Idaho Power’s Transmission System

Greg Travis
Nov. 8, 2018
Presentation Outline

• Acronyms and definitions
• Energy Imbalance Market (EIM)
• Idaho Power’s transmission system
• Path 14 ID-NW
• Open discussion
Acronyms and Definitions

- **ATC**: Available Transmission Capacity
  - Long-term firm transmission capacity not previously allocated

- **Transmission path**:
  - A single transmission line or multiple adjacent lines.

- **Transmission contingencies**:
  - **N-1**: Loss of any single element
  - **Credible N-2**: Loss of two elements with a significant probability of occurrence (common structure)

- **WECC**: Western Electricity Coordinating Council
  - Regional Reliability Organization and Compliance Monitor as defined by the North American Electric Reliability Corporation (NERC)
Western Transmission System
Southern Idaho System Overview

Path 14
Idaho-Northwest
Import ATC = 0 MW

Path 55
Brownlee East

Path 17
Sierra - Idaho
Import ATC = 0 MW

Path 18
Montana – Idaho
Import ATC = 0 MW

Path 19
Bridger West
Import ATC = 86 MW

Path 20
Path C

ATC = 26 MW
Path 14
Idaho—Northwest

Existing Path 14
1,200 MW

Rebuild alternative
1,965 MW

New line (B2H)
2,250 MW
Summary

• The EIM is beneficial and Transmission makes it possible.
• Idaho Power’s transmission system is highly reliable providing operational flexibility and access to a diverse pool of resources.
• However, there is very little ATC.
• Increasing transmission capacity to the Northwest is a good option moving forward.
Open Discussion
Boardman to Hemingway Transmission Line Project

IRPAC, November 2018
PROJECT OVERVIEW

• 500 kV transmission line

• 500 MW summer, 200 MW winter

• Connecting SW Idaho with Mid-C market

• Proposed by Idaho Power along with permitting partners (PacifiCorp, BPA)
PURPOSE & NEED

✓ Least-cost, least-risk resource

➢ 5 IRPs in a row

✓ Provide energy for customers across Mountain West and Pacific Northwest

✓ Flexibility: able to accommodate future changes in technology
COSTS

• Total cost to date is ~$99 million

• Total cost estimate is $1 to 1.2 billion, includes:
  • Permitting
  • Engineering
  • Construction
  • Substations
  • 20% contingency
  • Idaho Power AFUDC
BENEFITS
✓ Provide energy, reliability, and resource flexibility
✓ Low operational costs
✓ Increased access to robust market hub
  ➢ Operating B2H is carbon neutral
✓ Remove constraints on the existing grid
✓ Regional efficiency and economic transferability
Idaho-Northwest Transmission Path
B2H Increases Available Capacity for IPC by 500 MW summer/200 MW winter
Process & Milestones

Federal Process
- 2008: Scoping Period
- 2009: Scoping Period
- 2011: Draft EIS
- 2018: Navy Record of Decision
- 2019: USFS Record of Decision

State Process
- 2008: Notice of Intent
- 2010: Project Order
- 2011: pASC Submitted
- 2012: Amended pASC Submitted
- 2013: ASC Deemed Complete
- 2014: Proposed Order
- 2015: Draft Proposed Order
- 2016: Final Order & Site Certificate

Pre-Construction & Construction
- 2017: Purchase Clearances
- 2018: Start Construction
- 2020: B2H In-Service

* Formal opportunities for public comment
ACHIEVEMENTS

✓ BLM review and routing process completed
  • Navy and USFS decisions expected soon

✓ Oregon DOE application deemed complete

✓ Outreach to landowners along project

✓ Outreach with stakeholders continues...
  • mitigation and micro-siting
THANK YOU!

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2019 IRP Supply-Side Resources
IRP Resource Options

- Solar PV—Single-axis tracking, utility scale
- Solar PV—Residential and commercial rooftop
- Lithium battery
- Zinc-Bromine flow battery
- Wind—Idaho and Wyoming
- Geothermal
- Reciprocating engines (natural gas)
- Simple-cycle combustion turbine (SCCT) (natural gas)
- Combined-cycle combustion turbine (CCCT) (natural gas)
- Pumped-storage hydro
- Nuclear—Small modular reactor (SMR)
- Small hydro
Solar PV
Utility-Scale, Single-Axis Tracking

- Seasonally correlated with load (summer)
- Zero variable costs
- Capital costs trending downward
- Renewable
- Scalable
- Annual capacity factor (CF) = 26%*
  - June–July CF = 41%
  - Dec–Jan CF = 9%
- Seasonally uncorrelated with load (non-summer)
- Uncertain
- Variable
- Project-to-project correlation

*Note: Solar PV CF data from NREL PVWatts, Mt. Home, Idaho site
Utility-Scale Solar PV Capital Costs

$/kW_AC (2016$)

2019  2021  2023  2025  2027  2029  2031  2033  2035  2037

Source: NREL 2018 ATB, Mid Technology Cost Scenario
Utility-Scale Solar PV Capital Costs

Source: NREL 2018 ATB, Mid Technology Cost Scenario
Utility-Scale Solar PV Capital Costs

$800  $900  $1,000  $1,100  $1,200  $1,300  $1,400

$/kW_AC (2016 $)

Source: NREL 2018 ATB, Mid Technology Cost Scenario

Fixed O&M = ±$9/kW year
Zero variable costs
Useful life = 25 years
Lithium Battery—Capital Costs

Assumed round-trip efficiency = 85–90%
Useful life = 10 years
Fixed O&M = ±$8/kW year
Variable O&M = ±$2/MWh

Source: NREL 2018 ATB
Zn–Br Flow Battery—Capital Costs

Assumed roundtrip efficiency = 65–70%
Useful life = 20 years
Fixed O&M = $12.75/kW year

Source: Lazard’s Levelized Cost of Storage—Version 3.0 (Nov. 2017)
Utility-Scale Solar PV and Battery

- 40 MW single-axis solar PV
- 10 MW/40 MWh lithium battery
- DC coupled—ITC eligible
- Fixed O&M = ±$9/kW year
- Var O&M = ±$2/MWh on battery output

Source: NREL 2018 ATB, Mid Technology Cost Scenario
Rooftop Solar PV Capital Costs

$/kW_AC (2016 $)

- Residential
- Commercial

Source: NREL 2018 ATB, Mid Technology Cost Scenario

- Fixed O&M (res) = ±$10/kW year
- Fixed O&M (comm) = ±$9/kW year
- Zero variable costs
- Useful life = 25 years
- Annual CF = 21%
Wind

- Less project-to-project correlation than solar
- Zero variable costs
- Capital costs trending downward
- Renewable
- Wyoming
  - High production (CF ~ 45–50%)
  - Distance from load (i.e., transmission expense)
  - Potential use of Idaho–Wyoming transmission path with retirement of Jim Bridger unit(s)
- Idaho
  - Lower production (CF ~ 25–30%)
  - Closer to load
- Zero or negative correlation with load
- Uncertain
- Variable
Wind—Capital Costs

Source: NREL 2018 ATB, Mid Technology Cost Scenario, Wyoming—Techno-Resource Group (TRG) #1, Idaho—TRG #7
Geothermal

Source: NREL 2018 ATB, Mid Technology Cost Scenario, Hydrothermal binary resource

Fixed O&M = $169/kW year
Annual CF = 85–90%
Zero variable costs
## Natural Gas Generation

<table>
<thead>
<tr>
<th>Technology</th>
<th>Overnight Capital Cost ($/kW)</th>
<th>Fixed O&amp;M ($/kW-year)</th>
<th>Variable O&amp;M ($/MWh)</th>
<th>Heat Rate (Btu/kWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>CCCT (300 MW)</td>
<td>$1,027</td>
<td>$10.40</td>
<td>$2.70</td>
<td>6,420</td>
</tr>
<tr>
<td>SCCT (170 MW)</td>
<td>$873</td>
<td>$12.00</td>
<td>$7.00</td>
<td>9,720</td>
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<tr>
<td>Reciprocating engines (3 x 18.5 MW)</td>
<td>$930</td>
<td>$12.00</td>
<td>$5.10</td>
<td>8,300</td>
</tr>
<tr>
<td>Reciprocating engines (6 x 18.5 MW)</td>
<td>$830</td>
<td>$12.00</td>
<td>$5.10</td>
<td>8,300</td>
</tr>
</tbody>
</table>

*Sources: Vendor and NREL 2018 ATB, Mid Technology Cost Scenario*
## PS Hydro, SMR, and Small Hydro

<table>
<thead>
<tr>
<th>Technology</th>
<th>Overnight Capital Cost ($/kW)</th>
<th>Fixed O&amp;M ($/kW year)</th>
<th>Variable O&amp;M ($/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pumped-storage hydro (500 MW/4000 MWh)</td>
<td>$1,800</td>
<td>$4.00</td>
<td>$0</td>
</tr>
<tr>
<td>Nuclear SMR (60 MW)</td>
<td>$4,200</td>
<td>$8.00</td>
<td>$2.00</td>
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<tr>
<td>Small hydro</td>
<td>$3,700–7,300</td>
<td>±$70</td>
<td>$0</td>
</tr>
</tbody>
</table>

Sources: Vendor and NREL 2018 ATB
2019 IRP Updated Portfolio Process
Portfolio Design Process
2017 vs. 2019 IRP

2017 IRP

- Manually:
  - Design portfolios
  - Identify specific deficits
  - Evaluate portfolio sufficiency
  - Calculate fixed costs
  - Combine fixed and variable costs

- Excel-based monthly evaluation under adverse weather

- Model variable costs in Aurora

2019 IRP

- Aurora-generated portfolios
- Fixed and variable costs
- Long-term WECC optimization (LT)
  - Initial NG and CO₂ case portfolios
  - Additional coal unit retirement portfolios
# Peak-Hour Capacity Planning Criteria

## 2017 IRP
- 95\textsuperscript{th}-percentile monthly peak hour
- 90\textsuperscript{th}-percentile hydro inflow condition

## 2019 IRP
- 15\% capacity margin peak hour
- 50\textsuperscript{th}-percentile hydro inflow condition
Energy Planning Criteria

2017 IRP
- 70th-percentile monthly average
- 70th-percentile hydro inflow condition

2019 IRP
- 50th-percentile hourly energy
- 50th-percentile hydro inflow conditions
Flexibility Planning Criteria

2017 IRP

• Qualitative assessment of need and new resource contribution

2019 IRP

• Hourly up and down regulating reserve calculated
  – Per 2018 Variable Energy Resource Study
  – Hourly generation forecast basis

• Resources carry specific regulation requirements

• Load net wind and solar
Aurora adds resources to:
1. Meet capacity planning margin (15%)
2. Flexible capacity requirements
3. Energy requirements

Aurora selects among resource options to add or remove based on:
1. Cost
2. Peak-hour capacity
3. Flexible capacity
4. Energy
2018 Variable Energy Resource Study

- NERC BAL-001-2 Standard
  - Rolling 30-minute balance requirement
- 2017 system data analyzed
  - Load and generation one-minute time step
  - Forecast two-hour ahead
- Reserve definitions seasonally calculated
- load net wind and solar