Office of the Secretary
Service Date
October 5, 2017

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR APPROVAL OF THE CAPACITY DEFICIENCY TO BE UTILIZED FOR AVOIDED COST CALCULATIONS	CASE NO. IPC-E-17-12 ORDER NO. 33898

On July 26, 2017, Idaho Power Company applied to the Commission for an Order approving the capacity deficiency period for the Company's avoided cost calculations under the Public Utility Regulatory Policies Act (PURPA). The Company asked that the Application be processed under Modified Procedure. The Commission issued a Notice of Application and Notice of Modified Procedure setting comment and reply deadlines. Order No. 33838. The Commission also granted intervention to the Idaho Hydroelectric Power Producers Trust, d/b/a IdaHydro. Order No. 33856. Commission Staff timely submitted comments. After the comment deadline, IdaHydro submitted comments styled as a "Response to Comments of the Commission Staff." Idaho Power timely submitted reply comments. No other comments were received.

Having reviewed the record, the Commission enters this Order approving the Company's Application and requested capacity deficiency period of July 2026 for the Company's avoided cost calculations. We also approve the updated published avoided cost rates attached to this Order. The Commission's decision is set out more fully below.

BACKGROUND

Under PURPA, electric utilities must purchase electric energy from qualifying facilities (QFs) at rates approved by the applicable state agency—in Idaho, this Commission. 16 U.S.C. § 824a-3; *Idaho Power Co. v. Idaho PUC*, 155 Idaho 780, 780, 316 P.3d 1278, 1287 (2013). The purchase or "avoided cost" rate shall not exceed the "'incremental cost' to the purchasing utility of power which, but for the purchase of power from the QF, such utility would either generate itself or purchase from another source." Order No. 32697 at 7, *citing Rosebud Enterprises v. Idaho PUC*, 128 Idaho 624, 917 P.2d 781 (1996); 18 C.F.R. § 292.101(b)(6) (defining "avoided cost").

The Commission has established two methods of calculating avoided cost, depending on the size and resource of the QF project: (1) the surrogate avoided resource (SAR) methodology, and (2) the integrated resource plan (IRP) methodology. *See* Order No. 32697 at 7-8. The SAR methodology is used to establish what are commonly called "published" avoided cost rates. *Id.* Published rates are available for wind and solar QFs[1] with a design capacity of up to 100 kilowatts (kW), and for QFs of all other resource types with a design capacity of up to 10 average megawatts (aMW). For QFs with a design capacity above the published rate eligibility caps, avoided cost rates are "individually negotiated by the QF and the utility using the [IRP methodology]." *Id.* at 2; Order No. 32176.

In calculating avoided cost, the Commission found it "reasonable, appropriate and in the public interest to compensate QFs separately based on a calculation of not only the energy they produce, but the capacity that they can provide to the purchasing utility." Order No. 32697 at 16. As to the capacity calculation for the SAR methodology, the Commission found it appropriate "to identify each utility's capacity deficiency based on load and resource balances found in each utility's IRP." *Id.* With respect to the IRP methodology, the Commission similarly stated

> [i]n calculating a QF's ability to contribute to a utility's need for capacity, we find it reasonable for the utilities to only begin payments for capacity at such time that the utility becomes capacity deficient. If a utility is capacity surplus, then capacity is not being avoided by the purchase of QF power. By including a capacity payment only when the utility becomes capacity deficient, the utilities are paying rates that are a more accurate reflection of a true avoided cost for the QF power.

Id. at 21.

The Commission found that "the IRP process determines when the utility will experience a need for new capacity." *Id.* at 23. The Commission acknowledged this determination has "an impact on calculations under the SAR and IRP methodologies." *Id.* Because the utility's IRP is reviewed by this Commission, but not "approved," the Commission found it "reasonable and fair to subject each utility's determination of capacity deficiency to further scrutiny." *Id.* The Commission directed that when a utility submits its IRP to the Commission, "a case shall be initiated to determine the capacity deficiency to be utilized in the SAR Methodology. The capacity deficiency determined through the IRP planning process will be the starting point, and will be presumed to be correct subject to the outcome of the proceeding." *Id.* Likewise, the Commission has considered updates to Idaho Power's capacity

[1] *See* Order No. 33785 (regarding battery storage facilities).

deficiency date for the IRP methodology in cases filed separately from the IRP. *See* Case Nos. IPC-E-14-22; IPC-E-15-20.

In 2015, the Commission confirmed July 2024 as Idaho Power's capacity deficiency period for the incremental cost IRP methodology and approved the updated SAR model based on that deficiency period and the updated SAR-based rates. Order No. 33377.

THE APPLICATION

Idaho Power stated that its 2017 IRP, which it filed with the Commission on June 30, 2017 (Case No. IPC-E-17-11), identifies a first peak-hour deficit in July 2026. Application at 2. Idaho Power described that peak-hour load deficits are determined using 90th percentile water and 95th percentile peak-load conditions. *Id.* at 2-3. The Company indicated that under the IRP's preferred portfolio, a first capacity deficiency of approximately 34 MW occurs in July 2026 and a first energy deficit of 143 MW occurs in July 2029. *Id.* at 3. The Company requested that the first capacity deficit date of July 2026 be used for avoided cost calculations for both the SAR and IRP methodologies. *Id.*

THE COMMENTS

A. Commission Staff

Staff reviewed the Application and supporting documentation and believed that the capacity deficit date of July 2026, as identified in the IRP, is reasonable. Staff Comments at 3-4. Specifically, Staff stated that it compared the 2015 Peak-Hour Load and Resource Balance (which was used to determine the current July 2024 capacity deficiency date) with the 2017 Peak-Hour Load and Resource Balance. *Id.* at 3. By comparing the two, Staff determined that the primary cause of the two-year shift in the capacity deficiency date (from July 2024 to July 2026) was

> a 103% increase in market purchase availability. The increase comes from two sources: (1) an additional 130 MW of import transmission capacity into the south side of its system by closing Valmy Unit 1 in 2019; and (2) an additional 80 MW of incremental transmission capacity through the Company's Idaho/Montana transmission pathway.

Id. Staff also identified other contributing factors to the two-year shift—assumptions that changed from the 2015 IRP to the 2017 IRP. *Id.* at 4. These assumptions include a decrease in the peak-hour load forecast, an increase in existing energy efficiency, and a slight increase in hydro generation and firm purchase power agreements. *Id.* Staff believed the changes in assumptions are reasonable. *Id.*

Thus, Staff supported the Company's request to use the July 2026 capacity deficiency date for avoided cost calculations for the SAR methodology. *Id.* Staff updated the SAR model accordingly and calculated new avoided cost rates, which were attached to Staff's comments. *Id.*

Regarding the IRP methodology, Staff supported the use of the July 2026 date as a starting point for avoided cost calculations. *Id.* Staff asserted that the capacity deficiency date is applied differently under the IRP methodology than it is under the SAR methodology. *Id.* Under the SAR methodology, "once the deficiency date is authorized, all new contracts signed within the two-year period are effectively valued (through published rates) using the same deficiency date." *Id.* In contrast, Staff asserted, "for IRP-based contracts, the deficiency date is allowed to float around the authorized deficiency date depending on the capacity contribution of projects within the PURPA queue until a new deficiency date is authorized." *Id.* Staff also discussed the filing schedule for the capacity deficiency date updates and other updates relevant to the calculation of avoided costs under PURPA. Specifically, Staff explained that utilities file their capacity deficiency date updates every two years, after filing their IRPs. In contrast, the Commission directed the utilities to file their annual fuel price and load forecast updates on or by October 15 of each year. Staff suggested that combining the fuel price and load forecast update with the capacity deficiency date update, in the years in which both occur, could reduce administrative burden for Staff, utilities, and interested parties. As a result, Staff requested that the Commission direct Staff to work with the utilities to establish a single filing date for the updates to fuel price and load forecasts and capacity deficiency dates.

B. IdaHydro Response

IdaHydro disputes Staff's and Idaho Power's assertion and reasoning that the Company will be capacity deficient in July 2026, instead of July 2024, because it will have more transmission capacity than assumed in the previous IRP, and thus more market access. IdaHydro Comments at 1. IdaHydro asserted this position is "factually contrary to the text of the IRP" and "conceptually contrary to [PURPA]." *Id.*

IdaHydro quoted the Company's IRP as stating that the Idaho/Montana pathway is "capacity-limited during the summer months." *Id.* at 2 (quoting Idaho Power IRP, Case No. IPC-E-17-11, at 59). Regarding transmission associated with Valmy Unit 1, IdaHydro stated that "it also appears that the Valmy plant currently occupies all the transmission capacity from the south of the system." *Id.* According to IdaHydro, the closure of that unit "opens only space that is currently occupied and does not clear additional transmission capacity." *Id.* To support this assertion, IdaHydro included an excerpt from the Idaho Power IRP, which indicated, in part, that

> . . . while Nevada is not considered a viable source for abundant wholesale energy, it may have potential to source seldom-needed capacity during peak loading periods. . . . For this reason, Idaho Power is assuming for the 2017 IRP that the retirement of North Valmy generating capacity can be adequately replaced with infrequent wholesale capacity imports across the Idaho-Nevada transmission path.
>
> Idaho Power recognizes the uncertainty of assuming wholesale capacity imports from Nevada can replace North Valmy generating capacity. The viability of the Idaho-Nevada path can be evaluated as the company continues to transition away from coal in a measured and responsible manner [and as Idaho Power commences participation in the western Energy Imbalance Market beginning in Spring 2018]. . . . As it continues its evaluation, Idaho Power recognizes the assumption that wholesale capacity imports from Nevada can replace North Valmy generating capacity may prove unfounded, and future IRPs may need to reflect such a change.

Id. at 2-3 (quoting Idaho Power IRP, Case No. IPC-E-17-11, at 68-69). IdaHydro thus asserted that "the IRP appears to trend toward less 'capacity' from future market and transmission trends, not more." *Id.* at 3.

IdaHydro also asserted that using the availability of transmission capacity for market purchases to extend the capacity deficiency date is "conceptually contrary to [PURPA]." *Id.* at 1. IdaHydro submitted that "'market purchase availability' does not supplant the capacity that PURPA anticipates [QFs] bring to a utilities [sic] system when ratemaking." *Id.* at 3. IdaHydro suggested that if no investment in base load resources is required because QFs "supplant such capacity, and the current Idaho Power base load balances intermittent 'must take' QF energy without additional investment, then Idaho Power's new capacity costs are being avoided by QF capacity" and new QFs should have a capacity payment. *Id.*

IdaHydro argued that if "market purchase availability" can count as utility capacity for determining the capacity deficiency date, then "QFs may never receive capacity compensation as contemplated by PURPA even though QFs displace new base load investment and capacity." *Id.* In brief, IdaHydro argued that QFs should receive capacity payments when

"QF energy displaces Idaho Power capacity without the need for new investment by the utility to balance intermittent 'must take' QF energy." *Id.* at 3-4.

IdaHydro concluded by asking the Commission to stay this proceeding pending the outcome of the IRP proceeding, Case No. IPC-E-17-11, because "this docket depends entirely upon the outcome" in that docket. *Id.*

C. Idaho Power Reply

In its reply, Idaho Power acknowledged Staff's acceptance of its justification for a July 2026 capacity deficiency date. Idaho Power Reply at 2. According to the Company, IdaHydro's position—that allowing transmission capacity and market access to meet capacity deficits is "factually contrary to the text of the IRP" and "conceptually contrary to" PURPA—is incorrect. *Id.*

Idaho Power explained that including "transmission capacity, or as [sic] sometimes referred to as import capability, in Idaho Power's load and resource balance is not contrary to the IRP." *Id.* Rather, it is included in this capacity deficiency case because it is included in the IRP. *Id.* Idaho Power explained that in the past, it has included import capability for the Idaho-Northwest transmission path, but that in the current load and resource balance, it has also included import capability from the Idaho-Nevada path and the Idaho-Montana path. *Id.* at 4. Idaho Power attached responses to production requests supporting its approach and explained that

> the import capability on the Idaho-Nevada path is a result of the analysis for closure of the Valmy coal plant, that—in essence—swaps out coal generation for import capability on that path. The 77 megawatts ("MW") of import capability on the Idaho-Montana path was not previously included in the 2015 IRP, but in Idaho Power's assessment of the regional transmission interconnections for the 2017 IRP and in conjunction with the closure of Valmy, the Company determined that an additional 77 MW of transmission capacity on the Idaho-Montana path could be assumed for peak-hour market purchases in July 2024-2026.

Id.

Idaho Power further asserted, citing and quoting Order No. 33425, that this Commission previously determined that a utility's import capability and its ability to purchase short-term using its transmission capacity should be treated the same as available generation resources, such as a signed QF contract or generation from its own plant, for purposes of setting the utility's capacity deficiency date for calculation of avoided cost prices. *Id.* at 2-3.

The Company concluded that it has "properly included its import capability in the capacity deficiency determination as authorized, and required, by the Commission." *Id.* at 5. The Company reiterated its request that the Commission issue an Order approving a first capacity deficit date of July 2026 to be used in the Company's avoided cost determinations under the SAR and IRP methodologies. *Id.* at 6.

COMMISSION FINDINGS

The Commission has jurisdiction over this matter under *Idaho Code* §§ 61-502 and 61-503. The Commission has the express statutory authority 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 may fix the same by Order. *Idaho Code* §§ 61-502 and 61-503. In addition, the Commission has authority under PURPA and FERC's implementing regulations to set avoided costs, to order electric utilities to enter into fixed-term obligations for the purchase of energy from qualified facilities and to implement FERC rules. The Commission may enter any final Order consistent with its authority under Title 61 and PURPA.

We have reviewed the record, including the Application and comments. We find Idaho Power's proposed capacity deficiency date of July 2026 to be reasonable and appropriate. The July 2026 date reflects an increase in market purchase availability based primarily on an increase in transmission capacity resulting from the closure of Valmy Unit 1 in 2019 and an increase in transmission capacity on the Company's Idaho/Montana transmission pathway.

We note that IdaHydro's comments, while filed as a response to Staff, were submitted out-of-time. *See* Order No. 33838. Regardless, we find that IdaHydro's points are not persuasive nor are they supported by the record. IdaHydro asserted that the IRP does not support an increase in market purchase availability due to the closure of Valmy Unit 1 and on the Idaho/Montana path. IdaHydro Comments at 1. We find that the record, and in particular the Company's IRP analysis, supports the assumption that such capacity is available and contributed to the July 2026 date.

IdaHydro also asserted that inclusion of transmission capacity available for market purchases is contrary to the requirements of PURPA. We disagree. We previously have found, in Case No. PAC-E-15-12 involving Rocky Mountain Power, that a utility's import capability (its ability to purchase short-term using its transmission capacity) should be treated the same as available generation resources such as a signed QF contract or generation from its own plant for purposes of determining the capacity deficiency date. Order No. 33425 at 6-7. There, the Company used existing plant generation, QF contracts, *and* available transmission capacity to balance its capacity needs. *Id.* at 7. We determined that "[i]mport capability constitutes capacity," and explained that when a utility has import capability available, it would use that to meet its capacity needs—it would not build a new resource. *Id.* Thus, if a utility has available transmission capacity, it is capacity surplus. *Id.*

We found that including the Company's

> import capability in the capacity deficit determination comport[ed] with the "incremental cost" mandate in PURPA. By including import capability, avoided cost rates appropriately recognize the Company's mix of available resources. And importantly, including import capability ensures that avoided cost rates do not favor QFs at the expense of Rocky Mountain's ratepayers, who ultimately bear the costs.

Id. (citing Order No. 33419 at 6). As a result, the Commission approved the Company's capacity deficit determination, which included consideration of the transmission capacity it had available for market purchases.

Similarly, here Idaho Power proposed to use available transmission capacity to import market purchases to meet its capacity needs. Consistent with our previous analysis, we find that when the utility has import capability available, it is reasonable to use that to meet capacity needs, rather than building a new resource. It is therefore appropriate to consider the utility's import capability when setting its capacity deficiency date. Doing so ensures that avoided cost payments to QFs include payments for capacity when the utility forecasts it will need capacity—not earlier—and thus protects ratepayers.

Staff's interpretation of capacity deficiency determinations under the IRP methodology—that July 2026 is a starting point and the actual deficiency date will "float around" depending on the capacity contributions of QFs in the queue—is a divergence from our prior Orders and from the Company's request in this Application. *See, e.g.,* Order No. 32697 at 23 (acknowledging that the IRP process determines when the utility will experience a need for new capacity); Order No. 33159 at 9 and Order No. 33377 at 3 (each approving new deficiency dates based on changes to the information from the last IRP); Application at 4 (requesting approval of a deficiency date of July 2026 for the SAR and IRP methodologies). We find that such a divergence, without a more thorough analysis of reasoning and potential impacts, would not be just or reasonable. Thus, we find the proposed July 2026 capacity deficiency date to be reasonable and we approve it for use in the SAR and IRP methodologies. We further find that Staff's updated SAR model, using the July 2026 date, and the resulting published avoided cost rates are just and reasonable, and we approve the rates.

We also find it reasonable and appropriate for Staff, utilities, and other interested parties to explore whether to combine future PURPA fuel price and load forecast updates with the capacity deficiency date updates every other year when all updates occur. Combined filings could reduce the administrative burden on parties and result in more efficient use of time and resources.

ORDER

IT IS HEREBY ORDERED that Idaho Power's Application for approval of the capacity deficiency to be utilized for avoided cost calculations is approved. We confirm that the Company's capacity deficiency period for the avoided cost SAR and IRP methodologies is July 2026.

IT IS FURTHER ORDERED that the updated SAR model and the SAR-based published avoided cost prices, attached hereto, are also approved.

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 5th day of October 2017.

PAUL KJELLANDER, PRESIDENT

KRISTINE RAPER, COMMISSIONER

ERIC ANDERSON, COMMISSIONER

ATTEST:

Diane M. Hanian
Commission Secretary

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IDAHO POWER COMPANY
AVOIDED COST RATES FOR WIND PROJECTS
XXXX, 2017
$/MWh
New Contracts and Replacement Contracts without Full Capacity Payments

Eligibility for these rates is limited to projects 100 kW or smaller.

LEVELIZED

CONTRACT LENGTH (YEARS)	ON-LINE YEAR 2017	2018	2019	2020	2021	2022
1	28.61	31.48	34.42	35.95	36.78	36.36
2	29.99	32.89	35.15	36.35	36.57	36.71
3	31.35	33.83	35.65	36.35	36.74	37.34
4	32.37	34.48	35.81	36.52	37.18	38.39
5	33.12	34.80	36.03	36.90	38.01	40.02
6	33.56	35.11	36.40	37.60	39.37	41.28
7	33.95	35.52	37.03	38.75	40.48	42.32
8	34.40	36.13	38.05	39.74	41.42	43.23
9	35.01	37.07	38.95	40.61	42.27	43.99
10	35.90	37.91	39.75	41.39	42.98	44.64
11	36.70	38.67	40.48	42.07	43.61	45.23
12	37.42	39.36	41.12	42.66	44.18	45.77
13	38.09	39.98	41.69	43.21	44.70	46.27
14	38.69	40.53	42.22	43.71	45.19	46.76
15	39.23	41.04	42.70	44.18	45.67	47.22
16	39.73	41.51	43.15	44.64	46.12	47.68
17	40.19	41.96	43.59	45.08	46.56	48.11
18	40.62	42.38	44.01	45.50	46.98	48.53
19	41.04	42.79	44.42	45.90	47.38	48.94
20	41.44	43.19	44.81	46.29	47.78	49.32

NON-LEVELIZED

CONTRACT YEAR	NON-LEVELIZED RATES
2017	28.61
2018	31.48
2019	34.42
2020	35.95
2021	36.78
2022	36.36
2023	37.10
2024	38.76
2025	42.05
2026	47.99
2027	49.35
2028	50.58
2029	52.04
2030	52.76
2031	53.50
2032	54.64
2033	55.49
2034	56.72
2035	58.16
2036	59.63
2037	61.27
2038	62.44
2039	63.98
2040	65.87
2041	67.01
2042	69.03

Note: These rates will be further adjusted with the applicable integration charge.

Note: The rates shown in this table have been computed using the U.S. Energy Information Administration (EIA)'s Annual Energy Outlook 2017, released January 2017. See Annual Energy Outlook 2017, Table 3.8 Energy Prices by Sector-Mountain at https://www.eia.gov/outlooks/aeo/tables_ref.cfm

ATTACHMENT
CASE NO. IPC-E-17-12
ORDER NO. 33898

IDAHO POWER COMPANY
AVOIDED COST RATES FOR SOLAR PROJECTS
XXXX, 2017
$/MWh
New Contracts and Replacement Contracts without Full Capacity Payments

Eligibility for these rates is limited to projects 100 kW or smaller.

LEVELIZED							NON-LEVELIZED	
CONTRACT LENGTH (YEARS)	ON-LINE YEAR						CONTRACT YEAR	NON-LEVELIZED RATES
	2017	2018	2019	2020	2021	2022		
1	28.61	31.48	34.42	35.95	36.78	36.36	2017	28.61
2	29.99	32.89	35.15	36.35	36.57	36.71	2018	31.48
3	31.35	33.83	35.65	36.35	36.74	37.34	2019	34.42
4	32.37	34.48	35.81	36.52	37.18	38.39	2020	35.95
5	33.12	34.80	36.03	36.90	38.01	45.36	2021	36.78
6	33.56	35.11	36.40	37.60	43.63	50.23	2022	36.36
7	33.95	35.52	37.03	42.26	47.82	53.87	2023	37.10
8	34.40	36.13	40.99	45.90	51.10	56.77	2024	38.76
9	35.01	39.57	44.19	48.84	53.79	59.10	2025	42.05
10	38.05	42.42	46.84	51.31	56.00	61.03	2026	79.43
11	40.62	44.83	49.10	53.38	57.86	62.69	2027	81.25
12	42.83	46.92	51.03	55.15	59.48	64.13	2028	82.94
13	44.76	48.72	52.70	56.70	60.90	65.41	2029	84.88
14	46.44	50.30	54.18	58.07	62.17	66.58	2030	86.08
15	47.93	51.70	55.49	59.30	63.32	67.65	2031	87.30
16	49.26	52.95	56.68	60.43	64.38	68.64	2032	88.94
17	50.46	54.09	57.76	61.47	65.37	69.55	2033	90.29
18	51.55	55.14	58.77	62.43	66.27	70.40	2034	92.03
19	52.55	56.11	59.70	63.32	67.12	71.20	2035	93.99
20	53.48	57.01	60.56	64.15	67.92	71.95	2036	95.98
							2037	98.16
							2038	99.87
							2039	101.96
							2040	104.40
							2041	106.11
							2042	108.71

Note: These rates will be further adjusted with the applicable integration charge.

Note: The rates shown in this table have been computed using the U.S. Energy Information Administration (EIA)'s Annual Energy Outlook 2017, released January 2017. See Annual Energy Outlook 2017, Table 3.8 Energy Prices by Sector-Mountain at https://www.eia.gov/outlooks/aeo/tables_ref.cfm

IDAHO POWER COMPANY
AVOIDED COST RATES FOR NON-SEASONAL HYDRO PROJECTS
XXXX, 2017
$/MWh

New Contracts and Replacement Contracts without Full Capacity Payments

Eligibility for these rates is limited to projects smaller than 10 aMW.

LEVELIZED

CONTRACT LENGTH (YEARS)	ON-LINE YEAR 2017	2018	2019	2020	2021	2022
1	28.61	31.48	34.42	35.95	36.78	36.36
2	29.99	32.89	35.15	36.35	36.57	36.71
3	31.35	33.83	35.65	36.35	36.74	37.34
4	32.37	34.48	35.81	36.52	37.18	38.39
5	33.12	34.80	36.03	36.90	38.01	44.84
6	33.56	35.11	36.40	37.60	43.22	49.36
7	33.95	35.52	37.03	41.92	47.11	52.75
8	34.40	36.13	40.70	45.30	50.16	55.45
9	35.01	39.33	43.68	48.04	52.67	57.63
10	37.84	41.99	46.15	50.35	54.74	59.44
11	40.24	44.24	48.27	52.28	56.48	61.00
12	42.30	46.19	50.07	53.94	58.00	62.35
13	44.11	47.87	51.63	55.39	59.33	63.55
14	45.69	49.35	53.02	56.68	60.52	64.65
15	47.08	50.66	54.25	57.84	61.61	65.66
16	48.33	51.84	55.36	58.90	62.61	66.60
17	49.46	52.91	56.39	59.88	63.54	67.47
18	50.49	53.90	57.33	60.79	64.40	68.27
19	51.43	54.81	58.22	61.63	65.20	69.04
20	52.31	55.67	59.03	62.41	65.96	69.75

NON-LEVELIZED

CONTRACT YEAR	NON-LEVELIZED RATES
2017	28.61
2018	31.48
2019	34.42
2020	35.95
2021	36.78
2022	36.36
2023	37.10
2024	38.76
2025	42.05
2026	76.38
2027	78.15
2028	79.80
2029	81.69
2030	82.85
2031	84.02
2032	85.61
2033	86.91
2034	88.61
2035	90.52
2036	92.45
2037	94.58
2038	96.24
2039	98.28
2040	100.66
2041	102.32
2042	104.85

Note: These rates will be further adjusted with the applicable integration charge.

Note: The rates shown in this table have been computed using the U.S. Energy Information Administration (EIA)'s Annual Energy Outlook 2017, released January 2017. See Annual Energy Outlook 2017, Table 3.8 Energy Prices by Sector-Mountain at https://www.eia.gov/outlooks/aeo/tables_ref.cfm

IDAHO POWER COMPANY
AVOIDED COST RATES FOR SEASONAL HYDRO PROJECTS
XXXX, 2017
$/MWh
New Contracts and Replacement Contracts without Full Capacity Payments

Eligibility for these rates is limited to projects smaller than 10 aMW.

LEVELIZED

CONTRACT LENGTH (YEARS)	ON-LINE YEAR 2017	2018	2019	2020	2021	2022
1	28.61	31.48	34.42	35.95	36.78	36.36
2	29.99	32.89	35.15	36.35	36.57	36.71
3	31.35	33.83	35.65	36.35	36.74	37.34
4	32.37	34.48	35.81	36.52	37.18	38.39
5	33.12	34.80	36.03	36.90	38.01	48.47
6	33.56	35.11	36.40	37.60	46.12	55.44
7	33.95	35.52	37.03	44.30	52.11	60.61
8	34.40	36.13	42.70	49.49	56.75	64.67
9	35.01	41.03	47.24	53.65	60.51	67.91
10	39.30	45.05	50.98	57.10	63.59	70.59
11	42.91	48.43	54.14	59.98	66.17	72.87
12	45.98	51.33	56.82	62.43	68.40	74.84
13	48.65	53.82	59.12	64.57	70.34	76.58
14	50.97	55.99	61.15	66.45	72.07	78.14
15	53.00	57.91	62.95	68.12	73.62	79.56
16	54.82	59.63	64.56	69.64	75.04	80.86
17	56.44	61.17	66.03	71.03	76.34	82.05
18	57.92	62.58	67.37	72.31	77.53	83.16
19	59.27	63.87	68.61	73.48	78.63	84.19
20	60.51	65.07	69.75	74.56	79.67	85.15

NON-LEVELIZED

CONTRACT YEAR	NON-LEVELIZED RATES
2017	28.61
2018	31.48
2019	34.42
2020	35.95
2021	36.78
2022	36.36
2023	37.10
2024	38.76
2025	42.05
2026	97.77
2027	99.85
2028	101.82
2029	104.03
2030	105.52
2031	107.02
2032	108.95
2033	110.59
2034	112.63
2035	114.89
2036	117.19
2037	119.68
2038	121.71
2039	124.12
2040	126.88
2041	128.92
2042	131.85

Note: A "seasonal hydro project" is defined as a generation facility which produces at least 55% of its annual generation during the months of June, July, and August. Order 32802.

Note: These rates will be further adjusted with the applicable integration charge.

Note: The rates shown in this table have been computed using the U.S. Energy Information Administration (EIA)'s Annual Energy Outlook 2017, released January 2017. See Annual Energy Outlook 2017, Table 3.8 Energy Prices by Sector-Mountain at https://www.eia.gov/outlooks/aeo/tables_ref.cfm

IDAHO POWER COMPANY
AVOIDED COST RATES FOR OTHER PROJECTS
XXXX, 2017
$/MWh
New Contracts and Replacement Contracts without Full Capacity Payments

Eligibility for these rates is limited to projects smaller than 10 aMW.

LEVELIZED

CONTRACT LENGTH (YEARS)	ON-LINE YEAR 2017	2018	2019	2020	2021	2022
1	28.61	31.48	34.42	35.95	36.78	36.36
2	29.99	32.89	35.15	36.35	36.57	36.71
3	31.35	33.83	35.65	36.35	36.74	37.34
4	32.37	34.48	35.81	36.52	37.18	38.39
5	33.12	34.80	36.03	36.90	38.01	43.43
6	33.56	35.11	36.40	37.60	42.09	47.00
7	33.95	35.52	37.03	41.00	45.18	49.71
8	34.40	36.13	39.93	43.68	47.61	51.89
9	35.01	38.67	42.30	45.87	49.63	53.65
10	37.27	40.80	44.28	47.73	51.31	55.12
11	39.21	42.61	45.99	49.30	52.72	56.40
12	40.88	44.20	47.46	50.65	53.97	57.51
13	42.36	45.57	48.73	51.84	55.06	58.51
14	43.65	46.78	49.86	52.89	56.05	59.43
15	44.79	47.86	50.88	53.85	56.96	60.28
16	45.82	48.83	51.80	54.74	57.80	61.08
17	46.75	49.72	52.65	55.56	58.59	61.82
18	47.61	50.54	53.45	56.33	59.32	62.51
19	48.40	51.31	54.19	57.04	60.00	63.17
20	49.14	52.02	54.88	57.71	60.66	63.79

NON-LEVELIZED

CONTRACT YEAR	NON-LEVELIZED RATES
2017	28.61
2018	31.48
2019	34.42
2020	35.95
2021	36.78
2022	36.36
2023	37.10
2024	38.76
2025	42.05
2026	68.09
2027	69.75
2028	71.28
2029	73.04
2030	74.07
2031	75.11
2032	76.57
2033	77.75
2034	79.30
2035	81.07
2036	82.88
2037	84.86
2038	86.38
2039	88.27
2040	90.51
2041	92.01
2042	94.40

Note: "Other projects" refers to projects other than wind, solar, non-seasonal hydro, and seasonal hydro projects. These "Other projects" may include (but are not limited to): cogeneration, biomass, biogas, landfill gas, or geothermal projects.

Note: The rates shown in this table have been computed using the U.S. Energy Information Administration (EIA)'s Annual Energy Outlook 2017, released January 2017. See Annual Energy Outlook 2017, Table 3.8 Energy Prices by Sector-Mountain at https://www.eia.gov/outlooks/aeo/tables_ref.cfm