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IDAHO PUBLIC
UTILITIES COMMISSION

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE COMMISSION'S REVIEW OF PURPA QF CONTRACT PROVISIONS INCLUDING THE SURROGATE AVOIDED RESOURCE (SAR) AND INTEGRATED RESOURCE PLANNING (IRP) METHODOLOGIES FOR CALCULATING PUBLISHED AVOIDED COST RATES.	)	CASE NO. GNR-E-11-03

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

M. MARK STOKES

1 Q. Please state your name and business address.

2 A. My name is M. Mark Stokes and my business

3 address is 1221 West Idaho Street, Boise, Idaho.

4 Q. By whom are you employed and in what capacity?

5 A. I am employed by Idaho Power Company ("Idaho

6 Power" or "Company") as the Manager of Power Supply

7 Planning.

8 Q. Please describe your educational background

9 and work experience with Idaho Power.

10 A. I am a graduate of the University of Idaho

11 with a Bachelor of Science Degree in Civil Engineering. I

12 also hold a Masters Degree in Business Administration from

13 Northwest Nazarene University and am a registered

14 Professional Engineer in the state of Idaho.

15 I joined Idaho Power in 1991 as a member of the

16 construction management team responsible for the

17 construction of the Milner Hydroelectric Project. In 1992,

18 I joined the Generation Engineering Department where I was

19 responsible for dam safety and regulatory compliance for

20 Idaho Power's 17 hydroelectric projects. In 1996, I began

21 working with Idaho Power's Hydro Services Group, a new

22 business initiative within the Power Production Department,

23 where I was responsible for business development and

24 marketing. In 1999, I returned to my previous position

25

1 within the Power Production Department to administer Idaho
2 Power's dam safety program.
3 In 2004, I accepted a position as the President of
4 Ida-West Energy Company, a subsidiary of IDACORP. In this
5 role, I was responsible for managing the overall operation
6 of the company as well as the operation and maintenance of
7 nine hydroelectric projects with qualifying facility
8 status. In 2006, I rejoined Idaho Power's Power Supply
9 business unit as the Manager of Power Supply Planning. The
10 Power Supply Planning Department is responsible for
11 resource planning, load forecasting, and cogeneration and
12 small power production contract management.
13 Q. What is the purpose of your testimony in this
14 matter?
15 A. The purpose of my testimony is to provide
16 direct testimony for Idaho Power in response to the Idaho
17 Public Utilities Commission's ("Commission") Order Nos.
18 32352 and 32388. My testimony will describe the current
19 status of Public Utility Regulatory Policies Act of 1978
20 ("PURPA") Qualifying Facility ("QF") projects on Idaho
21 Power's system, as well as the current implementation of
22 both the Surrogate Avoided Resource- ("SAR") and Integrated
23 Resource Plan- ("IRP") based avoided cost methodologies in
24 Idaho. I will address issues related to risk and harm to
25 Idaho Power customers through the implementation of PURPA,

1 the Company's proposal for the Commission to set the
2 eligibility cap for published rates at 100 kilowatts ("kW")
3 for all QF resources, and to utilize the IRP-based
4 methodology for establishing the avoided cost for all PURPA
5 QF projects. My testimony also includes a recommendation
6 that the Commission establish a procedure that will
7 formalize negotiation of PURPA contracts. I will also
8 discuss the Company's request to lower the maximum
9 authorized contract term of PURPA QF power purchase
10 agreements.

11 **I. SUMMARY OF RECOMMENDATIONS**

12 Q. Could you please summarize the recommendations
13 of your testimony?

14 A. Yes. My testimony will discuss and recommend:

15 1. That the Commission set the eligibility
16 cap for published avoided cost rates at 100 kW for all QF
17 resource types;

18 2. That the Commission authorize Idaho
19 Power to utilize the IRP-based methodology for establishing
20 avoided cost rates, for both published and negotiated
21 rates, for all PURPA QFs;

22 3. That the Commission establish an
23 authorized negotiation process and procedure by which a
24 PURPA QF can obtain a power purchase agreement with Idaho
25 Power; and

4. That the Commission reduce the maximum authorized PURPA QF power purchase agreement contract term from the current 20 years to a maximum term of five years.

II. CURRENT STATUS OF PURPA QFS ON IDAHO POWER'S SYSTEM

Q. Could you please describe the current status of PURPA QF development on Idaho Power's system?

A. Yes. Idaho Power has a very large amount of PURPA QF generation both currently operating on its system, and under contract to come on-line in the near term. In fact, Idaho Power has more PURPA QF generation on its system than any other utility, of any size, in the northwest region of the United States. When this is considered in proportion to Idaho Power's load, both peak and minimum, it is even more extreme and concerning.

As of December 31, 2011, Idaho Power had 119 PURPA QF projects under contract with an estimated nameplate rating of 989 megawatts ("MW"). Of those projects, 96 (606 MW) are currently on-line, and an additional 23 projects (383 MW) are scheduled to come on-line between now and early 2014. The majority of QF projects that are under contract, but not yet operational, are estimated to be on-line by the end of 2012. Additional information about Idaho Power's QF projects is provided in Exhibit No. 1.

Q. How does this compare to other regional utilities?

A. Idaho Power researched PURPA activity in the region, and has summarized it in the table below. This table contains the PURPA QF nameplate rating, 2011 annual average utility customer load, and PURPA nameplate rating as a percentage of load, reported by utility and by state. As shown in the table below, the amount of PURPA QF development on Idaho Power's system significantly exceeds the QF development of any other Northwest utility.

PURPA Nameplate by State and Utility (MW)

	ID	OR	MT	UT	WA	WY	CA	Total
Idaho Power	940	28	21					989
PacifiCorp	65	167		179	6	378	20	815
Avista	7				95			102
Northwestern Energy			351					351
Portland General Electric		14						14
Puget Sound Energy					44			44

2011 Annual Average Load by State and Utility (aMW)

	ID	OR	MT	UT	WA	WY	CA	Total
Idaho Power	1,771	87						1,858
PacifiCorp	386	1,526		2,735	468	1,133	94	6,342
Avista	382				714			1,096
Northwestern Energy			733					733
Portland General Electric		2,403						2,403
Puget Sound Energy					2,507			2,507

PURPA Percentage of Average Load by State and Utility

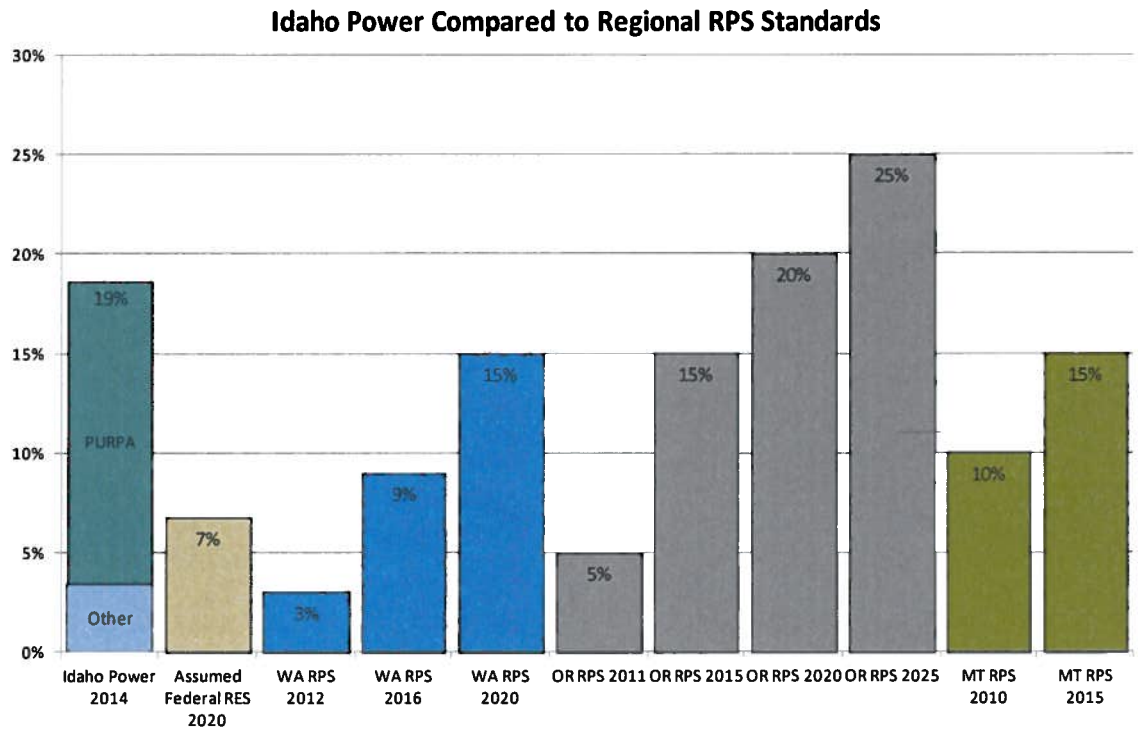
	ID	OR	MT	UT	WA	WY	CA	Total
Idaho Power	53.1%	32.2%						53.2%
PacifiCorp	16.8%	10.9%		6.5%	1.3%	33.4%	21.3%	12.9%
Avista	1.8%				13.3%			9.3%
Northwestern Energy			47.9%					47.9%
Portland General Electric		0.6%						0.6%
Puget Sound Energy					1.8%			1.8%

The table above highlights that Idaho Power with 1,858 average megawatts ("aMW") of average annual load has

989 MW of PURPA contracts. In comparison, PacifiCorp with 6,342 aMW of load in its six state service territory (almost three and a half times more load than Idaho Power) only has 815 MW of PURPA QF resources. Other comparisons from the table are just as striking with Puget Sound Energy having 2,507 aMW of load and only 44 MW of PURPA and Portland General Electric with 2,403 aMW of load and only 14 MW of PURPA.

Q. How does the amount of PURPA QF generation Idaho Power has under contract compare to the federal renewable electricity standard ("RES") Idaho Power assumes in its IRP and other state renewable portfolio standards ("RPS") requirements?

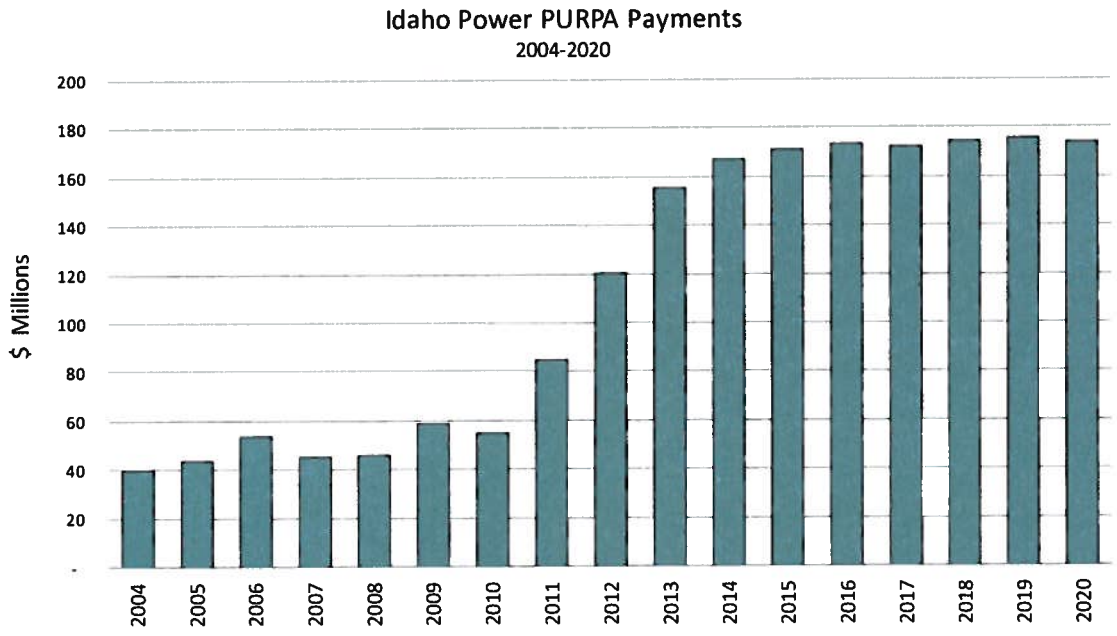
A. Idaho Power's 2011 IRP assumes a federal RES requirement will be implemented in the near future that will require 15 percent of generation be renewable starting in 2020. The figure below shows how the current level of PURPA QF generation added to Idaho Power's other eligible renewable resources in 2014 compares to the assumed RES requirement (in 2020) and to other regional state RPS requirements. It is important to note that the assumed federal RES requirement also includes subtracting hydroelectric generation from the sales base used to calculate the requirement, which has been proposed in past draft legislation.



As shown in the figure above, with just the current level of PURPA generation Idaho Power has under contract coupled with Idaho Power's other qualifying long-term power purchase agreements, the Company would meet the assumed federal RES standard by nearly three times, six years ahead of schedule. This comparison is done only to show the magnitude of QF development compared to various mandatory RPS requirements. Because Idaho Power does not receive the renewable energy certificates ("REC") from most of its QF generation, PURPA generation cannot be used to meet any potential RPS requirements and Idaho Power cannot represent to customers they are receiving renewable energy from the QFs for which it does not receive the RECs.

1 In comparison to other state RPS requirements, in
2 2014, Idaho Power will exceed the state of Washington's 15
3 percent requirement in 2020, the state of Oregon's 15
4 percent requirement in 2015, and the state of Montana's 15
5 percent requirement in 2015. In addition, in 2014 Idaho
6 Power would be just shy of meeting the state of Oregon's 20
7 percent requirement in 2020.
8 Q. What does this large amount of PURPA
9 generation cost Idaho Power customers?
10 A. Through October 2011, Idaho Power customers
11 have incurred a cost of a little over $1.1 billion for all
12 PURPA projects that have come on-line since 1982, when the
13 first PURPA project began delivering energy to Idaho Power.
14 The future cost of the current 119 PURPA projects under
15 contract with Idaho Power is estimated to cost Idaho Power
16 customers an additional $3.6 billion over the remaining
17 life of the contracts for a total historical and estimated
18 future cost of $4.7 billion. Details of these costs are
19 presented in Exhibit No. 2.
20 Q. How are the costs of PURPA paid for?
21 A. PURPA costs are paid for by Idaho Power's
22 customers as a power supply expense that runs through the
23 annual Power Cost Adjustment ("PCA") mechanism. Each year
24 100 percent of the power supply expense related to PURPA
25 QFs is passed through the PCA, and collected from Idaho

1 Power's customers. The increase in PURPA costs will result
2 in a direct increase to each customer's monthly bill to pay
3 for the power produced by these projects.
4 Q. Is there a trend with the power supply
5 expense related to PURPA?
6 A. Absolutely. PURPA expenses are growing at a
7 very rapid pace and becoming quite large. The figure below
8 shows the historical and projected increase in PURPA QF
9 power supply expense from 2004 through 2020, and includes
10 only the contracts approved by the Commission as of
11 December 31, 2011. Details of these costs are also
12 included in Exhibit No. 2.



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14 As shown in the figure above, annual PURPA power
15 supply expenses in 2004 were approximately $40 million. It
16 took over 20 years of accumulation of PURPA contracts to

1 reach the $40 million in costs seen in 2004. Five years
2 later, in 2009, that amount grew by 50 percent to
3 approximately $60 million. Just three years later, in
4 2012, that $60 million will double to $120 million of
5 annual PURPA power supply costs. That number increases to
6 $167 million by 2014 and by 2026, it will be $186 million
7 annually, an approximate 465 percent increase in costs from
8 2004.
9 Q. How do these large increases in PURPA power
10 supply expenses affect customer rates?
11 A. As stated earlier, PURPA power supply costs
12 are paid for by Idaho Power's customers through the PCA
13 mechanism. Each year 100 percent of the power supply
14 expense related to PURPA QFs is passed through the PCA, and
15 collected from Idaho Power's customers. The dramatic
16 increases discussed above in annual PURPA power supply
17 costs have a corresponding and equally dramatic impact on
18 customers' bills. As shown in the figure below, the effect
19 of the increase in PURPA power supply costs alone will
20 increase the annual PCA rate from the $62.9 million
21 currently approved in base rates to $78.4 million, with
22 three months of the PCA year still remaining.
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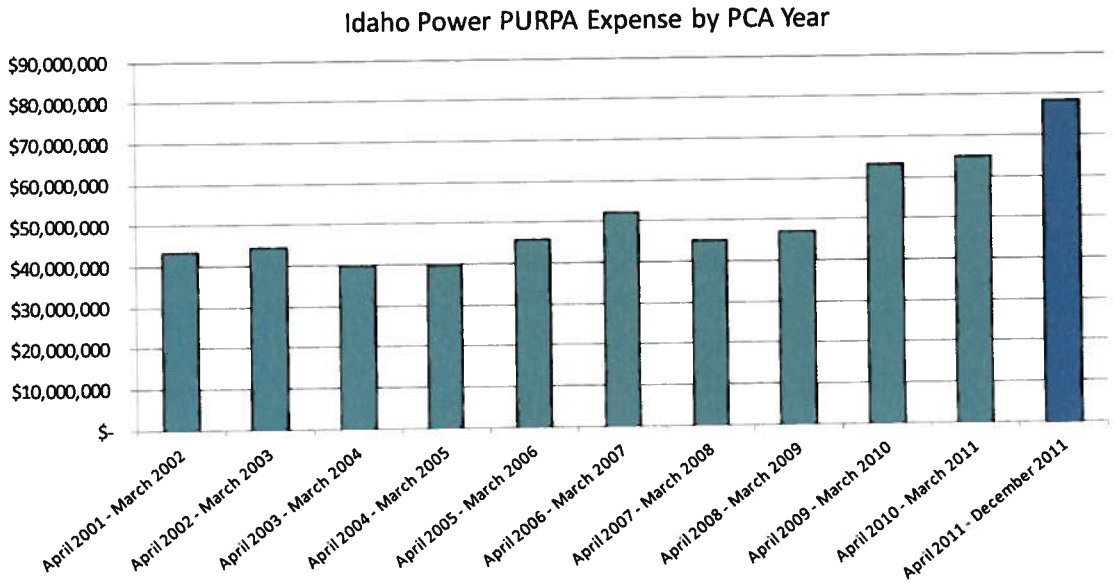
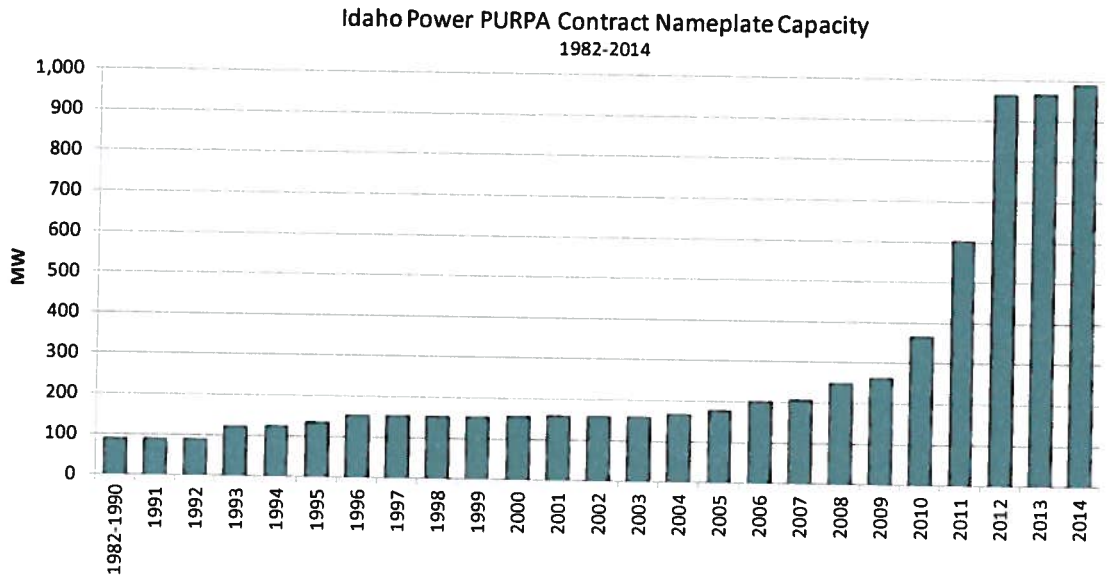


The level of increase in near term PURPA power supply expense, through 2014, results in dramatic annual increases in customers' bills. The average Schedule 19, Large Power Service, customer's bill will increase by approximately $138,000 annually. The average residential customer will see an increase of just under $100 per year. Annual increases to the Company's largest customers, the Special Contract customers, will range from just over $1 million to more than $3.6 million annually. This price impact is not speculation. It is based entirely upon the projected cost of the currently existing PURPA QF generation, along with the QF projects that have executed power purchase agreements approved by the Commission. If Idaho Power never acquires another kilowatt of PURPA QF generation, these increases will still take place based

upon the current QF projects and approved contracts the Company has now.

Q. Is there a corresponding trend with the amount of generation provided by QFs?

A. Yes. The amount of generation provided, and projected to be provided by QFs to Idaho Power increases in a similar fashion, as shown in the figure below:



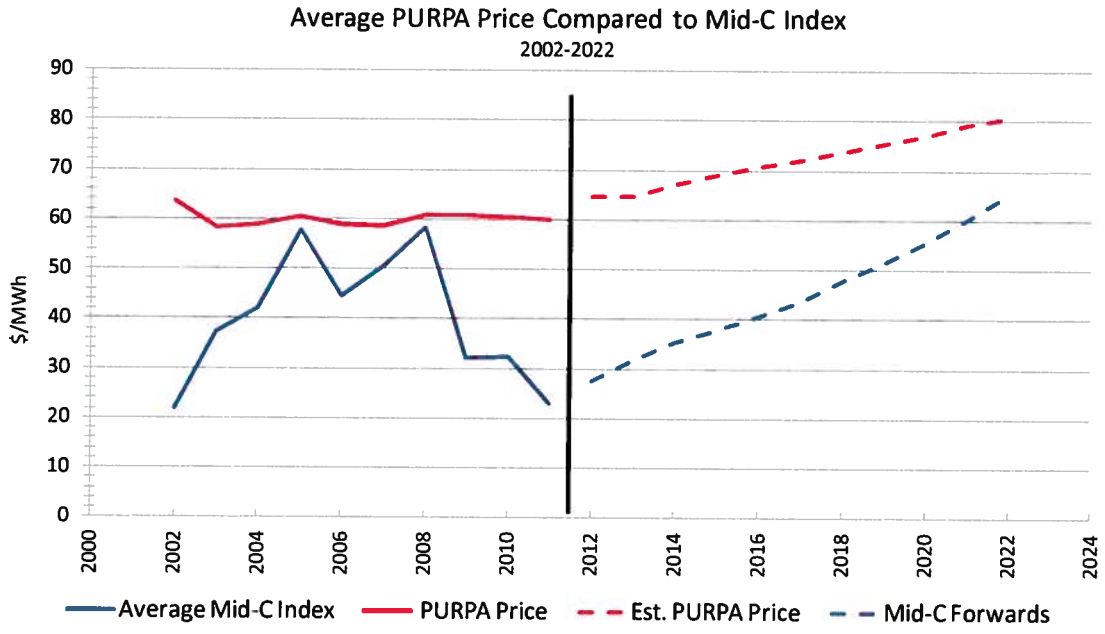
In summary, over the 10 years between 2004 and 2014, the number of Idaho Power PURPA projects on-line since 2004 has increased by 95 percent (61 projects in 2004 to 119 projects currently under contract), total nameplate capacity has increased 530 percent (157 MW in 2004 to 989 MW currently under contract) and total estimated cost has increased 318 percent ($40 million in 2004 to a projected cost in 2014 of $167 million).

1 Even if no additional PURPA project contracted with
2 Idaho Power, the amount of energy and financial impact of
3 the existing projects under contract is dramatic. However,
4 PURPA project development within the Idaho Power service
5 territory continues. In October 2011, a new 20 MW solar
6 project contract was submitted and approved by the
7 Commission, in November 2011 a 22 MW biomass project and a
8 40 MW wind project were submitted for Commission approval,
9 and in December 2011 a 1.27 MW hydro project was submitted
10 for approval. In addition to these projects, Idaho Power
11 continues to receive numerous inquiries from potential
12 PURPA projects of all types.
13 In fact, over a recent three-day period (January 25,
14 26, and 27, 2012) the Company received nine new requests
15 for published rate contracts from QFs in its Oregon service
16 territory. These requests are for projects 10 MW and under
17 with rates determined by the SAR avoided cost methodology.
18 The Company additionally has three other QFs located in
19 Idaho attempting to wheel their output to the Company's
20 Oregon jurisdiction to obtain published SAR-based avoided
21 cost rates. In contrast to the current requests from 12
22 QFs representing approximately 90 MW, Idaho Power currently
23 has six QF projects providing approximately 28 MW located
24 in its Oregon jurisdiction. Idaho Power has requested
25 authorization from the Public Utility Commission of Oregon

1 to utilize the IRP avoided cost methodology for all
2 projects over 100 kW. Advice No. 12-02 and Case No. UM
3 _____ filed on January 27, 2012. Additionally, Idaho Power
4 has requested the Idaho Commission to exercise its
5 jurisdiction over three proposed QF projects that have
6 requested Oregon QF contracts, but have points of delivery
7 in Idaho.
8 Q. Does the recent increase in PURPA projects
9 mean Idaho Power can avoid building any new resources for
10 some time?
11 A. No. Because a vast majority of the new
12 PURPA contracts are for wind projects, Idaho Power will
13 still have to build new resources in order to meet
14 projected growth in peak-hour demand. Wind resources
15 provide less than 5 percent of capacity on peak and
16 therefore do little to meet Idaho Power customers' growing
17 summertime peaking needs.
18 **III. HARM TO CUSTOMERS**
19 Q. What effect does the very large and dramatic
20 increase in PURPA power supply expenses that you have set
21 forth above have on Idaho Power customers?
22 A. The effect is that customers are harmed by the
23 QF transactions that the Company is legally required to
24 enter into. Customers will pay much more for QF generation
25 than they would otherwise pay for Idaho Power to either

1 generate the same amount of electricity from its own
2 generation resources or to purchase that same amount of
3 electricity from the wholesale market. This is directly
4 contrary to the federal definition of avoided cost. It is
5 also directly contrary to the requirement that customers be
6 held indifferent to whether the Company purchased
7 electricity from the QF or otherwise acquired it.
8 Q. It is clear that customers are paying a lot of
9 money for QF generation, and that this amount will increase
10 substantially. Is this increase acceptable because the
11 amount of generation received from PURPA QFs will also
12 increase substantially?
13 A. No. If the greatly increased amount of QF
14 generation coming onto the system were priced properly, and
15 if that generation were bringing adequate value to the
16 system, then Idaho Power customers might be indifferent.
17 However, PURPA generation is not currently bringing
18 adequate value to the system and, in fact, is providing a
19 very large amount of generation at times when it is not
20 needed, at a price that exceeds the cost to Idaho Power to
21 generate using its own resources, and at a cost that
22 exceeds what Idaho Power can get for it at market. This is
23 extremely harmful to customers.
24 Q. How can one determine the value that QF
25 purchases bring to the system?

A. One approach to determine the value of QF purchases is to compare PURPA contract rates to historical and forward market prices. Investigation reveals that there has been a significant difference between the historical prices paid to PURPA resources and the Mid-C index and, on a forward looking basis, there continues to be a significant difference between PURPA prices and the Mid-C forward market prices. This difference is illustrated in the following figure:



In 2005 and 2008, the average price paid to PURPA projects was reasonably close to the Mid-C index price; however, the Mid-C index was down significantly in 2009 and 2010, and dropped further in 2011, yet the price paid to PURPA projects remained relatively constant. And, as

1 illustrated above, there continues to be a significant gap
2 between PURPA prices and Mid-C forwards out past 2022.
3 Q. Does Idaho Power need PURPA generation?
4 A. There are limited times when Idaho Power
5 utilizes this generation to serve load, and the Company
6 reflects such use in its IRP planning process. However,
7 Idaho Power is currently purchasing large amounts of PURPA
8 generation that exceeds the needs of its customers. For
9 example, the figure below shows Idaho Power's projected
10 monthly surplus/deficit position in 2014 and the only
11 monthly energy deficit is projected to occur in July.
12 Idaho Power is in a surplus position in all months of the
13 year except July, and does not have a need for any
14 additional QF generation outside of that month. Overall,
15 the projected annual average surplus on the Company's
16 system is 526 aMW and this projected surplus includes 284
17 aMW of PURPA generation. If all of the PURPA generation is
18 removed, the portfolio still has an average surplus of 242
19 aMW.
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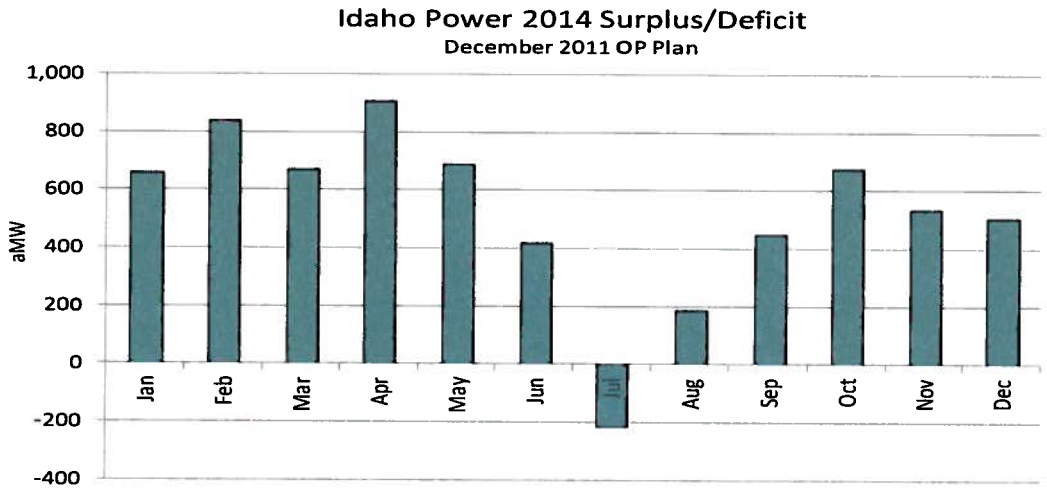

The net result is that Idaho Power is buying a significant amount of energy that its customers do not need, at above market prices, and, in many instances, the Company will end up selling that energy back into the market at a significant loss. This is very harmful to customers, as it works to inflate the power supply expenses they must bear.

Q. Could you explain?

A. Yes. To illustrate the significance of this issue, the differential between what Idaho Power will pay for PURPA generation in 2012 and the amount it would pay to purchase the same amount of generation as a "firm" product in the Mid-C market is on the order of $69 million – that is an overpayment of $69 million dollars in one year. For 2013, the differential in QF purchase price and market price results in an overpayment to the QFs of $80 million. For the 10-year period between 2012 and 2021, this

1 differential results in an average overpayment of $67
2 million per year, totaling $670 million. The present value
3 of this overpayment is close to half a billion dollars
4 ($493,000,000).
5 That is only part of the harm to customers. There
6 is an additional cost associated with moving unneeded QF
7 generation to market when it is not needed to serve
8 customers. Not only are customers overpaying for
9 generation the system does not need, but when the QF
10 generation cannot be used to serve Idaho Power's load (11
11 months where it is surplus), it must be moved to market.
12 To move this QF generation to market at Mid-C, the Company
13 will have to sell it as a standard "firm" product.
14 Additionally, transmission expenses are incurred to
15 move energy to the Mid-C market. Non-firm energy typically
16 trades at a discount to a firm energy product — this
17 discount may be as much as $5 per megawatt-hour ("MWh").
18 So, if on average, Idaho Power incurs an additional $3 per
19 MWh to firm the energy and an additional $3 per MWh in
20 transmission costs plus transmission losses of $1.50 per
21 MWh, with PURPA generation projected to exceed 2.4 million
22 MWh per year beginning in 2013, this adds an additional $18
23 million per year. This increases the $67 million loss to
24 $85 million per year. While these are just estimates, they
25

1 illustrate the type of additional costs that will be
2 incurred to get PURPA generation to the market.
3 Q. Are there any other costs that are unaccounted
4 for in the current avoided cost methodologies that harm
5 customers?
6 A. Yes. There are a number of additional costs
7 that Idaho Power and its customers may incur as a result of
8 the amount of intermittent PURPA resources currently under
9 contract. Although difficult to quantify, additional costs
10 may be incurred in the following areas:
11 1. New Resources. It may be necessary for
12 Idaho Power to add additional utility-owned generation
13 resources to assist with integration of variable QF
14 resources;
15 2. Maintenance Costs. As a result of
16 operating its existing resource portfolio differently,
17 Idaho Power may incur additional maintenance costs if, for
18 example, thermal units are cycled more frequently to assist
19 with integration of variable QF resources;
20 3. Imputed Debt. Idaho Power's borrowing
21 costs may increase if Idaho Power's credit ratings are
22 impacted by the amount debt rating agencies impute on Idaho
23 Power's balance sheet. The amount of imputed debt will
24 depend on the magnitude of the PURPA obligations and the
25

1 agency's assessment of the likelihood that Idaho Power will
2 be able to recover these costs.
3 The current indications are that Idaho Power's
4 customers are paying above-market prices for significant
5 amounts of energy that the system does not need, and they
6 will continue to do so at substantial harm well into the
7 future.
8 Q. Most of the Company's data is based on
9 nameplate capacity numbers of the various QFs, but QFs do
10 not typically generate at nameplate capacity do they?
11 A. No, not all the time. However, sometimes they
12 do and when they do, Idaho Power must have the
13 infrastructure and ability to handle the generation as it
14 is delivered to the electric system. There are several
15 times when QF generation has and will generate at or close
16 to nameplate capacity. For example, on December 21, 2011,
17 Idaho Power received a large amount of energy from its QF
18 wind resources. On this day Idaho Power received 7,028 MWh
19 (293 aMW) from the 20 PURPA wind projects on-line
20 (nameplate rating of 398 MW). Based on an average energy
21 price contained in those contracts, Idaho Power incurred a
22 power purchase expense of approximately $535,000 for the
23 day for the wind generation ($76.12 per MWh). On that same
24 day, the short-term, daily average Mid-C market price was
25 $29.75 per MWh. If Idaho Power had purchased the same

1 amount of energy as provided by the PURPA wind projects on
2 that day, Idaho Power would have only incurred a power
3 purchase expense of approximately $209,000. Thus on
4 December 21, 2011, the PURPA wind energy power purchase
5 expenses were $326,000 greater than alternative market
6 purchases. This additional cost will be included in the
7 annual PCA and collected directly from Idaho Power's
8 customers. If this example were an isolated incident, the
9 Company might not be so concerned. However, these
10 circumstances occur frequently enough to suggest a thorough
11 examination is warranted, as is the purpose of this case.
12 The December 21, 2011, example is not only a good
13 example of QF generation operating at or near nameplate
14 capacity but also a good example of what is wrong with the
15 current avoided cost methodology employed in Idaho.
16 Avoided cost is supposed to mean <u>the incremental cost to</u>
17 <u>Idaho Power of electric energy or capacity or both which,</u>
18 <u>but for the purchase from the QF, Idaho Power would</u>
19 <u>generate itself or purchase from another source</u>. 18 C.F.R.
20 § 292.101(b)(6). When customers must pay more for QF
21 generation than what that generation can be sold at market
22 at times when it cannot be used to serve load, customers
23 are no longer being held indifferent to the QF transaction.
24 This is discussed further by Company witness Karl
25 Bokenkamp. Mr. Bokenkamp's testimony will propose

1 adjustments to the current IRP-based avoided cost
2 methodology to more properly align the methodology with the
3 definition of avoided cost.
4 Q. Is wind generation the main concern of Idaho
5 Power with regard to QF generation?
6 A. Wind generation is a major concern because of
7 the extremely large quantity that is currently operating on
8 the Company's system, the additional projects that have
9 approved, long-term power purchase agreements and are
10 scheduled to come on-line in the near future, and the
11 continued interest from QF developers in developing new
12 wind projects and forcing the Company to purchase the
13 output through PURPA. However, the main concern of Idaho
14 Power in this case is not limited to concerns over wind
15 alone, and extends to all PURPA QF projects regardless of
16 the generation technology or motive force.
17 Q. What is the significance of large amounts of
18 intermittent and variable QF energy being inconsistent with
19 the Company's least cost, long-term IRP process?
20 A. As a public utility, Idaho Power is obligated
21 to engage in a planning process that ensures it prudently
22 acquires resources accounting for cost, risk, and
23 environmental concerns. Diversity in generation resources
24 (e.g., thermal, hydro, renewable, etc.) is consistent with
25 good utility planning practices. However, wind generation

1 is by far the largest form of intermittent and variable
2 generation on Idaho Power's system, and more is being
3 proposed by QF developers. From an operational perspective
4 (policy and legal arguments aside), it is neither good
5 utility practice nor prudent for Idaho Power to be
6 acquiring such large amounts of wind generation such as
7 that which is currently scheduled to come onto its system.
8 In fact, the preferred portfolio in Idaho Power's 2011 IRP
9 does not include any new wind resources for the next twenty
10 years.
11 The 2011 IRP Advisory Council and members of the
12 public participating in the IRP process have been in
13 general agreement for some time that significant amounts of
14 wind generation is not a good choice for Idaho Power for
15 the following reasons: (1) it does very little to meet
16 Idaho Power's peak-hour needs, i.e., less than 5 percent on
17 peak; (2) its intermittent and variable nature, requiring
18 regulating reserves and providing unreliable energy
19 deliveries; and (3) it creates a substantial amount of
20 surplus energy during times when Idaho Power's customers'
21 demand is low.
22 Q. How has the IRP planning process been
23 frustrated or circumvented by PURPA?
24 A. The IRP process was established in order to
25 evaluate different resource types and allow informed

1 decisions regarding future generation resources based on
2 cost, risk, and environmental concerns. The IRP planning
3 process involves input from the public during the creation
4 of the plan through monthly meetings with the IRP Advisory
5 Council and following the completion of the plan by way of
6 the Commission's public comment period.
7 A new IRP is created every two years and it is
8 common for a resource to be evaluated in two or three IRP
9 cycles before it reaches the point of being considered a
10 "committed" resource. In addition, before building a new
11 resource, an application is filed with the Commission
12 requesting a Certificate of Public Convenience and
13 Necessity ("CPCN"). During this process, the proposed
14 resource is again scrutinized by the Commission and the
15 public is allowed to provide comments.
16 In the case of Langley Gulch, a 300 MW combined
17 cycle combustion turbine ("CCCT"), the need for this new
18 resource was identified as early as Idaho Power's 2004 IRP.
19 In the 2004 and 2006 IRPs, this resource was identified as
20 a coal plant, and it was not until 2007 that it was changed
21 to a natural gas CCCT. Between the IRP and CPCN processes,
22 Langley Gulch was evaluated and scrutinized for over five
23 years before the CPCN was granted for the addition of this
24 300 MW resource.
25

1 In contrast, Idaho Power was obligated to sign PURPA
2 wind contracts totaling 294 MW during a two-month period in
3 late 2010 without any evaluation or thought given to
4 whether these wind resources were needed, or how they would
5 impact customer rates or the reliable operation of Idaho
6 Power's electrical system. In addition, the only
7 opportunity for the public to comment was during the
8 Commission approval process for the power purchase
9 agreements, which primarily focuses on whether the
10 established rules and prior Commission orders regarding
11 PURPA were followed.

12 **IV. CURRENT APPLICATION OF THE SAR AND IRP METHODOLOGIES**

13 Q. Could you describe the methods currently
14 utilized in Idaho to establish avoided cost rates?
15 A. Yes. The Commission currently utilizes two
16 methodologies for determining avoided cost: the SAR- and
17 IRP-based methodologies.
18 Q. What determines a QF's eligibility for rates
19 determined by the two different methodologies?
20 A. The determination of which methodology is used
21 has historically been based on the size of the QF project,
22 and has recently been further differentiated by not only
23 size but also resource type. Until recently, all QF
24 projects that generated up to 10 aMW monthly were eligible
25 for published rates established by the SAR methodology.

1 Correspondingly, all QF projects over 10 aMW were only
2 eligible for negotiated rates based upon the IRP
3 methodology.
4 In Order No. 32262 from Phase II of this proceeding,
5 the Commission determined that the eligibility cap for
6 published rates based on the SAR methodology for wind and
7 solar QFs remain at 100 kW. Consequently, the IRP-based
8 methodology is currently applicable to all QFs over 10 aMW
9 and all wind and solar QFs over 100 kW.
10 **A. <u>SAR Methodology</u>.**
11 Q. Could you describe the SAR methodology?
12 A. Yes. As its name implies, the SAR methodology
13 estimates avoided cost by estimating the cost of a
14 surrogate avoided resource which, at present, the
15 Commission has determined is a natural gas-fired CCCT. The
16 SAR methodology uses that cost to set published, or
17 standard, avoided cost rates. Published, or standard,
18 rates are required by Federal Energy Regulatory Commission
19 ("FERC") for projects up to 100 kW.
20 The SAR methodology consists of two primary cost
21 components: (1) the fuel cost component and (2) the non-
22 fuel variable cost components. The fuel cost component
23 simply utilizes the long-term natural gas price forecast
24 produced by the Northwest Power and Conservation Council
25 ("NPCC"). The avoided cost prices established by the SAR

1 model are adjusted by the Commission whenever the NPCC
2 revises its long-term natural gas price forecast.
3 The non-fuel variable components of the SAR
4 methodology include the capital cost component of the CCCT,
5 other fixed and variable operating costs, and escalation
6 rates that are applied over time. The non-fuel variables
7 are further divided into two general categories: (1)
8 utility-specific variables and (2) generic variables.
9 Utility-specific variables relate to each utility's cost of
10 capital. Because they are a direct outcome of general rate
11 cases, they are updated after a utility rate case with a
12 resulting change in the utility's cost of capital.
13 The other generic variables are updated periodically
14 and were most recently examined and updated in 2009, Case
15 No. GNR-E-08-02. In that case, the Commission approved a
16 stipulation between the utilities, Commission Staff, and
17 several QF developers as to a revision of the non-fuel
18 variables in the SAR methodology. The generic non-fuel
19 variables, or the non-fuel related SAR costs, are: heat
20 rate, equivalent availability factor, capital cost,
21 variable operations and maintenance ("O&M"), O&M escalation
22 rate, SAR escalation rate, fixed O&M, and general
23 inflation.
24 The SAR methodology produces two different sets of
25 avoided cost rates, one for "fueled" projects that utilize

1 fossil fuels, and one for "non-fueled" projects that apply
2 for all other resource types. The avoided cost rates for
3 "fueled" projects are adjusted annually based on the
4 average monthly gas price during the previous calendar
5 year. Therefore, the rates change each year and track with
6 natural gas prices. The "non-fueled" rates are based on an
7 initial price from the NPCC's most recent medium gas price
8 forecast, which is then escalated at a uniform rate
9 throughout the term of the contract. Under this method,
10 the avoided cost rate for the entire term of the contract
11 is known at the time the contract is signed.
12 **B. IRP Methodology.**
13 Q. Could you please describe the current IRP
14 methodology?
15 A. Yes. On December 15, 2011, as part of the
16 present proceeding, the three utilities gave a presentation
17 for the parties to this case at the Commission regarding
18 the present application of the IRP methodology. The
19 components of the methodology were described, and the
20 methodology was demonstrated on four example QF resources
21 to produce sample avoided cost rate calculations. Idaho
22 Power's December 15, 2011, presentation is attached as
23 Exhibit No. 3.
24 The IRP methodology consists of three components:
25 (1) the avoided cost of energy, (2) the avoided cost of

capacity, and (3) an integration cost for variable and intermittent resources. The avoided cost of energy is calculated using the AURORA electric market model, which is also used to make future resource decisions in the IRP. The total portfolio cost of a "Base Case," which includes the preferred resource portfolio from the IRP, is compared to a "Study Case," which includes the same IRP preferred portfolio with the PURPA resource added. The difference in the total portfolio cost of these two cases, on a monthly basis, is divided by the MWh of generation from the PURPA resource to establish an avoided cost of energy in dollars per MWh. This establishes the avoided cost of energy component.

Q. How is the avoided cost of capacity calculated in the IRP methodology?

A. To determine the avoided cost of capacity, the capital or fixed cost of a CCCT (taken from the IRP) is used as the surrogate resource that Idaho Power would avoid building. The cost in dollars per kilowatt-month for the CCCT is first multiplied by the nameplate capacity of the PURPA resource and then converted to an annual cost by multiplying by 12. This cost is then multiplied by the peak-hour capacity factor of the PURPA resource to account for the amount of capacity the PURPA resource will provide during Idaho Power's peak-hour load period between 3:00

1 p.m. and 7:00 p.m. in July. Due to the uncertain and
2 variable nature of intermittent resources, a 90 percent
3 exceedance capacity factor calculated from representative
4 projects in Idaho Power's service territory is used as a
5 benchmark. If the peak-hour generation of the PURPA
6 resource exceeds the generation of the benchmark resource
7 for that period, the PURPA resource will receive a
8 proportionally higher peak-hour capacity factor that is
9 used to calculate the avoided cost of capacity. Likewise,
10 if the PURPA resource provides less generation than the
11 benchmark resource during the peak-hour period, the PURPA
12 resource will receive a proportionally lower peak-hour
13 capacity factor.
14 While baseload resources such as biomass and
15 geothermal may be capable of producing 100 percent of
16 nameplate during the peak-hour period, forced outages
17 remain a possibility. Therefore, applicable forced outage
18 rates taken from the NPCC's Sixth Power Plan are used to
19 derive the peak-hour capacity factor for these types of
20 resources in calculating the avoided cost of capacity. For
21 all resource types, the resulting avoided cost of capacity
22 is held constant for all months of the year in the
23 analysis.
24 The avoided cost of energy and the avoided cost of
25 capacity are then added together to get a monthly avoided

cost rate. However, the avoided cost of capacity is excluded until the first month Idaho Power's load and resource balance shows a peak-hour deficit based on existing and committed resources as identified in the IRP. Also, for wind and solar PURPA resources, a deduction to the avoided cost of energy is applied to account for the cost of integrating these variable and intermittent resources.

Q. Do you have current examples of the rates calculated using the IRP methodology?

A. Yes. As part of the December 15, 2011, presentation, Idaho Power evaluated four sample QF projects using the IRP methodology. Details of the evaluation and the results are presented in Exhibit No. 3. The avoided cost rates were calculated for 10 aMW generation resources consisting of: (1) base load (geothermal, biomass, anaerobic digesters, and co-generation), (2) canal drop hydro, (3) fixed photovoltaic ("PV") solar, and (4) wind.

As can be seen in Exhibit No. 3 the resulting 20-year, levelized avoided cost rate in dollars per MWh for each resource is: (1) base load (geothermal, biomass, anaerobic digesters, and co-generation) - $65.00, (2) canal drop hydro - $80.31, (3) fixed PV solar - $75.60, and (4) wind - $43.08.

1 Q. What assumptions were used in the AURORA model
2 to determine the avoided cost of energy for the sample
3 projects?
4 A. Prior to preparing each IRP, Idaho Power
5 updates and calibrates the AURORA model. The sample
6 avoided cost of energy calculations were performed using
7 the same AURORA model setup used for the Company's latest
8 planning document, the 2011 IRP, with three exceptions.
9 First, Idaho Power prepares a load forecast on an
10 annual basis which is typically finalized in September of
11 each year. Because the load forecast is one of the
12 earliest items required in the preparation of the IRP, the
13 load forecast used in the 2011 IRP was completed in
14 September of 2010. In September of 2011, the Company
15 prepared a new load forecast as is typically done for the
16 IRP process. The updated load forecast provides current
17 expectations of future load growth which have been in a
18 state of flux due to the economic recession over the past
19 few years. Because the updated load forecast is based on
20 the most current information, Idaho Power believes it
21 should be used in any evaluation and analysis work the
22 Company does, including the calculation of avoided cost
23 rates. Therefore, the avoided cost of energy in the sample
24 calculations were performed with the AURORA model using the
25 most current load forecast.

Second, the forecast of natural gas prices must also be determined early in the preparation of the IRP. The natural gas price forecast used in the 2011 IRP was finalized in August of 2010, and since that time natural gas prices and forecast future prices have dropped considerably. Therefore, the Company used the most current natural gas price forecast prepared by the NPCC in the AURORA model to calculate the avoided cost of energy for the sample projects.

Third, a carbon adder is used in the AURORA model for the IRP analysis to evaluate the risk, impact, and costs of various levels of carbon regulation. Because of the uncertainty in what future carbon costs may be, if any, Idaho Power does not believe it is appropriate to include these costs in the AURORA model for the purpose of calculating the avoided cost of energy. While appropriate for purposes of evaluating future resource acquisitions in the IRP process, these potential carbon costs do not exist today, and would be inappropriate to include in the avoided cost analysis. Therefore, no carbon adder was used in the AURORA model to calculate the avoided cost of energy for the sample calculations.

V. THE IRP BASED-METHODOLOGY SHOULD BE USED FOR ALL AVOIDED COST RATES

Q. Does the Company have a recommendation for the Commission with regard to the continued use of the SAR methodology?

A. Yes. The Company recommends that the Commission abandon the use of the SAR methodology to determine a utility's avoided cost and instead use the IRP-based avoided cost methodology for all QF projects, and for published as well as negotiated rates.

Q. Is this position consistent with Idaho Power's submissions in Phase I, GNR-E-10-04, and Phase II, GNR-E-11-01?

A. Yes. In both prior phases to this proceeding, Idaho Power has asked for the IRP methodology to be applied to the avoided cost calculation for all QF generation. Idaho Power has stressed and reiterated the severe problems with the current SAR methodology and 10 aMW published rate eligibility in the Joint Petition of the three utilities, in Idaho Power's Comments, and in its Reply Comments in Case No. GNR-E-10-04, all of which are incorporated herein by this reference. Those problems and issues are also discussed in my Direct and Rebuttal Testimony as submitted in Case No. GNR-E-11-01, which are also incorporated herein by this reference. These problems have not gone away, and

1 continue to have a substantial negative impact on
2 customers. Those problems include:
3 1. The continuing and unchecked
4 requirement for the Company to acquire QF generation,
5 pursuant to avoided cost rates, with no regard for the
6 Company's need for additional generation on its system, nor
7 the availability of other lower cost resources, and in a
8 manner inconsistent with the definition of avoided cost;
9 2. Circumvention of the Company's required
10 IRP planning process and a continuing requirement to
11 acquire generation outside of that established process that
12 inflates customers' power supply costs;
13 3. System reliability and other
14 operational issues caused by a rapid and large scale
15 increase in intermittent and unreliable generation sources;
16 and
17 4. Most importantly, a dramatic increase
18 in the price that Idaho Power's customers must pay for
19 their energy needs as a direct result of the large
20 quantities of additional QF generation at prices in excess
21 of the Company's avoided cost, and beyond that which would
22 otherwise be considered prudent.
23 Q. What does the Company mean by "beyond that
24 which would otherwise be considered prudent"?
25

A. The addition of large quantities of QF generation such as those currently facing the Company, the majority of which are variable and intermittent in nature, is inconsistent with its least-cost IRP planning process, and it creates operational and reliability issues. It also forces the Company to make uneconomic decisions, or to engage in negative economic transactions.

It is good utility practice to have diversity among generation resources, but too much of any single resource creates challenges. From an operational perspective, Idaho Power has reached or is nearing a saturation point with adding intermittent, variable generation to its resource portfolio. This and other operational issues are discussed further in the testimony of Company witness Tessia Park.

Q. Do you believe the SAR Methodology calculates an accurate avoided cost rate?

A. No. A utility-owned CCCT will be economically dispatched and will only be run when needed for system reliability or when the market price of energy is more than the variable operating cost of the plant. On the other hand, a PURPA project is incented to generate as much electricity as possible because the avoided cost rate calculated by the SAR methodology will almost always be higher than the variable cost of operating the plant.

1 The SAR methodology assumes the PUPRA resource will
2 have a 90 percent annual capacity factor, while Idaho
3 Power's new Langley Gulch CCCT is expected to have an
4 annual capacity factor of about 60 percent. This results
5 in the PURPA resource generating substantial additional
6 amounts of energy, all at times when a utility-owned CCCT
7 would not be dispatched because of economics.
8 Q. Can you provide a comparison of the cost of a
9 utility-owned CCCT to the avoided cost rate calculated by
10 the SAR methodology?
11 A. Yes. The Company has prepared a comparison of
12 the expected cost of the Langley Gulch CCCT to the current
13 avoided cost rates calculated with the SAR methodology.
14 As previously stated in my testimony, an important
15 input into the levelized cost of production calculation for
16 a generation resource is the assumed level of annual
17 capacity utilization or capacity factor over the life of
18 the resource. A capacity factor of 50 percent would
19 suggest that over a project's lifetime, it would be
20 expected to produce 50 percent of the output that it could
21 have produced if it had operated every hour at its rated
22 capacity. Therefore, at a higher capacity factor, the
23 levelized cost will be less because the plant would
24 generate more MWh over which to spread the fixed costs.
25

1 Conversely, lower capacity factor assumptions reduce the
2 MWh and the levelized cost is higher.
3 For PURPA QF projects, the published avoided cost
4 rate determined by the SAR methodology is based on the
5 levelized cost of a CCCT (the same type of plant as Langley
6 Gulch) at an assumed capacity factor of 90 percent. The
7 current 20-year, levelized published avoided cost rate for
8 a QF project coming on-line in 2013 is $70.92 per MWh.
9 The estimated 20-year, levelized cost of Langley
10 Gulch is $68.55 per MWh using a 90 percent capacity factor
11 assumption (to be consistent with the SAR capacity factor
12 assumption), and Idaho Power's current natural gas price
13 forecast. This comparison indicates the current SAR
14 published avoided cost rate is $2.37 per MWh higher than
15 Langley Gulch. In other words, over the next 20 years,
16 Idaho Power's customers will be paying $2.37 per MWh more
17 for PURPA QF generation than what it would cost Idaho Power
18 to produce at Langley Gulch.
19 In addition, Idaho Power's customers will be paying
20 $2.37 per MWh more for resources that provide little if any
21 capacity during peak-hour summer load periods. Langley
22 Gulch on the other hand will be fully available to serve
23 customer needs during these times.
24 Langley Gulch will also only be run when Idaho Power
25 needs the energy to serve load or when it is economical to

1 make surplus sales in the market. Idaho Power has the
2 ability to operate Langley Gulch in this fashion because it
3 is dispatchable. QF resources on the other hand are not
4 dispatchable and are incented to provide as much energy as
5 possible at the published avoided cost rate, much of which
6 will have to be sold at a loss. Therefore, the total cost
7 of the PURPA resource is much greater than the total cost
8 of a utility-owned CCCT.
9 Q. What do you think is the root cause of the
10 problems with using the SAR methodology to set avoided cost
11 rates?
12 A. First, the SAR Methodology does not correctly
13 model the operation of a PURPA resource because it assumes
14 the resource is operated at a very high annual capacity
15 factor. However, this is much different than the way a
16 utility would economically dispatch a CCCT. The fact that
17 PURPA resources are not dispatchable creates a large
18 difference in the value or total cost.
19 Second, seasonal and heavy/light load pricing
20 adjustments have been made in recent PURPA contracts to try
21 to incent PURPA resources to deliver energy at times when
22 it is more valuable. However, the SAR methodology does not
23 value the energy at the times it is delivered to the
24 utility.
25

1 Third, resources are not interchangeable. Wind
2 turbines are not equal to combined cycle combustion
3 turbines. Different types of generation resources have
4 different operating characteristics and the differences in
5 operational characteristics have different values to a
6 utility. Some characteristics may permit the utility to
7 avoid certain costs while the characteristics of other
8 resources may actually burden the utility with additional
9 costs.
10 Fourth, the SAR methodology is static and only
11 updated periodically, and the published avoided cost rate
12 does not change as resources are added to the utility's
13 portfolio.
14 Q. Why should the IRP methodology be used for
15 setting all avoided cost rates?
16 A. The primary reason the IRP methodology is
17 better than the SAR methodology is that the IRP methodology
18 places a more appropriate value on the energy a QF project
19 delivers based on the time it is delivered to the utility.
20 Solar resources tend to receive higher overall pricing
21 because energy is primarily delivered during the heavy load
22 hours of the day when energy prices and load are typically
23 higher. Resources that deliver more energy during light
24 load hours (nighttime, Sundays, and holidays) will see
25 reduced avoided cost rates that account for the lower value

1 of the energy that is delivered during these periods. In
2 addition, the IRP methodology is able to assign pricing
3 down to a much smaller time frame, which allows a better
4 estimate of the actual value of the energy.
5 The IRP methodology is also significantly more
6 flexible than the SAR methodology and can be updated more
7 frequently as conditions and assumptions change. As
8 utilities prepare IRPs every two years, the models used to
9 calculate energy prices in the IRP methodology are also
10 updated to account for the most current forecasts of load,
11 natural gas prices, and other factors that influence the
12 market value of energy. The IRP methodology also allows
13 for the model to be updated as each incremental resource is
14 added to a utility's generation portfolio.
15 Q. From an administrative ease perspective, would
16 it be better to continue to use the SAR methodology to set
17 published avoided cost rates?
18 A. No. When viewing the proposals in my
19 testimony in aggregate, it is evident that continuing to
20 use the SAR methodology actually creates additional
21 administrative burden. One only has to review the case
22 history regarding the application of the SAR methodology
23 and disputes over updating the inputs used in the
24 methodology to realize it would create a burden to continue
25 using the SAR methodology with its only purpose being to

1 set published rates. Published avoided cost rates could be
2 set using the IRP methodology in the same manner Idaho
3 Power is proposing to establish negotiated rates for QF
4 contracts.
5 Q. How are you proposing the IRP methodology be
6 used to set published avoided cost rates?
7 A. As each utility prepares an IRP every two
8 years, the IRP methodology could be used to calculate
9 avoided cost rates for sample projects as was done for the
10 parties in this case and presented on December 15, 2011.
11 These rates would then become the published rate for each
12 type of resource for the next two years until the next IRP
13 was completed.
14 Q. Does your proposal also include a
15 recommendation regarding the eligibility cap for published
16 avoided cost rates?
17 A. Yes. In Phase II of these proceedings
18 (GNR-E-11-01), the Commission maintained the eligibility
19 cap for wind and solar QF resources at 100 kW, while
20 published rates remained available to all other QF resource
21 types up to 10 aMW. Idaho Power's recommendation is that
22 the eligibility cap for all QF resources be set at 100 kW.
23 Q. Why do you think it is important to set the
24 eligibility cap at 100 kW for all QF resources?
25

A. If the IRP methodology is used to establish both published rates and rates for negotiated contracts, the rates should remain similar as long as the assumptions and forecasts used for the IRP remain valid. For negotiated contracts (projects larger than the eligibility cap), the utility would have the ability to update the assumptions or forecasts as warranted. However, for the published rate, a correction may not be possible until the next IRP is completed, which could be as long as two years. Therefore, setting the eligibility cap at 100 kW for all resource types would minimize the risk to customers of paying higher than avoided cost rates due to unforeseen circumstances or events.

VI. RECOMMENDATION TO ESTABLISH AN AUTHORIZED NEGOTIATION PROCESS AND PROCEDURE

Q. Does Idaho Power have a recommendation regarding the establishment of an authorized negotiation process and procedure by which a PURPA QF can obtain a power purchase agreement with Idaho Power?

A. Yes. In the recent past there have been numerous issues surrounding a QF developer's "grandfathered" rights to published avoided cost rates that have been superseded in the normal course of updating the rate. Even more recently, issues regarding a determination of the point in time when a utility has a legally

1 enforceable obligation as to price and other terms in a QF
2 contract have been disputed.
3 In order to resolve these issues and disputes going
4 forward, Idaho Power recommends the Commission establish
5 formal processes and procedures that will eliminate any
6 future questions surrounding these issues. Idaho Power
7 recommends that this be done through the development and
8 implementation of a PURPA QF contraction process and
9 negotiation tariff schedule.
10 **VII. CONTRACT TERM**
11 Q. Does Idaho Power have a recommendation for the
12 Commission with regard to the maximum authorized contract
13 term for a PURPA QF power purchase agreement?
14 A. Yes. The Company recommends that the
15 presently authorized maximum contract term of 20 years be
16 reduced to 5 years. A contract term of 20 years containing
17 a fixed price schedule shifts market price risk from the
18 project developer/owner entirely onto Idaho Power's
19 customers. By locking in a single fixed price or a
20 schedule of fixed prices, PURPA projects are hedging the
21 variable market value of the energy for the fixed prices
22 contained in the contract, at the expense of Idaho Power's
23 customers. While there is a need to provide a schedule of
24 fixed prices in the contract, 20 years is simply too long
25 given the amount of change that can take place and the

1 amount of risk this brings to customers. This is further
2 addressed in the direct testimony of witness William
3 Hieronymus.
4 Q. Do you have any concluding remarks?
5 A. Idaho Power respectfully urges the
6 Commission to set the published rate eligibility cap at 100
7 kW for all QF resource types and allow both published
8 avoided cost rates and negotiated avoided cost rates to be
9 determined using the IRP methodology as described
10 previously in my testimony and with the modifications
11 proposed by Company witness Bokenkamp.
12 While the application of the IRP methodology with
13 the proposed modifications appears complicated at first,
14 Idaho Power believes it is the best method for determining
15 avoided cost rates that are aligned with the Federal Energy
16 Regulatory Commission's definition of a utility's avoided
17 cost. Prior to proposing the continued use of the IRP
18 methodology with modifications, Idaho Power has thoroughly
19 tested the methodology and found it to actually be less of
20 an administrative burden than the current application of
21 the IRP methodology.
22 Idaho Power also urges the Commission to establish
23 an authorized negotiation process and procedure that will
24 govern the contract negotiation process. This will
25 eliminate future disputes over issues regarding

1 "grandfathering," the determination of when a legally
2 enforceable obligation exists, and the applicable stream of
3 prices that should be included in any contract.
4 Finally, in order to limit the risk customers are
5 exposed to through longer-term contracts, Idaho Power urges
6 the Commission to reduce the standard contract term from 20
7 years to five years. Idaho Power believes all of these
8 proposed changes will resolve several problems that exist
9 with the current implementation of PURPA in the state of
10 Idaho, and protect utility customers from further harm.
11 Q. Does this conclude your testimony?
12 A. Yes.
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BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. GNR-E-11-03

IDAHO POWER COMPANY

STOKES, DI
TESTIMONY

EXHIBIT NO. 1

PURPA QF Projects as of December 31, 2011

On-line	Resource Type	Project Name	State	County	MW
1	Biomass	Tamarack Cspp	ID	Adams	5.00
2	Biomass	Cogen Co	OR	Grant	10.00
3	Cogen	Magic Valley	ID	Minidoka	10.00
4	Cogen	Magic West	ID	Elmore	10.00
5	Cogen	Tasco - Nampa	ID	Canyon	2.00
6	Cogen	Tasco - Twin Falls	ID	Twin Falls	3.00
7	Digester	B6 Anaerobic Digester	ID	Gooding	2.28
8	Digester	Bettencourt Dry Creek BioFactory, LLC	ID	Twin Falls	2.25
9	Digester	Big Sky West Dairy Digester (DF-AP #1, LLC)	ID	Gooding	1.50
10	Digester	Double A Digester	ID	Lincoln	4.50
11	Digester	Pocatello Waste	ID	Bannock	0.46
12	Hydro	Arena Drop	ID	Canyon	0.45
13	Hydro	Barber Dam	ID	Ada	3.70
14	Hydro	Birch Creek	ID	Gooding	0.05
15	Hydro	Black Canyon #3	ID	Gooding	0.14
16	Hydro	Blind Canyon	ID	Gooding	1.50
17	Hydro	Box Canyon	ID	Twin Falls	0.36
18	Hydro	Briggs Creek	ID	Twin Falls	0.60
19	Hydro	Bypass	ID	Jerome	9.96
20	Hydro	Canyon Springs	ID	Twin Falls	0.13
21	Hydro	Cedar Draw	ID	Twin Falls	1.55
22	Hydro	Clear Springs Trout	ID	Twin Falls	0.52
23	Hydro	Crystal Springs	ID	Twin Falls	2.44
24	Hydro	Curry Cattle Company	ID	Twin Falls	0.22
25	Hydro	Dietrich Drop	ID	Jerome	4.50
26	Hydro	Elk Creek	ID	Idaho	2.00
27	Hydro	Falls River	ID	Fremont	9.10
28	Hydro	Faulkner Ranch	ID	Gooding	0.87
29	Hydro	Fisheries Dev.	ID	Gooding	0.26
30	Hydro	Geo-Bon #2	ID	Lincoln	0.93
31	Hydro	Hailey Cspp	ID	Blaine	0.06
32	Hydro	Hazelton A	ID	Jerome	7.70
33	Hydro	Hazelton B	ID	Jerome	7.60
34	Hydro	Horseshoe Bend Hydro	ID	Boise	9.50
35	Hydro	Jim Knight	ID	Gooding	0.34
36	Hydro	Kasel & Witherspoon	ID	Twin Falls	0.90
37	Hydro	Koyle Small Hydro	ID	Gooding	1.25
38	Hydro	Lateral # 10	ID	Twin Falls	2.06
39	Hydro	Lemoyne	ID	Gooding	0.08
40	Hydro	Little Wood Rvr Res	ID	Blaine	2.85
41	Hydro	Littlewood / Arkoosh	ID	Lincoln	0.87
42	Hydro	Low Line Canal	ID	Twin Falls	7.97
43	Hydro	Low Line Midway Hydro	ID	Twin Falls	2.50
44	Hydro	Lowline #2	ID	Twin Falls	2.79
45	Hydro	Magic Reservoir	ID	Blaine	9.07
46	Hydro	Malad River	ID	Gooding	0.62
47	Hydro	Marco Ranches	ID	Jerome	1.20
48	Hydro	Mile 28	ID	Jerome	1.50
49	Hydro	Mill Creek (City of Cove)	OR	Union	0.80
50	Hydro	Mitchell Butte	OR	Malheur	2.09
51	Hydro	Mora Drop Small Hydroelectric Facility	ID	Ada	1.85
52	Hydro	Mud Creek/S & S	ID	Twin Falls	0.52
53	Hydro	Mud Creek/White	ID	Twin Falls	0.21
54	Hydro	Owyhee Dam Cspp	OR	Malheur	5.00
55	Hydro	Pigeon Cove	ID	Twin Falls	1.89
56	Hydro	Pristine Springs #1	ID	Jerome	0.13

PURPA QF Projects as of December 31, 2011

On-line	Resource Type	Project Name	State	County	MW
57	Hydro	Pristine Springs Hydro #3	ID	Jerome	0.20
58	Hydro	Reynolds Irrigation	ID	Canyon	0.26
59	Hydro	Rim View	ID	Gooding	0.20
60	Hydro	Rock Creek #1	ID	Twin Falls	2.05
61	Hydro	Rock Creek #2	ID	Twin Falls	1.90
62	Hydro	Sagebrush	ID	Lincoln	0.43
63	Hydro	Sahko Hydro	ID	Twin Falls	0.50
64	Hydro	Schaffner	ID	Lemhi	0.53
65	Hydro	Shingle Creek	ID	Adams	0.22
66	Hydro	Shoshone #2	ID	Lincoln	0.58
67	Hydro	Shoshone Cspp	ID	Lincoln	0.37
68	Hydro	Snake River Pottery	ID	Gooding	0.07
69	Hydro	Snedigar	ID	Twin Falls	0.54
70	Hydro	Tiber Dam	MT	Liberty	7.50
71	Hydro	Trout-Co	ID	Gooding	0.24
72	Hydro	Tunnel #1	OR	Malheur	7.00
73	Hydro	White Water Ranch	ID	Gooding	0.16
74	Hydro	Wilson Lake Hydro	ID	Jerome	8.40
75	Industrial	Simplot Pocatello	ID	Power	12.00
76	Landfill gas	Hidden Hollow Landfill Gas	ID	Ada	3.20
77	Wind	Bennett Creek Wind Farm	ID	Elmore	21.00
78	Wind	Burley Butte Wind	ID	Cassia	21.30
79	Wind	Camp Reed Wind Park, LLC	ID	Elmore	22.50
80	Wind	Cassia Wind Farm LLC	ID	Twin Falls	10.50
81	Wind	Fossil Gulch Wind	ID	Twin Falls	10.50
82	Wind	Golden Valley Wind	ID	Cassia	12.00
83	Wind	Horseshoe Bend Wind	MT	Cascade	9.00
84	Wind	Lime Wind Energy	OR	Baker	3.00
85	Wind	Oregon Trail Wind	ID	Twin Falls	13.50
86	Wind	Thousand Springs Wind	ID	Twin Falls	12.00
87	Wind	Tuana Gulch Wind	ID	Twin Falls	10.50
88	Wind	Hot Springs Wind Farm	ID	Elmore	21.00
89	Wind	Milner Dam Wind	ID	Cassia	19.92
90	Wind	Payne's Ferry Wind Park, LLC	ID	Twin Falls	21.00
91	Wind	Pilgrim Stage Station Wind	ID	Twin Falls	10.50
92	Wind	Rockland Wind Project	ID	Power	80.00
93	Wind	Salmon Falls Wind	ID	Twin Falls	22.00
94	Wind	Sawtooth Wind Project	ID	Elmore	21.00
95	Wind	Tuana Springs Expansion	ID	Twin Falls	35.70
96	Wind	Yahoo Creek Wind Park, LLC	ID	Twin Falls	21.00
				Subtotal	**605.86**

PURPA QF Projects as of December 31, 2011

Not On-line	Resource Type	Project Name	State	County	MW
1	Biomass	Yellowstone Power	ID	Gem	10.00
2	Biomass	Dynamis	ID	Ada	22.00
3	Digester	Double B Dairy	ID	Cassia	2.00
4	Digester	Rock Creek Dairy	ID	Twin Falls	4.00
5	Digester	Swager Farms	ID	Twin Falls	2.00
6	Hydro	Fargo Drop Hydro	ID	Canyon	1.27
7	Hydro	Clark Canyon Dam	MT	Beaverhead	4.70
8	Landfill Gas	Hidden Hollow Energy II Landfill Gas Project	ID	Ada	3.20
9	Solar	Grand View Solar	ID	Elmore	20.00
10	Solar	Murphy Solar	ID	Owhyee	20.00
11	Wind	Cold Springs Windfarm	ID	Elmore	23.00
12	Wind	Cottonwood Wind Park	ID	Twin Falls	20.00
13	Wind	Deep Creek Wind Park	ID	Twin Falls	20.00
14	Wind	Desert Meadow Windfarm	ID	Elmore	23.00
15	Wind	Hammett Hill Windfarm	ID	Elmore	23.00
16	Wind	High Mesa	ID	Elmore	40.00
17	Wind	Lava Beds Wind	ID	Bingham	18.00
18	Wind	Mainline Windfarm	ID	Elmore	23.00
19	Wind	Notch Butte Wind	ID	Jerome	18.00
20	Wind	Rogerson Flats Wind Park	ID	Twin Falls	20.00
21	Wind	Ryegrass Windfarm	ID	Elmore	23.00
22	Wind	Salmon Creek Wind Farm	ID	Twin Falls	20.00
23	Wind	Two Ponds Windfarm	ID	Elmore	23.00
				Subtotal	**383.17**
119	**Total Projects Under Contract**				**989.03**

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. GNR-E-11-03

IDAHO POWER COMPANY

STOKES, DI
TESTIMONY

EXHIBIT NO. 2

Idaho Power Company PURPA Expense

Historical		
Year	aMW	Expense
1982	0	$241,681
1983	3	$1,947,675
1984	10	$8,419,576
1985	27	$16,201,679
1986	45	$23,089,962
1987	45	$22,938,180
1988	46	$23,378,405
1989	55	$29,049,008
1990	56	$29,409,440
1991	51	$27,969,279
1992	43	$22,148,359
1993	65	$33,596,827
1994	62	$30,884,222
1995	75	$37,999,969
1996	89	$43,716,927
1997	107	$55,971,675
1998	104	$54,957,741
1999	106	$56,152,052
2000	98	$53,685,443
2001	83	$44,976,174
2002	79	$43,931,661
2003	75	$38,186,005
2004	77	$39,840,544
2005	82	$43,327,053
2006	104	$53,666,055
2007	89	$45,494,057
2008	86	$45,885,564
2009	111	$59,011,557
2010	104	$54,972,118
2011	162	$85,015,997
	Total	**$1,126,064,887**

Forecast		
Year	aMW	Expense
2012	213	$120,482,150
2013	274	$155,210,454
2014	284	$166,947,907
2015	283	$171,257,482
2016	280	$173,427,475
2017	272	$172,227,474
2018	270	$174,432,632
2019	265	$175,616,330
2020	258	$174,141,098
2021	254	$176,548,408
2022	253	$178,754,351
2023	250	$181,645,438
2024	241	$183,240,619
2025	239	$185,748,585
2026	235	$185,908,600
2027	228	$185,127,749
2028	214	$177,699,725
2029	196	$168,409,199
2030	191	$167,527,389
2031	134	$125,520,070
2032	104	$99,380,022
2033	42	$39,374,103
2034	30	$28,101,276
2035	30	$28,525,215
2036	22	$20,619,789
2037	5	$5,623,914
	Total	**$3,621,497,454**

BEFORE THE

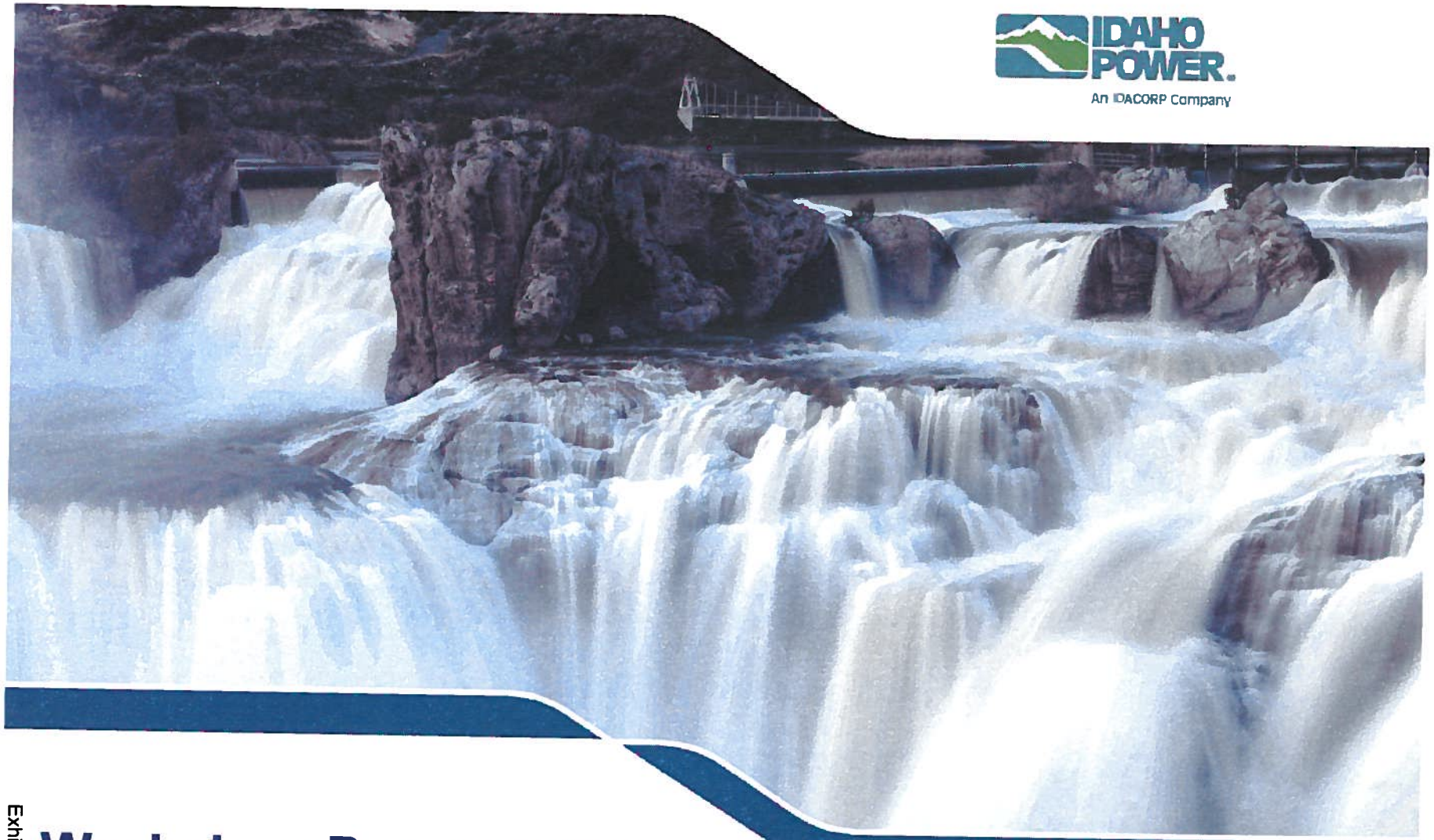
IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. GNR-E-11-03

IDAHO POWER COMPANY

STOKES, DI
TESTIMONY

EXHIBIT NO. 3



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Workshop Presentation
Avoided Cost - IRP Methodology

December 15, 2011

Project Size and Pricing Methodology

Current Requirements:

PURPA Projects (excluding wind and solar)

10 aMW or less - Published avoided cost rate
Greater than 10 aMW - Negotiated contract and pricing

Wind and Solar PURPA Projects

100 kW or less - Published avoided cost rate
Greater than 100 kW - Negotiated contract and pricing

Published Avoided Cost Rates

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Surrogate Avoided Resource (SAR) Methodology

- Previously established and Commission approved SAR pricing model is periodically updated by the Commission staff whenever the Northwest Power and Conservation Council revises its long-term natural gas price forecast
- Last update was August 31, 2011 (Commission Order 32337)

Published Avoided Cost Rates

IDAHO POWER
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IPUC Order 32337

IDAHO POWER COMPANY
AVOIDED COST RATES FOR NON-FUELED PROJECTS
August 9, 2011
$/MWh

Eligibility for these rates is limited to wind and solar projects 100 kW or smaller, and to non-wind and non-solar projects smaller than 10 aMW

LEVELIZED							NON-LEVELIZED	
CONTRACT LENGTH (YEARS)	ON-LINE YEAR						CONTRACT YEAR	NON-LEVELIZED RATES
	2011	2012	2013	2014	2015	2016		
1	51.32	53.20	54.91	56.58	58.39	60.32	2011	51.32
2	52.22	54.02	55.71	57.45	59.31	61.31	2012	53.20
3	53.05	54.81	56.53	58.33	60.26	62.35	2013	54.91
4	53.83	55.60	57.37	59.23	61.24	63.37	2014	56.58
5	54.60	56.40	58.22	60.16	62.21	64.38	2015	58.39
6	55.38	57.21	59.10	61.08	63.17	65.38	2016	60.32
7	56.16	58.05	59.98	61.99	64.13	66.39	2017	62.39
8	56.96	58.88	60.85	62.91	65.10	67.40	2018	64.68
9	57.75	59.71	61.72	63.83	66.05	68.39	2019	66.96
10	58.54	60.53	62.59	64.74	67.00	69.39	2020	69.30
11	59.33	61.36	63.45	65.64	67.95	70.37	2021	71.80
12	60.12	62.18	64.31	66.54	68.89	71.34	2022	74.46
13	60.90	63.00	65.17	67.43	69.81	72.32	2023	77.11
14	61.68	63.81	66.01	68.32	70.74	73.28	2024	79.93
15	62.45	64.61	66.85	69.19	71.65	74.23	2025	82.92
16	63.21	65.41	67.68	70.06	72.56	75.18	2026	85.91
17	63.96	66.20	68.51	70.92	73.45	76.11	2027	89.09
18	64.71	66.98	69.32	71.77	74.34	77.04	2028	92.46
19	65.45	67.75	70.12	72.61	75.22	77.95	2029	95.93
20	66.18	68.51	70.92	73.44	76.08	78.86	2030	99.50
							2031	103.32
							2032	107.27
							2033	111.39
							2034	115.69
							2035	120.18
							2036	124.87

Avoided Cost Rates for Negotiated Agreements

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Negotiated Agreements

- Any proposed project greater than 10 aMW
- All wind and solar projects greater than 100 kW

Integrated Resource Plan (IRP) Methodology

- Previous Commission orders directed utilities to use the IRP Methodology to establish the purchase price for negotiated PURPA contracts

IRP Methodology

Based on the Integrated Resource Plan (IRP)

- Idaho PUC requires utilities to prepare an IRP every two years
- Determines resource needs for the next 20 years

Thorough review of all current information and forecasts of the following items:

- Customers expected energy needs (load forecast)
- Existing generation resource capability and costs
- Cost of new generation resources
- Natural gas prices
- Other policies and issues that may impact resource choice and costs

One of the tools Idaho Power uses to perform the IRP analysis is the AURORA electric market model

AURORA Model

Analysis software that simulates the operation of the entire WECC (Western Electricity Coordinating Council) and forecasts:

- Electric energy prices
- Market value of electric generating units
- Market value of contracts and portfolios

AURORA applies economic principles, dispatch simulation and bidding strategies to model the relationships of supply, transportation, and demand for electric energy and forecasts market prices and resource operation based on forecasts of key fundamental drivers such as demand, fuel prices, and hydro conditions

IRP Methodology

The avoided cost rate calculated with the IRP Methodology is comprised of three components:

Avoided Cost of Energy

- Comparison of a Base Case AURORA model run to a Study Case AURORA model run

Avoided Cost of Capacity

- Excel spreadsheet

Integration Cost

- Excel spreadsheet

Avoided Cost of Energy

Avoided cost of energy (established for each specific project) =

AURORA Base Case – AURORA Study Case

- Base Case Total portfolio cost from the IRP
- Study Case Total portfolio cost with the PURPA project added

The avoided cost of energy is then divided by the estimated MWh of generation from the proposed PURPA project to get a $/MWh rate

Avoided Cost of Energy

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AURORA Modeling

A single PURPA project is typically too small to actually impact the operational dispatching of larger Idaho Power generation resources

AURORA calculates an hourly market value of energy based upon all generation resources, customer loads, and transmission capability within the WECC

This hourly AURORA market value of energy is assigned to the PURPA project as the avoided cost of energy as the project is either adding to Idaho Power surplus energy sales or reducing Idaho Power market purchases

Avoided Cost of Energy

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AURORA Model Setup and Inputs

- 2011 IRP Base Case Assumptions
- Current Long-term Natural Gas Price Forecast
  - The natural gas price forecast has been updated with the recent Northwest Power and Conservation Council forecast issued on August 9, 2011, which is the same forecast used in Commission Order 32337 revising published avoided cost rates
- Current Load Forecast
  - Idaho Power's most recent load forecast was prepared in Q3 2011

Avoided Cost of Energy

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AURORA Model Setup and Inputs (Cont)

- Carbon Adder
  - The carbon adder used for the IRP analysis has been removed from the model for the Base Case and Study Case model runs. An estimation of carbon costs is required in the IRP for planning purposes; it is not an actual cost that exists today.

- Hourly Energy Shape of PURPA project
  - This data is provided by the project developer and is included in the model

Avoided Cost of Energy

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Project Provided Hourly Energy Shape

- The AURORA model produces a unique energy price for every hour for the term of the proposed contract

- It is critical to get accurate estimated hourly generation from a proposed PURPA project for at least a one year period so that the resulting AURORA calculated energy price will reflect the project's ability to deliver energy to Idaho Power during peak energy demands as well as the project's delivery of energy during low value periods

Avoided Cost of Energy

Sample hourly generation data received from a proposed solar project

			Average MW for each hour using Mountain Standard Time											
Hour Start	Hour End	Hour	January	February	March	April	May	June	July	August	September	October	November	December
12:00 AM	1:00 AM	1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1:00 AM	2:00 AM	2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2:00 AM	3:00 AM	3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3:00 AM	4:00 AM	4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4:00 AM	5:00 AM	5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5:00 AM	6:00 AM	6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6:00 AM	7:00 AM	7	0.0	0.0	0.0	0.4	0.7	0.8	0.6	0.3	0.0	0.0	0.0	0.0
7:00 AM	8:00 AM	8	0.0	0.0	1.1	3.6	5.3	5.5	5.0	4.1	3.6	1.5	0.0	0.0
8:00 AM	9:00 AM	9	0.6	2.9	5.9	8.6	10.7	10.5	10.4	9.5	9.0	7.9	3.7	1.1
9:00 AM	10:00 AM	10	4.0	6.9	11.0	12.4	15.9	15.0	15.4	14.5	14.7	13.1	9.6	5.5
10:00 AM	11:00 AM	11	7.1	11.0	13.9	14.7	17.6	17.5	19.1	18.7	17.8	16.7	14.3	8.9
11:00 AM	12:00 PM	12	9.7	13.6	15.1	15.2	17.9	18.8	20.0	19.3	18.8	17.5	15.5	11.5
12:00 PM	1:00 PM	13	10.6	14.2	15.9	14.6	19.1	18.8	20.0	19.7	18.3	16.9	15.6	14.2
1:00 PM	2:00 PM	14	10.0	14.8	15.8	15.6	17.8	18.8	20.0	18.9	18.4	17.3	15.8	14.6
2:00 PM	3:00 PM	15	8.8	13.2	16.0	15.5	16.6	17.6	19.4	18.4	17.2	17.0	12.4	13.3
3:00 PM	4:00 PM	16	6.3	10.7	14.5	13.4	14.9	15.3	17.3	15.6	15.0	13.9	9.5	11.2
4:00 PM	5:00 PM	17	3.1	7.0	10.6	9.5	10.8	12.5	13.5	11.5	10.9	9.1	3.2	0.0
5:00 PM	6:00 PM	18	0.2	2.4	6.6	4.8	7.0	7.2	8.7	7.1	6.0	0.8	0.0	0.0
6:00 PM	7:00 PM	19	0.0	0.0	0.2	1.1	2.7	3.1	3.4	2.6	0.0	0.0	0.0	0.0
7:00 PM	8:00 PM	20	0.0	0.0	0.0	0.0	0.0	0.8	0.6	0.0	0.0	0.0	0.0	0.0
8:00 PM	9:00 PM	21	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9:00 PM	10:00 PM	22	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10:00 PM	11:00 PM	23	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11:00 PM	12:00 AM	24	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Avoided Cost of Energy

The AURORA model provides a unique energy price for every hour of the contract term:

175,200 individual prices (8,760 hours per year x 20 years)

Idaho Power condenses the 175,200 individual hourly prices into unique monthly heavy and light load energy price components that are then included in the contact:

480 individual energy prices (24 prices per year x 20 years)

Avoided Cost of Capacity

- The annualized capital (fixed) cost of a CCCT from the IRP is the basis for the capital cost ($/kW month)
- This $/kW month value is converted to a total annual capital cost based on the nameplate rating of the proposed project
- The total annual capital cost is then multiplied by the project specific peak-hour capacity factor
- This result is then divided by the MWh of generation from the proposed PURPA project, resulting in a $/MWh rate for avoided cost of capacity
- An avoided cost of capacity component is included in the total avoided cost rate beginning in the first month Idaho Power's IRP indicates a capacity deficit (currently identified as July 2016)

Avoided Cost of Capacity

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Peak-Hour Capacity Factor

The peak-hour capacity factor is a proposed project's expected capacity that will be available during Idaho Power's peak energy demand period in the hours from 3:00 pm to 7:00 pm during the month of July

Calculated in two steps:

1) Benchmarking a resource type's (wind, solar, canal drop, etc) ability to deliver energy to Idaho Power during Idaho Power's peak energy demand periods and determination of the expected capacity by using the 90th percentile, which is also used in the IRP for peak-hour planning

2) Reconciliation of the Benchmark resource to the specific PURPA project

Avoided Cost of Capacity

Peak-Hour Capacity Factor

Idaho Power Benchmark resource peak-hour capacity factors

Resource Type	Average Peak-Hour Capacity Factor	90th Percentile Peak- Hour Capacity Factor (Expected Capacity)
Wind	27.4%	3.9%
Canal Drop	78.7%	67.1%
Solar	51.9%	33.2%
Base Load *	100.0%	92.0%

* Note – It is assumed that a Base Load resource has control of operations and fuel supply to enable the project to plan to operate at 100% during peak-hours. A forced outage rate of 8% is deducted from the 100% capacity factor to establish an expected capacity factor during peak hours. The 8% forced outage rate is the forced outage rate applicable to a variety of Base Load type resources as identified in the Northwest Power and Conservation Council's 6th Power Plan.

Avoided Cost of Capacity

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Peak-Hour Capacity Factor

Reconciliation of the Benchmark resource to the proposed project:

- The project's average peak-hour capacity factor for the peak-hours in July from 3:00 pm to 7:00 pm is calculated based on the hourly generation data provided by the project
- The project's average peak-hour capacity factor is then divided by the Benchmark resource average peak-hour capacity factor, resulting in a capacity multiplier
- The Benchmark resource 90th percentile peak-hour capacity factor is then multiplied by the capacity multiplier, resulting in the peak-hour capacity factor to be applied to the specific Project

Integration Cost

- $6.50 per MWh
- Currently being applied to wind and solar resources
- Values may be adjusted as additional integration studies are completed

Sample Projects

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Selected Projects

- Solar PV — 20 MW, fixed mounting system
- Wind — 22 MW
- Base Load — 20 MW, representative of digester and biomass projects
- Canal Drop — 20 MW, small hydro, April – October generation

Generic data applicable to all sample projects:

- 20-year contract term
- January 1, 2013 online date
- Actual hourly generation data from a proposed project was used in each of these sample project analyses

Sample Project – Solar PV

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Project Provided Hourly Generation Data

			Average MW for each hour using Mountain Standard Time											
Hour Start	Hour End	Hour	January	February	March	April	May	June	July	August	September	October	November	December
12:00 AM	1:00 AM	1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1:00 AM	2:00 AM	2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2:00 AM	3:00 AM	3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3:00 AM	4:00 AM	4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4:00 AM	5:00 AM	5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5:00 AM	6:00 AM	6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6:00 AM	7:00 AM	7	0.0	0.0	0.0	0.4	0.7	0.8	0.6	0.3	0.0	0.0	0.0	0.0
7:00 AM	8:00 AM	8	0.0	0.0	1.1	3.6	5.3	5.5	5.0	4.1	3.6	1.5	0.0	0.0
8:00 AM	9:00 AM	9	0.6	2.9	5.9	8.6	10.7	10.5	10.4	9.5	9.0	7.9	3.7	1.1
9:00 AM	10:00 AM	10	4.0	6.9	11.0	12.4	15.9	15.0	15.4	14.5	14.7	13.1	9.6	5.5
10:00 AM	11:00 AM	11	7.1	11.0	13.9	14.7	17.6	17.5	19.1	18.7	17.8	16.7	14.3	8.9
11:00 AM	12:00 PM	12	9.7	13.6	15.1	15.2	17.9	18.8	20.0	19.3	18.8	17.5	15.5	11.5
12:00 PM	1:00 PM	13	10.6	14.2	15.9	14.6	19.1	18.8	20.0	19.7	18.3	16.9	15.6	14.2
1:00 PM	2:00 PM	14	10.0	14.8	15.8	15.6	17.8	18.8	20.0	18.9	18.4	17.3	15.8	14.6
2:00 PM	3:00 PM	15	8.8	13.2	16.0	15.5	16.6	17.6	19.4	18.4	17.2	17.0	12.4	13.3
3:00 PM	4:00 PM	16	6.3	10.7	14.5	13.4	14.9	15.3	17.3	15.6	15.0	13.9	9.5	11.2
4:00 PM	5:00 PM	17	3.1	7.0	10.6	9.5	10.8	12.5	13.5	11.5	10.9	9.1	3.2	0.0
5:00 PM	6:00 PM	18	0.2	2.4	6.6	4.8	7.0	7.2	8.7	7.1	6.0	0.8	0.0	0.0
6:00 PM	7:00 PM	19	0.0	0.0	0.2	1.1	2.7	3.1	3.4	2.6	0.0	0.0	0.0	0.0
7:00 PM	8:00 PM	20	0.0	0.0	0.0	0.0	0.0	0.8	0.6	0.0	0.0	0.0	0.0	0.0
8:00 PM	9:00 PM	21	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9:00 PM	10:00 PM	22	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10:00 PM	11:00 PM	23	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11:00 PM	12:00 AM	24	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Sample Project – Solar PV

IDAHO POWER
An IDACORP Company

Avoided Cost of Energy

Direct output from the AURORA Model

- 20 MW nameplate rating
- 20-year contract term
- January 1, 2013 online date

Levelized Avoided Cost of Energy **$54.83**

Sample Project – Solar PV

Avoided Cost of Capacity

Peak-hour Capacity Factor Calculation

- Project Provided Data
  - July, hours 3 – 7 pm average capacity factor 64.6%
- Benchmark resource - Idaho Power solar system data
  - July, hours 3 – 7 pm average capacity factor 51.9%
  - July, hours 3 – 7 pm 90th percentile capacity factor 33.2%
- Calculation
  - 64.6% divided by 51.9% equals a capacity multiplier of 1.24
  - 33.2% times the multiplier of 1.24 equals a peak hour capacity factor of **41.2%**

Sample Project – Solar PV

IDAHO POWER
An IDACORP Company

Avoided Cost of Capacity

Sample annual calculation - calendar year 2017

Capital cost of a CCCT per the 2011 IRP = **$15.16** per kW-month

($15.16 X (**20 MW** X 1,000)) X 12 months = $3,638,400 annual capital cost

$3,638,400 X **41.2% peak-hour capacity factor** = $1,499,021

$ 1,499,021 / **39,848 MWh** annual energy production = $37.62 per MWh

Levelized Avoided Cost of Capacity for 20-year contract term **$27.27**

Sample Project – Solar PV

IDAHO POWER
An IDACORP Company

Integration Cost

- $6.50 per MWh
- Values may be adjusted as additional integration studies are completed

Sample Project – Solar PV

IDAHO POWER
An IDACORP Company

Total Levelized Avoided Cost

• Avoided Energy Cost	$54.83
• Avoided Capacity Cost	$27.27
• Integration Cost	($6.50)
Total	$75.60

Levelized cost estimate based on:

20-year contract term

January 1, 2013 online date

Sample Project – Wind

Project Provided Hourly Generation Data

			Average MW for each hour using Mountain Time and adjusted for Daylight Savings Time											
Hour Start	Hour End	Hour	January	February	March	April	May	June	July	August	September	October	November	December
12:00 AM	1:00 AM	1	8.6	10.7	11.4	11.0	10.0	12.4	7.8	8.2	7.8	8.8	8.1	7.9
1:00 AM	2:00 AM	2	8.4	9.8	11.4	11.3	10.0	12.2	7.5	8.3	7.1	7.5	8.0	8.2
2:00 AM	3:00 AM	3	8.2	9.7	11.3	11.1	9.7	11.4	6.6	8.8	6.5	7.1	7.8	7.9
3:00 AM	4:00 AM	4	7.7	7.8	11.5	11.4	8.9	10.1	6.0	8.4	7.1	6.6	7.9	8.1
4:00 AM	5:00 AM	5	8.2	8.0	11.5	10.6	9.4	9.6	6.7	6.0	6.8	6.3	7.9	8.1
5:00 AM	6:00 AM	6	8.3	8.1	12.8	11.0	9.4	7.6	6.1	7.0	6.3	6.2	7.4	8.0
6:00 AM	7:00 AM	7	7.7	8.1	12.1	10.8	8.3	7.1	4.9	5.1	6.2	6.3	7.9	8.5
7:00 AM	8:00 AM	8	7.8	8.7	10.8	9.4	7.2	6.3	5.5	3.8	4.5	6.3	7.5	8.2
8:00 AM	9:00 AM	9	7.7	7.5	8.0	8.8	7.5	6.4	5.3	4.0	3.6	4.5	7.5	7.7
9:00 AM	10:00 AM	10	6.7	6.3	8.4	8.7	7.2	6.2	5.4	4.1	3.6	4.7	7.0	7.9
10:00 AM	11:00 AM	11	6.1	5.7	8.6	8.7	7.5	6.3	5.3	4.1	4.1	4.7	6.5	7.3
11:00 AM	12:00 PM	12	5.7	6.3	7.7	8.6	7.2	5.1	5.1	3.8	4.1	4.9	6.2	7.1
12:00 PM	1:00 PM	13	5.5	6.7	6.0	8.9	7.0	4.2	5.2	3.7	4.1	5.2	6.3	7.2
1:00 PM	2:00 PM	14	5.7	6.2	5.5	8.8	8.2	3.8	5.0	4.4	4.9	5.1	6.5	7.5
2:00 PM	3:00 PM	15	6.1	6.0	6.9	9.7	8.7	4.1	4.3	5.1	5.5	5.9	6.4	7.2
3:00 PM	4:00 PM	16	6.6	5.8	7.2	9.0	8.0	4.4	4.8	5.2	5.9	6.2	5.9	7.2
4:00 PM	5:00 PM	17	7.5	5.5	7.9	9.2	7.8	4.7	5.5	5.3	5.5	7.0	6.0	7.9
5:00 PM	6:00 PM	18	9.3	6.0	8.0	8.9	8.0	5.4	5.6	4.5	4.9	7.8	7.4	8.6
6:00 PM	7:00 PM	19	9.6	6.3	8.8	8.7	8.5	5.1	5.0	4.7	5.6	9.2	7.9	8.6
7:00 PM	8:00 PM	20	9.8	7.1	9.7	8.6	9.0	6.4	6.0	5.2	6.2	9.3	8.2	9.1
8:00 PM	9:00 PM	21	8.8	8.4	10.0	8.8	8.7	8.3	7.3	6.2	6.4	8.5	8.1	9.3
9:00 PM	10:00 PM	22	9.2	9.8	11.7	9.0	9.6	9.7	7.1	7.2	7.1	9.3	8.4	8.8
10:00 PM	11:00 PM	23	8.8	9.9	12.0	10.5	9.5	11.4	5.9	7.3	8.0	10.2	8.8	8.5
11:00 PM	12:00 AM	24	8.9	9.8	10.4	11.0	9.0	12.5	7.7	8.1	8.3	8.9	8.6	8.7

Sample Project – Wind

IDAHO POWER
An IDACORP Company

Avoided Cost of Energy

Direct output from the AURORA Model

- 22 MW nameplate rating
- 20-year contract term
- January 1, 2013 online date

Levelized Avoided Cost of Energy **$48.10**

Sample Project – Wind

Avoided Cost of Capacity

Peak-hour Capacity Factor Calculation

- Project Provided Data
  - July, hours 3 – 7 pm average capacity factor 23.7%
- Benchmark resource - Idaho Power wind data
  - July, hours 3 – 7 pm average capacity factor 27.4%
  - July, hours 3 – 7 pm 90th percentile capacity factor 3.9%
- Calculation
  - 23.7% divided by 27.4% equals a capacity multiplier of 0.86
  - 3.9% times the multiplier of 0.86 equals a peak hour capacity factor of **3.4%**

Sample Project – Wind

IDAHO POWER
An IDACORP Company

Avoided Cost of Capacity

Sample annual calculation - calendar year 2017

Capital cost of a CCCT per the 2011 IRP = **$15.16** per kW-month

($15.16 X (**22 MW** X 1,000)) X 12 months = $4,002,240 annual capital cost

$ 4,002,240 X **3.4% peak-hour capacity factor** = $136,076

$ 136,076 / **66,192 MWh** annual energy production = $2.06 per MWh

Levelized Avoided Cost of Capacity for 20-year contract term **$1.48**

Sample Project – Wind

IDAHO POWER.
An IDACORP Company

Integration Cost

- $6.50 per MWh
- Values may be adjusted as additional integration studies are completed

Sample Project – Wind

IDAHO POWER
An IDACORP Company

Total Levelized Avoided Cost

• Avoided Energy Cost	$48.10
• Avoided Capacity Cost	$1.48
• Integration Cost	($6.50)
Total	$43.08

Levelized cost estimate based on:

20-year contract term

January 1, 2013 online date

Sample Project – Base Load

Project Provided Hourly Generation Data

			Average MW for each hour using Mountain Time and adjusted for Daylight Savings Time											
Hour Start	Hour End	Hour	January	February	March	April	May	June	July	August	Septembe	October	November	December
12:00 AM	1:00 AM	1	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4
1:00 AM	2:00 AM	2	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4
2:00 AM	3:00 AM	3	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4
3:00 AM	4:00 AM	4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4
4:00 AM	5:00 AM	5	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4
5:00 AM	6:00 AM	6	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4
6:00 AM	7:00 AM	7	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4
7:00 AM	8:00 AM	8	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4
8:00 AM	9:00 AM	9	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4
9:00 AM	10:00 AM	10	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4
10:00 AM	11:00 AM	11	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4
11:00 AM	12:00 PM	12	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4
12:00 PM	1:00 PM	13	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4
1:00 PM	2:00 PM	14	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4
2:00 PM	3:00 PM	15	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4
3:00 PM	4:00 PM	16	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4
4:00 PM	5:00 PM	17	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4
5:00 PM	6:00 PM	18	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4
6:00 PM	7:00 PM	19	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4
7:00 PM	8:00 PM	20	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4
8:00 PM	9:00 PM	21	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4
9:00 PM	10:00 PM	22	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4
10:00 PM	11:00 PM	23	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4
11:00 PM	12:00 AM	24	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4

Sample Project – Base Load

IDAHO POWER
An IDACORP Company

Avoided Cost of Energy

Direct output from the AURORA Model

- 20 MW nameplate rating
- 20-year contract term
- January 1, 2013 online date

Levelized Avoided Cost of Energy **$49.96**

Sample Project – Base Load

Avoided Cost of Capacity

Peak-hour Capacity Factor Calculation

- Project Provided Data
  - July, hours 3 – 7 pm average capacity factor 100.0%
- Benchmark resource - Idaho Power base load data
  - July, hours 3 – 7 pm average capacity factor 100.0%
  - July, hours 3 – 7 pm capacity factor (8% forced rate) 92.0%
- Calculation
  - 100.0% divided by 100.0% equals a capacity multiplier of 1.0
  - 92.0% times the multiplier of 1.0 equals a peak hour capacity factor of **92.0%**

Sample Project – Base Load

IDAHO POWER
An IDACORP Company

Avoided Cost of Capacity

Sample annual calculation - calendar year 2017

Capital cost of a CCCT per the 2011 IRP = **$15.16** per kW-month

(**$15.16** X (**20 MW** X 1,000)) X 12 months = $3,638,400 annual capital cost

$ 3,638,400 X **92.0% peak-hour capacity factor** = $3,347,328

$ 3,347,328 / **161,184 MWh** annual energy production = $20.77 per MWh

Levelized Avoided Cost of Capacity for 20-year contract term **$15.04**

Sample Project – Base Load

Integration Cost

- $0.00 per MWh
- Values may be adjusted as additional integration studies are completed

Sample Project – Base Load

IDAHO POWER
An IDACORP Company

Total Levelized Avoided Cost

• Avoided Energy Cost	$49.96
• Avoided Capacity Cost	$15.04
• Integration Cost	($0.00)
Total	$65.00

Levelized cost estimate based on:

20-year contract term

January 1, 2013 online date

Sample Project – Canal Drop

Project Provided Hourly Generation Data

			Average MW for each hour using Mountain Time and adjusted for Daylight Savings Time											
Hour Start	Hour End	Hour	January	February	March	April	May	June	July	August	September	October	November	December
12:00 AM	1:00 AM	1	0.0	0.0	0.0	2.7	13.2	15.6	17.2	16.0	12.3	4.0	0.0	0.0
1:00 AM	2:00 AM	2	0.0	0.0	0.0	2.7	13.2	15.6	17.2	16.0	12.3	4.0	0.0	0.0
2:00 AM	3:00 AM	3	0.0	0.0	0.0	2.7	13.2	15.6	17.2	16.0	12.3	4.0	0.0	0.0
3:00 AM	4:00 AM	4	0.0	0.0	0.0	2.7	13.2	15.6	17.2	16.0	12.3	4.0	0.0	0.0
4:00 AM	5:00 AM	5	0.0	0.0	0.0	2.7	13.2	15.6	17.2	16.0	12.3	4.0	0.0	0.0
5:00 AM	6:00 AM	6	0.0	0.0	0.0	2.7	13.2	15.6	17.2	16.0	12.3	4.0	0.0	0.0
6:00 AM	7:00 AM	7	0.0	0.0	0.0	2.7	13.2	15.6	17.2	16.0	12.3	4.0	0.0	0.0
7:00 AM	8:00 AM	8	0.0	0.0	0.0	2.7	13.2	15.6	17.2	16.0	12.3	4.0	0.0	0.0
8:00 AM	9:00 AM	9	0.0	0.0	0.0	2.7	13.2	15.6	17.2	16.0	12.3	4.0	0.0	0.0
9:00 AM	10:00 AM	10	0.0	0.0	0.0	2.7	13.2	15.6	17.2	16.0	12.3	4.0	0.0	0.0
10:00 AM	11:00 AM	11	0.0	0.0	0.0	2.7	13.2	15.6	17.2	16.0	12.3	4.0	0.0	0.0
11:00 AM	12:00 PM	12	0.0	0.0	0.0	2.7	13.2	15.6	17.2	16.0	12.3	4.0	0.0	0.0
12:00 PM	1:00 PM	13	0.0	0.0	0.0	2.7	13.2	15.6	17.2	16.0	12.3	4.0	0.0	0.0
1:00 PM	2:00 PM	14	0.0	0.0	0.0	2.7	13.2	15.6	17.2	16.0	12.3	4.0	0.0	0.0
2:00 PM	3:00 PM	15	0.0	0.0	0.0	2.7	13.2	15.6	17.2	16.0	12.3	4.0	0.0	0.0
3:00 PM	4:00 PM	16	0.0	0.0	0.0	2.7	13.2	15.6	17.2	16.0	12.3	4.0	0.0	0.0
4:00 PM	5:00 PM	17	0.0	0.0	0.0	2.7	13.2	15.6	17.2	16.0	12.3	4.0	0.0	0.0
5:00 PM	6:00 PM	18	0.0	0.0	0.0	2.7	13.2	15.6	17.2	16.0	12.3	4.0	0.0	0.0
6:00 PM	7:00 PM	19	0.0	0.0	0.0	2.7	13.2	15.6	17.2	16.0	12.3	4.0	0.0	0.0
7:00 PM	8:00 PM	20	0.0	0.0	0.0	2.7	13.2	15.6	17.2	16.0	12.3	4.0	0.0	0.0
8:00 PM	9:00 PM	21	0.0	0.0	0.0	2.7	13.2	15.6	17.2	16.0	12.3	4.0	0.0	0.0
9:00 PM	10:00 PM	22	0.0	0.0	0.0	2.7	13.2	15.6	17.2	16.0	12.3	4.0	0.0	0.0
10:00 PM	11:00 PM	23	0.0	0.0	0.0	2.7	13.2	15.6	17.2	16.0	12.3	4.0	0.0	0.0
11:00 PM	12:00 AM	24	0.0	0.0	0.0	2.7	13.2	15.6	17.2	16.0	12.3	4.0	0.0	0.0

Sample Project – Canal Drop

IDAHO POWER
An IDACORP Company

Avoided Cost of Energy

Direct output from the AURORA Model

- 20 MW nameplate rating
- 20-year contract term
- January 1, 2013 online date

Levelized Avoided Cost of Energy **$47.27**

Sample Project – Canal Drop

Avoided Cost of Capacity

Peak-hour Capacity Factor Calculation

- Project Provided Data
  - July, hours 3 – 7 pm average capacity factor 86.2%
- Benchmark resource - Idaho Power canal drop data
  - July, hours 3 – 7 pm average capacity factor 78.7%
  - July, hours 3 – 7 pm 90th percentile capacity factor 67.1%
- Calculation
  - 86.2% divided by 78.7% equals a capacity multiplier of 1.10
  - 67.1% times the multiplier of 1.10 equals a peak hour capacity factor of **73.8%**

Sample Project – Canal Drop

IDAHO POWER
An IDACORP Company

Avoided Cost of Capacity

Sample annual calculation - calendar year 2017

Capital cost of a CCCT per the 2011 IRP = **$15.16** per kW-month

($15.16 X (**20 MW** X 1,000)) X 12 months = $3,638,400 annual capital cost

$ 3,638,400 X **73.8% peak-hour capacity factor** = $2,685,139

$ 2,685,139 / **59,530 MWh** annual energy production = $45.11 per MWh

Levelized Avoided Cost of Capacity for 20-year contract term **$33.04**

Sample Project – Canal Drop

Integration Cost

- $0.00 per MWh
- Values may be adjusted as additional integration studies are completed

Sample Project – Canal Drop

IDAHO POWER
An IDACORP Company

Total Levelized Avoided Cost

• Avoided Energy Cost	$47.27
• Avoided Capacity Cost	$33.04
• Integration Cost	($0.00)
Total	$80.31

Levelized cost estimate based on:

20-year contract term

January 1, 2013 online date

Sample Project Results

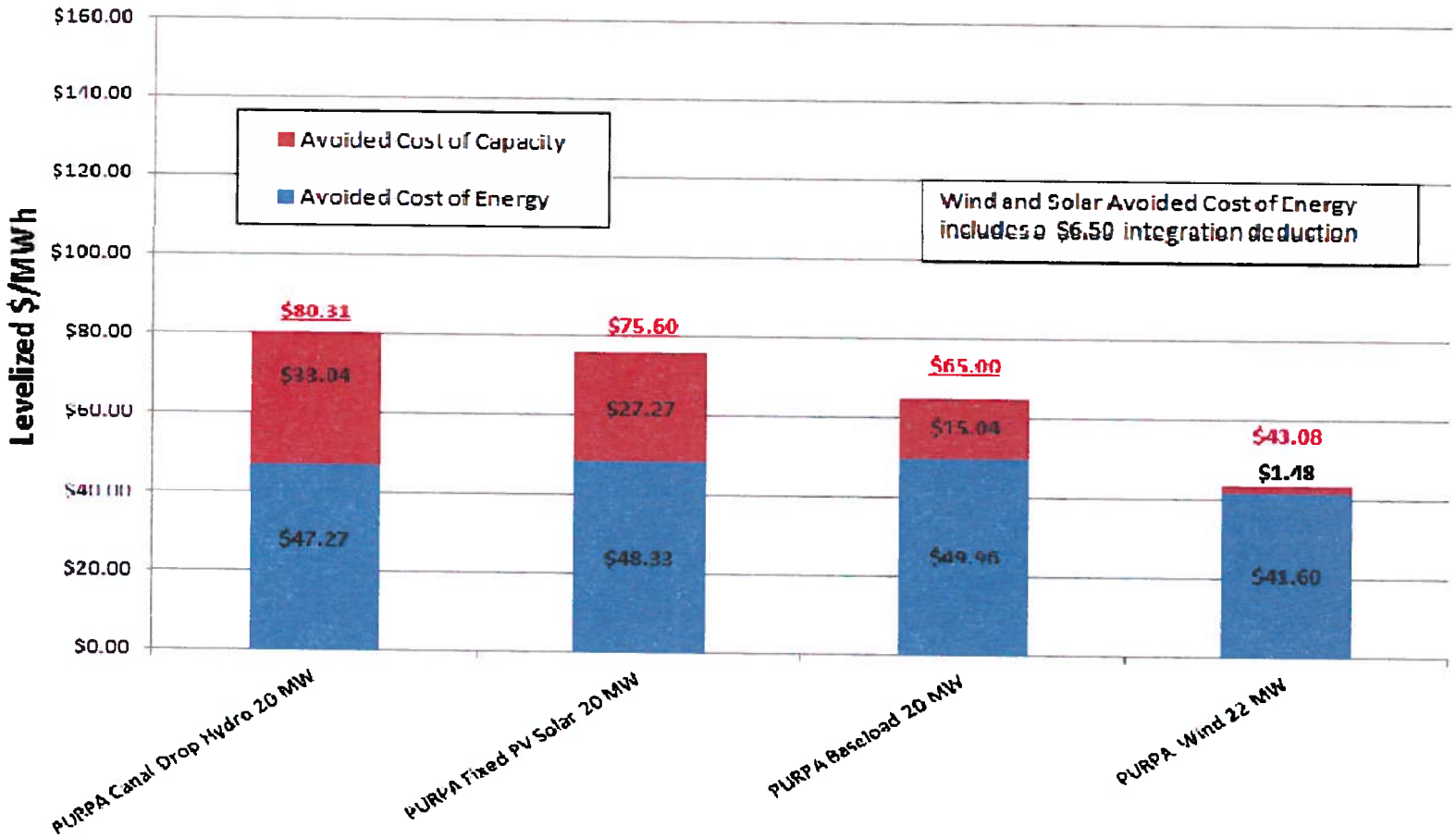
Levelized value for 20-year contract term (project coming online in January 2013)
Idaho Power Results

	Wind				Solar				Base Load			Canal Drop Hydro		
Year	Energy	Capacity	Resource Integration	Total	Energy	Capacity	Resource Integration	Total	Energy	Capacity	Total	Energy	Capacity	Total
2013	$32.43	$0.00	($6.50)	$25.93	$38.07	$0.00	($6.50)	$31.57	$33.70	$0.00	$33.70	$31.91	$0.00	$31.91
2014	$33.60	$0.00	($6.50)	$27.10	$39.61	$0.00	($6.50)	$33.11	$35.16	$0.00	$35.16	$33.16	$0.00	$33.16
2015	$35.49	$0.00	($6.50)	$28.99	$41.37	$0.00	($6.50)	$34.87	$37.04	$0.00	$37.04	$34.98	$0.00	$34.98
2016	$38.53	$0.91	($6.50)	$32.94	$44.40	$19.14	($6.50)	$57.04	$39.92	$10.39	$50.31	$38.12	$27.57	$65.70
2017	$39.70	$2.06	($6.50)	$35.26	$45.67	$37.62	($6.50)	$76.79	$41.31	$20.77	$62.08	$39.08	$45.10	$84.18
2018	$41.01	$2.06	($6.50)	$36.57	$47.33	$37.68	($6.50)	$78.51	$42.66	$20.80	$63.46	$40.57	$45.18	$85.75
2019	$43.70	$2.06	($6.50)	$39.26	$50.04	$37.75	($6.50)	$81.29	$45.27	$20.84	$66.11	$43.02	$45.26	$88.28
2020	$45.65	$2.06	($6.50)	$41.21	$52.46	$37.77	($6.50)	$83.73	$47.58	$20.82	$68.40	$44.70	$45.35	$90.05
2021	$48.34	$2.07	($6.50)	$43.91	$55.26	$37.89	($6.50)	$86.65	$50.36	$20.92	$71.28	$47.48	$45.43	$92.91
2022	$52.30	$2.07	($6.50)	$47.87	$59.20	$37.97	($6.50)	$90.67	$54.18	$20.96	$75.14	$51.23	$45.52	$96.75
2023	$54.15	$2.08	($6.50)	$49.73	$61.20	$38.04	($6.50)	$92.74	$56.33	$21.00	$77.33	$52.84	$45.61	$98.45
2024	$56.18	$2.08	($6.50)	$51.76	$63.64	$38.06	($6.50)	$95.20	$58.42	$20.99	$79.41	$54.88	$45.71	$100.59
2025	$59.68	$2.09	($6.50)	$55.27	$67.24	$38.20	($6.50)	$98.94	$61.78	$21.09	$82.87	$58.73	$45.80	$104.53
2026	$62.51	$2.09	($6.50)	$58.10	$70.69	$38.28	($6.50)	$102.47	$64.98	$21.13	$86.11	$61.50	$45.90	$107.40
2027	$65.03	$2.10	($6.50)	$60.63	$73.39	$38.36	($6.50)	$105.25	$67.52	$21.18	$88.70	$64.49	$46.00	$110.49
2028	$69.07	$2.10	($6.50)	$64.67	$77.35	$38.39	($6.50)	$109.24	$71.47	$21.17	$92.64	$68.10	$46.10	$114.20
2029	$71.73	$2.11	($6.50)	$67.34	$80.29	$38.54	($6.50)	$112.33	$74.46	$21.27	$95.73	$70.25	$46.21	$116.46
2030	$70.13	$2.11	($6.50)	$65.74	$77.58	$38.63	($6.50)	$109.71	$72.48	$21.32	$93.80	$68.32	$46.32	$114.64
2031	$72.23	$2.12	($6.50)	$67.85	$79.91	$38.72	($6.50)	$112.13	$74.66	$21.38	$96.04	$70.37	$46.43	$116.80
2032	$74.40	$2.12	($6.50)	$70.02	$82.31	$38.76	($6.50)	$114.57	$76.90	$21.37	$98.27	$72.48	$46.54	$119.02
Levelized	**$48.10**	**$1.48**	**($6.50)**	**$43.08**	**$54.83**	**$27.27**	**($6.50)**	**$75.60**	**$49.96**	**$15.04**	**$65.00**	**$47.27**	**$33.04**	**$80.31**

Sample Project Results

Idaho Power Results

Levelized value for 20-year contract term, project coming online in January 2013



CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on the 31st day of January 2012 I served a true and correct copy of the DIRECT TESTIMONY OF M. MARK STOKES upon the following named parties by the method indicated below:

Commission Staff Donald L. Howell, II Kristine A. Sasser Deputy Attorneys General Idaho Public Utilities Commission 472 West Washington (83702) P.O. Box 83720 Boise, Idaho 83720-0074	_X_ Hand Delivered ____ U.S. Mail ____ Overnight Mail ____ FAX _X_ Email don.howell@puc.idaho.gov kris.sasser@puc.idaho.gov
Avista Corporation Michael G. Andrea Avista Corporation 1411 East Mission Avenue, MSC-23 P.O. Box 3727 Spokane, Washington 99220-3727	____ Hand Delivered ____ U.S. Mail ____ Overnight Mail ____ FAX _X_ Email michael.andrea@avistacorp.com
PacifiCorp d/b/a Rocky Mountain Power Daniel E. Solander PacifiCorp d/b/a Rocky Mountain Power 201 South Main Street, Suite 2300 Salt Lake City, Utah 84111	____ Hand Delivered ____ U.S. Mail ____ Overnight Mail ____ FAX _X_ Email daniel.solander@pacificorp.com
Kenneth Kaufmann LOVINGER KAUFMANN, LLP 825 NE Multnomah, Suite 925 Portland, Oregon 97232	____ Hand Delivered ____ U.S. Mail ____ Overnight Mail ____ FAX _X_ Email kaufmann@lklaw.com
Exergy Development, Grand View Solar II, J.R. Simplot, Northwest and Intermountain Power Producers Coalition, Board of Commissioners of Adams County, Idaho, and Clearwater Paper Corporation Peter J. Richardson Gregory M. Adams RICHARDSON & O'LEARY, PLLC 515 North 27th Street (83702) P.O. Box 7218 Boise, Idaho 83707	____ Hand Delivered ____ U.S. Mail ____ Overnight Mail ____ FAX _X_ Email peter@richardsonandoleary.com greg@richardsonandoleary.com

Exergy Development Group James Carkulis, Managing Member Exergy Development Group of Idaho, LLC 802 West Bannock Street, Suite 1200 Boise, Idaho 83702	____Hand Delivered ____U.S. Mail ____Overnight Mail ____FAX _X_ Email jcarkulis@exergydevelopment.com
Grand View Solar II Robert A. Paul Grand View Solar II 15690 Vista Circle Desert Hot Springs, California 92241	____Hand Delivered ____U.S. Mail ____Overnight Mail ____FAX _X_ Email robertapaul08@gmail.com
J.R. Simplot Company Don Sturtevant, Energy Director J.R. Simplot Company One Capital Center 999 Main Street P.O. Box 27 Boise, Idaho 83707-0027	____Hand Delivered ____U.S. Mail ____Overnight Mail ____FAX _X_ Email don.sturtevant@simplot.com
Northwest and Intermountain Power Producers Coalition Robert D. Kahn, Executive Director Northwest and Intermountain Power Producers Coalition 1117 Minor Avenue, Suite 300 Seattle, Washington 98101	____Hand Delivered ____U.S. Mail ____Overnight Mail ____FAX _X_ Email rkahn@nippc.org
Board of Commissioners of Adams County, Idaho Bill Brown, Chair Board of Commissioners of Adams County, Idaho P.O. Box 48 Council, Idaho 83612	____Hand Delivered ____U.S. Mail ____Overnight Mail ____FAX _X_ Email bdbrown@frontiernet.net
Clearwater Paper Corporation Marv Lewallen Clearwater Paper Corporation 601 West Riverside Avenue, Suite 1100 Spokane, Washington 99201	____Hand Delivered ____U.S. Mail ____Overnight Mail ____FAX _X_ Email marv.lewallen@clearwaterpaper.com

Renewable Energy Coalition
Thomas H. Nelson, Attorney
P.O. Box 1211
Welches, Oregon 97067-1211

____Hand Delivered
____U.S. Mail
____Overnight Mail
____FAX
_X_ Email nelson@thneslon.com

John R. Lowe, Consultant
Renewable Energy Coalition
12050 SW Tremont Street
Portland, Oregon 97225

____Hand Delivered
____U.S. Mail
____Overnight Mail
____FAX
_X_ Email jravenesanmarcos@yahoo.com

Dynamis Energy, LLC
Ronald L. Williams
WILLIAMS BRADBURY, P.C.
1015 West Hays Street
Boise, Idaho 83702

____Hand Delivered
____U.S. Mail
____Overnight Mail
____FAX
_X_ Email ron@williamsbradbury.com

Wade Thomas, General Counsel
Dynamis Energy, LLC
776 East Riverside Drive, Suite 150
Eagle, Idaho 83616

____Hand Delivered
____U.S. Mail
____Overnight Mail
____FAX
_X_ Email wthomas@dynamisenergy.com

Idaho Windfarms, LLC
Glenn Ikemoto
Margaret Rueger
Idaho Windfarms, LLC
672 Blair Avenue
Piedmont, California 94611

____Hand Delivered
____U.S. Mail
____Overnight Mail
____FAX
_X_ Email glenni@envisionwind.com
margaret@envisionwind.com

Interconnect Solar Development, LLC
R. Greg Ferney
MIMURA LAW OFFICES, PLLC
2176 East Franklin Road, Suite 120
Meridian, Idaho 83642

____Hand Delivered
____U.S. Mail
____Overnight Mail
____FAX
_X_ Email greg@mimuralaw.com

Bill Piske, Manager
Interconnect Solar Development, LLC
1303 East Carter
Boise, Idaho 83706

____Hand Delivered
____U.S. Mail
____Overnight Mail
____FAX
_X_ Email billpiske@cableone.net

Renewable Northwest Project
Dean J. Miller
McDEVITT & MILLER LLP
420 West Bannock Street (83702)
P.O. Box 2564
Boise, Idaho 83701

____Hand Delivered
____U.S. Mail
____Overnight Mail
____FAX
_X_ Email joe@mcdevitt-miller.com

Megan Walseth Decker
Senior Staff Counsel
Renewable Northwest Project
917 SW Oak Street, Suite 303
Portland, Oregon 97205

____Hand Delivered
____U.S. Mail
____Overnight Mail
____FAX
_X_ Email megan@rnp.org

North Side Canal Company and Twin Falls Canal Company
Shelley M. Davis
BARKER ROSHOLT & SIMPSON, LLP
1010 West Jefferson Street, Suite 102 (83702)
P.O. Box 2139
Boise, Idaho 83701-2139

____Hand Delivered
____U.S. Mail
____Overnight Mail
____FAX
_X_ Email smd@idahowaters.com

Brian Olmstead, General Manager
Twin Falls Canal Company
P.O. Box 326
Twin Falls, Idaho 83303

____Hand Delivered
____U.S. Mail
____Overnight Mail
____FAX
_X_ Email olmstead@tfcanal.com

Ted Diehl, General Manager
North Side Canal Company
921 North Lincoln Street
Jerome, Idaho 83338

____Hand Delivered
____U.S. Mail
____Overnight Mail
____FAX
_X_ Email nscanal@cableone.net

Birch Power Company
Ted S. Sorenson, P.E.
Birch Power Company
5203 South 11th East
Idaho Falls, Idaho 83404

____Hand Delivered
____U.S. Mail
____Overnight Mail
____FAX
_X_ Email ted@tsorenson.net

Blue Ribbon Energy LLC
M. J. Humphries
Blue Ribbon Energy LLC
4515 South Ammon Road
Ammon, Idaho 83406

____Hand Delivered
____U.S. Mail
____Overnight Mail
____FAX
_X_ Email blueribbonenergy@gmail.com

Arron F. Jepson
Blue Ribbon Energy LLC
10660 South 540 East
Sandy, Utah 84070

____Hand Delivered
____U.S. Mail
____Overnight Mail
____FAX
_X_ Email arronesq@aol.com

Idaho Conservation League
Benjamin J. Otto
Idaho Conservation League
710 North Sixth Street (83702)
P.O. Box 844
Boise, Idaho 83701

____ Hand Delivered
____ U.S. Mail
____ Overnight Mail
____ FAX
_X_ Email botto@idahoconservation.org

Snake River Alliance
Ken Miller
Clean Energy Program Director
Snake River Alliance
350 North 9th Street #B610
P.O. Box 1731
Boise, Idaho 83701

____ Hand Delivered
____ U.S. Mail
____ Overnight Mail
____ FAX
_X_ Email kmiller@snakeriveralliance.org

Donovan E. Walker