Transmission Planning, Investment, and Cost Allocation in US ISO Markets

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1 Introduction and Background

U.S. transmission investments by Commission-jurisdictional transmission providers increased from $2 billion/year in the 1990s to $20 billion/year in 2013–2017. In 2017, the US electric power system had annual revenues of over $400 billion. In ISOs, transmission investment decisions can change the entry decisions for generators. Even modest improvements in modeling and decision making can result in billions of dollars of cost savings. Such potential indicates the need for improvements to the decision process, modeling, and cost allocation in the electric power transmission planning.

For the first eight decades of the twentieth century, the US electric power system was characterized mostly by weakly interconnected vertical-integrated for-profit utilities that owned and controlled the generation, transmission, and distribution inside a franchised system boundary. Most of these utilities were cost-of-service regulated by the state of physical residence. Generally, planning consisted of forecasting load growth, deciding on the next generator to build and expanding transmission and distribution to reliably deliver the power to load. Load forecasts were based on forecasted economic growth. During this period, load growth, increasing economies of scale in generation, and other technological advances resulted in lower prices and a dominance of large nuclear and coal generators that required large amounts of rate-based capital.

In 1935, the Federal Power Act was amended to fill the regulatory 'gap' for transmission and wholesale sales in interstate commerce. Rates (aka prices) for transmission and wholesale sales are required to be just and reasonable and not

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M. R. Hesamzadeh et al. (eds.), *Transmission Network Investment in Liberalized Power Markets*, Lecture Notes in Energy 79,
https://doi.org/10.1007/978-3-030-47929-9_6

unduly discriminatory. Federal Power Commission (later renamed as the Federal Energy Regulatory Commission or hereinafter simply the Commission) was given this responsibility. For the next five decades, cost-of-service regulation determined these prices.

Over time, reliable operations became more important and the interconnections between utilities in different states were used to increase reliability and to execute economic trades often based on prices known as 'split the savings.' To facilitate this trading, some utilities formed power pools.

In 1978, fearing shortages of natural gas, Congress passed the Powerplant and Industrial Fuel Use Act (FUA) that outlawed the use of natural gas in new generators. In addition, in 1978, the Natural Gas Policy Act (NGPA) promoted a pricing regime to increase supply and removed the barriers to intrastate and interstate trade. Over time, the assumptions of the NGPA and FUA that natural gas was in short supply proved incorrect. In 1987, the FUA was repealed. Over time, most sections of NGPA were repealed.

Also in 1978, to encourage new forms of generation, Congress passed the Public Utility Regulatory Policies Act (PURPA) that required utilities to the purchase of energy from certain sources including co-generation, wind and solar at the utilities 'avoided costs' (similar to a feed-in tariff). A few states set avoided-cost rates high enough to attract wind and solar facilities. In other states, industrial customers built co-generation. PURPA gave birth to independent power producers (IPPs).

In the late 1970s and early 1980s, the prime rate for capital rose significantly and load growth in many utilities was considerably lower than predicted. The result was very expensive excess capacity. During the 1980s, economies of scale for coal and nuclear generation stopped increasing. Some policy discussions raised the idea of generation competition instead of geographic franchised monopolies (for example, see Joskow and Schmalensee 1983). Some utilities saw their generation investment as not earning a reasonable return on equity and sold off some of their generation to independent power producers. The average price of coal plants was about 200% of book value and average price of nuclear plants was about 10% of book value. To encourage competition, the Commission required open access to the transmission system as a condition of mergers. 'Experts' testified that open access would cause instability and blackouts. This was proven incorrect by actual experience.

In 1996, the Commission's Order 888 required that all utilities provide open access to their transmission system. Utilities had the option of forming an independent system operator (ISO). ISOs were given the responsibility for operating day-ahead and real-time energy and ancillary service auction markets with market power mitigation. This market design regulated by the Commission produced just and reasonable prices. In addition, ISOs were given certain transmission planning responsibilities including generation interconnection.

After correcting some early mistakes, the ISO energy markets have performed remarkably well and improved over time as the modeling, software and the underlying hardware all increased in capability to produce more efficient results. Over the next two decades after Order 888, seven ISOs formed and grew in geographic size. Today, US ISO markets account for over two-thirds of generation and consumption. The

ISO energy markets are highly competitive. The efficient energy dispatch function remains an independent monopoly service provided by the ISO. In the transmission sector, competition to build produces cost savings. The ISO remains an independent monopoly service for planning the transmission system.

In the 2000s, concerns about climate change and cleaner energy increased. Governments around the world increased subsidies for renewable energy and imposed carbon taxes. The competition in generation, technology advances in natural gas production, and renewable subsidies brought new challenges. Lower ISO energy prices caused concerns about premature retirement of coal and nuclear generators. Some states established aggressive 'clean energy' standards to combat climate change and other environmental issues. New federal and state subsidies formed the incentives to build wind, solar, and geothermal generators.

In 2003, to further articulate the open access interconnection process, Order 2003 separated the transmission expansion process and generation interconnection process. The rule implicitly used a vertical-integrated utility model and explicitly excluded transmission service from the interconnection process.

In 2005, Energy Policy Act added Section 219 to the FPA stating in part 'The rule shall (1) promote reliable and economically efficient transmission and generation of electricity by promoting capital investment in the enlargement, improvement, maintenance, and operation of all facilities for the transmission of electric energy in interstate commerce, regardless of the ownership of the facilities.' This responsibility falls to the Commission. The states retained regulation of retail prices, distribution, and siting decisions for generation, transmission, and distribution.

Historically, reliability standards were guidelines and compliance was voluntary. Steps to formalize, standardize, and computerize reliability started after the 1965 Northeast Blackout. Generally, reliability was confined to a vertically integrated utility and was a weakly defined concept that often included considerable judgment. Due in part to the 2003 Northeast Blackout, EPAct 2005 gave the Commission formal authority to regulate and enforce reliability standards.

In 2007, Order 890 required greater consistency and transparency in the transmission planning process on both local and regional level, economic planning studies, and cost allocation. In 2011, Order 1000 required the transmission planning process to consider transmission needs driven by public policy requirements established by state or federal laws or regulations. The rule requires that each public utility transmission provider must participate in a regional transmission planning process that has a regional cost allocation method for new transmission facilities selected in the regional transmission plan. Costs allocation must be 'roughly commensurate' with estimated benefits.

Over time, experience with the process raised the need for a course correction. In 2014, Former FERC commissioner Clark (2018) argued that less benefit has come from Order 1000 than expected. Clark concludes that the Commission should tailor the rule for ISOs.

Many transmission projects (often labeled repair and replacement of existing facilities, asset management or supplemental) have limited or no ISO review for either benefits or costs. The project costs are placed into rate base. Over the last decade, PG&E spent over 60% of its annual capital additions on 'self-approved' projects and overall ISOs, about 47% of the projects receive limited review (Bone 2018). In 2019, Huntoon states that 'virtually none of the costs [capital spending on transmission] is supported by cost-benefit analysis.' Industrial customers state they are seeing transmission costs rise each year without any benefits to show for it (RTO insider July 4, 2016).

From 2013 to 2018, competition was limited to only 2% of total U.S. transmission investments. Nevertheless, competitive processes led to innovations in proposed solutions, low bids, cost caps, cost control measures, and innovative financial structuring. Winning bids for competitive process averaged 40% below initial cost estimates while non-competitive projects were completed at 34% above initial estimates (Pfeifenberger et al. 2018). Subsequently, a study commissioned by the utilities argued that these claims were incorrect (Nicholson et al. 2019).

In the future, the mix of assets will change the nature of power systems and the way we model them. Traditional expansion-planning models focus on peak periods and certain off-peak periods. The penetration of renewables brings reliability concerns making the traditional analytic assumptions no longer valid. For example, it will be increasingly difficult to predict peak or stressful operation periods. 'Off-peak' or low consumption periods may experience higher prices and scarcity due to the lack of wind and/or solar generation.

In addition, it appears there will be a proliferation of new smaller devices, for example, smaller generators and storage devises. There will also be at least 100 times more information about the power system from smart meter penetration and phasor measurement units (PMUs) allowing more price-responsive demand to achieve economic efficiency. The regulatory response and modeling often experience significant institutional inertia. Market responses are much faster.

Existing approaches to transmission planning and investment have implicit and explicit assumptions, and approximations that need to be re-examined in the context of a smarter grid and increased amounts of energy from wind and solar generators, batteries, and price-responsive demand. Some approximations and assumptions in current models were necessary to make the planning problem computationally practical decades ago. Other assumptions and approximations are made to simplify uncertainty, such as failure modes and demand growth. Still, other assumptions and approximations were made in order to harmonize planning and investment approaches with the market design *de jour*. Many of these assumptions and approximations are out of date and limit advancements in optimal planning and cost allocation of the electric grid.

With the advent of large amounts of wind and solar along with storage and more price-responsive demand, the current approaches need to be modified. Today, for computational and management reasons, reliability models are decomposed, compartmentalized, and reduced in size using a mixture of engineering judgment, experience, and less transparent modeling. Planning results are tested for adequate voltage stability, short circuits, transient stability, and various other aspects of reliability. Over time, more of the constraints have been and will be modeled explicitly over larger regions as the data, hardware, and software for solving the problem improve.

The important issues are finding efficient transmission expansions, siting, cost overruns, efficient rate design, beneficiaries-pay cost allocation, and risk allocation.

In Sect. 2, we present the necessary components of 'reliable and economically efficient' power systems. In Sect. 3, we examine the principal uncertainties in planning. In Sect. 4, we examine the transmission expansion models. In Sect. 5, we analyze the transmission competition processes. In Sect. 6, we examine the cost and transmission rights allocations. In Sect. 7, we examine the transmission expansion process. In Sect. 8, we conclude with recommendations.

2 'Reliable and Economically Efficient'

The FPA requires that the Commission promote 'reliable and economically efficient transmission and generation.' The Commission accomplishes this through a combination of competition and cost-based regulation. The transmission expansion process consists of reliability upgrades, economic expansions, public policy projects, interconnection, cost allocation, and transmission rights allocation.

2.1 Co-Optimization

In 2013, Liu et al. (2013) strongly recommended co-optimization (optimization of the entire system) for planning. Co-optimization has many dimensions. Currently, the transmission planning process is decomposed into many separate analyzes. Some issues get less attention. For example, until recently the fuel supply was not analyzed explicitly because it was assumed not be a constraint on the optimal transmission expansion. Some reliability issues are studied in isolation without fully examining the options or cost/benefit analysis.

Reliability is a process of creating rules and penalties for non-compliance to reduce the probability of cascading blackouts, serious equipment damage, and forced load curtailment. Cascading blackouts affect large geographic areas and their prevention is a club good for those areas. The focus of planning has been N-1 reliability, that is, the system operation must be stable and able to survive the failure of any one asset with a high probability. In some areas, this focus is N-2. Reliability includes other rules for situational awareness, vegetation management, for example, tree trimming, and operator training that are not discussed in this chapter.

Reliability engineers and economic planners differ significantly in education and orientation. Reliability engineers often ignore the benefit/cost of the reliability solution. Without strong regulatory oversight, a cost-of-service regulated transmission owner would choose the solution with the higher capital costs. With smart grid technologies, less expensive alternatives may be available. Future planning should consider cheaper alternatives like remedial action schemes (RAS) and price-responsive demand.

Economic planners focus on finding efficient expansions with reliability rules as constraints. They prefer price-responsive demand to balance and stabilize the system as the first choice. Consequently, the reliability projects and efficient planning often proceed separately.

Reliable and economically efficient are concepts that should not be separated. Most if not all projects have both economic and reliability effects. Reliability upgrades are almost always by definition highly beneficial because they reduce the probability of a costly cascading blackout or forced curtailments. Reliability is an economic issue disguised in engineering terms. The economic benefits of not having a cascading blackout can and have been quantified. Economic upgrades have reliability benefits and reliability upgrades have economic benefits. Consequentially, it is more efficient to analyze both reliable and economically efficient projects as economic projects.

In ISOs, interconnection for large generation without access to transmission makes little sense. Order 2003 requires an interconnection customer to pay for interconnection before knowing the costs or scope of its transmission service. It could be better to present a complete cost of market participation. The transmission expansion process should include the interconnection process to maximize the expected economic efficiency of future power systems.

2.2 Price-Responsive Demand

Almost all reliability planning explicitly or implicitly employs a value of lost load (VOLL) calculation in its process. The VOLL is calculated by taking a reliability metric, for example, 1 outage event in 10 years using the average cost of constructing and operating a CT. The average cost of the marginal CT is the implied VOLL. Table 1 presents some examples of implied VOLL under various assumptions. Depending on the metric and the assumption in the analysis, the VOLL is usually greater than \$2000/MWh and often much greater. Few would believe that that given the choice of consuming at \$2000/MWh or more (over 20 times more than current average prices) and voluntarily reducing consumption, many consumers would choose the latter. To a reliability engineer, load reduction looks like a remedial action scheme (RAS). To economists, load reduction is a normal reaction to market prices.

Price-responsive demand is explicitly bidding a demand function into the energy auction markets. Historically, it was not possible to signal and charge most consumers the actual cost of producing energy because the metering process was incapable of measuring consumption over intervals less than a month. With the advent of smart interval meters and the high-speed Internet, measuring consumption and responding to dynamic prices are no longer a technical problem. High renewable penetration has made time-of-use pricing much less efficient.

Table 1 Various VOLL assumptions

Value of service (VOLL) \$/MW-year	Net capital cost (net CONE) \$/MWH	Hours per outage event hours/event	Optimal LOLE events/year	Optimal nines
\$4000	\$120,000	5	6.0	2.5
\$4000	\$80,000	5	4.0	2.6
\$4000	\$40,000	5	2.0	2.9
\$2000	\$120,000	5	12.0	2.2
\$2000	\$80,000	5	8.0	2.3
\$2000	\$40,000	5	4.0	2.6
\$20,000	\$120,000	5	1.2	3.2
\$20,000	\$80,000	5	0.8	3.3
\$20,000	\$40,000	5	0.4	3.6

Source Astrape Consulting (2013, p. 29)

Price-responsive demand can resolve many reliability issues. Forced unexpected curtailment and voluntary reductions in consumption have different values. Price-responsive demand can shift demand to other periods acting like storage. It can forego voluntarily consumption reducing the peak in the energy market and saving money while increasing the efficiency of the market. Price-responsive demand does not need a capacity commitment because it can get off the system when prices are high and is in effect its own reserve. It can also be a reserve (ancillary service) in the energy market, for example, AGC.

The transmission expansion plan should maximize the expected economic efficiency of future power systems using a price-responsive demand curve that includes VOLL at the high end, but more price sensitivity at the lower end.

Price-responsive demand should be modeled comparably to generators. If the load chooses to be explicitly price-responsive (bid into the market), it should have comparable bidding parameters to generation and storage. For example, load can bid the value of consumption in a single period or can bid a single value for an entire eight-hour shift using minimum run parameters. Price-responsive demand needs no capacity commitments since demand will voluntarily curtail itself when the price is too high.

2.3 *Market Power*

Restriction of transmission access creates market power concern by creating barriers to entry for efficient generation. The game theoretic discussions can be found in Sauma and Oren (2007) and Kimbrough et al. (2014). Game theoretic analysis adds an additional computational burden to an already difficult problem. In addition, game theoretic approaches are often very complex and require many assumptions that move markets away from market efficiency. In the US ISO energy markets, to avoid market power issues, generator offers are mitigated if necessary and transmission markets are predominately, cost-of-service regulated. Some transmission projects are competitively procured.

2.4 Siting and Eminent Domain

States retain the rights to determine the generation resource mix and have siting authority inside their respective states. At the state level, there is an ongoing debate of the balance between markets, subsidies, environmental, and regulatory concerns.

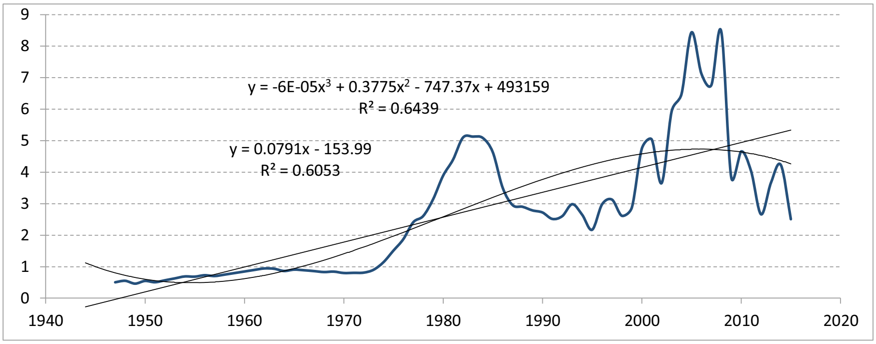
3 Uncertainty

All forecasts are wrong. Some are useful (generally attributed to the statistician George Box). History shows that power system planning is subject to profound long-run uncertainties in policy, externalities, technology, fuel costs, load shape, and load growth. Uncertainties in planning require planners to develop scenario visions of the future. Traditional planning methods have typically applied simple and ad hoc methods to address power system uncertainties. Integration of large amounts of renewable and distributed resources presents additional challenges.

Perhaps the biggest issue affecting ISO transmission planning is the uncertainty over the generation mix. Shifts are occurring in the generation mix with reductions in coal and nuclear offset by increases in natural gas and renewables. These changes have been accompanied by lower energy prices that pressure some types of generation to exit the market. However, there has been substantial resistance from both generators and states for some generators to exit due to, consideration of market externalities, such as resilience, fuel security, jobs, and importance of plants to local communities. These issues are usually not addressed directly in planning models.

3.1 Natural Gas Price Uncertainty

Natural gas prices are very difficult to forecast and currently are the principal determinant of energy prices. Figure 1 shows the history of natural gas prices and two regressions (linear and cubic). In 2018, the price of natural gas in real terms was the essentially same as it was in 1978. The linear regression shows a price increase over time. The cubic fit shows a mild cyclic behavior. Both have large error bands. The historic tendency is to predict future prices using a depletion theory that requires future long-term price forecasts to increase with a static economic resource base. Cyclic prices could be the result of new technology stimulated by higher prices that



Data source: U.S. Energy Information Administration

Fig. 1 U.S. Natural Gas Wellhead Price (in \$2006/MMBtu). *Data source* U.S. Energy Information Administration

increases the economic resource base. Under certain assumptions, using natural gas CCCT generation to charge EVs is more efficient and less polluting than gasoline vehicles.

3.2 Weather Uncertainty

Historically, the largest contingency was the largest generator on the system. In the near future, bad weather forecasts may be the largest contingency. Seventy percent of generator failures are due in part to weather. Fossil generator output is a function of temperature and the time since the last maintenance. Demand is a function of temperature and humidity. Transmission capability is due in part to weather. Solar output is a function of sunshine. Wind output is a nonlinear function of wind velocity and extreme cold temperatures. Hydro-output is a function of rain and snowfall. This creates difficulty in determining where and when the system is under the most stress. A cloudy and windless day or sequence of days requires significant amounts of storage discharge, fossil fuel generators, and/or price-responsive demand. A sunny and windy day may need little other generation with storage charging.

3.3 Technology Innovation Uncertainty

In the past, technology innovation has lowered the cost of coal generation. More recently, it has lowered the costs of wind and solar generation and the cost of natural gas. FACTS devices, better information and faster computers have increased the controllability of the transmission system and topology optimization (see O’Neill et al. 2005a, b; Fisher et al. 2008; Hedman et al. 2008, 2009, 2010). Smart meters have made price-responsive demand easier to implement. Technology innovations are difficult if not impossible to predict.

3.4 Risk Management

More complex risk-management techniques have been suggested such as value at risk and conditional value at risk. Most of these approaches are at the research stage of development for planning. Moreover, risk tolerance is both individual and systemic. The governments must decide what risks to socialize and what risks are privatized. Socialized risks can create moral hazards.

3.5 Summary

New uncertainties add more complexity to the process and a less predictable evolution of power systems. They raise questions of whether existing planning methods are adequate. As renewable penetration increases, flexibility for generators, load, and transmission becomes more important. Some ISOs recognize the need to incent operational flexibility. Therefore, co-optimization should include the ability to model flexibility (for example, ramping capability and operational range) in resource portfolios. Modeling operational reserve requirements and proper modeling of the costs of fossil fuel unit cycling need consideration. It is possible to develop co-optimization tools that handle uncertainty, but at a significant increase in computational burden and debate among the market participants. In ISOs, transmission expansions need greater transparency because they must pass market participants and Commission review.

4 Models

Models approximate reality. Models must tradeoff fidelity, detail, breath, and scope with the computational burden and cost of operation. Useful models must pass a benefit/cost test. New models must work against the institutional inertia—the traditional way of doing things. The result is a suite of models where each model focuses on a particular part of the process. This leads to iteration between high-level models with less detail and greater scope and more focused higher-fidelity models with greater detail and less scope. Some models test for reliable (feasible) solutions. Some search for economically efficient (optimal) solutions.

Lower-fidelity models are used to solve many rough-cut scenarios quickly in preliminary high-level analysis. Larger, higher-fidelity models are used to ensure the detailed or final decisions are consistent with lower-fidelity models.

Good approximations simplify the formulation to make it easier to solve while minimizing the impact on the optimal outcome. Today, approximations are mostly a mathematical art form passed from one generation of modelers to the next often with insufficient testing and documentation. They became part of 'good utility practice.' Weak approximations yield weak results that are harder to support.

4.1 Literature Review of Models

Many planning models use approximations to handle the magnitude of the problem and the computational difficulty presented by binary investment decisions. Garver (1970) and Villasana et al. (1985) presented linear programming approaches for finding feasible transmission network expansions given future loads and generation. Dusonchet and El-Abiad (1973) discussed the use of dynamic programming to deal with the size and complexity of a transmission planning optimization problem.

Romero and Monticelli (1994) proposed a method for solving network expansion-planning problems using mixed-integer programming, by relaxing the network problem to a transportation model and then successively introducing the complicating constraints. Baughman et al. (1995) discussed models for the inclusion of transmission expansion decisions. Gallego et al. (1996) presented a least-cost transmission expansion problem using simulated annealing. Gallego et al. (1998) presented a genetic algorithm approach for solving the transmission expansion problem. De la Torre et al. (2008) presented a mixed-integer program for long-term transmission investment planning in a competitive pool-based electricity market. Kazerooni and Mutale (2010) solve the N-1 security constrained transmission expansion optimization problem with environmental constraints. O'Neill et al. (2013) proposed a stochastic two-stage chance-constrained mixed-integer planning model. The objective of the model is to maximize the expected economic efficiency from investment.

Commercial models require higher documentation, verification, and transparency. Commercial modeling tools include production cost models that simulate operations, capacity expansion models, and reliability models. The model types and the issues they address are in Table 2.

ISOs use commercial models along with internal software. The ISO New England uses a high-level production cost model (http://www.iso-ne.com). The New York ISO uses ABB's Gridview, GE's MAPS (http://www.gepower.com) and Portfolio Ownership and Bid Evaluation (http://www.nyiso.com). PJM, Midwest ISO and SPP use Ventyx PROMOD (http://www.ventyx.com). California ISO uses ABB Gridview and PLEXOS (https://energyexemplar.com).

Table 2 Model type and reliability issue

Reliability issue	Model type		
	Generation and transmission capacity expansion	Production cost (unit commitment and dispatch)	Reliability (AC power flow, dynamic stability)
Generator adequacy (meet demand satisfying the loss of load probability	Often	Yes	No
Flexibility (adequate ramp rate and operating range)	Depends	Yes	No
Transmission adequacy (maintain thermal, voltage, and stability limits)	Mostly no	Partially	Yes
Generator contingencies (maintain reliability in a generator failure)	Mostly no	Somewhat	Yes
Transmission contingencies (maintain reliability in a transmission line failure)	Mostly no	Somewhat	Yes
Frequency stability (maintain frequency using inertia, primary frequency (governor) response, and regulating reserves	Mostly no	Somewhat	Yes
Voltage stability (maintain system voltage using reactive power)	No	No	Yes
Transient/rotor angle stability	No	No	Yes

Source Boyd (2016) modified

4.2 Hydro-Dominated Systems Models

Hydro-dominated systems have a different focus than non-hydro-dominated systems. For hydro-dominated systems, the main concern is a multiyear drought. In addition, hydro-generators are often a significant distance from load. Pereira and Granville (2001) explored a Benders decomposition approach to solving mixed-integer programming problems for the transmission expansion problem. Alguacil et al. (2003) proposed a mixed-integer programming formulation of the long-term transmission expansion problem with binary transmission investment decisions and applied it to a 46-node single period model of the Brazilian power system. Binato et al. (2005) presented a sigmoid function approach for binary investment variables in the optimal transmission expansion problem and tested it on a model of the south-eastern Brazilian system. In a market dispatch, the most important parameter is the opportunity cost of hydropower that changes based on the water levels in the reservoirs.

4.3 Production Cost Models

The current framework for production cost modeling involves simulations of the economic dispatch process for a chosen footprint and time horizon. The dispatch simulations may be performed with DC power flow or 'transportation-type' transmission constraints and with or without unit commitments, the introduction of binary decisions adds one or more orders of magnitude to the computations. While the current production cost modeling framework is useful for quantifying the economic effects of specific projects, it is weak as a tool for seeking the economically efficient set of projects from among a set of proposals or potential projects. For example, given a set of potential transmission and generation expansions, many production cost models do not give the option to find the economically optimal combination of projects under different scenarios. Such abilities may be useful in the context of analysis to support system-wide planning for the integration of renewable resources. Most optimal transmission expansion models do not incorporate transmission investments as binary decision variables. Co-optimized, stochastic models are mostly experimental and in limited use.

4.4 Reliability Models

Reliability models are necessary because the high-level models cannot adequately model reliability issues. Reliability models test the candidate transmission and generation expansions for reliability violations. Generally, they are high fidelity models with a narrow focus. They simulate dynamic events that occur in seconds not minutes. A transient stability model simulates whether generators remain synchronized after a contingency. AC power flow models check steady-state operational feasibility. Traditional reliability analysis focuses on periods of high load and whether the system remains stable after a power plant loss, a transmission line loss or power system instability. System dynamic models simulate dynamic events under fault conditions to examine transient stability. Network reliability models include GE's Positive Sequence Load Flow (PSLF), and Siemens' Power System Simulator for Engineering (PSSE).

4.5 Model Size and Approximations

Models can quickly balloon in size and computational complexity making it important to reduce its size without over-compromising fidelity. The ideal high-level planning model is a large, high fidelity, stochastic, mixed integer, AC power flow, and variable topology model. At this point, it is in the early research stage. The objective of the model is to maximize the expected market surplus (benefits to society) from new and existing investment. The approach advocated here integrates aspects from production cost modeling and investment models with large scale. It adds the capability to optimize transmission expansions over alternatives. Optimal topology including transmission switching is relevant because if a low capacity line in a circuit could block a valuable line then the low capacity line can be removed to improve the market performance. The model also recognizes generic generation investment alternatives and co-optimizes generation with transmission expansions with specified reliability levels and environmental goals.

The models are simplified in various ways. Simplifications include changing the granularity in topology, time step, number of periods and scenarios. In addition, some binary variables are converted to continuous variables. Table 3 presents the various degrees of fidelity and approximations. Planning and investment model can reasonably be given 10–50 times longer to solve than the day-ahead market models.

When high-level models are relaxed, this may create a need for additional intermediate models with more detail. One approximation or assumption may imply another. As the time step gets larger, for example, from one hour to one day, startup, and ramp rates issues fade in importance or disappear. Less granularity may remove the need to model the explicit probability of failure, unit commitment, minimum up and downtime constraints and ramp rate constraints. Approximations of this type may cause the model to lose some of the issues that new technology presents, for example, imposing a greater requirement on system ramp rate capabilities to respond to weather events, or near real-time decisions to start combustion turbines. Storage can be modeled as 'pumped' storage with time lags between charging and discharging or battery type without time lags.

Another approach is to model a typical and/or extreme weather day or week for selected seasons. Here, time granularity allows for commitment decisions. Sensitivity and scenario analysis can address many issues including sensitivity to data inputs, assumptions, and approximations. The list of possible sensitivities is large and can be computationally intense.

Table 3 Potential approximations and fidelity for high-level and intermediate models

Parameter/asset	Fidelity		
	High	Intermediate	Weak
Time period			
Year increment	1 year	5 years	10 years
Seasonal	Week	4 seasons	Peak annual
Daily	24 h	4 periods	Daily peak
Network topology			
Minimum voltage level	69 kV or lower	130 kV	225 kV
Geographic	Nodal	Balancing area	State level
Network equations	AC	DC	Transportation
Topology optimization	Optimal	Transmission switching	None
Max capacity	Flexible	Seasonal	Steady state
Generator			
Startup	Binary	Relaxed penalized binary	None
Minimum operating level	Binary	Relaxed penalized binary	None
Avoidable costs	Yes	Average costs	Marginal costs
Maximum operating level (generation and transmission)	Weather dependent	Steady state with moderate penalties for minor violations	Steady state with strong penalties for violations
Ramp rates	Yes	No	No
Minimum run time	Yes	No	No
Reliability	Full N-1	Sub-regional capacity set aside	ISO capacity set aside
Inelastic demand scenarios	5	3	1
Price-responsive demand	Like generators	Simple demand curve	None
Storage	Full arbitrage	Fixed	None
Relative computational difficulty	>1000	>50	1

5 Transmission Competition Models

In this section, we examine three ISO competition models: merchant transmission, competitive solicitation, and the sponsorship. Each has different positive aspects. To function properly, the rules must be firm, understood, and applied consistently.

5.1 *The Merchant Transmission Model*

In 2000, the Commission first granted negotiated rate authority to a merchant transmission project developer [see TransEnergie US Ltd., 91 FERC ¶ 61,230, at 61,838 (2000)]. A transparent open season process allocates some or all transmission capacity. Investors and their customers in a merchant transmission project assume the full market risk of the project. Currently, this process takes place outside the ISO transmission expansion process.

5.2 *The Competitive Solicitation Model*

In the competitive solicitation model, transmission planners with stakeholder input identify the efficiency-enhancing projects and then solicit bids from developers. The solicitation details should include who assumes the risks, what to build, and bidder qualifications. Market participants submit offers to build with their offer costs (that is, revenue requirements). The winning projects are eligible for regional cost allocation. CAISO, MISO. ERCOT, and SPP use this approach.

5.3 *The Sponsorship Model*

In the sponsorship model, transmission planners and stakeholders identify transmission needs and allow developers to propose potential solutions. The sponsorship model is performing well at finding innovative solutions. The choice of winning projects can be more subjective and subject to challenge. PJM, ISO-NE, and NYISO have used the sponsorship model.

5.4 *Cost Caps*

All projects in the transmission planning process should have cost caps and be evaluated at the cost caps. Cost caps for projects change the standard transmission development process by transferring some of the risk of overruns from ratepayers to the builder who is in the best position to control costs. Developers who fail to stay within their caps risk both the project and the offer cost recovery.

6 Cost and Transmission Rights Allocation

6.1 Beneficiaries Pay

Cost allocation occurs after each iteration of the optimal transmission plan. Cost allocation is a part of setting just and reasonable rates as the law requires. Conceptually, there is a general agreement and a circuit court decision (see *Illinois Commerce Commission, v. FERC*, U. S. Court of Appeals for the Seventh Circuit, August 6, 2009) that beneficiaries of transmission should pay for the transmission. The Commission requires that costs of transmission projects should be allocated to its beneficiaries 'roughly commensurate' to benefits. They also may receive the tradable associated transmission rights. There are significant disagreements on what beneficiaries-pay means, how much each market participant should pay and how the transmission rights are allocated. New projects must have a pre-construction benefit/cost ratio greater than one. If actual costs decrease the ratio below one, the additional costs of the projects should be based on rules set out when the project was authorized.

Some legacy approaches to cost allocation are license plate, postage stamp, highway/byway, distribution factor, and voltage level. Many do not pass the beneficiaries-pay cost allocation test. Beneficiaries often include generators, but generators are seldom allocated costs in the transmission expansion process. Order 1000 explicitly allows transmission expansion costs to be allocated to generation (Order 1000-A, 139 FERC ¶ 61,132 at P 680), but seldom does. Generally, transmission expansion costs are assigned to load regardless of the benefits to other market participants.

Benefits should be determined by the expected change in benefits or profits at the node due to the upgrade. When cost allocation disagreements occur, usually the strongest disagreements are in allocating costs to market participants not expected to benefit or not allocating cost to those who benefit (free riders). The 'Argentina' method where market participants vote on cost allocation based on proportion to their proposed cost allocation (see Littlechild and Ponzano 2007) as a method for allocation cost may be an appropriate approach to cost allocation. It could be binding or advisory.

Beneficiaries-pay cost allocation should be used for all projects including reliability and interconnection projects.

6.2 Theory of Cost Allocation

Some argue that transmission expansion is a public good. Since each transmission asset has a finite capacity and can become congested, it should not be characterized as a public good. When transmission assets become congested, they take on the characteristics of private good. Transmission should instead be characterized as a club good.

Cooperative game theory allows the participants to form into groups to cooperate and negotiate the cost allocation. Cooperative game theory contrasts with non-cooperative game theory where market participants are not allowed to communicate explicitly with each other. Markets are often analyzed under the non-cooperative game theory paradigm, for example, a Nash or perfect equilibrium as the model for deciding the optimal expansion. There is a vast literature on game theoretic cost allocation (see Young 1985, 1995). Many approaches are mathematically complex, others are computationally intensive and still others are both. Cost allocation using cooperative game theory includes the Shapley value, Nucleolus, and empty core models. If the market has an empty core or a free-rider problem, the market participants may not be able to agree on allocation rules and the Commission must impose them.

Projects may be complementary or mutually exclusive. For cost allocation in a multi-project environment, all projects should be taken as a whole. The value for all projects taken as a whole is not the sum of the individual value of each individual project.

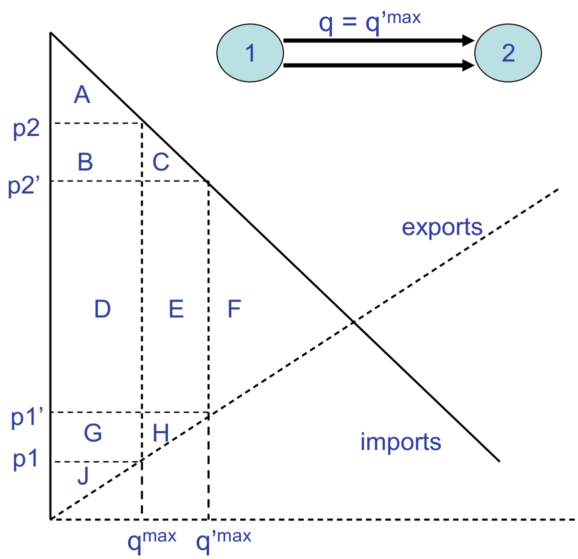
6.3 Two-Node Example of Cost Allocation

We present a simple model of cost allocation. All costs and benefits are expected. To simplify the examples, we assume market participants are risk neutral. First, we calculate the difference in the expected costs of energy at each bus with and without the new investments. This is a relatively easy problem to solve since the investment decisions are fixed.

Let SB be the incremental efficiency gains or benefits from a set of transmission projects; let DTR be the new transmission rights created by the expansion and TTC be the total cost of the transmission expansion. Auction the DTR, receiving RTR. Let NR (net revenues) = RTR–TTC. If NR $\geq$ 0, no cost allocation is necessary.

Let B_i be the difference between the expected costs of energy under the expected optimal investment and the costs of energy under no investment for a market participant or defined group of market participants i. $B_i > 0$ corresponds to lower costs of energy consumption for market participants i or higher profits for production under the investment as compared to no investment.

Example 1 Add a line from 1 to 2 increasing capacity from q^{max} to q'^{max}



Example 1 presents the benefits of an expansion similar to Hogan (2010). The pre-expansion export transmission capacity is q^{max}, and the benefits to the import region 2 benefits are the area A. The FTR or flowgate benefits are the area D + B + G = $(p2 - p1)q^{max}$ and the benefits to the export region are the area J.

After the expansion, the value of transmission rights is D + E = $(p2' - p1')q'^{max}$.

The post-expansion capacity is q'^{max} with cost of TTC. After the expansion, the total value of transmission rights is D + E = $(p2' - p1')q'^{max}$. The efficiency criterion to build is C + E + H (benefits) > TTC (total costs). The incremental benefits to the import region are the area B + C, the incremental transmission right benefits are the area E, and the benefits to the export region are the area G + H. The existing transmission rights are diminished by B + G. B and G are called pecuniary benefits (aka business stealing) because they are transfers from transmission rights holders not efficiency gains to regions 1 and 2.

If E > TTC, a merchant transmission developer will build for transmission rights.

If C + E + H > TTC > E, merchant transmission will not build without support from regions 1 and 2. A cost allocation is: the total net benefits are TB = C + E + H. The import region 2 is willing to pay up to B + C, the transmission incremental right holders are willing to pay up to E, and import region 1 is willing to pay up to G + H. Since C + E + H > TTC, there is a cost allocation where all beneficiaries are better off.

Should winners compensate the losers? Losers in this example are original transmission rights holders. If B + D + G − (D + E) < 0, the value of transmission rights decrease. This value is transferred to regions 1 and 2. By the assumptions, there is enough value to compensate the loss.

6.4 Transmission Rights and Allocation

In ISOs, the fundamental unit of a transmission right is a flowgate right with no risk of becoming a liability. A financial transmission right (FTR) is the right or obligation to receive or pay the price difference between two nodes and is cashed out in the day-ahead market. An FTR is a portfolio of purchases and sales of flowgate rights. They are sold under projected day-ahead market topology in proportion to the distribution factors between the two nodes. The portfolio changes if the topology changes. Who should take the risk of topology changes? An FTR has the risk of becoming a liability if the nodal price differences are negative and an underfunding risk if the topology in the day-ahead market is different from the FTR auction topology assumption. Who should take the risk or get the reward of topology changes? The TO who changed the topology or the transmission rights holders.

6.5 Numerical Examples of Beneficiaries Pay

In the series of two-node examples below, we illustrate some properties of the beneficiaries-pay cost allocation and the allocation of transmission rights to beneficiaries. In these examples, the flowgate right on flowgate 12 and the FTR from node 1 to node 2 are the same. We illustrate with example how generators benefit, how load benefits, how FGR holders benefit, and how to allocate costs to multiple beneficiaries. It is a straightforward calculation to extend the examples to a reticulated network.

Base Case Table 4 has the energy market parameters for the base case. The cost of flowgate 12 upgrade is $10/MW.

Table 4 Generators, load, and transmission parameters

Unit	Gen at node 1	Flowgate 12	Gen at node 2	Load at node 2
Network	①---②			
Minimum operating level (MW)	0	0	0	0
Maximum operating level (MW)	900	100	1200	1100
Marginal value (>0) or Marginal costs (<0) in $/MWh	−10	0	−50	90

Table 5 Base case: economically efficient solution with market surplus of $48,000 and flowgate 12 capacity is 100 MW

Unit	Gen node 1	Flowgate 12	Gen node 2	Load node 2
Dispatch in MWh	100	100	1000	1100
Maximum operating level (MW)	900	100	1200	1100
LMP/flowgate marginal price in $/MWh	10	40	50	50
Revenue (≥0)/payment (≤0) in $	1000	4000	50000	−55000
Cost (≤0)/value (≥0) in $	−1000	0	−50000	99000
Profit (≥0)/benefit (≥0) in $	0	4000	0	44000

The auction market results without a transmission upgrade are in Table 5. The economically efficient solution has a market surplus of $48,000. The marginal flowgate value on flowgate 12 is $40/MWh.

Case 2 With an expansion of at a cost of $7000, the capacity of flowgate 12 is 800 MW. The market results for Case 2 are in Table 6. The market surplus without the cost of expansion increases from $48,000 in the pre-expansion base case to $76,000—an increase of $28,000. The net benefits of expansion netting out the expansion cost is $21,000 ($28,000 − $7000). The B/C is $28,000/$7000 = 4. The entity that paid for the upgrade receives 700 MW flowgate 12 rights. The net benefits of the expansion accrue to the flowgate rights holder. The flowgate 12 value increases from $4000 to $32,000 for net increased benefits of $28,000. There is no net benefit change for generators or load.

Case 3 With an expansion of 900 MW at a cost of $9000, the capacity of the transmission flowgate is 1000 MW. The market results for Case 3 are in Table 7 with a marginal flowgate value of $0/MWh and the LMPs are the same at both nodes. The market surplus without the cost of expansion increases from $48,000 in the pre-expansion base case to $80,000—an increase of $32,000. The benefits of the expansion accrue to the generator at node 1 whose profits increase from 0 to $36,000 compared to base case. The flowgate is decongested and loses $4000 in value from the expansion compared to the base case. The generator and load at node

Table 6 Case 2: economically efficient solution with market surplus of $76,000 and flowgate 12 capacity of 800 MW

Unit	Gen node 1	Flowgate 12	Gen node 2	Load node 2
Dispatch in MWh	800	800	300	1100
Maximum operating level (MW)	900	800	1200	1100
LMP/flowgate marginal price in $/MWh	10	40	50	50
Revenue (≥0)/payment (≤0) in $	8000	32000	15000	−55000
Cost (≤0)/value (≥0) in $	−8000	−7000	−15000	99000
Profit (≥0)/benefit (≥0) in $	0	25000	0	44000

Table 7 Case 3: economically efficient solution with market surplus of $80,000 and flowgate 12 capacity of 1000 MW

Unit	Gen node 1	Flowgate 12	Gen node 2	Load node 2
Dispatch in MWh	900	900	200	1100
Maximum operating level (MW)	900	1000	1200	1100
LMP/flowgate marginal price in $/MWh	50	0	50	50
Revenue (≥0)/payment (≤0) in $	45000	0	10000	55000
Cost (≤0)/value (≥0) in $	−9000	0	−10000	99000
Profit (≥0)/benefit (≥0) in $	36000	0	0	44000

2 do not benefit. The generator at node 1 (the only beneficiary of the upgrade) would pay $9000 for the upgrade and receive 900 MW flowgate rights on flowgate 12 as a future congestion hedge.

Case 4 We increase the flowgate 12 capacity by 901 MW to 1101 MW at a cost of $9010. In addition, we increase the generation capacity at node 1–1150. The market results for Case 4 are in Table 8. The market surplus without the cost of expansion increases from $48,000 in the pre-expansion base case to $88,000—an increase of $40,000. All benefits accrue to the load at node 2 whose benefits increase from $44,000 to $88,000. The marginal flowgate value is $0/MWh and the energy prices are the same at both nodes. All benefits of the expansion accrue to the load at node 2 whose benefits increase from $44,000 in the pre-expansion base case to $88,000. The generators do not benefit. The load pays $9010 for the upgrade and receives 901 MW flowgate rights on flowgate 12 as a hedge against future congestion.

Case 5 We increase the flowgate 12 capacity by 901 to 1101 MW at a cost of $9010. In addition, we increase the generation capacity at node 1–1150 and add a zero marginal cost generator with a capacity of 500 MW. The market results for Case 5 are in Table 9. The market surplus without the cost of expansion increases from $48,000 in the base case to $93,000—an increase of $45,000. The load at node 2 and the new generator at node 1 benefit. The load at node 2 benefits increase from $44,000 to $88,000. The generator at node 1 benefits is $5000. With a marginal

Table 8 Case 4: economically efficient solution with market surplus of $88,000. Flowgate 12 capacity of 1105 MW and generation capacity at node 1–1150

Unit	Gen node 1	Flowgate 12	Gen node 2	Load node 2
Dispatch in MWh	1100	1100	0	1100
Maximum operating level (MW)	1150	1101	1200	1100
LMP/flowgate marginal price in $/MWh	10	0	10	10
Revenue (≥0)/payment (≤0) in $	11000	0	0	11000
Cost (≤0)/value (≥0) in $	−11000	−9010	0	99000
Profit (≥0)/benefit (≥0) in $	0	0	0	88000

Table 9 Case 5: economically efficient solution with market surplus of $93,000 and flowgate 12 capacity of 1105 MW and generation capacity at node 1–1150

Unit	Node 1		–	Node 2	
	Gen 1	Gen 2	Flowgate 12	Gen1	Load
Dispatch in MWh	600	500	1100	0	1100
Maximum operating level (MW)	1150	500	1101		
LMP/flowgate marginal price in $/MWh	10	10	0	10	10
Revenue (≥0)/payment (≤0) in $	6000	5000	0	0	11000
Cost (≤0)/value (≥0) in $	−6000	0	−9010	0	99000
Profit (≥0)/benefit (≥0) in $	0	5000	0	0	88000

Table 10 Beneficiaries-pay cost allocation

	Incremental benefits	Share of benefits	Allocated costs in $	Allocated flowgate 12 rights in MW
Load	44000	0.898 (=44/49)	8091	809
Gen2	5000	0.102 (=5/49)	919	92
Total	49000	1	9010	901

flowgate value of $0/MWh and loses $4000, the energy prices are the same at both nodes.

The incremental benefits of the expansion that accrue to the load at node 2 are $44,000 compared to pre-expansion case. The new generator at node 1 benefits is $5000. The load and new generator at node 1 pay $9010 for the upgrade and receive flowgate rights on 901 MW upgrade in proportion to their benefits. The load and gen2 pay and receive flowgate rights in proportion to the benefits. The calculations are in Table 10

6.6 *Efficient Incentives*

Currently, ISOs have two dominant transmission rate designs: stated rates and formula rates. Stated rates are set in a rate case and stay in effect until another rate case is filed or the Commission finds them unjust and unreasonable and changes them. For stated rates, the TO can keep any profits it earns by reducing its average costs between rate cases. Formula rates are set in a rate case and are updated annually based on actual costs. The formula stays in effect until another rate case is filed or the Commission finds it unjust and unreasonable and changes them. It is unusual for the Commission to find either rate unjust and unreasonable.

In 2000, Léautier (2000) proposed a regulatory contract that induces network operators to optimally expand the grid. The proposed mechanism builds on a contract used in England and Wales. In 2009, Léautier and Thelen (2009) find that vertical separation is not sufficient to induce grid expansion and needs a well-designed incentive scheme.[1] Contemporaneously, Hogan et al. (2010) considered combining the merchant and regulatory approaches that rely on FTRs. They suggested benchmark or price regulation for monopoly transmission and practical incentive mechanisms on two-part tariffs. The basic idea is that, in order to promote expansion of transmission networks, the foregone congestion rents are compensated to the TRANSCO with an increase of the fixed part of the tariff. The overtime rebalancing of the fixed and variable parts of the two-part tariff also promotes convergence to an optimal social-welfare steady state. In 2018, Hesamzadeh et al. (2018) proposed an approach to optimal pricing/investment that combines the Hogan et al. (2010) approach with the Loeb and Magat (1979) subsidy approach and suggested ways to incorporate demand and cost functions changing over time. Also, recently, Vogelsang (2018) advocates the Hesamzadeh et al. (2018) as a mechanism that compares favorably to a central planning and stakeholder bargaining approaches.[2]

The Commission's principal focus is getting new transmission built that is reliable and economically efficient over large regions. The principal impediments are rights of ways and beneficiaries-pay cost allocation. ISOs have more than one TO and much of the literature assumes a single TO.

7 Transmission Expansion Process

The optimal transmission planning process needs high fidelity data, good expansion proposals, a good suite of models, reasonable assumptions about the future, transparency, and market participant involvement. In addition, due to the uncertainty and approximations, this process must be iterative.

7.1 Scenarios

Scenarios are the result of a vigorous transparent public debate. Scenarios need to focus on assumptions about technology, environment, input prices, government mandates, and the probability of each scenario. Technological innovation and scientific discoveries have perplexed prognosticators for centuries. The assumptions about technological innovation can radically change the model outcomes. Controversial but important scenario parameters include the future prices of coal, oil, natural gas, and carbon (or amount of carbon emissions permitted). EIA produces annual long-term

[1] See also Léautier's chapter in this book (chapter "Regulated Expansion of the Power Transmission Grid").

[2] See also Vogelsang's paper in this book (chapter "A Simple Merchant-Regulatory Incentive Mechanism Applied to Electricity Transmission Pricing and Investment: The Case of H-R-G-V").

forecasts that are generally considered the default assumptions in analysis. This is not because EIA necessarily gets it right, but because they are the least biased and have the best information base. Some policy objectives are exogenously determined and can be incorporated with constraints and modification of cost coefficients. Each environmental pollutant (for example, CO_2, SO_2, or NO_x) can be priced or constrained in any geographic region. Minimum resource portfolios (for example, wind, solar or geothermal) can be required for any geographic region. The models are used to guide the planning process. Transmission projects are chosen to maximize economic efficiency.

7.2 Strawman Transmission Expansion and Interconnection Process for ISOs

We present a strawman transmission expansion process that includes the interconnection process.

Step 1. Update system data including transmission topology, generator, load, and storage parameters

Step 2. Estimate future demand, asset costs and operating parameters, and fuel costs. Create future scenarios. Assign a probability to each scenario.

Step 3. Find the expected optimal ('reliable and economically efficient') topology. This is a complex optimization problem. All scenario project results including cost allocation using beneficiaries-pay approach are presented to stakeholders. New generators may drop out of the process.

Step 4. Assemble a set of transmission projects that could lead to an economically efficient result. Conduct a competition for new projects chosen by the process.

Step 5. Have identified beneficiaries vote on transmission cost allocation weighted by the proposed cost allocation. Consumers may reduce their share of the cost allocation by agreeing to be price-responsive demand.

Step 6. Coordinate expansion with neighboring system.

Step 7. If there is general agreement, file the results at the Commission. If not go to step 2 or submit the results to the Commission to resolve disagreements.

8 Summary, Conclusions, and Recommendations for Further Study

8.1 Summary

In this paper, we presented a process for transmission planning, raised questions for approximations and relaxations, and examined several approaches to allocation of transmission costs and rights. The Commission must approve expansions, cost allocation, and transmission rights awards. Each state holds the ultimate veto over transmission expansion in the state because it retains the eminent domain decision for most projects.

8.2 Recommendations for Study of Modeling Process, Cost and Transmission Rights Allocation

- Consider merging the interconnection with transmission planning processes to co-optimize and to clear up the inconsistencies and uncertainties, to lower transactions costs and to increase the expected economic efficiency.
- Promote greater transparency and participation of the market participants especially those who receive a cost allocation.
- Generation and load are treated comparably.
- Combine the analysis of reliability and economic projects.
- Encourage the industry to improve modeling capability.
- Expand the competition models to more projects.
- Beneficiaries pay should be the overarching cost allocation principle.
- Those who request a public policy upgrade should pay for it.
- Offer flowgate rights on the upgrades.

The transmission expansion is a complicated and complex process. It should be subject to continuous improvement and not be static.

Glossary

B/C Expected benefit/expected cost ratio
DFAX Distribution factor
EPAct Energy Policy Act
ERIS Energy resource interconnection service
FGR Flowgate right that entitles the holder to the marginal value of a flowgate (FMV)

Flowgate A transmission line or collection of tightly interconnected transmission assets

FMV Flowgate marginal value is the value of another unit of capacity on the flowgate

FTR Financial transmission right obligation to pay/receive the difference in nodal energy prices. It is a portfolio of purchases and sale of flowgate rights. The value of the portfolio is determined by the flowgate marginal values

FUA Powerplant and Industrial Fuel Use Act

IPP An independent power producer not owned by the interconnected utility

ISO Independent system operator (an RTO is also an ISO.)

LGIA Large generator interconnection agreement

NITS Network Integration Transmission Service allows a network customer to integrate and economically dispatch and regulate its current and planned network resources to serve its network load in a manner comparable to the way a transmission provider uses its transmission system to serve its native load customers. Order No. 676-H, 2014

NRIS Network resource interconnection service

OATT Open access transmission tariff

Option FTR Financial transmission right the right to receive flowgate rights. It is a portfolio of purchases and subsequent sale of flowgate rights

PMU Phasor measurement unit

Pseudo tie is a transmission service that allows the generator to be dispatched by the receiving BA. The energy transfer is updated in real time and included in the actual net interchange term like tie line in the affected BAs' control ACE equations or alternate (NERC)

PURPA Public Utility Regulatory Policy Act

RAS Remedial action scheme that generally relies on control mechanisms to satisfy reliability

Resource adequacy Occurs when all generators are available there is enough generation to serve forecasted non-price-responsive load and have sufficient reserves taking into account the transmission constraints and outages

RTO Regional transmission operator

Specific delivery is a contract between a generator and load that requires energy injected into the system to be delivered to the load. This is physically impossible except in simple systems. A milder form of contract requires the injections correspond to the withdrawals

Sunk cost is a cost that has already been incurred and has no value in an alternative use

TLR Transmission line loading relief

TO Transmission owner

VOLL Value of lost load

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