BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

BUCKHAM, DI
TESTIMONY

EXHIBIT NO. 19

Greg Miller

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MARSH

Jeff Pleimann
Insurance & Risk Administrator
Idaho Power
1221 West Idaho St.
Boise, ID 83702

December 21st, 2020

Subject: Wildfire / Excess Liability and Property Premiums

Dear Jeff,

This letter summarizes information regarding insurance premiums paid by Idaho Power for coverage for liability related to wildfire currently, as well as information on what Idaho Power should expect to pay in the future assuming maintenance of existing levels of coverage.

ALLOCATION OF CURRENT PREMIUMS TO WILDFIRES

Coverage for Idaho Power's liability for wildfire is provided within your excess liability insurance tower, with three separate insurers. Generally, insurers are reluctant to attribute how much of a policy is related to a specific risk. With regard to wildfire risk, however, it is understood that a significant portion of Idaho Power's excess liability policies are related to wildfires. Additionally, the latest excess liability policy was purchased expressly to cover Idaho Power's exposure to wildfire-related risk. As a result, the full premium in this layer is due to wildfire liability risk, since Idaho Power would not have purchased this layer but for the desire for additional protection for wildfire-related risk.

FUTURE PREMIUM INCREASE EXPECTATIONS

The mutual insurance company that provides Idaho Power's primary excess liability policy, has advised all policyholders that they should expect excess liability premiums for 2021 to increase, on average, at least 15% over 2020 levels. In addition, they have advised that utilities in wildfire prone areas will be charged a "wildfire load" in addition to their base premium. The load varies depending on the relative exposure. For Idaho Power, we have been informed that the load will be up to $1 million beginning in 2021, with the potential to increase annually thereafter.

The insurance company that provides Idaho Power's second layer of excess liability coverage has not formally advised policyholders of anticipated increases for 2021. For most renewals in 2020 from the insurance company, the premiums are increasing between 10 and 15%. We anticipate the same range will apply in 2021 for most utilities, including Idaho Power.

For the third layer of excess liability coverage, this is placed in the commercial market and is therefore subject to general market conditions. For 2020, the commercial market for excess liability for electric utilities has seen rate increases generally falling between 20% and 50%. We anticipate Idaho Power will be at the higher end of this range.

For 2022 and beyond, we anticipate the liability insurance market to temper and annual rate of premium growth should decrease in magnitude after the significant recent and near-term adjustments; however we do not have significant clarity to future market conditions and future increases could continue to be notable. Our expectation is subject to change based on wildfire losses in the western U.S.

With regard to insurance premiums in general, losses from natural disasters, including wildfires (whether natural or human-caused), and the various causes of losses across numerous forms of coverage, are a concern to underwriters and have contributed to the general hardening of the insurance market and associated sizeable increases in premiums.

Please let me know if you have any questions.

Sincerely,

Greg Miller
Managing Director

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

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TESTIMONY

EXHIBIT NO. 20

RatingsDirect®

May 7, 2007

Criteria | Corporates | Utilities:

Standard & Poor's Methodology For Imputing Debt For U.S. Utilities' Power Purchase Agreements

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Standard & Poor's Methodology For Imputing Debt For U.S. Utilities' Power Purchase Agreements

For many years, Standard & Poor's Ratings Services has viewed power supply agreements (PPA) in the U.S. utility sector as creating fixed, debt-like, financial obligations that represent substitutes for debt-financed capital investments in generation capacity. In a sense, a utility that has entered into a PPA has contracted with a supplier to make the financial investment on its behalf. Consequently, PPA fixed obligations, in the form of capacity payments, merit inclusion in a utility's financial metrics as though they are part of a utility's permanent capital structure and are incorporated in our assessment of a utility's creditworthiness.

We adjust utilities' financial metrics, incorporating PPA fixed obligations, so that we can compare companies that finance and build generation capacity and those that purchase capacity to satisfy customer needs. The analytical goal of our financial adjustments for PPAs is to reflect fixed obligations in a way that depicts the credit exposure that is added by PPAs. That said, PPAs also benefit utilities that enter into contracts with suppliers because PPAs will typically shift various risks to the suppliers, such as construction risk and most of the operating risk. PPAs can also provide utilities with asset diversity that might not have been achievable through self-build. The principal risk borne by a utility that relies on PPAs is the recovery of the financial obligation in rates.

The Mechanics Of PPA Debt Imputation

A starting point for calculating the debt to be imputed for PPA-related fixed obligations can be found among the "commitments and contingencies" in the notes to a utility's financial statements. We calculate a net present value (NPV) of the stream of the outstanding contracts' capacity payments reported in the financial statements as the foundation of our financial adjustments.

The notes to the financial statements enumerate capacity payments for the five years succeeding the annual report and a "thereafter" period. While we have access to proprietary forecasts that show the detail underlying the costs that are amalgamated beyond the five-year horizon, others, for purposes of calculating an NPV, can divide the amount reported as "thereafter" by the average of the capacity payments in the preceding five years to derive an approximate tenor of the amounts combined as the sum of the obligations beyond the fifth year.

In calculating debt equivalents, we also include new contracts that will commence during the forecast period. Such contracts aren't reflected in the notes to the financial statements, but relevant information regarding these contracts are provided to us on a confidential basis. If a contract has been executed but the energy will not flow until some later period, we won't impute debt for that contract until the year that energy deliveries begin under the contract if the contract represents incremental capacity. However, to the extent that the contract will simply replace an expiring contract, we will impute debt as though the future contract is a continuation of the existing contract.

We calculate the NPV of capacity payments using a discount rate equivalent to the company's average cost of debt, net of securitization debt. Once we arrive at the NPV, we apply a risk factor, as is discussed below, to reflect the benefits of regulatory or legislative cost recovery mechanisms.

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Balance sheet debt is increased by the risk-factor-adjusted NPV of the stream of capacity payments. We derive an adjusted debt-to-capitalization ratio by adding the adjusted NPV to both the numerator and the denominator of that ratio.

We calculate an implied interest expense for the imputed debt by multiplying the same utility average cost of debt used as the discount rate in the NPV calculation by the amount of imputed debt. The adjusted FFO-to-interest expense ratio is calculated by adding the implied interest expense to both the numerator and denominator of the equation. We also add implied depreciation to the equation's numerator. We calculate the adjusted FFO-to-total-debt ratio by adding imputed debt to the equation's denominator and an implied depreciation expense to its numerator.

Our adjusted cash flow credit metrics include a depreciation expense adjustment to FFO. This adjustment represents a vehicle for capturing the ownership-like attributes of the contracted asset and tempers the effects of imputation on the cash flow ratios. We derive the depreciation expense adjustment by multiplying the relevant year's capacity payment obligation by the risk factor and then subtracting the implied PPA-related interest expense for that year from the product of the risk factor times the scheduled capacity payment.

Risk Factors

The NPVs that Standard & Poor's calculates to adjust reported financial metrics to capture PPA capacity payments are multiplied by risk factors. These risk factors typically range between 0% to 50%, but can be as high as 100%. Risk factors are inversely related to the strength and availability of regulatory or legislative vehicles for the recovery of the capacity costs associated with power supply arrangements. The strongest recovery mechanisms translate into the smallest risk factors. A 100% risk factor would signify that all risk related to contractual obligations rests on the company with no mitigating regulatory or legislative support.

For example, an unregulated energy company that has entered into a tolling arrangement with a third-party supplier would be assigned a 100% risk factor. Conversely, a 0% risk factor indicates that the burden of the contractual payments rests solely with ratepayers. This type of arrangement is frequently found among regulated utilities that act as conduits for the delivery of a third party's electricity and essentially deliver power, collect charges, and remit revenues to the suppliers. These utilities have typically been directed to sell all their generation assets, are barred from developing new generation assets, and the power supplied to their customers is sourced through a state auction or third parties, leaving the utilities to act as intermediaries between retail customers and the electricity suppliers.

Intermediate degrees of recovery risk are presented by a number of regulatory and legislative mechanisms. For example, some regulators use a utility's rate case to establish base rates that provide for the recovery of the fixed costs created by PPAs. Although we see this type of mechanism as generally supportive of credit quality, the fact remains that the utility will need to litigate the right to recover costs and the prudence of PPA capacity payments in successive rate cases to ensure ongoing recovery of its fixed costs. For such a PPA, we employ a 50% risk factor. In cases where a regulator has established a power cost adjustment mechanism that recovers all prudent PPA costs, we employ a risk factor of 25% because the recovery hurdle is lower than it is for a utility that must litigate time and again its right to recover costs.

We recognize that there are certain jurisdictions that have true-up mechanisms that are more favorable and frequent than the review of base rates, but still don't amount to pure pass-through mechanisms. Some of these mechanisms

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are triggered when certain financial thresholds are met or after prescribed periods of time have passed. In these instances, in calculating adjusted ratios, we will employ a risk factor between the revised 25% risk factors for utilities with power cost adjustment mechanisms and 50%.

Finally, we view legislatively created cost recovery mechanisms as longer lasting and more resilient to change than regulatory cost recovery vehicles. Consequently, such mechanisms lead to risk factors between 0% and 15%, depending on the legislative provisions for cost recovery and the supply function borne by the utility. Legislative guarantees of complete and timely recovery of costs are particularly important to achieving the lowest risk factors.

Illustration Of The PPA Adjustment Methodology

The calculations of the debt equivalents, implied interest expense, depreciation expense, and adjusted financial metrics, using risk factors, are illustrated in the following example:

Example Of Power-Purchase Agreement Adjustment

($000s)	Assumption	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter
Cash from operations	2,000,000						
Funds from operations	1,500,000						
Interest expense	444,000						
Directly issued debt							
Short-term debt	600,000						
Long-term due within one year	300,000						
Long-term debt	6,500,000						
Shareholder's Equity	6,000,000						
Fixed capacity commitments	600,000	600,000	600,000	600,000	600,000	600,000	4,200,000*
NPV of fixed capacity commitments							
Using a 6.0% discount rate	5,030,306						
Application of an assumed 25% risk factor	1,257,577						
Implied interest expense¶	75,455						
Implied depreciation expense	74,545						
Unadjusted ratios							
FFO to interest (x)	4.4						
FFO to total Debt (%)	20.0						
Debt to capitalization (%)	55.0						
Ratios adjusted for debt imputation							
FFO to interest (x)§	4.0						
FFO to total debt (%)**	18.0						
Debt to capitalization (%)¶¶	59.0						

*Thereafter approximate years: 7. ¶The current year's implied interest is subtracted from the product of the risk factor multiplied by the current year's capacity payment. §Adds implied interest to the numerator and denominator and adds implied depreciation to FFO. **Adds implied depreciation expense to FFO and implied debt to reported debt. ¶¶Adds implied debt to both the numerator and the denominator. FFO--Funds from operations. NPV--Net present value.

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Short-Term Contracts

Standard & Poor's has abandoned its historical practice of not imputing debt for contracts with terms of three years or less. However, we understand that there are some utilities that use short-term PPAs of approximately one year or less as gap fillers pending the construction of new capacity. To the extent that such short-term supply arrangements represent a nominal percentage of demand and serve the purposes described above, we will neither impute debt for such contracts nor provide evergreen treatment to such contracts.

Evergreen Treatment

The NPV of the fixed obligations associated with a portfolio of short-term or intermediate-term contracts can lead to distortions in a utility's financial profile relative to the NPV of the fixed obligations of a utility with a portfolio of PPAs that is made up of longer-term commitments. Where there is the potential for such distortions, rating committees will consider evergreen treatment of existing PPA obligations as a scenario for inclusion in the rating analysis. Evergreen treatment extends the tenor of short- and intermediate-term contracts to reflect the long-term obligation of electric utilities to meet their customers' demand for electricity.

While we have concluded that there is a limited pool of utilities whose portfolios of existing and projected PPAs don't meaningfully correspond to long-term load serving obligations, we will nevertheless apply evergreen treatment in those cases where the portfolio of existing and projected PPAs is inconsistent with long-term load-serving obligations. A blanket application of evergreen treatment is not warranted.

To provide evergreen treatment, Standard & Poor's starts by looking at the tenor of outstanding PPAs. Others can look to the "commitments and contingencies" in the notes to a utility's financial statements to derive an approximate tenor of the contracts. If we conclude that the duration of PPAs is short relative to our targeted tenor, we would then add capacity payments until the targeted tenor is achieved. Based on our analysis of several companies, we have determined that the evergreen extension of the tenor of existing contracts and anticipated contracts should extend contracts to a common length of about 12 years.

The price for the capacity that we add will be derived from new peaker entry economics. We use empirical data to establish the cost of developing new peaking capacity and reflect regional differences in our analysis. The cost of new capacity is translated into a dollars per kilowatt-year (kW-year) figure using a weighted average cost of capital for the utility and a proxy capital recovery period.

Analytical Treatment Of Contracts With All-In Energy Prices

The pricing for some PPA contracts is stated as a single, all-in energy price. Standard & Poor's considers an implied capacity price that funds the recovery of the supplier's capital investment to be subsumed within the all-in energy price. Consequently, we use a proxy capacity charge, stated in $/kW, to calculate an implied capacity payment associated with the PPA. The $/kW figure is multiplied by the number of kilowatts under contract. In cases of resources such as wind power that exhibit very low capacity factors, we will adjust the kilowatts under contract to reflect the anticipated capacity factor that the resource is expected to achieve.

We derive the proxy cost of capacity using empirical data evidencing the cost of developing new peaking capacity.

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We will reflect regional differences in our analysis. The cost of new capacity is translated into a $/kW figure using a weighted average cost of capital and a proxy capital recovery period. This number will be updated from time to time to reflect prevailing costs for the development and financing of the marginal unit, a combustion turbine.

Transmission Arrangements

In recent years, some utilities have entered into long-term transmission contracts in lieu of building generation. In some cases, these contracts provide access to specific power plants, while other transmission arrangements provide access to competitive wholesale electricity markets. We have concluded that these types of transmission arrangements represent extensions of the power plants to which they are connected or the markets that they serve. Irrespective of whether these transmission lines are integral to the delivery of power from a specific plant or are conduits to wholesale markets, we view these arrangements as exhibiting very strong parallels to PPAs as a substitute for investment in power plants. Consequently, we will impute debt for the fixed costs associated with long-term transmission contracts.

PPAs Treated As Leases

Several utilities have reported that their accountants dictate that certain PPAs need to be treated as leases for accounting purposes due to the tenor of the PPA or the residual value of the asset upon the PPA's expiration. We have consistently taken the position that companies should identify those capacity charges that are subject to operating lease treatment in the financial statements so that we can accord PPA treatment to those obligations, in lieu of lease treatment. That is, PPAs that receive operating lease treatment for accounting purposes won't be subject to a 100% risk factor for analytical purposes as though they were leases. Rather, the NPV of the stream of capacity payments associated with these PPAs will be reduced by the risk factor that is applied to the utility's other PPA commitments. PPAs that are treated as capital leases for accounting purposes will not receive PPA treatment because capital lease treatment indicates that the plant under contract economically "belongs" to the utility.

Evaluating The Effect Of PPAs

Though history is on the side of full cost recovery, PPAs nevertheless add financial obligations that heighten financial risk. Yet, we apply risk factors that reduce debt imputation to recognize that utilities that rely on PPAs transfer significant risks to ratepayers and suppliers.

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BEFORE THE

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CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

BUCKHAM, DI TESTIMONY

EXHIBIT NO. 21

IDAHO POWER COMPANY

PRO FORMA COST OF CAPITAL
SUMMARIZED
December 31, 2023 Capitalization
(000's)

	(1)	(2)	(3)	(4)	(5)
Line No		Capitalization Structure Amount	Percent	Embedded Cost	Weighted Cost
1	Long-term Debt	2,601,100	49.0%	4.895%	2.399%
2	Common Equity	2,707,000	51.0%	10.400% *	5.304%
3	Total Capitalization	$5,308,100	100.000%		7.702%

Note:
* Requested Rate of Return

IDAHO POWER COMPANY
PRO FORMA COST OF LONG-TERM DEBT
As of 12/31/2023
(000's)

Line No.	(1) Class and Series	(2) Coupon Rate	(3) Settlement Date	(4) Maturity Date	(5) Principal Amount Issued	(6) Principal Amount Outstanding	(7) Price	(8) Discount/ (Premium)	(9) Issuance Costs	(10) Net Proceeds	(11) Yield To Maturity	(12) Effective Cost
	First Mortgage Bonds:											
1	6.00% Series due 2032	6.00%	11/15/2002	11/15/2032	100,000	100,000	98.706	1,294.0	441.2	98,264.8	6.127%	6,127.1
2	5.5% Series due 2033	5.50%	5/13/2003	4/1/2033	70,000	70,000	99.198	561.4	3,810.2	65,628.4	5.949%	4,164.3
3	5.5% Series due 2034	5.50%	3/26/2004	3/15/2034	50,000	50,000	98.483	758.5	149.4	49,092.1	5.626%	2,813.0
4	5.875% Series due 2034	5.875%	8/16/2004	8/15/2034	55,000	55,000	97.890	1,160.5	173.3	53,666.2	6.051%	3,328.2
5	5.30% Series due 2035	5.30%	8/26/2005	8/15/2035	60,000	60,000	98.569	858.6	3,399.7	55,741.7	5.802%	3,481.3
6	6.30% Series due 2037	6.30%	6/22/2007	6/15/2037	140,000	140,000	99.051	1,328.6	450.0	138,221.4	6.396%	8,953.9
7	6.25% Series due 2037	6.25%	10/18/2007	10/15/2037	100,000	100,000	98.982	1,018.0	477.5	98,504.5	6.362%	6,362.3
8	4.85% Series due 2040	4.85%	8/30/2010	8/15/2040	100,000	100,000	99.080	920.0	534.9	98,545.1	4.943%	4,943.4
9	4.30% Series due 2042	4.30%	4/13/2012	4/1/2042	75,000	75,000	99.184	612.0	1,397.8	72,990.2	4.463%	3,347.2
10	4.00% Series due 2043	4.00%	4/8/2013	4/1/2043	75,000	75,000	98.991	756.8	179.2	74,064.0	4.072%	3,054.3
11	3.65% Series due 2045	3.65%	3/6/2015	3/1/2045	250,000	250,000	98.564	3,590.0	19,137.5	227,272.5	4.185%	10,462.3
12	4.05% Series due 2046	4.05%	3/10/2016	3/1/2046	120,000	120,000	98.992	1,209.6	14,689.4	104,101.0	4.898%	5,877.1
13	4.20% Series due 2048	4.20%	3/16/2018	3/1/2048	220,000	220,000	98.880	2,464.0	5,532.0	212,004.0	4.420%	9,723.8
14	4.20% Series due 2048	4.20%	4/3/2020	3/1/2048	230,000	230,000	113.013	-29,929.9	621.1	259,308.8	3.482%	8,009.4
15	1.90% Series due 2030	1.90%	6/22/2020	7/15/2030	80,000	80,000	98.940	848.0	3,925.3	75,226.7	2.577%	2,061.4
16	4.99% Series due 2032	4.99%	12/22/2022	12/22/2032	23,000	23,000	99.500	115.0	85.0	22,800.0	5.102%	1,173.5
17	5.06% Series due 2042	5.06%	12/22/2022	12/22/2042	25,000	25,000	99.500	125.0	93.0	24,782.0	5.130%	1,282.6
18	5.06% Series due 2043	5.06%	3/8/2023	3/8/2043	60,000	60,000	99.500	300.0	222.0	59,478.0	5.130%	3,078.0
19	5.20% Series due 2053	5.20%	3/8/2023	3/8/2053	62,000	62,000	99.500	310.0	229.0	61,461.0	5.258%	3,259.9
20	5.50% Series due 2053	5.50%	3/14/2023	3/15/2053	400,000	400,000	98.182	7,272.0	1,480.0	391,248.0	5.652%	22,609.0
21	5.60% Series due 2053	5.60%	10/16/2023	10/15/2053	140,000	140,000	99.000	1,400.0	520.0	138,080.0	5.696%	7,974.2
22												
23	Total First Mortgage Bonds				2,435,000	2,435,000		(3,027.9)	57,547.5	2,380,480.4	5.014%	122,086.2
24												
25	Pollution Control Revenue Bonds:											
26	Humboldt 1.45% Series 2003, due 2024	1.45%	8/21/2019	12/1/2024	49,800	49,800	99.200	398.4	4,352.9	45,048.7	3.442%	1,714.1
27	Sweetwater 1.70% Series 2006, due 2026	1.70%	8/21/2019	7/15/2026	116,300	116,300	99.200	930.4	8,612.9	106,756.7	3.027%	3,519.8
28												
29	Total Pollution Control Revenue Bonds				166,100	166,100		1,329	12,966	151,805	3.151%	5,234
30												
31												
32	TOTAL DEBT CAPITAL				2,601,100	2,601,100		(1,699)	70,513	2,532,286	4.895%	127,320