the October 15 compliance filing deadline. *Id.*

As an alternative to rejecting the Platts forecast and implementing a NYMEX forwards-based methodology change that was asserted to be inconsistent with the Company's IRP, the Company proposed updating the gas forecast with the Platts December 2021 update. *Id.* The Company stated that the Confidential Attachment No. 1 included: (1) Table 1, the Natural Gas Forecast Pricing based on Platts December 2021 update; (2) Graph 1, showing the relative change in the Platts forecasts; and (3) Table 2, Henry Hub Annuals from Platts December forecast, which was the same table Staff requested for the Platts July forecast in discovery. *Id.* at 8-9.

4. January 1st Effective Date

The Company disagreed with Staff's proposal that this update take effect on January 1, 2022, and that future load and gas price forecast updates for the ICIRP methodology take effect January 1 following the October 15 filing. *Id.* at 9. The Company stated that the "October 15 update to the load and natural gas price forecasts is intended to be a routine update to those limited assumptions, with the underlying source or methodology vetted in the IRP process, not in the update proceedings". *Id.* at 9. The Company explained that "the Commission has historically approved these updates with an effective date of October 15." *Id.* The Company further explained that the "October 15 effective date is critical to ensure that projects that may enter the energy sales agreement queue after October 15 are priced appropriately based on the most updated information." *Id.* The Company pointed to the Commission's regular approval of "past October updates effective as of October 15 of the applicable year, even though the order may be dated after that date." *Id.*

The Company cautioned that "[c]reating a lag between the update filing date and the effective date creates the potential for projects to try to anticipate the impact the update will have on avoided cost pricing." *Id.* at 9. As the Company explained, if "projects believe the update will result in lower avoided cost pricing, there may be the potential for claims that projects have established legally enforceable obligations as they try to remain eligible for the old pricing." *Id.* The Company argued that "[m]oving the effective date to January 1 thus creates the potential for increased litigation, does not create any benefit, and is unnecessary." *Id.* The Company pointed to past instances where multiple projects attempted to stake a claim to what they perceived as more favorable rates or beneficial contract terms before a change in rates. *Id.* The Company mentioned '"run-on-the-bank' situations ranging from approximately 200-700 MW of wind over the course of several months and more than 1,000 MW of proposed solar projects over the course of approximately one-months' time." *Id.* at 10. The Company argued that "[c]reating a lag from October 15 to January 1 every year with the natural gas and load forecast update unnecessarily opens up what should be a routine compliance filing into a potential driver of controversy and additional litigation over pricing and avoided cost rate eligibility." *Id*. Thus, the Company recommended that the Commission maintain its current practice of using an October 15 effective date and filing deadline for the annual update filings. *Id.*

COMMISSION FINDINGS AND DISCUSSION

The Commission has jurisdiction over this matter under *Idaho Code* §§ 61-501, -502 and -503. The Commission is empowered to investigate rates, charges, rules, regulations, practices, and contracts of public utilities and to determine whether they are just, reasonable, preferential, discriminatory, or in violation of any provision of law, and to fix the same by order. *Idaho Code* §§ 61-502 and 61-503. In addition, the Commission has authority under PURPA and FERC regulations to set avoided costs, to order electric utilities to enter fixed-term obligations for the purchase of energy from QFs, and to implement FERC rules. The Commission may enter any final order consistent with its authority under Title 61 and PURPA.

Pursuant to this authority, we have reviewed the record, including the Filing, the Supplement, the Second Supplement, the comments, and reply comments. We find that the Filing complies with our directives in Order Nos. 32697 and 32802. The load growth forecast, and the proposed Peak Hours and Premium Peak Hours are reasonable given the information available at this time, and the contract information was confirmed. We therefore approve the Company's annual update to its load growth forecast, Peak Hours and Premium Peak Hours, and contract information.

After reviewing Staff's comments and the Company's reply, we find Staff's recommendation for the Company to file a three-year natural gas forecast utilizing the latest NYMEX forwards prices to be reasonable. This forecast represents current market conditions and aligns with other similar forecasts filed by the two other electric utilities. Moreover, contracts negotiated through the use of the IRP Methodology are typically two-year contracts. Therefore, near term pricing is a more accurate reflection of market conditions and anticipated natural gas prices. We note the similarity in using either the NYMEX or the Platts December 2021 forecast update proposed by the Company on reply. However, this case is intended to annually update load and gas forecasts as of October 15 of each year. The Platts update is inappropriate for use with this annual load and gas forecast because it was not generated until December. We find it reasonable and just that the Company reevaluate its natural gas price forecast methodology prior to the next annual update.

We further find it reasonable for this Filing to have an effective date of January 1, 2022. Having an effective date after the filing deadline will provide more time to review the utilities' filings and prevent having an identical filing deadline and effective date. We recognize the opportunity for gaming that such a change may present. However, QFs can anticipate and track these annual filings and submit contracts to the utility to capitalize on pricing no matter which effective date is chosen. If the fears of the Company are realized, we will reevaluate our timing for filing and effective dates. We further find it reasonable that all subsequent filings by the Company, and the other Idaho electric utilities subject to PURPA, to update load forecast, natural gas price forecast, and contracts used as inputs to calculate their IRP have an effective date of January 1 of the year following their annual filings.

ORDER

IT IS HEREBY ORDERED that the Company's annual updates to its energy load, contracts, the Peak Hours, and the Premium Peak Hours used to calculate capacity payments for energy storage QFs and applied to energy storage QFs that deliver energy in the window after the first deficit year in the SAR Method, are reasonable and approved, effective January 1, 2022.

IT IS FURTHER ORDERED that the Company file a three-year natural gas forecast update as a compliance filing to this case, utilizing the latest NYMEX forwards prices to determine IRP avoided cost rates for contracts signed after January 1, 2022, until the effective date of the next natural gas price forecast annual update.

IT IS FURTHER ORDERED that the Company shall reevaluate the Company's natural gas price forecast methodology prior to the next annual update, especially the method used to determine the first three years of the forecast time horizon used to determine IRP-based avoided cost rates.

IT IS FURTHER ORDERED that all Idaho electric utilities subject to PURPA shall continue to file their load forecast, natural gas price forecast, and contracts used as inputs to calculate their IRP each year in compliance with Order Nos. 32697, 32802, and 35274, with all future updates effective January 1 of the following year.

THIS IS A FINAL ORDER. Any person interested in this Order may petition for reconsideration within twenty-one (21) days of the service date of this Order with regard to any matter decided in this Order. Within seven (7) days after any person has petitioned for reconsideration, any other person may cross-petition for reconsideration. *See Idaho Code* § 61-626.

DONE by Order of the Idaho Public Utilities Commission at Boise, Idaho this 21st day of January 2022.

ERIC ANDERSON, PRESIDENT

KRISTINE RAPER, COMMISSIONER

JOHN CHATBURN, COMMISSIONER

ATTEST:

Jan Noriyuki
Commission Secretary

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