Generation Interconnection and ELCC Values for Variable Resources

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PREPARED FOR
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   • 2021 capacity additions
   • ERCOT and the UK’s “Connect and Manage”

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3. Determination of ELCC for Variable Resources
Generation Interconnection: 2021 Capacity Additions

PJM, NYISO, and ISO-NE have interconnected significantly less renewable generation despite the regions’ significant renewable development gap.

<table>
<thead>
<tr>
<th>RTO Size</th>
<th>ERCOT</th>
<th>Outside ISO/RTO</th>
<th>MISO</th>
<th>PJM</th>
<th>SPP</th>
<th>CAISO</th>
<th>NYISO</th>
<th>ISO-NE</th>
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<td>80 GW</td>
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<td>5,328</td>
<td>5,082</td>
<td>4,629</td>
<td>2,425</td>
<td>1,656</td>
<td>359</td>
<td>341</td>
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<td>200 GW</td>
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<td>180 GW</td>
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Lawrence Berkeley National Lab
Estimated Renewables Development Gap

Data compiled Jan. 11, 2022.
* Includes hydro, biomass, oil, geothermal and energy storage capacity.
Source: S&P Global Market Intelligence

Substantial Differences in Generation Interconnection Processes

Generation interconnection processes and study criteria differ substantially across the regions:

- ERCOT’s generation interconnection process is generally seen as more effective
  - Efficient handoff of study roles by ERCOT and Transmission Owners limits restudy needs
  - Projects can be developed and interconnected within 2-3 years; in other regions, the interconnection study process itself takes longer than that
  - Upgrades focused more on local needs (similar to ERIS) and are recovered through postage stamp
  - Network constraints managed through market dispatch – which imposes higher congestion and curtailment risks on interconnecting generators but yields more efficient outcomes and risk sharing
  - See working-paper.pdf (enelgreenpower.com)  [Note: Brattle was not involved]

- Attractive: UK “Connect and Manage” (replaced prior “Invest and Connect”)
  - Similar to ERIS; reduced lead times by 5 years; network constraints addressed later (e.g., with congestion management)  https://www.gov.uk/guidance/electricity-network-delivery-and-access#connect-and-manage

- Generation interconnection study criteria matter, yet differ substantially across RTOs
  - PJM’s stringent study criteria tend to trigger more “deep network” upgrades, which increases churn and restudy requirements; will often be less cost effective than congestion management
Generation interconnection processes, studying one generator at a time, are ineffective in determining the most cost-effective transmission solutions. Pro-active planning is needed:

- **For example**: A review of PJM generation interconnection studies for 15.5 GW of individual offshore wind plants identified $6.4 billion in onshore transmission upgrades ($400/kW)

- **In contrast**: the recent PJM Offshore Wind Transmission Study that proactive evaluated all existing state public policy needs identified only $3.2 billion in onshore upgrades for over 75 GW of renewable resources (up to 17 GW of offshore wind, 14.5 GW of onshore wind, 45.6 GW of solar, and 7.2 GW of storage) ($40/kW)

- Upgrades also provide substantial PJM-wide economic benefits: reduced congestion, curtailments, emissions (App B)
ELCC for Variable Resources

How to determine ELCC for energy delivered over non-firm/energy-only injection rights?

- Several RTOs (MISO, PJM) are exploring how to determine the UCAP (capacity credits) of variable resources when only a portion of the transmission injection rights are “firm”
- It is reasonable that UCAP cannot exceed firm rights
  - But: by how much does energy delivered over non-firm transmission contribute to (or reduce) the ELCC of the resources?
- ELCC is a “probabilistic” concept; the availability of firm and non-firm transmission rights affects energy actually delivered
  - Firm transmission/injection rights tend to be 99.9% deliverable
  - Non-firm depend on location but may be >95% deliverable; can be determined easily based on historical or projected renewable energy curtailments
- It is not reasonable to assume zero energy will be delivered over non-firm rights
  - In PJM, curtailments on non-firm rights are rare (and small); and PJM’s energy-only interconnection study criteria are very stringent (requiring significant transmission upgrades)

Source: PowerPoint Presentation (misoenergy.org)
Johannes (Hannes) Pfeifenberger, a Principal at The Brattle Group, is an economist with a background in electrical engineering and over twenty-five years of experience in wholesale power market design, renewable energy, electricity storage, and transmission. He also is a Visiting Scholar at MIT’s Center for Energy and Environmental Policy Research (CEEPR), a Senior Fellow at Boston University’s Institute of Sustainable Energy (BU-ISE), a IEEE Senior Member, and currently serves as an advisor to research initiatives by the U.S. Department of Energy, the National Labs, and the Energy Systems Integration Group (ESIG).

Hannes specializes in wholesale power markets and transmission. He has analyzed transmission needs, transmission benefits and costs, transmission cost allocations, and transmission-related renewable generation challenges for independent system operators, transmission companies, generation developers, public power companies, industry groups, and regulatory agencies across North America. He has worked on transmission, resource adequacy, and wholesale power market design matters in SPP, MISO, PJM, New York, New England, ERCOT, CAISO, WECC, Alberta and Ontario.

He received an M.A. in Economics and Finance from Brandeis University’s International Business School and an M.S. and B.S. ("Diplom Ingenieur") in Power Engineering and Energy Economics from the University of Technology in Vienna, Austria.

The views expressed in this presentation are strictly those of the presenter(s) and do not necessarily state or reflect the views of The Brattle Group or its clients.
These solely reliability-driven processes account for > 90% of all transmission investments

- None involve any assessments of economic benefits (i.e., cost savings offered by the new transmission)
- Which also means these investments are not made with the objective to find the most cost-effective solutions
- Will yield higher system-wide costs and electricity rates

Planning for economic and public-policy projects: less than 10% of all transmission investments

Interregional planning processes are large ineffective

- Essentially no major interregional transmission projects have been planned and built in the last decade
Current U.S. Transmission Planning = Higher Total Costs

Current planning processes do not yield the most valuable transmission infrastructure and result in higher overall costs:

- Reactive, reliability-driven planning results in piecemeal, higher-cost transmission solutions
- Failure to evaluate multiple benefits of most transmission projects: does not result in the selection of the highest-value projects that reduce system-wide costs
- Failure to evaluate the full range of plausible futures (to explicitly account for long-term uncertainties): results in higher-cost outcomes when the future deviates from base case planning assumptions, which usually are based on “business-as-usual” or “current-trends” forecast
- Failure to consider interregional transmission solutions: result in higher-cost regional and local transmission investments

More pro-active, multi-value, and scenario-based transmission planning processes are needed, as discussed in:

- 21st Century Transmission Planning: Benefits Quantification and Cost Allocation (presentation)
- Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs (report)
- A Roadmap to Improved Interregional Transmission Planning (report)
Additional Reading on Transmission

Pfeifenberger, Transmission Planning and Benefit-Cost Analyses, presentation to FERC Staff, April 29, 2021.
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