BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF IDAHO POWER COMPANY'S APPLICATION FOR APPROVAL OF SPECIAL CONTRACT AND TARIFF SCHEDULE 33 TO PROVIDE ELECTRIC SERVICE TO BRISBIE, LLC'S DATA CENTER FACILITY	)	**CASE NO. IPC-E-21-42** **ORDER NO. 35777**

On December 22, 2021, Idaho Power Company ("the Company" or "Idaho Power") applied to the Idaho Public Utilities Commission ("Commission") seeking approval of a special contract ("ESA" or "Brisbie ESA") for electric service between the Company and Brisbie, LLC ("Brisbie") for Brisbie's new enterprise data center, for rates proposed in Tariff Schedule 33, and approval of the regulatory framework for the on-going implementation and administration of the ESA without change or condition. The Company filed the direct testimony of Timothy E. Tatum and Pawel P. Goralski in support of its Application.

On January 21, 2022, the Commission issued a Notice of Application and set a 14-day intervention deadline. Order No. 35293. Clean Energy Opportunities for Idaho ("CEO") was granted intervention into this case. Order No. 35318. There were no other intervenors.

The Commission issued a Notice of Modified Procedure setting public comment and Company reply comment deadlines. Order No. 35337.

Staff filed comments on April 27, 2022.[1] The Company filed reply comments on May 6, 2022.[2] No other public or party comments were received.

With this Order, we approve the Company's ESA for electric service between the Company and Brisbie subject to the modifications discussed herein.

[1] Due to the amount of material Brisbie and/or the Company claimed as "trade secrets", production request responses by the Company and comments filed in this case by the parties had redactions. *See Idaho Code* §§ 74-107(1) and 48-801 *et seq*. Staff worked diligently with Idaho Power and Brisbie to significantly reduce what was claimed as a trade secret by Brisbie and/or the Company. This makes review and approval of this ESA by the Commission more transparent and available for public review. Further, and most importantly these substantive matters are set forth in this Order without redaction. Had the parties insisted that these matters remain confidential the Commission would be hard pressed to find that the public interest was served by approval of this ESA, especially in this case where the generation associated with the Brisbie ESA will be a system resource that could have impacts on other Company customers.

[2] On June 8, 2022, the Company filed replacement comments with fewer redactions.

THE APPLICATION

Brisbie is a large power service customer ("LPS"). LPS customers are those who use between 10,000 kilowatts ("kW") and 20,000 kW of power. LPS customers that receive service in excess of 20,000 kW are required to make special contract arrangements with the Company. "[E]ach special contract customer is considered a separate class with different conditions and contract terms affecting their rates . . . [.]" Application at 2 (quoting Order No. 33038 at 11).

The Brisbie ESA encompasses pricing, cost and credit components, and terms and conditions based upon Brisbie's acquisition of new renewable resources[3] for Brisbie's expected electric service load.

In addition to the ESA, the Company specifically requested approval of several components of the regulatory framework to implement and administer it. These components include: (1) authority to procure renewable resources for the purpose of supporting Brisbie's energy needs under a standard procurement agreement; (2) the cost basis and pricing structure for the supply of retail electric service by the Company; (3) the compensation structure for excess renewable energy generation and capacity contribution of the renewable resources; (4) authorization to treat bill credits provided to Brisbie under the proposed compensation structure as prudently incurred expenses for ratemaking purposes; and (5) the cost recovery mechanisms necessary to protect existing customers from unreasonable cost shifting and to ensure the Company's cost recovery for service.

If approved, the ESA becomes effective on the date of the final order issued in this case. The Company believes that approval of the ESA is in the public interest. The Company represented that the ESA incorporated the goals of balancing renewable energy requirements and current energy economic realities in an equitable manner that considers new and existing customers as well as the Company.

THE COMMENTS

1. Staff Comments

Staff reviewed the Application to ensure other customers would not be harmed by the Company's provision of electrical service to Brisbie under the proposed Schedule 33. Staff's review focused on: (1) the overall structure and design of the rates; (2) the Company's No-Harm

[3] The Company represented that, "Brisbie has a sustainability objective to support 100% of its operations with new renewable resources." Application at 2.

Analysis; (3) cost recovery for the construction of related transmission facilities to connect Brisbie's data center to the Company's system; (4) the treatment of Renewable Energy Credit(s) ("REC(s)") generated by Brisbie's selected renewable resources and the allocation of system-generated RECs in the Power Cost Adjustment ("PCA"); (5) the provisions in the ESA mitigating risk; (6) treatment of the costs and benefits in the PCA and in base rates; and (7) the need for future Brisbie and other Clean Energy Your Way construction projects ("CEYW-Construction") renewable resource Power Purchase Agreement(s) ("PPA(s)") to be reviewed and authorized.[4] Staff Comments at 3-4.

A. Rate structure

Staff noted that the Company planned to procure enough renewable resources to meet Brisbie's initial annual energy requirements in the short-term through a PPA[5] and will build or procure additional resources to meet Brisbie's energy requirements going forward. Staff's evaluation of the ESA focused on whether the rate structure and design would prevent cost shifting to the Company's other customer classes. Staff cited four reasons that make this analysis critical:

I. The acquisition of Brisbie's resource(s) will bypass the Company's established process used for planning and selecting the Company's other resources that ensure the Company's new resources are needed for the system and are least-cost to customers;[6]

II. Brisbie's resource(s) will be connected to the system and will be used to serve system load as though it is a Company resource, but 100 percent of the energy attributes (i.e. RECs) will be claimed by Brisbie;

III. Brisbie will be the Company's largest customer with a large impact to the Company's system and cost structure, increasing the overall risk to customers; and

IV. The rate design for the ESA will likely be used as a model for future CEYW-Construction customers, further increasing the risk of potential impacts to customers in the future.

Id. at 6.

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[4] The Commission is currently considering the Company's Application to offer the CEYW program under flexible, subscription, and construction models in Case No. IPC-E-21-40. The CEYW program will offer participants additional opportunities to be served with clean energy.

[5] The PPA associated with the Brisbie ESA was approved on April 12, 2023, in Case No. IPC-E-22-29. Order No. 35739.

[6] The Company requested to procure Brisbie's renewable resource(s) with the ESA without Commission approval. Application at 4.

Staff was concerned with the amount of excess energy that may be generated by Brisbie and future CEYW-Construction projects. Staff believed excess energy should use avoided cost as a baseline; expressing concern that due to the size of Brisbie's resources there may eventually be upward pressure on all customer rates.

Staff noted that Brisbie's resources will be sized to meet 100 percent of its annual energy requirements. Because Brisbie would have relatively steady load throughout the day and its resource(s)—Staff assumed solar—will not produce during all hours, Brisbie would need to rely on the Company's system during certain periods.

Staff noted its proposed rate design could be analyzed on a "virtual behind the meter" framework, which it argued was appropriate because: (1) the structure of the ESA requires 100 percent of the renewable PPA costs to be passed through to Brisbie, similar to other large customers that have generation capability and generate into their own load; and (2) the renewable resource(s) the Company will procure for Brisbie will connect directly to the Company's system separate from Brisbie's load, the data center consumption and the production from its renewable resource will be netted mathematically on an hourly basis using metered data. *Id.* at 7-8.

Staff stated that using a virtual behind the meter framework was ideal because it allowed it to analyze net consumption ("Supplemental Generation")—electricity delivered to Brisbie from the Company's system—based on principles of cost of service ("COS"); and (2) net production ("Excess Solar Generation")—generation exported to the Company's system by Brisbie—on principles of avoided cost. *Id.* at 8.

Staff supported the Company's rate structure for Supplemental Generation if it is based on COS principles. For energy exported to the Company's system—Excess Solar Generation—Staff argued that principles established through the Public Utility Regulatory Policies Act of 1978 ("PURPA"), including rates based on avoided costs, were most appropriate for holding customers harmless.

Staff stated that ideally the amount of "energy and capacity consumed and exported by Brisbie would occur on a net basis to minimize any asymmetry or double counting of its value." *Id.* Staff indicated that the "Company proposes to track and price energy production and consumption on a net basis." *Id*. For capacity and capacity-driven costs, the Company proposed 100 percent of Brisbie's resource(s) capacity contribution be sold to the Company's system, while

100 percent of Brisbie's capacity-related needs for consumption were to be sourced from the Company's system. *Id.*

Energy Treatment

Staff stated that the Company's proposed treatment for energy was congruent with its ideal framework since the amount of renewable generation and Brisbie's consumption would be netted hourly. According to Staff, the Company "plans to track the metered net differences hourly in kWhs and has developed its rate proposals for Supplemental Energy generation and Brisbie's excess solar generation (net exports to the Company's system) reflecting the differences in hourly value depending on whether Brisbie is a net consumer or net producer." *Id*. at 9.

Staff reviewed the Company's proposed method for determining Supplemental Energy rates, and recommended approval, as filed. Staff supported the proposed method because it was "based on COS incorporating attributes from approved special contracts but also includes marginal cost pricing needed to appropriately charge Brisbie for its energy use supplied from the Company's system." *Id*. at 10.

Staff noted Supplemental Energy rates would be based on a two-block pricing structure. The first 20 megawatt(s) ("MW(s)") of energy load (Block 1) was priced at current Schedule 19T energy rates—based on embedded average cost determined in the Company's last rate case. Staff supported this proposal because the first 20 MWs of Brisbie's load would be the most stable pattern of consumption. Any load exceeding 20 MWs (Block 2) is priced at a marginal cost rate using the Avoided Cost Averages[7] from the most recently acknowledged Integrated Resource Plan ("IRP"). Staff agreed with using marginal cost pricing for Block 2 because it would ensure Brisbie pays the full price of the next increment of energy above what customer embedded average rates are intended to recover. By paying full price, Staff believed upward pressure on the average cost of energy used to establish the embedded average cost of energy for all other ratepayers would be minimized.

Staff noted that, under the Company's proposal, the proposed Block 2 rates would be updated every two years upon acknowledgment of the IRP and only the first few years of the Avoided Cost Averages will be utilized. Staff believed these rates would be fairly accurate because

[7] Avoided Cost Averages are the mean avoided cost of energy determined in each hour of a dispatch run of the Company's preferred portfolio in the Company's production cost model. The averages are collected for Summer On-Peak, Summer Mid-Peak, Summer Off-Peak, Non-Summer Mid-Peak, Non-Summer Off-Peak periods for each year across the Company's 20-year planning horizon.

the inputs and assumptions will be based on the latest historical data. Staff recommended that the Avoided Cost Averages, along with all other pricing components from the IRP, be filed for Commission approval soon after the IRP was filed so the Commission could process the application in parallel with the IRP filing and authorize them soon after IRP acknowledgment.

Excess Energy Generation Credit

Staff recommended approval of the Company's method for calculating the Excess Energy Generation[8] credit provided there was an additional 85 percent adjustment consistent with Schedule 86. Staff argued that because "these are forecasted energy prices generated through the Company's IRP, the hourly rates should also be backstopped by actual Mid-C prices so the price for the energy credits is determined by the lower of the proposed AURORA-based rates (with the additional 85% adjustment) or the actual Mid-C market prices." *Id.* at 11. Staff believed "the proposed AURORA-generated firm price provides a reasonable avoided cost of energy price for non-firm energy when adjusted by the 82.4% adjustment factor as proposed; however, Staff believe[d] that the 85% adjustment consistent with Schedule 86 needs to also be included . . . ." *Id*. at 12.

Staff believed the Company's reasons for adjusting Schedule 86 are applicable here because the Company must take the excess generation from Brisbie's renewable resource(s). This amount could be very large given that the nameplate capacity of Brisbie's selected renewable resource(s) could be 3.5 times larger than its peak loads to meet annual energy requirements for all hours. Staff argued this would require the Company to sell any excess energy on the market and incur additional transmission-related costs. Staff believes that the 85 percent adjustment factor would protect customers. *Id.* at 12.

Staff mentioned an additional concern with the accuracy of using the IRP Mid-C price forecast to determine the excess generation price ("Excess Generation Price"). Staff believed "it should be compared to the actual Mid-C market price on an hourly basis to safeguard customers from overpaying for excess generation from Brisbie's renewable resources." *Id.* According to

[8] The Company's proposed method for determining Excess Energy Generation payments is based on the amount of Excess Energy Generation in each hour. The Excess Energy Generation credit Brisbie receives will be calculated using the amount of Excess Energy Generation each hour multiplied by the Excess Generation Price for that hour. The Excess Generation Price is determined by taking the hourly Mid-C price forecast from the IRP, assumed to be a firm-energy market price, and then adjusted by 82.4 percent to determine a non-firm energy market price. The 82.4 percent non-firm adjustment mirrors the non-firm adjustment in the Company's Cogeneration and Small Power Production Non-Firm Energy – Schedule 86.

Staff, "[u]sing forecasted prices, as proposed by the Company, instead of actual market prices introduces a source of risk that could cause other customers to pay more than their avoided cost." *Id.* at 13.

Capacity Treatment

The Company's proposed capacity treatment is incongruent with Staff's proposed framework because the capacity of Brisbie's renewable resource is not netted from the capacity needed to serve Brisbie's load. According to Staff, "[t]he Company assumes 100% of the capacity needed for the Brisbie data center will be provided by the Company's system and that 100% of the contribution of capacity from its renewable resources will be provided to the Company's system and compensated through a capacity credit." *Id.* According to Staff, "the capacity treatment in the ESA has two components: (1) Renewable Capacity Credit; and (2) demand charges." *Id*. Brisbie will receive the Renewable Capacity Credit "for the value of capacity contribution its resource(s) provide to the Company's system that avoid future additions of capacity. *Id.* at 13-14. Staff opined that PURPA provided the most appropriate standard to evaluate the Company's capacity credit proposal. The demand charges are designed to primarily recover the cost of capacity that the Company must hold to meet Brisbie's load.

Renewable Capacity Credit

Staff recommended two changes to the Company's proposed renewable capacity credit.[9] Staff argued: (1) Brisbie should not receive any payments for avoiding capacity cost until the Company's system is capacity deficient; and (2) payments for the contribution of capacity should be based on the "time of output" rate structure used for IRP-based energy storage PURPA projects. *Id.* at 14.

Staff recommended "that the payment for the renewable capacity credit should not begin for any tranche of capacity procured for Brisbie until the authorized first capacity deficiency date occurs." *Id.* at 15. Staff also recommended "the rate structure for capacity credits should be based on the avoided capacity cost rate and payment structure used to compensate PURPA IRP-based energy storage Qualifying Facilities ("QF") projects as approved in Case No. IPC-E-20-02." *Id.*

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[9] The Company's proposed method for determining the Renewable Capacity Credit bases the amount of capacity on the nameplate capacity multiplied by a Capacity Contribution Factor determined in the IRP. This amount of capacity is multiplied by a Renewable Capacity Credit rate to determine the renewable capacity credits Brisbie receives. Under the Company's proposal, Brisbie would receive capacity credits when the resource begins commercial operation, and the value of the capacity credit—based on a dollar per kilowatt per year amount— would remain the same for the duration of the contract. Staff Comments at 14.

Staff believed that the IRP-based implementation of this rate structure should be used because the size of Brisbie's resource(s) exceed the 100 kW published rate limit approved by the Commission for solar, wind, or energy storage QFs." *Id.*

Staff recommended the surrogate resource used to determine the capacity credit should be based on the lowest cost capacity resource included for selection within the Company's most recent IRP. However, Staff believed the type of "resource and its avoided capacity cost should not change for the life of the contract." *Id.* Staff further recommended this resource and its capacity cost should be identified using the most recently acknowledged IRP at the time that the PPA—or a resource construction agreement—is signed.

Staff believed its proposed rate and payment structure was appropriate because it ensured Brisbie's resources were compensated for the capacity avoidance delivered. Additionally, Staff believed "this rate and payment structure was developed to provide compensation for avoiding capacity cost, specifically for energy storage resources, and the ESA mentions that storage resources could potentially be added in the future." *Id.* at 16.

Demand Charges

Staff reviewed the Company's proposed method for determining demand charges and recommended approving the demand charges as proposed.

B. No-Harm Analysis

Staff did not believe the Company's No-Harm Analysis provided sufficient evidence to establish that the ESA would hold other customers harmless. The results of the Company's analysis showed that the system with the ESA could provide a $17.8 million benefit to customers over a 10-year period.

Staff believed the analysis was insufficient because it relied on a single set of input assumptions that may change over the life of the ESA. Because the analysis did not evaluate a range of values for the different risk variables that could affect the results of the analysis, Staff did not rely on the results of the No-Harm Analysis as a primary consideration in determining a recommendation for the Company's rate proposals. *Id.* at 17.

C. Transmission facility construction cost

"Staff reviewed the Construction Agreement . . . and believe[d] that the costs necessary to provide ongoing electric service to the Brisbie data center, including transmission construction cost and ongoing operation and maintenance cost up to the point of delivery, [would] not be borne by other ratepayers." *Id.* at 17.

D. REC ownership

Staff noted Brisbie's goal is to supply 100 percent of its annual energy requirements from its own renewable resources and that all RECs from these resources will be owned by Brisbie per its ESA with the Company. Staff assumed that, to accomplish this goal, Brisbie would necessarily be using the Company's system as a battery. Accordingly, any energy Brisbie generated with its own resources then stored on the Company's system and redistributed back to itself would have RECs already owned by Brisbie. Staff questioned whether it would be fair for Brisbie to also receive REC value from the system in the same way as other customers receive REC value through the PCA.

Staff recommended the Company hold a workshop with Staff and other interested parties to evaluate how REC benefits in the PCA should be allocated to Brisbie and other CEYW-Construction customers before these customers begin generating renewable energy.

E. ESA provisions

Staff recommended the Company include parent guarantees in each ESA for the life of the associated PPA. *Id.* at 18. Staff noted that the Company and Brisbie had written additional provisions in the ESA "that should financially protect customers." *Id*. at 18. Staff believed the guarantees in place should protect other retail customers. Staff would like to see similar contract provisions and guarantees in future CEYW-Construction contracts for all customers.

F. Accounting treatment in PCA and GRC

Staff supported the proposed accounting treatment for Schedule 33 in the PCA. Since no treatment of Schedule 33 costs, revenues, or loads in the development of future base rates was proposed, Staff recommended scheduling a workshop with the Company to discuss the treatment of Schedule 33 costs, revenues, and loads to ensure timely processing of the Company's next General Rate Case ("GRC"). *Id.*

G. Authorization of renewable resource PPAs

Staff agreed that the selection of the resource and rates in the PPA need not be authorized by the Commission because the cost of the PPA would be 100 percent passed through to Brisbie; that said, Staff recommended the Commission review and approve all CEYW-Construction PPAs to ensure no costs were passed on to the general body of customers. To ensure that Brisbie resources do not over-generate, Staff recommended the Commission direct the Company to provide the following information with its annual PCA filing: (1) the amount of consumption and generation from the renewable resource(s) serving Brisbie and other CEYW-Construction projects; and (2) an annual Brisbie load forecast compared to Brisbie's annual generation forecast for all signed PPA's, broken down monthly.

H. Summary of Staff's recommendations

1. All pricing components determined from the IRP should be filed separately for Commission approval soon after the IRP is filed so the Commission can process the application in parallel with the IRP filing and authorize them soon after IRP acknowledgement;
2. For Excess Energy Generation credits, apply an additional 85 percent adjustment consistent with Schedule 86;
3. For Excess Energy Generation credits, utilize the lower of the proposed Aurora-based rates (with the additional 85 percent adjustment) and actual Mid-C market prices on an hourly basis;
4. For renewable capacity credits, Brisbie not receive any payments for avoiding capacity cost until the Company's system is capacity deficient;
5. For renewable capacity credits, the rate structure should be based on the avoided capacity cost rate and payment structure used to compensate PURPA IRP-based energy storage QF projects as approved in Case No. IPC-E-20-02;
6. For renewable capacity credits, the resource(s) used as a surrogate to determine avoided capacity cost should be identified using the most recently acknowledged IRP at the time that the PPA (or a resource construction agreement) is signed and should use the lowest cost capacity resource included for selection within the IRP;
7. For renewable capacity credits, the peak and premium peak hours that are authorized in the Load and Natural Gas Forecast Annual Update for PURPA as required by Order No. 34913 should be used to update the peak and premium peak per kWh rate on the same schedule as the other IRP updates utilizing the peak and premium peak hours authorized at the time of the IRP updates;
8. Schedule a workshop to discuss the treatment of Schedule 33 costs, revenues, and loads in base rates prior to the next general rate case;

9. The Company hold a workshop to evaluate how system-generated REC benefits are passed on to CEYW-Construction customers in the PCA;
10. Every CEYW-Construction customer PPA—or a resource construction agreement—be reviewed and authorized by the Commission; and
11. The Company provide the following items annually with the PCA filing: (1) the amount of consumption and generation from the renewable resources serving Brisbie and other CEYW-Construction projects; and (2) an annual Brisbie load forecast that is compared to Brisbie's annual generation forecast for all signed PPA's broken down monthly.

2. Company Reply Comments

The Company supported Staff's recommendation to approve the Brisbie ESA but disagreed with Staff's proposed ESA modifications. The Company understood that the Brisbie ESA set forth a novel framework and was distinct from projects under the traditional PURPA framework because the customer was bringing both load and resources.

The Company stated that, although the "matching of Brisbie's load to its resources may not be perfect hour-to-hour, the structure of the Brisbie ESA . . . incentivizes the parties to right-size resources and minimize the imbalance of renewable resource generation to load." Company's Reply Comments at 2. The Company further explained that "the agreement does not serve as a source of revenue for excess generation for Brisbie and Brisbie's rate structure covers the cost of balancing associated load and resources." *Id*.

The Company noted Staff's support of the pricing components related to the rates that Brisbie would pay for service from the Company, the guarantees provided in each PPA, and accounting treatment in the PCA.

For new components of the Brisbie ESA, the Company sought to establish crediting mechanisms that "reasonably and fairly reflect the energy and capacity value of the new resources to Idaho Power's system." *Id*. at 6. The Company shared Staff's desire to ensure consistency when valuing energy and capacity on its system but reiterated its position that the agreement with Brisbie was unlike a standard power purchase under PURPA. Unlike standard PURPA projects, the Company explained, "Brisbie-associated resources will be fully negotiated additions to the Company's generating portfolio." *Id*. Accordingly, as the Company further explained, these resources will be procured like system resources—either secured with a PPA or Company-owned—and are distinctly different from PURPA projects where the Company *must buy* the generation at established rates. As noted by the Company, under the Brisbie arrangement, the customer agreed to financially support its accompanying renewable resources. The Company argued that "separating these renewable resources from the customer that necessitated them is not a reasonable way to identify resource value." *Id*. The Company further argued that "to move the ESA compensation structure closer to a PURPA-like valuation methodology," as Staff recommended, was misapplied. *Id.* at 7. Rather than viewing the Brisbie ESA in the context of PURPA, the Company believed the arrangement was "best characterized as a novel and fair approach to serving a stable, large load customer and supporting that customer's renewable resource needs in a way that enhances Idaho Power's system to the benefit of all customers." *Id.* at 8.

The Company considered Staff's proposed "virtual behind the meter" framework to be incorrect. The Company stated that, contrary to Staff's comments, no aspect of Brisbie's load is unstable. The Company noted that Brisbie is expected to have a 90 percent load factor. According to the Company, "the renewable resources to support Brisbie's load were specifically required to be system resources to *prevent* the kind of load instability that Staff has referenced." *Id*. at 7.

A. The Company's responses to Staff's individual recommendations

Pricing Updates

The Company agreed and supported Staff's first recommendation.

Excess Energy Generation Credits

The Company disagreed with Staff's second recommendation regarding the proposal to approve the Excess Energy Generation credit calculation in the ESA by adding an 85 percent adjustment. The Company iterated that its economic analysis of the ESA, as described in the Application, demonstrated no harm to other classes of customers. The Company stated that Staff's proposed adjustment to Excess Energy Generation credit would increase the benefits other customer classes receive at the expense of Brisbie.

The Company also disagreed with Staff's third recommendation that the Excess Energy Generation credit be the '"lower of' the AURORA-generated [Mid-C] market price in the ESA and the actual hourly Mid-C market price." *Id*. at 9 (quoting Staff Comments at 20). The Company acknowledged Staff's statement, "that the Mid-C forecast is a good basis for the Excess Energy Generation credit," noting also "Staff's belief that the proposed Aurora-generated firm price provided "a reasonable avoided cost of energy price for non-firm energy when adjusted by the 82.4% adjustment factor as proposed." *Id.* at 10 (quoting Staff Comments at 12).

The Company addressed Staff's concern that the Brisbie agreement would create considerable surplus energy during certain periods "and that the Company may overcompensate Brisbie in some hours if the Mid-C forecast is higher than the market price." *Id*. The Company argued that Staff "overlooks the possibility that, in some hours, the forecast price may be lower than the market price." *Id*. Because the Company could not guarantee "whether any Brisbie-associated excess generation will result in system use or a market sale in any given hour" it believes a "reasonable market proxy is the best, most predictable basis to establish a reasonable hourly energy credit amount." *Id*. The Company recapped its proposal to update the forecast with each IRP to ensure the Mid-C forecast included remains current. The Company noted that its inability to incorporate an hourly "lesser of" credit as recommended by Staff, because "the actual Mid-C ICE market settles in Heavy Load and Light Load amounts—that is, there are two prices per day and each hour is settled at either the Heavy Load or Light Load price." *Id*. The Company stated it explored "the potential of a Heavy Load/Light Load excess energy compensation structure and determined that the hourly AURORA-forecast was more granular . . . ." *Id*. The Company believed the proposed AURORA-generated forecast offers "stability and predictability" to both parties. *Id*.

Renewable Capacity Credit

The Company and Staff were aligned in achieving the same outcome—capacity costs accurately reflecting capacity value—but disagreed on approach. The Company proposed assigning the costs and benefits for capacity without netting. The Company pointed out Staff's framework to "extend the virtual behind-the-meter approach to the capacity portion of Brisbie's load service by hypothetically netting Brisbie's new, incremental system load by the capacity of the new, incremental renewable resources." *Id.* at 11. The Company noted that "[t]his construct already contemplates that the hypothetical netting occurs at the time Brisbie's load service begins, irrespective of an Idaho Power deficiency date." *Id.*

The Company argued Brisbie should not be viewed as bringing only resources but, rather, as load with resources. Brisbie, the Company stated, will pay for the cost of its reliance on the system through a demand charge and is also covering the cost of bringing new capacity through the resources acquired on its behalf. Staff's fourth recommendation, which the Company believes only considers one-side of the equation, would result in charging Brisbie twice for capacity—once for the demand associated with its load and again as a deduction to the capacity credit value of its resources.

The Company also disagreed with Staff's fifth recommendation that the rate structure for the renewable capacity credit should be based on the avoided capacity rate used to compensate PURPA QF storage projects because Brisbie's associated resources are not comparable to PURPA storage projects. The Company argued its proposal was consistent with the determination of capacity contribution of similar resources within the IRP. The Company stated that the IRP is the appropriate venue for Staff's exploration of methods for determining capacity contribution of renewables.

Although the Company agreed Staff's sixth recommendation to base the surrogate resource used to determine avoided capacity cost should be determined by the least-cost capacity resource from the most recent IRP when the PPA is signed had merit, it believed "the determination of a surrogate resource is best handled in the context of [Demand Side Management ("DSM")] alternate cost." *Id.* at 13. The Company stated, "if the capacity cost basis is changed for DSM, the ESA as written will adopt the new method, making it unnecessary and premature to make such a change in this case." *Id.* The Company considered "it important to maintain consistency with current practice with respect to DSM alternate cost." *Id.*

The Company argued that Staff's seventh recommendation that the renewable capacity credit be determined based on a dispatchable capacity resource—like storage—would result in the mischaracterization of a non-dispatchable resource's capacity contribution and is inconsistent with the method used in the IRP. The Company believed the Effective Load Carrying Capability ("ELCC") model provides a better method for determining capacity contribution since it can be applied across resource types and can effectively and reasonably determine an individual resource's capacity contribution at a point in time. Further, the Company suggested the ELCC method already evaluates when a renewable resource will provide capacity with respect to its peak, opposed to a storage QF which requires "the Company must make assumptions about the amount and duration of dispatch at peak to develop capacity contribution and must receive the correct economic signal to ensure that dispatch occurs at peak value time periods." *Id*. at 13-14.

Workshops

The Company responded to Staff's eighth and ninth recommendations indicating it would be happy to host a workshop before its next GRC to discuss the treatment of Brisbie's costs but sought clarification on whether the workshop was a public workshop or limited to parties in this case.

The Company stated it would host a workshop to discuss REC-related transactions but did not believe there was anything to evaluate on the topic. The Company agreed with Staff's position that 100 percent of the RECs generated by Brisbie's renewable resource(s) should be retained by Brisbie, but disagreed with Staff's position that Brisbie and other CEYW-Construction customers should not receive the benefits from RECs generated by the Company's system through the PCA. The Company stated that under its REC Management Plan, all Company-owned RECs are sold and the proceeds are passed through the PCA for the benefit of all customers through reduced power supply costs. The Company argued that Brisbie and other CEYW-Construction customers are still customers buying energy from the Company and should have the benefit of PCA power supply cost reduction through REC sales.

Future Renewable Construction Agreements

The Company disagreed with Staff's tenth recommendation that all Brisbie and future CEYW-Construction PPA should be reviewed by the Commission. The Company pointed out that Staff even recommended that selection of resources and rates in the PPAs do not need Commission authorization since 100 percent of the PPA's costs would pass through to Brisbie (and future CEYW-Construction customers). Since Brisbie (and other CEYW-Construction customers) would fully pay for its resource(s), the Company argued that no Commission review was necessary.

The Company opposed Staff's recommendation that the "other elements within the PPA . . . should be reviewed by the Commission." *Id.* at 16 (quoting Staff Comments at 19). Staff's example of interconnection agreements deserving Commission review was unpersuasive to the Company. The Company noted that interconnection agreements are not included in PPAs and non-PURPA generation interconnection agreements are not within the Commission's jurisdiction. *Id.* The Company clarified that it would require all new resources to have Network Resource Interconnection Service which it suggested would ensure new resources will be paid for by the cost causer through the agreed upon PPA prices. *Id.*

The Company added that "if there are specific elements of a PPA that Staff believes need Commission review and approval, the Company would like to have those articulated." *Id.* The Company opined that it would be an administrative burden to seek Commission review for each PPA under the CEYW-Construction offering.

Annual PCA Treatment

The Company supported Staff's 11th recommendation to include Brisbie's (and future CEYW-Construction customer's) load plus the consumption and generation from the resource serving them in the PCA. The Company would provide the required information when Brisbie began taking service.

COMMISSION FINDINGS AND DECISION

The Commission has jurisdiction over this matter under *Idaho Code* §§ 61-501, -502, and -503. *Idaho Code* § 61-501 authorizes the Commission to "supervise and regulate every public utility in the state and to do all things necessary to carry out the spirit and intent of the [Public Utilities Law]." *Idaho Code* §§ 61-502 and -503 empower the Commission 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. Pursuant to its statutory duties, the Commission has the authority to determine reasonable rates and review and investigate contracts. *Empire Lumber Co. v. Washington Water Power Co.*, 114 Idaho 191, 192, 755 P.2d 1229, 1230 (1987).

Commission Rule of Procedure 281, IDAPA 31.01.01.281, states that "[t]he Commission bases its decisions and issues its orders on the hearing record . . . the Commissioners' record and items officially noted." The Commission, "may officially note . . . in its orders . . . [i]ts own orders, notices, rules, certificates and permits, and those of any other regulatory agency, state or federal" without providing the parties an opportunity to refute or respond. IDAPA 31.01.01.263.01-02.

Order Nos. 35482, 35532, 35607, and 35735—all concerned a special contract between another large power service customer and the Company in Case No. IPC-E-22-06 under the CEYW-Construction program. We affirmed the findings of Order No. 35482 in Order Nos. 35532, 35607, and clarified the methodology for calculating the renewable capacity credit in Order No. 35735. The contract in Case No. IPC-E-22-06 contained many similar provisions to the ESA in this case, including a similar compensation mechanism for excess generation and renewable capacity credits. Staff's conclusions and rationale and the Company's arguments put forth on the record in this case align with their respective positions in Case No. IPC-E-22-06.

The Commission has reviewed the record, including the Company's Application, the proposed Schedule 33, the supporting testimony, all iterations of Staff and the Company's comments, and our findings in Order Nos. 35482, 35532, 35607, and 35735. Based on our review, and consistent with our authority under Title 61, we find it to be fair, just, and reasonable to approve the ESA between Brisbie and the Company subject to the modifications discussed below.

We acknowledge the Company's willingness, consistent with Staff's recommendations, to meet with Staff to discuss the treatment of Schedule 33 costs, revenues, and loads in base rates prior to the next general rate case and to hold a workshop to evaluate how system-generated REC benefits are passed on to CEYW-Construction customers in the PCA. We also acknowledge the Company's agreement with Staff's proposal to provide specific information related to the ESA and other CEYW-Construction projects in its annual PCA filing. Last, we note the Company and Staff agree that all pricing components of the ESA stemming from the Company's IRP be filed with, or shortly after, submission of the IRP. We find the above Staff recommendations to be reasonable requirements for the Company that will result in increased transparency and understanding of the ESA and other CEYW-Construction projects' impacts on the Company's system and other customers. We direct the Company to meet with Staff, prior to the next GRC or as soon as possible thereafter, to discuss the treatment of Schedule 33 costs, revenues, and loads in base rates. We further direct the Company to hold a workshop on REC-related transactions and PCA impacts of "system-generated RECs."

We recognize that, although the Company agreed with some of Staff's specific recommendations and was generally aligned with Staff on some pricing aspects and the common goal of standard methodological consistency when valuing energy and capacity, the Company generally disagreed with Staff's application of a "PURPA-like valuation methodology", Company Reply Comments at 7, to the pricing and compensation elements under the ESA and other CEYW-Construction agreements.

We now address the Company's specific disagreements with Staff's proposals on the treatment of excess generation credits, renewable capacity credits, and future PPAs, and direct the Company to make specific modifications to its ESA and Schedule 33 consistent with our findings.

Excess Generation Credits

We find it fair just and reasonable for the Excess Energy Generation rate under the ESA to be the lower of the Excess Energy Price (with the 85 percent adjustment) or the actual high or low load hour Mid-C market price (without any adjustment) for each hour of excess energy delivered. We note the Company first proposed the 85 percent adjustment method in Case No. IPC-E-01-40 as a reasonable way to: (1) cover the purchase and transmission costs it incurs when it resells excess non-firm energy that it was obligated to purchase on the wholesale market and (2) conversely, to assure that it buys non-firm energy it wishes to retain at a price equivalent to what that energy would cost on the wholesale non-firm market. This adjustment strikes a reasonable balance between compensating energy projects and protecting customers and we see no justification for abandoning it in this case. We further find that applying Staff's "backstop mechanism" whereby the excess generation credit rate will be based on the lower of the Excess Generation Price (with the 85% adjustment) and the actual high- or low-load hour Mid-C market price (without any adjustments) for each hour, will prevent cost-shifting to other customers and prevent Brisbie from being compensated for energy at higher than the market rate when the energy is delivered to the Company. Finally, we note this treatment aligns with our previous determinations regarding this type of excess generation credit in Order Nos. 35482 and 35607.

Renewable Capacity Credits

We find it fair, just, and reasonable that Brisbie receive payments for capacity avoidance starting on the Company's capacity deficiency date. Specifically, Brisbie shall not receive any payments for capacity avoidance until the system is capacity deficient. The capacity deficiency date shall be the date authorized through the Company's biennial PURPA deficiency date filing at the time the PPA or other resource construction agreement is executed. This treatment follows our previous determination in Order No. 35482.

We find it fair, just, and reasonable that compensation for renewable capacity credits under the ESA use the rate and payment structure recently approved by Order No. 35735. Specifically, we direct the Company to work with Brisbie to implement a rate and payment structure under the ESA for valuing renewable capacity credits consistent with the Commission-approved method in Order No. 35735. We note this method was presented to the Commission after extensive collaboration between the Company and Staff and is the method which both the Company and Staff believe provides the best outcome for the Company's CEYW-Construction program customers and other classes of customers. In addition, applying this structure to the ESA will provide a consistent methodology for future, anticipated resource combinations (solar plus battery and/or wind plus battery) associated with the ESA and potentially for similarly situated CEYW-Construction projects.

Review of Future PPAs

We find it fair, just, and reasonable that all future CEYW-Construction project- associated PPAs, or resource construction agreements, be reviewed and approved by the Commission. We are unpersuaded by the Company's argument against providing future CEYW-Construction-associated PPAs or construction agreements for Commission review and approval. We find that providing a PPA for review and approval is necessary to ensure that costs are not unduly shifted to other customers or classes of customers. We find it reasonable that if a special contract under the CEYW-Construction program references an associated PPA and makes certain representations about that PPA's impact on other customers, then the PPA itself should be provided for Commission review and approval. This determination is also consistent with our previous determination on this issue in Order No. 35482.

PCA

Last, we find it fair, just, and reasonable that the credits for excess energy generation and capacity included in power supply expense be subject to 95 percent sharing in the PCA. Subjecting excess generation and renewable capacity credits to 95 percent sharing under the PCA, we believe, will induce the Company to negotiate for the least-cost rates. We note this is consistent with how the Company's other negotiated net power supply expenses are treated and with our previous determination regarding 95% sharing for the excess generation and renewable capacity credits in the energy services agreement in Order Nos. 35482 and 35607.

ORDER

IT IS HEREBY ORDERED that the Brisbie ESA and Tariff Schedule 33 are approved with the modifications discussed above. The Company shall file an updated ESA and Schedule 33 addressing the Commission's modifications within 90 days of the service date of this Order.

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 regarding 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. *Idaho Code* § 61-626.

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DONE by Order of the Idaho Public Utilities Commission at Boise, Idaho this 11th day of May 2023.

ERIC ANDERSON, PRESIDENT

JOHN R. HAMMOND, JR., COMMISSIONER

EDWARD LODGE, COMMISSIONER

ATTEST:

Jan Noriyuki
Commission Secretary

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