The Paradigm Shift in the Role of the Transmission Network

Lorenzo Kristov
Principal, Market and Infrastructure Policy

Conference on Transmission Policies to Unlock America’s Renewable Energy Resources
Stanford University – September 15, 2011

Outline of the presentation

• What is the paradigm shift?
• Valuing the benefits of transmission expansion
  – The traditional vertically-integrated utility paradigm
  – Competitive wholesale power markets with open access transmission service
• Impacts of new public policies on transmission needs and transmission planning
  – Access to renewable generation
  – Policy-driven transmission planning under uncertainty about future needs
  – Competitive opportunities to build rate-based transmission
• California ISO initiatives and perspectives
What is the paradigm shift?

1. From traditional, vertically-integrated, regulated monopoly utilities, to competitive wholesale energy markets and open-access transmission service operated by ISOs and RTOs (“electric restructuring”)

2. From gradual, incremental transmission expansion to meet load growth and occasional new generation, to a massive turnover of the supply fleet in response to environmental policy directives

3. From expansion based on traditional reliability and economic-benefits criteria, to a new public-policy-driven basis for approving transmission additions, with uncertainty about future needs

4. From all transmission being built by incumbent utilities to new opportunities for independent developers

Major federal reforms affecting transmission planning and investment

<table>
<thead>
<tr>
<th>Year</th>
<th>Order</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>1996</td>
<td>Order 888</td>
<td>- transmission open access&lt;br&gt;- encouraged but did not require transmission planning</td>
</tr>
<tr>
<td>1999</td>
<td>Order 2000</td>
<td>- established regional scope, planning and inter-regional coordination functions of RTOs, but RTO formation remained voluntary</td>
</tr>
<tr>
<td>2003</td>
<td>Order 2003</td>
<td>- standardized generation interconnection processes</td>
</tr>
<tr>
<td>2006</td>
<td>Order 679</td>
<td>- rate incentives for transmission investment</td>
</tr>
<tr>
<td>2007</td>
<td>Order 890</td>
<td>- required transmission providers (such as CAISO) to have coordinated, open, and transparent regional transmission planning process</td>
</tr>
<tr>
<td>2011</td>
<td>Order 1000</td>
<td>- builds on Order 890 to include: processes for identifying policy-driven transmission needs; procedures to include non-incumbent transmission owners; inter-regional coordination and cost allocation</td>
</tr>
</tbody>
</table>
Principal potential benefits of a proposed transmission addition or upgrade

- Increased system reliability
- Improvements in system operation, capacity utilization
- Lower costs of energy and operating reserves
- Lower costs of generation capacity to meet peak load (particularly with non-coincident peak loads)
- Lower environmental emissions (unless expansion increases utilization of more polluting generation) and better spatial dispersion of emissions
- Possible improvements in system losses
- NEW – Accommodation of major shifts in the supply fleet driven by public policy objectives (e.g., 33% RPS)

Valuing transmission in the Vertical Integrated (VI) Utility Paradigm

- To meet demand growth in an area with no reduction in reliability (regulatory mandate), the utility can either construct local generation or expand transmission
  - Utility’s retail price of electricity is regulated, so it maximizes profits by pursuing the least-cost solution
- Example of utility benefit calculation for transmission expansion
  - Local generation costs $50/MWh, and imported energy $20/MWh
  - => transmission upgrade of 10 MW of capacity yields benefit of $300/hr
    \[ \text{benefit} = (\text{local cost} - \text{imported cost}) \times \text{capacity} \times \text{hours} \]
  - An economic benefit of transmission is the generation cost savings from increased ability to exploit locational cost differences
- Alternatively, utility may maximize profits by installing new high-cost local generation that operates only in high-demand hours
  - Combustion turbine costing $150/MWh but needed only for a small number of hours may be more cost effective than transmission upgrade
Transmission versus generation risk considerations

- Transmission upgrade with low-cost distant generation entails significant regulatory risk
  - Longer time horizon to construct new transmission
  - Can require large amount of distant generation to realize efficient utilization of new transmission line
  - Challenge to obtain regulatory siting and environmental permits
  - Commitments of previous regulator must be honored by current and future regulators

- Relying on local generation maintains permanent “load pockets” – regions with insufficient transmission capacity to meet all demand with imported energy
  - San Francisco Bay Area, San Diego Area
  - May be strong local opposition to building new generation

Paradigm Shift to Wholesale Markets

- Elements of the new market paradigm
  - Generation sector is subject to competition
  - Transmission service is subject to non-discriminatory (open access) requirements, mainly under ISOs/RTOs
  - VI utility retains distribution system, and may or may not face competition to serve retail customers in its territory
  - Transmission planning and new generation interconnection are under the transmission system operator

- Wholesale markets are the vehicle for generation competition and non-discriminatory transmission service
  - Market structure includes day-ahead and real-time (intra-day) energy and reserve services
  - May include forward locational capacity to ensure adequacy under peak-load conditions
  - System is optimized based on participants bids and offers, rather than on actual costs that were available to the VI utility
Implications of the shift to markets for transmission planning

• Economic value of transmission expansion is increased ability to exploit locational *price* differences
  – Prices may differ from costs due to any factors that reduce the competitiveness of supply resources
  – E.g., local market power may exist in load pockets, where load exceeds the capability of transmission to import energy from cheaper external resources
  – Such constraints may exist in the wholesale market paradigm because they were optimal under the prior VI utility paradigm

• A new potential benefit of a transmission upgrade is to limit the exercise of local market power by increasing competition, thus reducing the cost of energy, reserves and resource adequacy capacity

Another aspect of the shift to markets – new transmission ownership and operating structures

• **Transco:** Consolidated ownership and operation of all divested transmission assets in a region or subregion, subject to regulated rate of return (e.g., for-profit ISO)

• **Transmission-owning utility or independent transmission company:** Ownership of some or all transmission in a subregion, subject to regulated rate of return, under independent operator such as ISO

• **Merchant transmission owner:** Owner of individual transmission assets, subject to market-based revenue and regulation, under the independent operator

• **Note:** All structures are consistent with open access requirements whether under ISO or RTO or not
The shift to public policy-driven transmission planning under uncertainty

- Environmental policy mandates – such as 33% RPS by 2020 – require massive changes to the supply fleet
  - Numerous resource rich areas (wind, solar radiation) beyond the reach of existing transmission and far from load centers
  - Needed transmission does not qualify under traditional reliability or economic-benefit criteria
  - Dozens of GW of generation project proposals far exceed needed capacity, creating uncertainty about actual geographic pattern of future generation development
  - Transmission development takes much longer than generation development, so transmission decisions cannot wait for certainty

- Competing objectives for transmission planners
  - Enable sufficient transmission to be built and energized in time to meet 33% RPS by 2020 policy mandate, but …
  - Minimize risk to ratepayers of funding under-utilized transmission

The strategy for transmission planning under the new paradigm

- Create new “public policy-driven” transmission category
- Adopt the given policy mandate as a planning objective
  - Final transmission plan and expected resource fleet must allow 33% of MWh consumed on an annual basis to come from renewable resources (8760-hour production simulation)
- Specify several alternative scenarios of potential renewable resource development, and identify transmission for each
  - Identifying preferred resource areas requires collaboration between ISO and state authorities that oversee resource procurement by load-serving entities and environmental generation permitting
- Approve transmission facilities found needed under multiple scenarios to minimize risk of under-utilized transmission
  - Defer approval of other facilities pending new information in next planning cycle
CAISO’s 2011/2012 Transmission Plan Cycle

May 2011 – October 2012

Phase 1
Develop ISO unified planning assumptions and study plan
- Specify State and Federal policy requirements and directives
- Adopt demand forecasts, energy efficiency, demand response
- Incorporate renewable and conventional generation additions and retirements
- Obtain stakeholder input from via public meetings and written comments

Phase 2
Technical Studies and Board Approval
- Reliability analysis
- Specify renewable resource scenarios and perform renewable delivery analysis
- Congestion analysis (economic benefits)
- Conduct multiple stakeholder meetings
- Publish comprehensive transmission plan
- ISO Board approval of plan

Phase 3
Receive proposals to build Board-approved policy and economic transmission projects.

A key challenge – how to specify the set of feasible generation development scenarios

- California's Renewable Energy Transmission Initiative (RETI) identified and analyzed all Competitive Renewable Energy Zones (CREZes)
- RETI results and other regulatory assessments were used in statewide (CTPG) and CAISO planning processes
  - (CTPG = California Transmission Planning Group)
- Evidence of commercial interest in each CREZ the CTPG considered:
  - Renewable resources in the CPUC's “discounted core” and in portfolios of publicly owned utilities (POUs)
  - The positions of the same resources in the generator interconnection queues of the ISO and the POUs
  - Environmental scores and “discounted core” information was developed within the CPUC's 2010 Long Term Procurement Planning process
- End result: Potentially viable CREZes still too numerous to provide enough certainty to transmission planning decisions
Interconnection queue far exceeds policy needs

<table>
<thead>
<tr>
<th>Transmission upgrade</th>
<th>Approval status</th>
<th>Renewable Potential</th>
</tr>
</thead>
<tbody>
<tr>
<td>Carrizo-Midway</td>
<td>Pending LGIA</td>
<td>Not yet filed</td>
</tr>
<tr>
<td>Sunrise Powerlink</td>
<td>Approved</td>
<td>1,700</td>
</tr>
<tr>
<td>Eldorado-Ivanpah</td>
<td>LGIA Approved</td>
<td>1,400</td>
</tr>
<tr>
<td>Pismo-Lugo</td>
<td>LGIA Not yet filed**</td>
<td>1,750</td>
</tr>
<tr>
<td>Valley-Corralitos River</td>
<td>Approved</td>
<td>4,700</td>
</tr>
<tr>
<td>West of Devers</td>
<td>LGIA Not yet filed</td>
<td>1,700</td>
</tr>
<tr>
<td>Tehachapi</td>
<td>Approved</td>
<td>4,500</td>
</tr>
<tr>
<td>Tehachapi Wind/Solar Diversity</td>
<td>N/A</td>
<td>1,000</td>
</tr>
<tr>
<td>Cool Water-Lugo</td>
<td>Pending LGIA</td>
<td>Not yet filed</td>
</tr>
<tr>
<td>South Contra Costa</td>
<td>LGIA Not yet filed</td>
<td>800</td>
</tr>
<tr>
<td>Borden-Gregg</td>
<td>LGIA Not yet filed</td>
<td>800</td>
</tr>
<tr>
<td>Path 42</td>
<td>Pending approval</td>
<td>Not yet filed</td>
</tr>
<tr>
<td>Other/Outside of ISO Grid</td>
<td>N/A</td>
<td>3,000</td>
</tr>
</tbody>
</table>

Total = $7.2 billion

Total TWh/year needed in ISO area to meet 33% goal: 44
33% RPS scenarios for 2020 cover a reasonable range renewable and load conditions

<table>
<thead>
<tr>
<th>Case</th>
<th>Case Title</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>33% Trajectory</td>
<td>Based on contracted activity</td>
</tr>
<tr>
<td>2</td>
<td>Environmental Constrained</td>
<td>High distributed solar</td>
</tr>
<tr>
<td>3</td>
<td>Cost Constrained</td>
<td>Low cost (wind, out of state)</td>
</tr>
<tr>
<td>4</td>
<td>Time Constrained</td>
<td>Fast development (out-of-state)</td>
</tr>
<tr>
<td>5</td>
<td>20% Trajectory</td>
<td>For comparison</td>
</tr>
<tr>
<td>6</td>
<td>33% Trajectory High Load</td>
<td>Higher load growth and/or energy program under-performance</td>
</tr>
<tr>
<td>7</td>
<td>33% Trajectory Low Load</td>
<td>Lower load growth and/or energy program over-performance</td>
</tr>
</tbody>
</table>

Fossil Plant Retirement – Once-Through-Cooling

<table>
<thead>
<tr>
<th>Unit</th>
<th>Capacity (MW)</th>
<th>Area</th>
</tr>
</thead>
<tbody>
<tr>
<td>Harbor</td>
<td>237.5</td>
<td>LDWP</td>
</tr>
<tr>
<td>Haynes 1-6</td>
<td>1670</td>
<td>LDWP</td>
</tr>
<tr>
<td>Scattergood 1-3</td>
<td>803</td>
<td>LDWP</td>
</tr>
<tr>
<td>Contra Costa 6-7</td>
<td>674</td>
<td>PG&amp;E_BAY</td>
</tr>
<tr>
<td>Pittsburg 5-6</td>
<td>629</td>
<td>PG&amp;E_BAY</td>
</tr>
<tr>
<td>Potrero</td>
<td>206</td>
<td>PG&amp;E_BAY</td>
</tr>
<tr>
<td>Humboldt Bay 1-2</td>
<td>135</td>
<td>PG&amp;E_VLY</td>
</tr>
<tr>
<td>Morro Bay 3-4</td>
<td>650</td>
<td>PG&amp;E_VLY</td>
</tr>
<tr>
<td>Moss Landing 6-7</td>
<td>1510.03</td>
<td>PG&amp;E_VLY</td>
</tr>
<tr>
<td>Alamitos 1-6</td>
<td>2010.38</td>
<td>SCE</td>
</tr>
<tr>
<td>El Segundo 3-4</td>
<td>670</td>
<td>SCE</td>
</tr>
<tr>
<td>Huntington Beach 1-4</td>
<td>901.55</td>
<td>SCE</td>
</tr>
<tr>
<td>Mandalay 1-2</td>
<td>430.29</td>
<td>SCE</td>
</tr>
<tr>
<td>Ormond Beach 1-2</td>
<td>1516.27</td>
<td>SCE</td>
</tr>
<tr>
<td>Redondo Beach 5-8</td>
<td>1343.01</td>
<td>SCE</td>
</tr>
<tr>
<td>Encina 1-6</td>
<td>946</td>
<td>SDG&amp;E</td>
</tr>
<tr>
<td>South Bay 1-4</td>
<td>683</td>
<td>SDG&amp;E</td>
</tr>
</tbody>
</table>
Potential need for 4,600 MW of upward flexible resources observed in the high-load scenario

Out of approximately 3,500 MW downward balancing requirements, observed some hours of shortages

Note: Downward balancing may be more effectively and efficiently managed using curtailment or storage rather than less economic dispatch of flexible resources to higher level to maintain downward flexibility
CAISO transmission planning initiatives, challenges and perspectives

- More comprehensive transmission planning process that considers reliability needs, economic benefits, renewable integration, distributed energy resources, once-through-cooling policy, air emissions policy
- Better integrate generation interconnection with transmission planning
  - Rely more on transmission planning to drive significant upgrades
  - Use policy-driven category to meet interconnection needs for preferred resource development areas
  - Assign cost for additional upgrades to generation developers
- Improve process for specifying resource portfolios used for planning
  - Incorporate findings of state environmental analysis
- Manage interconnection queue to eliminate inactive or excessively delayed projects, reducing upgrade needs for projects later in queue

... continued

- Ensure availability of flexible capacity needed for reliable operation with larger amounts of variable renewables
  - Incorporate “integration resources” in resource scenarios so that transmission planning can account for operational needs
- Accelerate market design initiatives to procure, compensate and help support sustained commercial viability of needed flexible resources
  - Expand opportunities for generation alternatives – such as demand response and storage – to participate in CAISO markets, with the goal of meaningful levels of deployment before 2020
- Refine local capacity studies for 2020 to inform procurement decisions in the 2011-2012 CPUC procurement cycle
  - Target procurement of capacity with needed flexibility and ramping capability, including new investment
- Inter-regional (i.e., west-wide) coordination in transmission planning – required by FERC Order 1000; compliance due in 18 months