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 Senior Fellow at Boston University's Institute of Sustainable Energy (BU-ISE), a Visiting Scholar at MIT’s Center for Energy and Environmental Policy Research (CEEPR), and serves as an advisor to research initiatives by the Lawrence Berkeley National Laboratory’s (LBNL’s) Energy Analysis and Environmental Impacts Division and the US Department of Energy’s (DOE’s) Grid Modernization Lab Consortium.

Hannes specializes in transmission and wholesale power markets. He has recent studied New York power grid needs, evaluated offshore wind transmission options in New York State and New England, analyzed the role of renewable generation and transmission in economy-wide decarbonization, and presented renewable integration challenges at a number of industry meetings, including the Atlantic Council and the Harvard Electricity Policy Group.

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.
Contents

1. The Need for Improved Planning
2. Quantifying Transmission Benefits
3. Transmission Cost Allocation
4. Summary and Recommendations

Additional Reading
Transmission Investment is at Historically High Levels

$20-25 billion in annual U.S. transmission investment, but:

- More than 90% of it justified solely based on reliability needs without benefit-cost analysis
  - About 50% solely based on “local” utility criteria (without going through regional planning processes)
  - The rest justified by regional reliability and generation interconnection needs
- While significant experience with transmission benefit-cost analyses exists, very few projects are justified based on economics and overall cost savings

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
  - For example: PJM generation interconnection studies for 15.5 GW of individual offshore wind plants identified $6.4 billion in onshore transmission upgrades
  - In contrast: A recent PJM study that proactive evaluated onshore upgrade needs for 17 GW of offshore wind (along with 14.5 GW of onshore wind and 45.6 GW of solar) identified only $3.2 billion in onshore upgrades
  - Result: at least 50% lower costs if renewable interconnection is planned proactively for the entire region’s public policy needs (rather than one project at the time)

- Failure to evaluate multiple benefits of 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
The Electricity Industry is Undergoing Fundamental Changes, Which Will Require Improved Planning Processes

As many have articulated, the industry faces fundamental changes along three important dimensions (the “3Ds”), which will fundamentally change grid planning and operations

1. DECARBONIZATION
To meet state, federal, and corporate clean-energy policy objectives, output from “emitting” resources (such as coal plants) is quickly replaced by renewable resources, with rapidly falling capital costs and close-to-zero variable costs. This is fundamentally changing (a) wholesale power prices; (b) grid operations; and (c) grid planning and investments.

2. DECENTRALIZATION
Declining costs of solar generation and batteries causes a shift away from large, central-station power plants to resources that are located on local electricity networks or “behind the meter” at homes and businesses—changing the role (but not decreasing the value) of the transmission grid.

3. DIGITALIZATION
The revolution in information and communication technologies and platforms that will continue to change nearly everything in our economy, including energy services, grid operations, and grid planning.
By issuing its Advance Notice of Proposed Rulemaking (ANOPR), FERC recognizes that transmission planning and cost allocation needs to be improved.

- FERC has been seeking comments in several specific areas:
  - Reforms to longer-term regional and interregional planning processes to take into account more holistic planning
  - Rethinking cost allocation for regional transmission facilities
  - Improvement of generation-interconnection process and cost allocation of related network upgrades
  - Enhanced transmission oversight over how new transmission facilities are identified and paid for

- FERC received ~170 comments on October 12; reply comments due November 30th
- FERC expected to issue one or several NOPR(s) next year
- Final rule(s) likely in early 2023
- Compliance likely would be in late 2023 or 2024 (unless held up in courts and rehearing)
Proposal: Transmission Planning for the 21st Century*

Available experience already points to proven planning practices that reduce total system costs and risks:

1. Proactively plan for future generation and load by incorporating realistic projections of the anticipated generation mix, public policy mandates, load levels, and load profiles over the lifespan of the transmission investment

2. Account for the full range of transmission projects’ benefits and use multi-value planning to comprehensively identify investments that cost-effectively address all categories of needs and benefits

3. Address uncertainties and high-stress grid conditions explicitly through scenario-based planning that takes into account a broad range of plausible long-term futures as well as real-world system conditions, including challenging and extreme events

4. Use comprehensive transmission network portfolios to address system needs and cost allocation more efficiently and less contentiously than a project-by-project approach

5. Jointly plan inter-regionally across neighboring systems to recognize regional interdependence, increase system resilience, and take full advantage of interregional scale economics and geographic diversification benefits

Experience with Proactive & Comprehensive Planning Processes

Although still rarely used, significant experience exists with successful proactive, multi-value, scenario- and portfolio-based transmission planning efforts:

<table>
<thead>
<tr>
<th>Source</th>
<th>Proactive Planning</th>
<th>Multi-Benefit</th>
<th>Scenario-Based</th>
<th>Portfolio-Based</th>
<th>Interregional Transmission</th>
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<td>Australian Examples:</td>
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<td>- Transgrid Energy Vision (2021)</td>
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Source: Brattle & Grid Strategies, *Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs*
Current planning processes do not (yet) take advantage of experience with proactive, multi-value, scenario- and portfolio-based transmission planning efforts

| Source: Brattle & Grid Strategies, Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs |

<table>
<thead>
<tr>
<th>Region / Organization</th>
<th>Proactive Generation &amp; Load</th>
<th>Multi-Value</th>
<th>Scenario-Based</th>
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</table>
Quantifying Transmission Benefits
Understanding Transmission-Related Benefits

The wide-spread nature of transmission benefits creates challenges in estimating benefits and how they accrue to different users

- **Broad in scope, providing many different types of benefits**
  - Increased reliability and operational flexibility
  - Reduced congestion, dispatch costs, and losses
  - Lower capacity needs and generation costs
  - Increased competition and market liquidity
  - Renewables integration and environmental benefits
  - Insurance and risk mitigation benefits
  - Diversification benefits (e.g., reduced uncertainty and variability)
  - Economic development from G&T investments

- **Wide-spread geographically**
  - Multiple transmissions service areas
  - Multiple states or regions

- **Diverse in their effects on market participants**
  - **Customers, generators, transmission owners** in regulated and/or deregulated markets
  - Individual market participants may capture one set of benefits but not others

- **Occur and change over long periods of time**
  - Several decades (50+ years), typically increasing over time
  - Changing with system conditions and future generation and transmission additions
  - Individual market participants may capture different types of benefits at different times
Quantifying Benefits Beyond Production Cost Savings

Relying on solely on traditionally-quantified Adjusted Production Cost (APC) Savings results in the rejection of beneficial transmission projects:

Source: Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs (brattle.com)
We have a Decade of Experience with Identifying and Quantifying a Broad Range of Transmission Benefits

SPP 2016 RCAR, 2013 MTF

Quantified
1. production cost savings*
   - value of reduced emissions
   - reduced ancillary service costs
2. avoided transmission project costs
3. reduced transmission losses*
   - capacity benefit
   - energy cost benefit
4. lower transmission outage costs
5. value of reliability projects
6. value of mtg public policy goals
7. Increased wheeling revenues

Not quantified
8. reduced cost of extreme events
9. reduced reserve margin
10. reduced loss of load probability
11. increased competition/liquidity
12. improved congestion hedging
13. mitigation of uncertainty
14. reduced plant cycling costs
15. societal economic benefits

MISO MVP Analysis

Quantified
1. production cost savings*
2. reduced operating reserves
3. reduced planning reserves
4. reduced transmission losses*
5. reduced renewable generation investment costs
6. reduced future transmission investment costs

Not quantified
7. enhanced generation policy flexibility
8. increased system robustness
9. decreased natural gas price risk
10. decreased CO₂ emissions output
11. decreased wind generation volatility
12. increased local investment and job creation

CAISO TEAM Analysis

(Proposed Multi Value Project Portfolio, Technical Study Task Force and Business Case Workshop August 22, 2011)

Quantified
1. production cost savings* and reduced energy prices from both a societal and customer perspective
2. mitigation of market power
3. insurance value for high-impact low-probability events
4. capacity benefits due to reduced generation investment costs
5. operational benefits (RMR)
6. reduced transmission losses*
7. emissions benefit

Not quantified
8. facilitation of the retirement of aging power plants
9. encouraging fuel diversity
10. improved reserve sharing
11. increased voltage support

NYISO PPTN Analysis

(AC Upgrades)

Quantified
1. production cost savings*
   (includes savings not captured by normalized simulations)
2. capacity resource cost savings
3. reduced refurbishment costs for aging transmission
4. reduced costs of achieving renewable and climate policy goals

Not quantified
5. protection against extreme market conditions
6. increased competition and liquidity
7. storm hardening and resilience
8. expandability benefits

(Proposed Multi Value Project Portfolio, Technical Study Task Force and Business Case Workshop August 22, 2011)

Fairly consistent across RTOs

*(Proposed Multi Value Project Portfolio, Technical Study Task Force and Business Case Workshop August 22, 2011)

(CPUC Decision 07-01-040, January 25, 2007, Opinion Granting a Certificate of Public Convenience and Necessity)
Brattle Group Reports on Transmission Benefit-Cost Analyses Summarize Much of the Available Experience

Toward More Effective Transmission Planning:
Addressing the Costs and Risks of an Insufficiently Flexible Electricity Grid

The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments

Documents proven approaches to quantifying various benefits
“Checklist” of Transmission Benefits With Proven Practices for Quantifying Them

We have documented in our recent report (filed with ANOPR comments), available proven practices:

1. Consider for each project (or synergistic portfolio of projects) the full set of benefits transmission can provide (see table)
2. Identify the benefits that plausibly exist and may be significant for that particular project or portfolio; then
3. Focus on quantifying those benefits

(See our recent report with Grid Strategies for a summary of quantification practices)

<table>
<thead>
<tr>
<th>Benefit Category</th>
<th>Transmission Benefit</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Traditional Production Cost Savings</td>
<td>Adjusted Production Cost (APC) savings as currently estimated in most planning processes</td>
</tr>
<tr>
<td>2. Additional Production Cost Savings</td>
<td>1. Impact of generation outages and A/S unit designations</td>
</tr>
<tr>
<td></td>
<td>2. Reduced transmission energy losses</td>
</tr>
<tr>
<td></td>
<td>3. Reduced congestion due to transmission outages</td>
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<td></td>
<td>4. Reduced production cost during extreme events and system contingencies</td>
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<td></td>
<td>5. Mitigation of typical weather and load uncertainty, including the geographic</td>
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<tr>
<td></td>
<td>diversification of uncertain renewable generation variability</td>
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<td></td>
<td>6. Reduced cost due to imperfect foresight of real-time system conditions, including</td>
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<td>renewable forecasting errors and intra-hour variability</td>
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<td>7. Reduced cost of cycling power plants</td>
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<td></td>
<td>8. Reduced amounts and costs of operating reserves and other ancillary services</td>
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<tr>
<td></td>
<td>9. Mitigation of reliability-must-run (RMR) conditions</td>
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<td></td>
<td>x. More realistic “Day 1” market representation</td>
</tr>
<tr>
<td>3. Reliability and Resource Adequacy Benefits</td>
<td>1. Avoided/deferred cost of reliability projects (including aging infrastructure</td>
</tr>
<tr>
<td></td>
<td>replacements) otherwise necessary</td>
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<tr>
<td>4. Generation Capacity Cost Savings</td>
<td>i. Capacity cost benefits from reduced peak energy losses</td>
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<td></td>
<td>ii. Deferred generation capacity investments</td>
</tr>
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<td></td>
<td>iii. Access to lower-cost generation resources</td>
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<tr>
<td>5. Market Facilitation Benefits</td>
<td>i. Increased competition</td>
</tr>
<tr>
<td>6. Environmental Benefits</td>
<td>i. Reduced expected cost of potential future emissions regulations</td>
</tr>
<tr>
<td>7. Public Policy Benefits</td>
<td>ii. Improved utilization of transmission corridors</td>
</tr>
<tr>
<td>8. Other Project-Specific Benefits</td>
<td>Reduced cost of meeting public policy goals</td>
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<tr>
<td></td>
<td>Examples: increased storm hardening and wild-fire resilience, increased fuel diversity</td>
</tr>
<tr>
<td></td>
<td>and system flexibility, reduced cost of future transmission needs, increased wheeling</td>
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<tr>
<td></td>
<td>revenues, HVDC operational benefits</td>
</tr>
</tbody>
</table>
Example: New York’s (Multi-Value) “Public Policy” Transmission Planning Process

New York DPS recently modified its “public policy” transmission planning process by mandating that a full set of benefits be considered. Resulted in approval and competitive solicitation of two major upgrades to the New York transmission infrastructure.

Summary of Quantified Benefits and Costs
(additional benefits considered qualitatively)

Simulating Forecast Uncertainty → Higher, More Accurate Benefits

Key takeaways

- Quantified transmission benefits can be significantly understated using the prevailing “Perfect Foresight” simulation approach:
  - RT = 10x DA at 20% renewables
  - RT = 3x DA at 50% renewables

- The higher benefit means optimal tradeoff shifts more from building local renewables to building more regional and interregional transmission to cost-effectively meet policy goals
Most transmission planning efforts do not adequately account for short- and long-term risks and uncertainties affecting power markets.

- **Short-Term Risks:** Transmission planning generally evaluates only “normal” system conditions. Planning process typically ignores the high cost of short-term challenges and extreme market conditions triggered by high-impact-low-probability (“HILP”) events due to weather, transmission outages, fuel supply disruption, or unexpected load changes associated with economic booms/busts. Can be addressed through modeling assumptions and sensitivities that capture these short-term challenges.

- **Long-Term Risks:** Planning does not adequately consider the full range of long-term scenarios. Does not capture the extent to which a less robust and flexible transmission infrastructure will help reduce the risk of high-costs incurred under different (long-term) future market fundamentals. Can be addressed through improved scenario planning that covers the full range of plausible futures.

A more flexible and robust grid provides “insurance value” by reducing the risk of high-cost (short- and long-term) outcomes due to inadequate transmission:

- Costs of inadequate infrastructure (typically are not quantified) can be much greater than the costs of the transmission investment.
- Project may not quite be cost effective in “base case” future but be highly beneficial in 3 out of 5 futures.
Risk Mitigation Through Transmission Investments

Additional considerations regarding the risk mitigation and insurance value of transmission infrastructure:

- Given that it can take a decade to develop new transmission, delaying investment can easily limit future options and result in a higher-cost, higher-risk overall outcomes
  - “Wait and see” approaches limit options, so can be costly in the long term
  - The industry needs to plan for both short- and long-term uncertainties more proactively – and develop "anticipatory planning" processes

- “Least regrets” planning too often only focuses on identifying those projects that are beneficial under most circumstances
  - Does not consider the many potentially “regrettable circumstances” where the failure to expand transmission could result in very high-cost outcomes
  - Focuses too much on the cost of insurance without considering the cost of not having insurance when it is needed

- Probabilistic weighting assumes risk neutrality and does not distinguish between investment options with very different risk distributions
In evaluating the Paddock-Rockdale Project, ATC evaluated seven plausible futures, spanning the range of long-term uncertainties. 

- The 40-year PV of customer benefits fell short of the $136 million PV of the project’s revenue requirement in the “Slow Growth” future, but exceeded the costs in all other futures.
- The net benefits in the other six futures ranged from:
  - $100 million (above cost) under the “High Environmental” future
  - to approx. $400 million under the “Robust Economy” and “High Wisconsin Growth” futures
  - reaching up to approx. $700 million under the “Fuel Supply Disruption” and “High Plant Retirements” futures

The analyses of multiple scenarios of plausible futures show:

- The estimated benefits can range widely across sets of plausible futures
- The project is beneficial in most (but not all) futures
- Not investing in the $136 million project can leave customers up to $700 million worse off in two of seven plausible futures
Transmission Cost Allocation
Disagreements on Cost-Allocation Creates Barriers Even for Clearly-Beneficial Projects

**Easiest:** develop “needed” local and regional reliability and generation interconnection transmission projects that do not involve cost sharing (now majority in many regions)

**Harder:** regionally share costs of transmission “needed” to meet regional reliability standards
- Most TOs strongly prefer recovering costs associated with their own ratebase
- Policy makers reluctant to pay for transmission that benefit other states

**Hardest:** share costs of projects that provide broad regional economic or public-policy benefits:
- Fundamentally different future views of the world
  - Planners and policy makers may disagree on the outlook of natural gas costs but they agree the cost exists; not so with carbon or other policy-related benefits, which create disagreements and are often ignored
- Large regional projects for environmental policies pit states that have them (often major population centers) against states that don’t (often more remote areas)
- Reluctance to pay for transmission that facilitates out-of-state generation investments with few direct local jobs

**Almost Impossible:** cost allocation for interregional projects; but mostly hypothetical because no significant interregional projects have been planned to date
Recommend 2-step approach:

1. Determine whether projects are beneficial overall, quantifying a broad set of benefits
   - Without quantifying most benefits, many desirable projects (or synergistic portfolios) will be rejected
   - Benefits that can be allocated precisely may only be a subset of total benefits
   - Avoid temptation to understate benefits in effort to reduce cost allocation to individual study participants

2. Evaluate how the cost of a broad portfolio of beneficial projects should be allocated based on their joint distribution of benefits
   - Reduces conflict: a broad set of benefits quantified for a portfolio of projects tends to be more stable over time and be distributed more uniformly
Order 1000 does not require that the cost of each project is allocated based on its benefits ... as long as the cost allocation for a portfolio of projects is roughly commensurate with overall benefits.

Even postage stamp (load-ratio share) allocation is appropriate and acceptable if:

- All customers tend to benefit from class or group of facilities
- Distribution of benefits is likely to vary (but “average out”) over long life of facilities

**Portfolio-based cost allocations are less controversial and easier to implement**

- Portfolio-wide benefits tend to be more even distributed and more stable over time
- One cost allocation analysis for portfolio vs. many analyses for many projects

Examples of portfolio-based cost allocations:

- **SPP Highway-Byway** (designed by RSC): Periodic review if benefits of all approved projects is roughly commensurate with costs of all projects
- **MISO MVPs** (with OMS input): Benefits of entire portfolio compared with allocated costs
MISO’s MVP Analyses: Benefits of the Portfolio (as a Whole) Significantly Exceed Postage-Stamp-Allocated Costs in all Regions

MISO’s MVP Portfolio provides benefits across the MISO footprint that are roughly equivalent to (postage-stamp) allocated costs

- MISO quantified 6 types of economic benefits (plus reliability and public policy benefits)

- MTEP17 analysis shows $22 to $75 billion in total benefits to MISO North and Central

- Total costs increased from $5.6 to $6.7 billion, but benefits grew even more

- B-C ratios exceed 1.5 to 2.6 in every zone

Summary and Recommendations
Summary and Recommendations

Broadly apply proven planning practices that reduce total system costs and risks:

1. **Proactively plan for future generation and load** by incorporating realistic projections of the anticipated generation mix, public policy mandates, load levels, and load profiles over the lifespan of the transmission investment.

2. **Account for the full range of transmission projects’ benefits** and use multi-value planning to comprehensively identify investments that cost-effectively address all categories of needs and benefits.

3. **Address uncertainties and high-stress grid conditions explicitly through scenario-based planning** that takes into account a broad range of plausible long-term futures as well as real-world system conditions, including challenging and extreme events.

4. **Use comprehensive transmission network portfolios** to address system needs and cost allocation more efficiently and less contentiously than a project-by-project approach.

5. **Jointly plan inter-regionally across neighboring systems** to recognize regional interdependence, increase system resilience, and take full advantage of interregional scale economics and geographic diversification benefits.
Focus less on addressing near-term reliability and local needs, but proactively on infrastructure that provides greater flexibility and higher long-term value at lower system-wide cost

- Recognize that every transmission project offers multiple values
- Lowest-cost transmission is not “least cost” from an overall customer-cost perspective

Improve benefit-cost analyses and cost allocations to offer more cost-effective and less controversial outcomes:

- More fully consider broad range of reliability, economic, and public-policy benefits, including experience gained through:
  - SPP value of transmission and RCAR benefits metrics
  - NYISO broad set of benefits quantified for public policy projects
  - MISO MVP benefits; CAISO economic and public policy projects

- Reduce divisiveness of cost allocation through broad set of portfolio-based benefits
  - Recognize broad range of benefits → more likely to be evenly distributed and exceed costs
  - Focus on larger portfolios of transmission projects → more uniform distribution of benefits
  - Broad range of benefits for a portfolio will also be more stable over time
Additional Reading on Transmission

Pfeifenberger, Transmission Planning and Benefit-Cost Analyses, presentation to FERC Staff, April 29, 2021.
<table>
<thead>
<tr>
<th>ENERGY &amp; UTILITIES</th>
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<td>Accounting</td>
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<tr>
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