Design and Valuation of High-Capacity HVDC Transmission to Connect Eastern and Western US Electric Grids

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Acknowledgements

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Ali Jahanbani-Ardakani
Abhinav Venkatraman
PART 1
• Introduction
• Data, assumptions, and tools
  ➔ Co-optimized expansion planning application GTD-Plan
• Design concepts and results
• Sensitivities

PART 2: A conclusion
• Non-quantified benefits
• Path forward
Introduction
North American HVDC Interconnection Seam Study:
A regional partnership funded by the
U.S. DOE’s Grid Modernization Initiative, 3/16-8/18

STUDY PARTICIPANTS

- National Renewable Energy Lab (NREL)
- Pacific Northwest National Lab (PNNL)
- Oak Ridge National Lab (ORNL)
- Argonne National Lab (ANL)
- Iowa State University (ISU)
- Southwest Power Pool (SPP)
- Mid-Continent ISO (MISO)
- Western Area Power Authority (WAPA)
- Western Electric Coordinating Council (WECC)

Technical Review Committee

Alberta Independent System Operator
Basin Electric Power Company
Black Hills Energy
Energy Exemplar
El Paso Electric
Electric Power Research Institute
Electric Reliability Council of Texas
Great River Energy
Hydro Quebec
Independent System Operator of Ontario
LS Power
Manitoba Hydro
Minnesota Power
National Grid
National Rural Electric Cooperative Association
NB Power
NextEra
NS Power
Public Service of New Mexico
SaskPower
Solar Energy Industry Association
TransCanyon
Tri-State Generation and Transmission
Utility Variable Integration Group
Western Electric Coordinating Council
Western Electric Coordinating Council
Xcel Energy

Disclaimer: Results/conclusions/perspectives communicated in this webinar are those of ISU researchers and are not necessarily embraced by any study participant or technical review committee member organization.
Introduction
There has been interest for a long time!

1923
Tying the Seasons to Industry

-Chicago Tribune

1952
Super Transmission System

-Bureau of Reclamation

1979
Interconnection of the Eastern and Western Grids

-Bonneville Power Administration

1994
East/West AC Intertie Feasibility Study

-Western Area Power Admin

“This is neither prophecy, propaganda, nor rhapsody, but the assured goal of scientific and economic forces at work.”
- Chicago Tribune, 1923

“Such a power system will inevitably come.”
- Bureau of Reclamation, 1952

“If power transfers of over 500 MW would result in significant benefits, the feasibility of the interconnection should be pursued.”
- BPA, 1979

“The systems as they exist today…are more robust than…the late 1960s and 1970s.”
- WAPA, 1994
Introduction

If it looked good in the past, what about today?

The Impact of
Weather is Greater

Daily patterns drive demand and supply

Energy Needs and Supply Change with the Seasons

Unimaginable computing

New Technologies

- Parallel computing environments, complex algorithms, and artificial intelligence offer new capabilities.
- 100,000 node transmission models can be simulated for an entire year, in a single day.
- The dawn of Exa-scale computing

Wind
Solar PV
HVDC
HVAC
Some recent proposals and studies


Introduction

Midwestern wind with large loads at coasts.
Little transmission to the east; almost none to the west.

Solar potential is in the south, but better in SW than SE.

High western solar at hour 8am or 3pm could contribute to eastern peaks at 11am or 6 pm.
Introduction

Given a high-renewable future for electric energy production, what is the economic value of increasing cross-seam transmission?

Today’s existing 1.4 GW (very little) back-to-back (B2B) HVDC

Rationale: Cost of the transmission build is significantly exceeded by direct economic energy & capacity savings due to:

1. **Resource quality**: reduced $/MWhr for wind/solar (accessing high-quality renewables)
2. **Daily energy**: lower cost of daily energy & op. reserves (sharing across time zones)
3. **Peaking capacity**: reduced capacity-build for planning reserves (sharing between regions peaking on different days of the year)
## Data, assumptions, and tools

Research-grade and commercial tools

<table>
<thead>
<tr>
<th>Tool</th>
<th>Assumptions/Features</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>CGTD-Plan (ISU)</strong></td>
<td>• Capital/operating costs 2024-2038</td>
</tr>
<tr>
<td></td>
<td>• Gen/transmission system 2038</td>
</tr>
<tr>
<td><strong>PLEXOS</strong></td>
<td>• Operating costs 2038</td>
</tr>
<tr>
<td></td>
<td>• Hourly unit commitment and economic dispatch</td>
</tr>
<tr>
<td><strong>PSSE</strong></td>
<td>• Preliminary analysis of AC power flow impacts</td>
</tr>
</tbody>
</table>
Data, assumptions, and tools

Consistent data between modeling domains

• Solar: 2012 NSRDB [https://nsrdb.nrel.gov/](https://nsrdb.nrel.gov/)
• Transmission and Generation:
  – WECC TEPPC 2024-Western Interconnection
  – MMWG 2026-Eastern Interconnection
• Load: 2012 FERC Form 714 and RTOs

Other data sources:

• Fuel cost forecasts according to AEO 2017 (med-gas)
• Demand growth per NEEM & E3 (WI) per state
• Gen investment base costs & maturation rates from NREL ATB ‘16
• Transmission base costs according to EIPC/B&V
• Gen & trans regional cost multipliers from EIPC/WECC
Data, assumptions, and tools

Key Assumptions for Expansion Planning Studies

- DG growth per AEO 2016, 3% per yr
- O&M/investment costs assessed at NPV w/ real DR=5.7%.
- Gen capacity investment limited to 40GW/yr
- Run for 15 yrs w/ 7 investment periods (every other yr)
- Retire gen unit if zero energy or reserves contribution
- Spur transmission cost approximated based on distance from wind/solar site to closest bus
Data, assumptions, and tools

Reduction and translation

- Full EI model, 2024
- Full WI model, 2024
- Full EI model, 2038
- Full WI model, 2038

Reduction Method 1

Red EI model, 2024

Reduction Method 2

Red WI model, 2024

CEP-to-PCM translation for 2038: TEP formulation

2038 generation investments & retirements

2038 T&G investments/retirements

98000 buses

CGT-Plan

Red EI/WI model, 2024-2038

68 buses

101 buses

169 buses

98000 buses
Data, assumptions, and tools

\( \rightarrow \) Co-optimized expansion planning application GTD-Plan

\[ \text{MIN NET PRESENT VALUE} \]

\[ \begin{align*}
\text{GTD Investment costs} \\
+ \text{Fixed O&M Costs} \\
+ \text{Var O&M Costs + Fuel Costs} \\
+ \text{Demand Response/EE Cost} \\
+ \text{Environmental Costs}
\end{align*} \]

WITH ASSUMPTIONS ON THE FUTURE...
investment costs, load growth, fuel cost, wind, solar, hydro performance

SUBJECT TO CONSTRAINTS ON:
network, operations, investments, environmental

| Year 1 | Year 2 | \( \cdots \) | Year 15 |

\( \rightarrow \) Identifies GTD investments (what, when, where, how much) to minimize NPV of investments + operations over 15-yr period
Data, assumptions, and tools

Co-optimized expansion planning application GTD-Plan

MENTAL IMAGE

D-Amount
D-Timing
G-Timing
T-Technology
T-Amount
T-Timing
G-Location
G-Amount
D-Technology
T-Location

A future plan

RUN PROD COST SIM OVER ENTIRE 15 YRS.

DC POWER FLOW EQTS ENFORCED.

Is total cost < best plan so far?
Data, assumptions, and tools

Flexibility constraints

1. Regulation reserves, RU, RD

\[ \sum_{k \in \text{Thermal, Hydro}} RU_k > f\left( \sigma^{1 \text{ min,up}}_{\text{NetLoad}} \right) \]

\[ \sum_{k \in \text{Thermal, Hydro}} RD_k > f\left( \sigma^{1 \text{ min,down}}_{\text{NetLoad}} \right) \]

2. Contingency reserves, CR

\[ \sum_{k \in \text{Thermal, Hydro}} CR_k > \Delta P_{\text{Max}} \]

These constraints imposed system-wide. They are valued at each unit’s cost to supply energy.
Data, assumptions, and tools

Development of operating blocks

8760 hr profiles of wind, hydro, solar, load

- Blocks defined by time-of-day
- Wind, hydro, solar dispatched up to per-unit gen based on VOM

19 op blocks/yr: semi-chronological - captures avg diurnal & seasonal variations of wind, solar, hydro, and load.
Data, assumptions, and tools

Annual planning reserves

Northwest Annual Peak
Jan 3 @ 10pm EST
4 additional 1-hour blocks
Each represents a regional peak
All load scaled by 1.15
Peaking resources at capacity value
Nonpeaking resources at capacity factor

Midwest Annual Peak
Aug 3 @ 5pm EST

Southwest Annual Peak
Aug 11 @ 11pm EST

East Annual Peak
Aug 21 @ 5pm EST
Design concepts

Design 1: No CS Transmission

Design 2a: Upgrade existing

Design 2b: Upgrade existing + 3 lines

Design 3: Macrogrid

- 3 line design with B2B investments allowed.
- Lines must have equal capacity.

<table>
<thead>
<tr>
<th>Renewables</th>
<th>State RPS</th>
<th>CO₂ cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>40%</td>
<td>Enforced</td>
<td>Zero</td>
</tr>
<tr>
<td>50%</td>
<td>Not enforced</td>
<td>Increases at $3/mton/yr</td>
</tr>
</tbody>
</table>
Results: 40% renewables, 2024-2038

<table>
<thead>
<tr>
<th>ECONOMICS, NPV SB</th>
<th>Design 1</th>
<th>Design 2a</th>
<th>Delta</th>
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<th>Design 3</th>
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</tr>
</thead>
<tbody>
<tr>
<td>Line Investment Cost</td>
<td>23.50</td>
<td>26.69</td>
<td>3.19</td>
<td>31.50</td>
<td>8.00</td>
<td>37.70</td>
<td>14.20</td>
</tr>
<tr>
<td>Generation Investment Cost</td>
<td>493.60</td>
<td>494.70</td>
<td>1.10</td>
<td>492.50</td>
<td>-1.10</td>
<td>494.20</td>
<td>0.60</td>
</tr>
<tr>
<td>Fuel Cost</td>
<td>855.10</td>
<td>852.70</td>
<td>-2.40</td>
<td>851.20</td>
<td>-3.90</td>
<td>845.60</td>
<td>-9.50</td>
</tr>
<tr>
<td>Fixed O&amp;M Cost</td>
<td>416.40</td>
<td>415.60</td>
<td>-0.80</td>
<td>413.70</td>
<td>-2.70</td>
<td>413.80</td>
<td>-2.60</td>
</tr>
<tr>
<td>Variable O&amp;M Cost</td>
<td>81.00</td>
<td>81.10</td>
<td>0.10</td>
<td>81.20</td>
<td>0.20</td>
<td>81.20</td>
<td>0.20</td>
</tr>
<tr>
<td>Carbon Cost</td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
</tr>
<tr>
<td>Regulation-Up Cost</td>
<td>31.60</td>
<td>30.97</td>
<td>-0.63</td>
<td>31.13</td>
<td>-0.47</td>
<td>30.02</td>
<td>-1.58</td>
</tr>
<tr>
<td>Regulation-Down Cost</td>
<td>45.10</td>
<td>44.20</td>
<td>-0.90</td>
<td>44.42</td>
<td>-0.68</td>
<td>42.85</td>
<td>-2.26</td>
</tr>
<tr>
<td>Contingency Cost</td>
<td>23.90</td>
<td>23.42</td>
<td>-0.48</td>
<td>23.54</td>
<td>-0.36</td>
<td>22.71</td>
<td>-1.20</td>
</tr>
<tr>
<td>Total Non-Xm Cost (Orange)</td>
<td>1947.01</td>
<td>1943</td>
<td>-4.01</td>
<td>1937.7</td>
<td>-9.01</td>
<td>1930.38</td>
<td>-16.34</td>
</tr>
<tr>
<td>15-yr B/C Ratio (Orange/Blue)</td>
<td>1.26</td>
<td>1.13</td>
<td>1.15</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

The below row provides annualized (over 20 yrs) perpetuity cost for the CP designs. Interpretation is that CP designs 2a, 2b, & 3 will see the above 15-year B/C plus a savings each year over 20 years equal to the annualized perpetuity cost in yellow.

<table>
<thead>
<tr>
<th>CAPACITY, GW</th>
<th>Design 1</th>
<th>Design 2a</th>
<th>Delta</th>
<th>Design 2b</th>
<th>Delta</th>
<th>Design 3</th>
<th>Delta</th>
</tr>
</thead>
<tbody>
<tr>
<td>Perpetuity (Annualized 20-yr) Cost</td>
<td>72.32</td>
<td>70.88</td>
<td>-1.45</td>
<td>69.94</td>
<td>-2.39</td>
<td>68.71</td>
<td>-3.62</td>
</tr>
<tr>
<td>Total gen invested (W/S/G)</td>
<td>461 (225/209/27)</td>
<td>459 (229/202/28)</td>
<td>-2.0 (7/-4/1)</td>
<td>458 (232/201/25)</td>
<td>-5.0 (10/-3/-3)</td>
<td>465 (230/209/26)</td>
<td>4.0 (8/-3/-1)</td>
</tr>
<tr>
<td>Total gen retired</td>
<td>202</td>
<td>212</td>
<td>10</td>
<td>226</td>
<td>14</td>
<td>222</td>
<td>20</td>
</tr>
<tr>
<td>Total 2038 creditable capacity</td>
<td>857.5</td>
<td>846</td>
<td>-11.5</td>
<td>822.5</td>
<td>-35</td>
<td>830.1</td>
<td>-27.4</td>
</tr>
<tr>
<td>Total AC Xm invested</td>
<td>92</td>
<td>95</td>
<td>3</td>
<td>89</td>
<td>-3</td>
<td>84</td>
<td>-8</td>
</tr>
<tr>
<td>Total DC Xm invested</td>
<td>0</td>
<td>7</td>
<td>7</td>
<td>20</td>
<td>20</td>
<td>58</td>
<td>58</td>
</tr>
</tbody>
</table>
### Results: 40% renewables, 2024-2038, Designs 1, 3

<table>
<thead>
<tr>
<th>Billion $</th>
<th>Design 1</th>
<th>Design 3</th>
<th>Δ</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Total Line Investment</strong></td>
<td>23.5</td>
<td>37.7</td>
<td>+14.2</td>
</tr>
<tr>
<td><strong>Gen Investment</strong></td>
<td>493.6</td>
<td>494.2</td>
<td>+0.6</td>
</tr>
<tr>
<td><strong>O&amp;M</strong></td>
<td>1453.1</td>
<td>1436.2</td>
<td>-16.9</td>
</tr>
<tr>
<td><strong>15-yr B/C Ratio (orange/blue)</strong></td>
<td>-</td>
<td>-</td>
<td>1.15</td>
</tr>
</tbody>
</table>

### GenRelatedSavings

\[
\frac{\Delta O&M + \Delta GenInv}{\Delta Trans} = \frac{16.9 - 0.6}{14.2} = 1.15
\]

- **Gen inv don’t change** (locations do!)
- **DC reduces AC inv**
- **DC retires more gen & reduces cred cap…due to reserve sharing.**

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<th>Capacity (GW)</th>
<th>Design 1</th>
<th>Design 3</th>
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</tr>
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<tbody>
<tr>
<td><strong>Invested AC transmission</strong></td>
<td>92</td>
<td>84</td>
<td>-8</td>
</tr>
<tr>
<td><strong>Invested DC transmission</strong></td>
<td>0</td>
<td>58</td>
<td>58</td>
</tr>
<tr>
<td><strong>Total invested gen (wind, solar, gas),</strong></td>
<td>461</td>
<td>465</td>
<td>4</td>
</tr>
<tr>
<td><strong>(225/209/27)</strong></td>
<td>(230/209/26)</td>
<td>(8/-3/1)</td>
<td></td>
</tr>
<tr>
<td><strong>Retired generation</strong></td>
<td>202</td>
<td>222</td>
<td>20</td>
</tr>
<tr>
<td><strong>2038 creditable capacity</strong></td>
<td>857</td>
<td>830</td>
<td>-27</td>
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# Results: 50% renewables, 2024-2038

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<tbody>
<tr>
<td>Line Investment Cost</td>
<td>61.21</td>
<td>73.89</td>
<td>12.68</td>
<td>74.88</td>
<td>13.67</td>
<td>80.1</td>
<td>18.89</td>
</tr>
<tr>
<td>Generation Investment Cost</td>
<td>704.03</td>
<td>703.32</td>
<td>-0.71</td>
<td>696.99</td>
<td>-7.04</td>
<td>700.51</td>
<td>-3.52</td>
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<tr>
<td>Fuel Cost</td>
<td>753.8</td>
<td>738.98</td>
<td>-14.82</td>
<td>737.3</td>
<td>-16.5</td>
<td>736.12</td>
<td>-17.68</td>
</tr>
<tr>
<td>Fixed O&amp;M Cost</td>
<td>455.6</td>
<td>450.2</td>
<td>-5.4</td>
<td>448.95</td>
<td>-6.65</td>
<td>450.23</td>
<td>-5.37</td>
</tr>
<tr>
<td>Variable O&amp;M Cost</td>
<td>64.5</td>
<td>63.9</td>
<td>-0.6</td>
<td>64.27</td>
<td>-0.23</td>
<td>64.39</td>
<td>-0.11</td>
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<tr>
<td>Carbon Cost</td>
<td>171.1</td>
<td>164.2</td>
<td>-6.9</td>
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<td>33.29</td>
<td>31.63</td>
<td>-1.66</td>
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<td>-3.33</td>
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<td>-6.66</td>
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<tr>
<td>Regulation-Down Cost</td>
<td>4.76</td>
<td>4.52</td>
<td>-0.24</td>
<td>4.29</td>
<td>-0.47</td>
<td>3.81</td>
<td>-0.95</td>
</tr>
<tr>
<td>Contingency Cost</td>
<td>24.41</td>
<td>23.19</td>
<td>-1.22</td>
<td>21.97</td>
<td>-2.44</td>
<td>19.52</td>
<td>-4.89</td>
</tr>
<tr>
<td>Total Non-Xm Cost (Orange)</td>
<td>2,211.49</td>
<td>2,179.94</td>
<td>-31.55</td>
<td>2,166.33</td>
<td>-45.16</td>
<td>2,163.71</td>
<td>-47.78</td>
</tr>
</tbody>
</table>

15-yr B/C Ratio (Orange/Blue)   | -          | -          | 2.48     | -          | 3.30     | -          | 2.52     |

The below row provides annualized (over 20 yrs) perpetuity cost for the CP designs. Interpretation is that CP designs 2a, 2b, & 3 will see the above 15-year B/C plus a savings each year over 20 years equal to the annualized perpetuity cost in yellow.

| Perpetuity (Annualized 20-yr) Cost | 72.32 | 70.88 | -1.37 | 69.94 | -2.51 | 68.71 | -4.19 |

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<tbody>
<tr>
<td>Total gen invested (W/S/G)</td>
<td>600 (386/177/37)</td>
<td>600 (392/172/36)</td>
<td>0 (-6/5/1)</td>
<td>600 (393/172/35)</td>
<td>0 (7/-5/-2)</td>
<td>600 (392/169/38)</td>
<td>0 (7/-6/1)</td>
</tr>
<tr>
<td>Total gen retired</td>
<td>240</td>
<td>285</td>
<td>45</td>
<td>287</td>
<td>47</td>
<td>294</td>
<td>54</td>
</tr>
<tr>
<td>Total 2028 creditable capacity</td>
<td>838.5</td>
<td>809.5</td>
<td>-29.0</td>
<td>792.0</td>
<td>-46.5</td>
<td>794.1</td>
<td>-44.4</td>
</tr>
<tr>
<td>Total AC Xm invested</td>
<td>228.9</td>
<td>251.3</td>
<td>22.4</td>
<td>234.8</td>
<td>-5.9</td>
<td>195.1</td>
<td>-33.8</td>
</tr>
<tr>
<td>Total DC Xm invested</td>
<td>0</td>
<td>25.6</td>
<td>25.6</td>
<td>35.9</td>
<td>35.9</td>
<td>125.8</td>
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</tr>
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## Results: 50% renewables, 2024-2038, Designs 1, 3

<table>
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<tr>
<th></th>
<th>Design 1</th>
<th>Design 3</th>
<th>Δ</th>
</tr>
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<tbody>
<tr>
<td><strong>Total Line Investment</strong></td>
<td>62.2</td>
<td>80.1</td>
<td>+18.9</td>
</tr>
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<td><strong>Gen Investment</strong></td>
<td>704.0</td>
<td>700.5</td>
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<td><strong>O&amp;M</strong></td>
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<td><strong>15-yr B/C Ratio (orange/blue)</strong></td>
<td>-</td>
<td>-</td>
<td>2.52</td>
</tr>
</tbody>
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### Gen Related Savings

$$\text{GenRelatedSavings} = \frac{\Delta O&M + \Delta \text{GenInv}}{\Delta \text{Trans}} = \frac{44.4 + 3.5}{18.9} = 2.52$$

- **Capacity (GW)**
  - **Invested AC transmission**: 228.9 - 195.1 = -33.8
  - **Invested DC transmission**: 0 - 125.8 = -125.8
  - **Total invested gen (wind, solar, gas)**: (600 / 600 / 0) = (386/172/36) - (392/169/38) = (7/-6/1)
  - **Retired generation**: 240 - 294 = -54
  - **2038 creditable capacity**: 838.5 - 794.1 = -44.4

DC reduces AC inv
Gen inv don’t change (locations do!)
DC retires more gen & reduces cred cap…due to reserve sharing.
Results: 40% renewable, 2024-2038

HVDC Investment

<table>
<thead>
<tr>
<th>Facility</th>
<th>MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>MC-ACDC</td>
<td>1774.7</td>
</tr>
<tr>
<td>RC-ACDC</td>
<td>915.8</td>
</tr>
<tr>
<td>STEGAL-ACDC</td>
<td>1493.6</td>
</tr>
<tr>
<td>SIDNEY-ACDC</td>
<td>848.8</td>
</tr>
<tr>
<td>LAMAR-ACDC</td>
<td>1021.3</td>
</tr>
<tr>
<td>BLACKWATER-ACDC</td>
<td>93.8</td>
</tr>
<tr>
<td>EDDYACDC</td>
<td>176.3</td>
</tr>
<tr>
<td>Cross-Tx. HVDC</td>
<td>3\times4779.0</td>
</tr>
<tr>
<td>TOTAL</td>
<td>20,661.3</td>
</tr>
</tbody>
</table>

B2B Facility

<table>
<thead>
<tr>
<th>Facility</th>
<th>MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>MC-ACDC</td>
<td>1634.9</td>
</tr>
<tr>
<td>RC-ACDC</td>
<td>1009.4</td>
</tr>
<tr>
<td>STEGAL-ACDC</td>
<td>1518.4</td>
</tr>
<tr>
<td>SIDNEY-ACDC</td>
<td>851.2</td>
</tr>
<tr>
<td>LAMAR-ACDC</td>
<td>1355.0</td>
</tr>
<tr>
<td>BLACKWATER-ACDC</td>
<td>114.5</td>
</tr>
<tr>
<td>EDDYACDC</td>
<td>198.9</td>
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<tr>
<td>TOTAL</td>
<td>6682.3</td>
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</tbody>
</table>

HVDC

<table>
<thead>
<tr>
<th>Capacity/segment</th>
<th>MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>TOTAL</td>
<td>57,915</td>
</tr>
</tbody>
</table>

Total HVDC path: 3920 miles

Total HVDC path: 7528 miles
Results: 50% renewable, 2024-2038

<table>
<thead>
<tr>
<th>B2B Facility</th>
<th>MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>MC-ACDC</td>
<td>2,636.4</td>
</tr>
<tr>
<td>RC-ACDC</td>
<td>3,387.6</td>
</tr>
<tr>
<td>STEGAL-ACDC</td>
<td>4,864.4</td>
</tr>
<tr>
<td>SIDNEY-ACDC</td>
<td>1,042.4</td>
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<tr>
<td>LAMAR-ACDC</td>
<td>7,298</td>
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<tr>
<td>BLACKWATER-ACDC</td>
<td>358.56</td>
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<tr>
<td>EDDYACDC</td>
<td>1,458.1</td>
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<td><strong>TOTAL</strong></td>
<td><strong>21,045</strong></td>
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</tbody>
</table>

<table>
<thead>
<tr>
<th>HVDC Investment</th>
<th>MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>MC-ACDC</td>
<td>1119.4</td>
</tr>
<tr>
<td>RC-ACDC</td>
<td>1389.0</td>
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<tr>
<td>STEGAL-ACDC</td>
<td>1681.9</td>
</tr>
<tr>
<td>SIDNEY-ACDC</td>
<td>1054.9</td>
</tr>
<tr>
<td>LAMAR-ACDC</td>
<td>2074.9</td>
</tr>
<tr>
<td>BLACKWATER-ACDC</td>
<td>34.4</td>
</tr>
<tr>
<td>EDDYACDC</td>
<td>138.4</td>
</tr>
<tr>
<td><strong>Cross-Tx. HVDC/line</strong></td>
<td><strong>3×9481.3</strong></td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td><strong>35,937</strong></td>
</tr>
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</table>

<table>
<thead>
<tr>
<th>HVDC</th>
<th>MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capacity/segment</td>
<td>8,389.5</td>
</tr>
<tr>
<td><strong>TOTAL HVDC</strong></td>
<td><strong>125,842</strong></td>
</tr>
</tbody>
</table>

Total HVDC path: 3920 miles

Total HVDC path: 7528 miles
Results: 50% renewable, 2024-2038

Cross-seam transm moves wind/gas eastward; solar westward
## Sensitivity to 50% case, Design 3

**Design 3: 50, 65, 74, & 85% renewables**

<table>
<thead>
<tr>
<th>% Renewable Penetration (energy)</th>
<th>7per, w/cap</th>
<th>2per, w/o cap</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>$3/mt/yr</td>
<td>$3/mt/yr</td>
</tr>
<tr>
<td>50%</td>
<td>50%</td>
<td>65%</td>
</tr>
<tr>
<td>Total gen invested (W/S/G), GW</td>
<td>600 (392/169/38)</td>
<td>792 (479/276/37)</td>
</tr>
<tr>
<td>Total gen retired, GW</td>
<td>294</td>
<td>348</td>
</tr>
<tr>
<td>Total AC Xm invested, GW</td>
<td>195</td>
<td>258</td>
</tr>
<tr>
<td>Cross-seam capacity, GW</td>
<td>25</td>
<td>23</td>
</tr>
</tbody>
</table>

Renewable pen cannot exceed 85% as higher requires more op-rsrvs than model has.

- Remaining 15% energy from nuclear & gas.
- All coal and oil, and some gas, are retired.
- AC Xm increases to facilitate wind/solar.
- Cross-seam Xm does not change much because 2nd-tier quality W/S being used.
1. B/C tracks cross-seam transmission capacity
2. Base condition is best, with B/C=2.5
3. All sensitivities invest > 10 GW
4. The no-sharing sensitivity has B/C ~ 0.9
5. Other four sensitivities have B/C > 1

⇒ Cross seam transmission pays for itself, + NQBs
Non-quantified benefits (NQBs)

- Post-2038 operational savings, 1-4$B/yr
- Additional reliability improvements via HVDC:
  - Improved system frequency response
  - Better local voltage control
- Efficient on/off-ramps nationwide making least-cost resources available at load centers, providing great flexibility for large changes in regional gen capacity
- National economic stimulus via 400,000 new jobs throughout 15 yr period
Improved reliability: trip Palo Verde (2700 MW)

Bus frequency in WECC and EI

Unassisted

Assisted

EI response

WI response

Path forward – Step 2a

140 attendees;
Website contains slides and video showing all presentations;
Available at:
https://register.extension.iastate.edu/transgridx/symposium-information/documents
Path forward – Step 2b

To address these concerns, we suggest the Commission, in cooperation with the U.S. Department of Energy, consider convening a series of meetings in partnership with the states, regional transmission organizations, members of Congress, and the private sector to discuss the Interconnection Seams Study and to identify the nation’s transmission needs, including integration of the nation’s major grids, as well as multi-state and inter-regional transmission challenges.

It is our hope that these proposed meetings will show how a unified transmission system could benefit our states’ economies — creating jobs and strengthening national security and resilience. A strong national transmission system will support the economic growth our states and the nation need.

Subject: Interconnection Seams Study

Members:
Arkansas  Kansas  Pennsylvania
California  Maryland  Rhode Island
Colorado  Massachusetts  South Dakota
Delaware  Minnesota  Virginia
Hawaii  Montana  Washington
Illinois  New York  Washington
Iowa  Oregon  Washington

https://governorswindenergycoalition.org/coalition-members/

Steve Bullock
Chair and
Governor of Montana

John Carney
Vice Chair and
Governor of Delaware

Jeff Colyer
Former Vice Chair and
Governor of Kansas

cc:
Hon. Lisa Murkowski, U.S. Senate Committee on Energy and Natural Resources
Hon. Maria Cantwell, U.S. Senate Committee on Energy and Natural Resources
Hon. Martin Heinrich, U.S. Senate Committee on Energy and Natural Resources
Hon. Greg Walden, U.S. House Committee on Energy and Commerce
Hon. Joe Barton, U.S. House Committee on Energy and Commerce
Hon. Rick Perry, U.S. Department of Energy
Hon. Francis Brooke, Special Assistant to the President
Path forward – Step 3

1. **Step 3a:** Additional studies (e.g., refine design): expansion planning, production cost, power flow, and dynamics.

2. **Step 3b:** Develop two oversight bodies:
   - Technical studies/design: the RTOs and utilities.
   - Regulatory issues: FERC and states.

3. **Last thought:** The thrust of the work presented is:
   
   Given a high renewables future, inter-market & cross-seam trading pays for itself in direct economic benefits plus additional significant (non-quantified) benefits in the form of
   - Post-2038 op savings;
   - Reliability
   - Flexibility to large changes in regional gen capacity
   - Economic stimulus

   But is a high renewable future (> 40% by energy) attractive?
It's now cheaper to build a new wind farm than to keep a coal plant running

BY IRINA IVANOVA
UPDATED ON: NOVEMBER 16, 2018 / 8:31 AM / MONEYWATCH

MidAmerican Energy News
Wind XII project positions MidAmerican Energy to hit 100 percent renewable goal

DES MOINES, Iowa – (May 30, 2018) – MidAmerican Energy Company will be the first investor-owned electric utility in the country to generate renewable energy equal to 100 percent of its customers' usage on an annual basis, upon completing its newest proposed wind energy project.

MidAmerican Energy proposed an additional investment of $922 million with the announcement of its Wind XII project that will be formally filed with the Iowa Utilities Board later today. The project, if approved, is expected to be completed in late 2021. Over the past three years, MidAmerican Energy has moved forward with its previously announced Wind XI and repowering projects, that when combined with Wind XII, will provide customers with 100 percent renewable energy on an annual basis. And, like MidAmerican’s previous wind projects, Wind XII will be accomplished without the need to ask for an increase in customers’ rates.

Xcel Resource Planning Executive: We Can Buy New Renewables Cheaper Than Existing Fossil Fuels

Jonathan Adelman discusses how the utility is setting an example in decarbonization ahead of his participation at the Power & Renewables Summit 2018.

JUAN MONDE | SEPTEMBER 11, 2018

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Questions?

James McCalley
(jdm@iastate.edu)
Transmission cost data

• Transmission investment base costs are used in conjunction with appropriate multipliers.
• EI:
  • 345 kV Single Circuit: $2,100,000/mile
  • 345 kV Double Circuit: $2,800,000/mile
  • 500 kV Single Circuit: $3,450,000/mile
  • 765kV AC single circuit: $5,550,000/mile
• WI:
  • 345 kV Single Circuit: $2,100,000
  • 345 kV Double Circuit: $2,800,000
  • 500 kV Single Circuit: $3,450,000
  • 800 kV, 6000 MW DC: $3,300,000/mile
  • LCC Converter: $472,000,000/terminal, VSC converter: $285,000,000/terminal
• Cost of upgrading existing B2B ties: $300,000/MW (2 converter stations).