PUBLIC WORKSHOP

IDAHO POWER COMPANY

APPLICATION TO COMPLETE THE STUDY REVIEW PHASE OF THE COMPREHENSIVE STUDY OF COSTS AND BENEFITS OF ON-SITE CUSTOMER GENERATION & FOR AUTHORITY TO IMPLEMENT CHANGES TO SCHEDULES 6, 8, AND 84 CASE NO. IPC-E-22-22

IDAHO PUBLIC UTILITIES COMMISSION

September 6, 2022, 7:00 PM (MDT)
September 7, 2022, 12:30 PM (MDT)
INTRODUCTIONS

Adam Rush – Public Information Officer
Travis Culbertson – Utilities Analyst
Joe Terry – Auditor III
Yao Yin – Utilities Analyst
Matt Suess – Engineer
Jolene Bossard – Utilities Compliance Investigator
Established in 1913. Idaho Code Sections 61, 62, and 63.

The Commission regulates Idaho's investor-owned utilities, ensuring adequate service and reasonable rates.

The Commission is made up of three commissioners appointed by the Governor.

The Commission makes the decisions in each case.

Commission Staff is made up of Auditors, Consumer Advocates, Engineers & Technical Analysts.

Commission Staff is a party in all filed cases and provides comments and recommendations to the Commissioners.
Public Hearing
IDAPA 31.01.01.241.04

• Types of Formal Hearings. The Commission generally conducts two (2) types of formal public hearings.

  a. A technical hearing is a public hearing where parties present witnesses and their prepared testimony and exhibits.

  b. A customer hearing is a public hearing for customers, public officials, and other persons not related to parties in the case to provide testimony. Unless otherwise ordered by the presiding officer, parties are prohibited from presenting evidence at the customer hearing.
PARTICIPATION

ONLINE:

- To chat open the feature in WebEx, select the chat icon in the lower right portion of the meeting window.
  - Type your questions or comments in the chat box;
  - Please be sure to use the “all panelists” option in the drop-down list when using chat to ensure your message will be seen by all.
- To speak directly online, click on the hand icon in the lower right corner by your name to be un-muted.

BY PHONE:

- Press *3 to raise and lower your hand;
  - When your line has been un-muted, you will hear an announcement indicating you’ve been un-muted.

The presentation is available on the Commission’s homepage at puc.idaho.gov (Workshop is recorded)
On June 30, 2022, Idaho Power Company (“Company”) applied to the Commission to complete a multi-phase process for a comprehensive cost and benefit study of on-site generation.

Why File for a case to study net excess energy from customer generators?

- **Commission Order No. 34046:**
  - “IT IS FURTHER ORDERED that Idaho Power shall initiate a docket to comprehensively study the costs and benefits of on-site generation on Idaho Power’s system, as well as proper rates and rate design, transitional rates, and related issues of compensation for net excess energy provided as a resource to the Company.”
The Commission identified the following criteria for a credible and fair study:

1. The study must use the most current data possible, and the data must be readily available to the public, and in the Commission's decision-making record.

2. The Company must design the study in coordination with the parties and the public, and the final scope of the study will be determined by the Commission.

3. The study must be written so it is understandable to an average customer, but its analysis must be able to withstand expert scrutiny.
The Commission identified the Study Framework:

- **Commission Order No. 35284:**
  - “IT IS FURTHER ORDERED that Idaho Power complete the study design for its Comprehensive study on the costs and benefits of on-site generation based on the Commission’s Study Framework findings and conclusions as more specifically defined and explained herein.”
  - “IT IS FURTHER ORDERED that the Company complete the Study in 2022 as soon as feasible.”
Case Processing so far

• On June 30, 2022, Idaho Power applied to the Commission to complete the multi-phase process for a comprehensive cost and benefit study of on-site generation.

• The Study Framework is based on initial work completed in IPC-E-21-21 and outlined in Order No. 35284.

• The Study is available for public review.
  • Value of Distributed Energy Resources (“VODER”)
  • www.puc.idaho.gov (Case Number: IPC-E-22-22)

• On August 31, 2022, Idaho Power Company held a public workshop.
  • To see the slides and presentation, visit www.idahopower.com/study
# Upcoming Dates

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<td>COMPANY REPLY COMMENTS DUE</td>
<td>October 26, 2022</td>
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Study

• **Section 3: Measurement Intervals**

• **Section 4: Export Credit Rate (“ECR”)**
  • Avoided Energy Value
  • Avoided Capacity Value
  • *Avoided Transmission and Distribution Costs*
  • Avoided Line Losses
  • Avoided Environmental Costs
  • Integration Costs

• **Section 5: Frequency of ECR Updates**

• **Section 6: Compensation Structure**

• **Section 7: Class Cost-of-Service**

• **Section 8: Recovering Export Credit Rate Expenditures**

• **Section 9: Project Eligibility Cap**

• **Section 10: Other Areas of Study**
  • Billing Structure
  • Export Credit Expiration

• **Section 11: Implementation Considerations**
  • Transitional Rates
Definitions

- **Customer-generators**: those that have a solar system currently exporting energy to the grid.

- **Export Credit Rate or ECR**: a monetary value for all exported energy.

- **Net Billing**: proposed program that includes a monetary value for any exported energy.

- **Net Energy Metering ("NEM")**: current kWh to kWh Program.
Definitions

• **Legacy System**: customer-generators that were grandfathered and meet criteria in Order No. 34509 and Order No. 34546.

• **Non-legacy System**: customer-generators that were not grandfathered and do not meet criteria in Order No. 34509 and Order No. 34546.

• **Power Cost Adjustment**: cost-recovery mechanism that passes both benefits and costs of supplying energy to customers.

• **VODER**: Value of Distributed Energy Resources Study.
Section 3 Measurement Intervals

• The length of time between meter reads.
• Net Energy Metering.
  • Monthly.
• Net Billing.
  • Hourly.
  • Real-time.
Section 4 Export Credit Rate

• The monetary value assigned to the customer’s exported energy.
Section 4 Components of ECR

1. Avoided Energy Costs
2. Avoided Generation Capacity Costs
3. Avoided Transmission & Distribution (T&D) Capacity Costs
4. Avoided Line Losses
5. Avoided Environmental Costs
6. Integration Costs
Section 4 Avoided Energy Costs

- Energy exported by the customer enables the Company to avoid the cost of producing that energy (or buying it on the wholesale market).
Section 4 Avoided Energy Costs

1. Determine the cost of energy
   a. Use the energy price forecasts in the Company’s most recently acknowledged Integrated Resource Plan (IRP)
   b. Use the Intercontinental Exchange Mid-Columbia (ICE Mid-C) futures exchange market (day-ahead pricing)
   c. Use the Western Energy Imbalance Market (EIM) Load Aggregation Point (ELAP) (real-time pricing)
   d. ICE Mid-C and ELAP are used as a historic average in the study, but current data can be used instead

2. Calculate the value (use a weighted average)
   a. Flat annual value
   b. Seasonal time variant value

3. Adjust for lack of "Firmness"
   Energy that can be delivered in specific quantities at specific times is "firm" and is worth more than uncertain or "non-firm" energy. The Commission directed the Company to treat customer-generated solar energy as non-firm. The study concludes that non-firm energy is worth about 82% of firm energy, on average.
## Section 4 Avoided Energy Costs

### Results
*(includes non-firm adjustment factor of 82.4%)*

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<tr>
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<th>Flat Annual Rate</th>
<th>Seasonal Time Variant Rate (On-Peak)</th>
<th>Seasonal Time Variant Rate (Off-Peak)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2021 IRP (forecast value)</td>
<td>1.89¢/kWh</td>
<td>2.68¢/kWh</td>
<td>1.83¢/kWh</td>
</tr>
<tr>
<td>ICE Mid-C (2019-2021 historical avg)</td>
<td>3.06¢/kWh</td>
<td>4.11¢/kWh</td>
<td>2.97¢/kWh</td>
</tr>
<tr>
<td>ELAP (2019-2021 historical avg)</td>
<td>2.82¢/kWh</td>
<td>5.10¢/kWh</td>
<td>2.64¢/kWh</td>
</tr>
</tbody>
</table>

Note: These calculations assume a real-time net billing scenario. An hourly net billing structure would yield slightly different results.
Energy exported by customers enables the Company to avoid the cost of installing more generation capacity. The value of this is the avoided generation capacity cost.
Section 4 Avoided Generation Capacity Costs

Avoided Generation Capacity Value = 

Levelized Fixed Cost of Avoided Resource \[ \times \] Capacity Contribution \[ \times \] "Nameplate" Generation Size

Energy Exported

Two methods proposed to calculate the capacity contribution:
1. Effective Load Carrying Capacity (ELCC) method
2. National Renewable Energy Laboratory (NREL) 8,760 method

Two methods proposed to calculate the overall value
1. Flat Annual value
2. Seasonal Time Variant value
Avoided Generation Capacity Value

1. $128.40/kW-year
2. Capacity Contribution
3. 64.11 MW

Energy Exported

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<th>Seasonal Time Variant Rate (Off-Peak)</th>
</tr>
</thead>
<tbody>
<tr>
<td>ELCC (2020-2021 historical avg)</td>
<td>1.06¢/kWh</td>
<td>14.03¢/kWh</td>
<td>zero</td>
</tr>
<tr>
<td>NREL (2020-2021 historical avg)</td>
<td>1.44¢/kWh</td>
<td>18.99¢/kWh</td>
<td>zero</td>
</tr>
</tbody>
</table>

Note: These calculations assume a real-time net billing scenario. An hourly net billing structure would yield slightly different results.
Section 4 Avoided T&D Capacity Costs

- When customers export energy near to where it is used, less energy must flow from the Company’s generators through its T&D lines. These reduced flows can delay the Company’s need to expand its T&D capacity, which avoids costs.
Section 4 Avoided T&D Capacity Costs

Method of Determination
1. List all T&D capacity projects for \(-15 / + 5\) years
2. Determine the capacity of each T&D segment, and the peak energy flow on that segment
3. Estimate the solar exports on each segment
4. Subtract the estimated solar exports from the peak flow. If the revised peak is less than T&D capacity, the capacity project can be deferred.
Section 4 Avoided T&D Capacity Costs

Results

- 9 of 447 projects deferred over 20 years
- Value of the deferrals = $307K (over 20 years)
- Annual cost avoidance = $15.4K

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<th>Seasonal Time Variant Rate (Off-Peak)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Avoided T&amp;D Cost</td>
<td>0.02¢/kWh</td>
<td>0.34¢/kWh</td>
<td>zero</td>
</tr>
</tbody>
</table>

Note: These calculations assume a real-time net billing scenario. An hourly net billing structure would yield slightly different results.
Section 4 Avoided Line Losses

• Energy is lost as it travels from the point of generation to the customers. Customer-generators who export energy adjacent to other customers avoid these losses. The avoided line losses have value.
Section 4 Avoided Line Losses

- Line losses were last measured in a 2012 study. The average result was 5.8%.
- Therefore, each 1.000 kWh exported by a customer is equal to 1.058 kWh generated by the Company. This increase is applied to the avoided energy cost.

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<th>Seasonal Time Variant Rate (Off-Peak)</th>
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</thead>
<tbody>
<tr>
<td>2021 IRP (forecast value)</td>
<td>0.11¢/kWh</td>
<td>0.16¢/kWh</td>
<td>0.11¢/kWh</td>
</tr>
<tr>
<td>ICE Mid-C (2019-2021 historical avg)</td>
<td>0.18¢/kWh</td>
<td>0.24¢/kWh</td>
<td>0.17¢/kWh</td>
</tr>
<tr>
<td>ELAP (2019-2021 historical avg)</td>
<td>0.16¢/kWh</td>
<td>0.30¢/kWh</td>
<td>0.15¢/kWh</td>
</tr>
</tbody>
</table>

Note: These calculations assume a real-time net billing scenario. An hourly net billing structure would yield slightly different results.
Section 4 Avoided Environmental Costs

• In accordance with Case No. IPC-E-21-21, Order No. 35284 at 27: “...the Study [shall] include an evaluation of all [environmental] benefits and costs that are quantifiable, measurable, and avoided costs that affect rates.”
Section 4 Avoided Environmental Costs

Typical environmental benefits that can result in avoided costs are:
1. Selling or buying Renewable Energy Certificates (RECs)
2. Avoided costs of Carbon Taxes
3. Avoided costs to achieve a mandated Renewable Portfolio Standard (RPS)

Study Conclusions:
1. There are legal and administrative barriers to monetizing RECs from customer generators. The effort required by each customer would be large and the resulting value would be small. No value is proposed.
2. Idaho Power is not subject to a Carbon Tax policy so there are no costs to avoid.
3. Idaho Power is not subject to a legislatively mandated RPS policy so there are no costs to avoid.
Section 4 Integration Costs

- To ensure grid reliability, the Company must keep a certain amount of generation capacity in reserve. The more variable energy – such as solar – on the grid, the more capacity the company must keep in reserve. This additional reserve capacity costs the company money.

- The “integration cost” is the cost for the Company to keep capacity in reserve for solar customer-generators.
**Section 4 Integration Costs**

- Idaho Power hired a contractor to perform an Integration Study in 2020, and the report provided estimates of the integration cost under different scenarios. Idaho Power proposes to use the baseline scenario result.

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<th>Seasonal Time Variant Rate (On-Peak)</th>
<th>Seasonal Time Variant Rate (Off-Peak)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Integration Cost</td>
<td>(0.293¢/kWh)</td>
<td>(0.293¢/kWh)</td>
<td>(0.293¢/kWh)</td>
</tr>
</tbody>
</table>
## Section 4 Summing It Up

<table>
<thead>
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<th>Seasonal Time Variant Rate (Off-Peak)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>2021 IRP (forecast value)</strong></td>
<td>2.80¢/kWh</td>
<td>16.92¢/kWh</td>
<td>1.64¢/kWh</td>
</tr>
<tr>
<td><strong>ICE Mid-C</strong></td>
<td><strong>4.03¢/kWh</strong></td>
<td><strong>18.43¢/kWh</strong></td>
<td><strong>2.85¢/kWh</strong></td>
</tr>
<tr>
<td><strong>(2019-2021 historical avg)</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>ELAP</strong></td>
<td>3.78¢/kWh</td>
<td>19.48¢/kWh</td>
<td>2.50¢/kWh</td>
</tr>
<tr>
<td><strong>(2019-2021 historical avg)</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Note: These calculations assume a real-time net billing scenario. An hourly net billing structure would yield slightly different results.
Section 5 Frequency of ECR Updates

• Evaluate data inputs of the ECR to determine when updates should occur.

• Balance the need for a stable ECR.
  • Forecasted Energy Price vs. Actual Market Price.
  • Every two years: Align updates to similar timeline of IRP.
  • 3 – 5 year rolling averages.
Section 6 Compensation Structure

• Evaluates the metering and billing arrangement for each exporting system.

• Net Energy Metering (“NEM”).
  • Current program done on a monthly measurement interval.

• Net Billing.
  • Compared at an hourly and real-time measurement interval.
Section 6 Compensation Structure (Cont’d)

• Average Residential Customer Comparison.

• Current NEM = $5 per month.

• Net Billing.
  • Hourly = $31.37
  • Real-time = $31.79

Reference VODER Page 76 – Figure 6.1: Average monthly bill for average residential customer with 8.5 kW solar system installed.
Section 7 Class Cost-of-Service ("CCOS")

• Used to design or allocate a fair share of the utility’s revenue requirement to various customer rate classes or schedules.

• Informs how a change in billing measurement interval may result in collection of revenue in excess of baseline.
Section 7 Class Cost-of-Service (Cont’d)

• Net Billing Hourly – Non-Legacy Systems Only
  • Revenue Requirement deficiency reduces by 9% and 7% for Schedule 6 and 8, respectively.

• Net Billing Real-time – Non-Legacy Systems Only
  • Revenue Requirement deficiency reduces by 16% and 7% for Schedule 6 and 8, respectively.
Section 8 Recovering Export Credit Rate Expenditures

Section 8.1
- These credits should be recorded in Account 555 Purchased Power Expense
- Recover these costs through the Power Cost Adjustment Mechanism (PCA) like other renewable power purchases
- Not subject to the 5% sharing band like all Qualifying Facilities
Section 8 Recovering Export Credit Rate Expenditures (Cont’d)

Section 8.2

• The bill impact varies depending on differing price scenarios

• Ranges from a .02% to a .05% increase to customer bills
Section 9 Project Eligibility Cap

- The existing project eligibility cap for the net metering program varies by customer type: 25 kW for residential and small general customers; 100 kW for commercial, industrial, and irrigation customers.

- The VODER Study states the rationale for a cap, in part, is to limit the amount that other customers subsidize some of the costs of net metering customers.
<table>
<thead>
<tr>
<th>Customer Type</th>
<th>Count</th>
<th>Total Capacity (MW)</th>
<th>Average Size (kW)</th>
<th>Project Cap (kW)</th>
<th>Average Size as % of Cap</th>
</tr>
</thead>
<tbody>
<tr>
<td>Residential</td>
<td>11,807</td>
<td>88.92</td>
<td>7.53</td>
<td>25</td>
<td>30%</td>
</tr>
<tr>
<td>Small General</td>
<td>73</td>
<td>0.57</td>
<td>7.77</td>
<td>25</td>
<td>31%</td>
</tr>
<tr>
<td>Commercial &amp; Industrial</td>
<td>200</td>
<td>6.56</td>
<td>32.80</td>
<td>100</td>
<td>33%</td>
</tr>
<tr>
<td>Irrigation</td>
<td>242</td>
<td>22.00</td>
<td>90.89</td>
<td>100</td>
<td>91%</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>12,322</strong></td>
<td><strong>118.04</strong></td>
<td><strong>9.58</strong></td>
<td></td>
<td><strong>35%</strong></td>
</tr>
</tbody>
</table>

Note: Numbers may not add up due to rounding.

Reference VODER Page 98.
Section 9 Project Eligibility Cap

- Order No. 28951 highlighted the importance of “safety, service quality and grid reliability” when determining the appropriate project eligibility cap.

- The adoption and the compliance of the IEEE 1547 standard (the national standard for the interconnection of distributed generation resources in the U.S.) resulted in lower risks associated with interconnection of distributed generation resources.

- Interconnection studies are typically required to ensure the compliance of the IEEE standard and to ensure the safety and reliability of the system.

- Modifying project eligibility cap may require re-evaluation of the interconnection requirements and processes.
Section 9 Project Eligibility Cap

- In terms of managing distribution system, Idaho Power periodically changes connections to its distribution line sections by closing and opening distribution switches.

- Modifying the project eligibility cap could impact the switching process.
Section 9 Project Eligibility Cap

• The VODER Study also considered four questions as to implementing a demand-based cap:

1. Should a demand-based system size cap apply to all customer-generators or only commercial, industrial, and irrigation customers?

• The VODER Study states retaining the 25-kW cap for residential and small general customers could be reasonable, because the average system size is roughly 30% of the 25-kW cap.
Section 9 Project Eligibility Cap

2. What is the definition of a customer’s demand for purposes of a system size cap?

• The VODER Study states a customer’s demand can be defined in a variety of ways. (e.g., maximum monthly demand, maximum 15-min demand, maximum hourly demand, over a given number of months such as the last 12 months.)
3. How will a demand-based system cap be defined for a customer without historical usage data?

- The VODER Study states customers could be incentivized to overestimate their demand to maximize the system size installed under a demand-related cap.
4. How do changes in system ownership that result in considerable changes in customer demand impact a customer-specific and demand-related cap?

- The VODER Study states that customers demand can increase or decrease over time. For example, a business owner could have a 50-kW demand and install a 50-kW generator based on 100% of the demand. But a new customer that purchases the building may have a 25-kW demand, and the generator would be 200% of the demand.
Section 10 Other Areas

Section 10.1 Billing Structure

Section 10.1.1 Evaluation of Bill Components

- The financial credit can be used on any expenses the customer may incur from Idaho Power
Section 10.1 Billing Structure

Section 10.1.2.1 Review of Accumulated kWh Credits

• 2021 17.1 million kWh accumulated
• Annual growth rate of 66% since 2014
• To determine the amount of financial credits from accumulated kWh
  1. Estimate kWh used over the next year (Left a balance of 7.5 million kWh)
  2. Used the average by class for financial benefit
     • This leads to a value of $548,675
  3. Used a sales based adjustment and FCA adjustment
     • Ends to a value of $290,116
Section 10.1 Billing Structure (cont’d)

Section 10.1.2.2 Review of Expiration of Accumulated kWh Credits

- Could have all excess kWh credits expire when converted to financial credits
- Valuing these would require a flat ECR.
  - Does not know when these credits were accrued
  - Therefore, variable rates would be impossible
Section 10.1 Billing Structure (cont’d)

Section 10.1.3 Review of Expiration of Accumulated kWh Credits.

• Can let customers transfer financial credits from one account to another owned by the same customer.

• Proposes to only allow application in January of each year to transfer credits.
Section 10.2 Access to Data

- Info is available on Idaho power’s website.
  - Hourly Usage rates
  - Solar energy information
  - Links to PV watts
  - Sample payback info
  - Interconnection requirements
Section 11 Implementation Considerations

• Transitional Rates:
  • Study does not include or propose any specific proposal for implementation.
  • Parties, public, stakeholders, and Staff can submit input on proper implementation.
  • Transition to ECR could be over a given number of years.

• Administrative Updates and Communication Materials:
  • System Changes.
  • Tariff Changes.
  • Customer Communication.
  • Installer Communication.
Review Process

What is next?

• Staff and other parties will continue to review the Application, VODER Study, workpapers, and production request responses.

• Will submit written comments that will outline position on:
  • Proposed VODER Study.
Review Process

What is next?

• Formal Hearings.
  • IDAPA 31.01.01.241.04
  • Customer Hearing.
  • Location, Date, and time have not been noticed.

• Commission will deliberate and issue an Order.
CUSTOMER COMMENTS

Customer written comments are due no later than **October 12, 2022**
(Reference Case Number IPC-E-22-22)

- Internet Website Address – www.puc.idaho.gov
  - Select - Case Comment Form
    (ONCE COMMENTS ARE SUBMITTED, THEY BECOME PART OF PUBLIC RECORD)
  
- Email Address – secretary@puc.idaho.gov

- Mail – IPUC, PO Box 83720, Boise, ID 83720-0074

- Public or Customer Hearing – TBD

COMMENTS ONLY
(QUESTIONS WILL NOT BE ADDRESSED)
CASE COMMENT FORM
## CASE SCHEDULE

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STAFF SECOND WORKSHOP

WEDNESDAY, SEPTEMBER 7, 2022, 12:30 PM

- Call: 1-415-655-0001, and enter 2456 391 6010
- Watch: idahogov.webex.com, enter 2456 391 6010
  - Password: 0907Workshop

CUSTOMER COMMENTS

- Continue to provide written comments
- Reference Case Number IPC-E-22-22
  - Website – www.puc.idaho.gov
  - Email Address – secretary@puc.idaho.gov
  - Mail – IPUC, PO Box 83720, Boise, ID 83720-0074
You can find case information and file comments on the PUC website

www.puc.idaho.gov

Case Number: IPC-E-22-22