Capricious Cables: Understanding the Key Concepts in Transmission Expansion Planning and Its Models

Six examples of transmission planning scenarios in which simplifications impact the modeling results can provide useful insights to non-technical participants in transmission planning. Because of modeling simplifications and future uncertainties, no single model can capture all aspects of transmission expansion planning. Instead, sensitivities and trends should be compared across multiple models and the results combined with broader contextual information.

Pearl Donohoo-Vallett, Michael Milligan and Bethany Frew

Pearl Donohoo-Vallett is an ESHI (Environment, Energy, Sustainability & Health Institute) affiliate at Johns Hopkins University. She is interested in robust decision-making and network design, focusing on the transmission network. Dr. Donohoo-Vallett holds a Ph.D. from the Engineering Systems Division at the Massachusetts Institute of Technology.

Michael Milligan is a Principal Analyst in the Transmission and Grid Integration Group at NREL. He has published more than 200 technical reports, journal articles, and book chapters on wind and solar integration and participates on the leadership team for numerous electricity advisory and working groups. Dr. Milligan holds a Ph.D. in Economics from the University of Colorado, Boulder.

Bethany Frew is a Postdoctoral Researcher in the Strategic Energy Analysis Center at NREL. Her primary research interest is to better understand how to meet electricity system needs with high penetrations of renewable energy through technical and institutional mechanisms. She holds a Ph.D. in Civil and Environmental Engineering from Stanford University.

Funding for the lead author was provided by NSF Grants OISE 1243482 and ECCS1128147. NREL's contribution to this work was supported by the U.S. Department

of Energy under Contract No. DE-AC36-08GO28308 with the National Renewable Energy Laboratory; funding provided by the Solar Energy Technologies Office.

I. Introduction

The extra-high-voltage transmission network is the bulk transport network of the power system. The design of this network determines which generation resources—whether hydropower, natural gas, wind, solar, coal, or geothermal—can be brought to market. Solving the major issues facing the power system will require more integrated and wide-area coordinated planning of the transmission network. These challenges include more load participating in operations, both as managed load and distributed production; rapid technology, cost, and customer changes; markets that could better reflect state policy objectives and long-term capacity and flexibility requirements; droughts and climate change; and costs, risks, and liabilities of natural gas as the default generation option. Transmission plans support decisions about what transmission is needed and where and when to build new transmission. Plans send investment and location signals to generators. They enable options that ensure low-cost, reliable grid operations. The complex economic and physical relationships in the power system, however, make it difficult to predict how the transmission planning decisions of today will impact the power system of the future. To understand how the power system may react to planning decisions today, wide-area transmission models are increasingly used to aid decision-makers and stakeholders.

In the United States, which consists of the Western Interconnection, Eastern Interconnection, and Electric Reliability Council of Texas (ERCOT) Interconnection, various stakeholders provide policy and technical input into a collaborative transmission planning process. In the Western Interconnection, the Regional Transmission Expansion Planning (RTEP) process is overseen by the Western Electricity Coordinating Council's (WECC) Transmission Expansion Planning Policy Committee. RTEP produces 10-year and 20-year regional-level plans. The Technical Advisory Subcommittee conducts the transmission planning study, including managing all data and modeling needs. Additional input and strategic guidance are provided by WECC's Scenario Planning Steering Group

and the Western Interstate Energy Board. In the Eastern Interconnection, technical and policy input from the Eastern Interconnection States' Planning Council helps to form scenarios that are evaluated by the Eastern Interconnection Planning Collaborative (EIPC). The EIPC conducts interregional macroeconomic analyses to complement local transmission planning efforts. In ERCOT, the independent system operator works with transmission service providers, market participants, and other stakeholders through the Regional Planning Group to fulfill transmission planning and construction needs.

The models used in these planning processes capture the interplay between transmission and capacity expansion. Building new lines allows multiple areas to share generator resources, thereby reducing the total required generating capacity among all constituent regions. These tradeoffs are shown in the *Comparing Resource Adequacy Metrics* study of the Western Interconnection in the United States (Ibanez and Milligan 2014). They analyzed alternative wind/solar build-out cases from the *Western Wind and Solar Integration Study Phase 2* (Lew et al 2013): the reference case had 8 percent annual energy from wind and 3 percent from solar, and alternative cases had 33 percent of annual demand supplied by wind and solar, split evenly, and high-wind/low-solar and high-solar/low-wind combinations. The objective of the *Comparing Resource Adequacy Metrics* study was to determine how much effective installed generator capacity could be replaced by transmission based on an assessment of resource adequacy. Key results are presented in **Figure 1**. The figure shows the reduction in effective capacity made possible by perfect transmission (copper sheet) within each subregion and by perfect transmission across the interconnection. Although copper sheet transmission is unlikely to ever be built, the example shows the tradeoff between transmission and generation and the impact that transmission can potentially have on the need for new resource additions. Transmission planning must necessarily account for this interplay.

Figure 1. Impact of Interconnection on Resource Adequacy in the Western United States (adapted from: Ibanez and Milligan 2014)

Transmission expansion planning models attempt to simulate tradeoffs in the planning process in their simplest form. Ideally, the transmission model would be able to capture all relevant considerations that could be brought to a planning process; however, in reality, even relatively simple models are difficult to solve because of the large number of complex computations required. As a result of this computational complexity, transmission system modelers simplify many aspects of the power system while trying to preserve the most important information. One way to retain the important information while also dealing with uncertainty is through **scenario analysis**, which evaluates multiple possible outcomes based on alternative, plausible inputs. In some cases, scenarios can be weighted by their respective probability of occurrence. Both scenario and **probabilistic** approaches are more robust than **deterministic** methods, which consider only a single possible outcome, or “single shot.”

The additional value from probabilistic methods, especially with increasing implicit variability and uncertainty from variable generation sources, may require advanced methods that capture a greater spectrum of possible scenarios (e.g., Gaikwad et al. 2015, NERC 2014). For example, a deterministic single-shot transmission planning result, below applied to a high-level graphic representative of Spain, yields different corridors and different capacities than a probabilistic dynamic programming model that was optimized throughout 30 years with investment decisions every 10 years. In this model, 50 percent of the lines constructed in the single-shot model are inconsistent with the dynamic programming model, with two 400-MW lines not constructed and one 400 MW line changed to a 750 MW line. Differences between the plans are circled in black on the single-shot map shown in **Figure 2**. Such simplifications as these can drive the results of an individual model since they can cause the model to miss solution-constraining information, as will be demonstrated in this article using simple examples for a subset of common simplifications.

Figure 2. Single-Shot Deterministic Compared to Dynamic Programming Probabilistic Modeling Results of Transmission Plans for Spain (Donohoo 2011)

Both the computational complexity and the difficulty of interpreting model results are driven by two characteristics of transmission networks. First, a transmission system is a network that obeys the laws of physics. Second, new investments in transmission or generation require significant financial capital to be committed over long periods, and because they can only be built in discrete increments, they are “lumpy.” As a result, planning models may not be intuitive and can be very sensitive to input parameters—small variations in model inputs can potentially produce very different model outputs. Adding to the complexity of understanding model results, modelers rarely have access to data governing specific generator contracts, ad hoc reliability constraints considered by system operators, or other proprietary data. Thus, some of the features of the existing transmission system are unknown and cannot be represented in the model at all. Given these complexities, the most important outcomes of a modeling exercise are understanding the system’s behavior, appreciating the model’s limitations, and grasping their implications.

Understanding the implications of modeling assumptions, simplifications, and lack of information can be difficult. This article explains the basic **transmission expansion planning model formulation** and highlights six of the major simplifications made in transmission expansion planning models. These examples also serve as the basis for questions that non-technical stakeholders in the transmission planning process can ask modelers to better understand the limitations and context of the model results in order to make more-informed investment decisions. These stakeholders include policy and environmental experts, state energy officials, public utility commission staff, tribal representatives, consumer advocates, and other groups involved in the transmission planning process. The examples shown in this article highlight two cases each from the categories:

- temporal simplifications,
- future generation development uncertainty, and
- inclusion of externalities.

Additional technical simplifications are also discussed. Examples presented here are very simple by design. The intent is to highlight simplifications made by various models and the necessity of context to explain the results of any given model both with the output of other models and with other power system relationships not captured in the modeling process.

II. The Basic Formulation

The transmission network expansion problem has been studied using computer algorithms since the late 1960s (Garver 1970). Although the algorithmic solving of the transmission expansion planning problem has evolved with dramatic increases in computational power, the core of the problem has not changed. Planning models are naturally framed as an optimization: minimize the cost required for the system to operate subject to physical and institutional constraints. Transmission expansion planning models minimize this cost by balancing the cost of new transmission investments against decreases in losses, generation costs, and the cost of “expected energy not served.” (Expected energy not served, EENS, is often the output of a probabilistic algorithm that produces a mathematical “expectation” that some load may not be served.)

Most models are presented in their mathematical forms. The set of equations describing the model, or formulation, are explained in **Box 1**, which shows the most common and critical elements of most models. The core of the optimization model is the **objective function**. This mathematical equation expresses the goal—objective—of the model. In a basic expansion planning model, the objective function minimizes the investment of the cost of new lines and operational (generation and non-served energy) costs on an annualized basis. The quantities the model can change to achieve the lowest cost are called **decision variables**. In a transmission planning model, the key decision variables represent whether a specific transmission line will achieve part of the goal of the objective function. This means that in the modeling process, some lines will be “built” and others will not. Following the objective function are **constraints**. These constraints set the conditions that a solution must meet; for example, a generator may not produce more power than its rated size. There are two key constraints in the transmission

expansion planning problem. The first, Constraint 1 in Box 1, is the energy balance at each bus. (The bus, or busbar, is a bar of metal that conducts electricity, usually contained within electrical equipment, where multiple electrical lines and/or equipment are connected. The bus is the common point of connection both in the physical world and in the corresponding model representation.) This constraint requires that the demand at each bus is equal to the sum of the energy generated at the bus plus the flow into the bus and minus the flow out of the bus. Throughout an entire system, this constraint implies that all demand must be met, and the quantity of the generation must be equal to the demand. The second key constraint, Constraint 2 in Box 1, is an approximation of the AC load flow. It relates the physical properties of the line to the phase of the alternating current at each bus. The formulae and terms used in Box 1 are the technical jargon used by modelers when describing which aspects of transmission planning their models capture. Understanding this terminology is important both for understanding information presented by modelers and being able to frame questions to modelers.

Box 1. Transmission Expansion Planning Model Formulation

Objective function: the goal of the model

Minimize:

$$\text{transmission_cost} + \text{operational_cost}$$

$$\text{operation_cost} = \text{cost_generation} + \text{cost_eens}$$

$$\text{transmission_cost} = \text{cost_per_line} * x$$

where x is the variable indicating whether or not a specific investment is selected

Decision Variables: the quantities that the model chooses. For transmission planning, the primary decision variable of interest is whether or not a transmission line between two nodes is constructed.

Constraints: restrictions on the values that variables may take or other conditions a solution must respect.

Constraint 1) $\text{demand}(i) = \text{generation}(i) + \text{eens}(i) + \text{flow_in}(i) - \text{flow_out}(i)$

The demand at any bus, i , must be equal to the amount of generation at that bus, the non-served energy, and the flow on any transmission lines into the bus minus any flow out on any transmission lines.

Constraint 2) $\text{flow}(i,j) = \gamma_{ij} (\theta_i - \theta_j)$

The flow on any transmission line between two buses (i and j) is proportional to the physical properties of the line and the difference in voltage angles at each bus. This constraint represents Kirchoff's second law and is an approximation that is called the DC load flow.

Constraint 3) $\text{flow}_k \leq \text{max_flow}_k$

The flow on any line, k , between two nodes cannot be greater than the maximum capacity rating for that line.

Constraint 4) $\text{gen_min} \leq \text{generation} \leq \text{gen_max}$

The output of any generator must be between its minimum and maximum output ratings.

Constraint 5) $x \in \{0,1\}$

Each possible investment, x , must be assigned a binary value of zero or one. The value is one if the line is constructed and zero if the line is not selected for construction.

III. Temporal Simplifications

Transmission lines are capital-intensive investments with economic life spans of 40 or more years. Throughout the life span of these investments, the power system will continue to evolve. Existing generators will retire, and new generators will be added. Loads will increase and decrease with the economy and new development patterns. Fuel prices will fluctuate as will technology adoption, market developments, operational standards and practices, national policies, and environmental regulations. None of these potential future values or events will be known with certainty, and even if they were known, a transmission expansion model cannot capture all of these varying future events and do so over all relevant time steps and timescales. Instead, modelers simplify the model and the number of time horizons to capture the most important details.

One of the most common simplifications made in transmission expansion planning models is to consider only a single investment decision time period. This is the first example in our set of six model simplifications considered here. With this simplification, modelers plan for a specific target year. Traditionally, plans have been constructed for short-term horizons (5–10 years) or long-term horizons (20–30 years).¹ The short-term horizon simplification is problematic because economies of scale are not captured in the modeling. As an example of these economies of scale, on a thermal-capacity basis, a 345 kV double-circuit line (tower with two sets of conductors) costs \$1,333/MW-mile, whereas a 765 kV, single-circuit line (tower with one set of conductors) costs 70 percent less, \$413/MW-mile²; however, with a limited time for demands to grow the need for larger lines, the full benefit of this line is never recognized. On the other hand, with a long-term horizon and the assumption of no new transmission throughout 20–30 years, there is a pent-up demand for new transmission, and large lines are almost exclusively selected.

This concept is illustrated in a simple three-bus model in **Figure 3**. In this model, a single load exists at Bus A with generators at Bus B and Bus C; these generators are already connected to Bus A via two 300 MW lines. These existing lines, however, cannot meet the new demands in years 10 and 20. In this system, there are two investment

options to expand the capacity: a 750 MW line from Bus A to Bus B for an annualized cost of 5 million USD (MUSD) or a 1,500 MW line in the same corridor for 7.25 MUSD annually. In the traditional myopic formulation, only the load in year 10 would be considered. In this case, only 400 MW of transmission capacity is required to meet the load, and the least-cost investment is the smaller 750 MW line. If, however, a second time horizon, 25 years, is considered, the demand has grown to 1,500 MW, and now an additional 900 MW of capacity is required to meet the demand at Bus A. The lowest-cost option is now the more expensive but larger line.

Figure 3. Test System for the Time Horizon Simplification

If the myopic model was used and only the smaller line was constructed, a second 750 MW line would have to be added to the system to meet the demand in year 25. This would have a net cost of 10 MUSD, 2.75 MUSD more than the single 7.25 MUSD line that would be sufficient to meet demand in both year 10 and year 25. Note that these cost figures, though somewhat arbitrary, are scaled to reflect relative costs of transmission

lines and generation. Given these costs, differentials between transmission options are commonly measured on the scale of millions of dollars.

Table 1. Investment Costs and Capacities for Time Horizon Simplification

	Cost (MUSD)	Capacity (MW)
Medium Line A–B	5	750
Large Line A–B	7.25	1,500

A possible conclusion from the example above is that larger lines should always be selected. A segment of the transmission planning makes the “right sizing” argument that lines should be built to the maximum capacity in a corridor (Stoel Rives 2010); however, this is not the argument we make here. The efficacy of right-sizing a line depends on the evolution of the power system throughout the lifetime of the investment, the size of the lines considered, and the difficulty of adding new lines in a specific geographic region. For example, right-sizing may not be the most economical solution for an area that has low demand and stagnant load growth. Instead, the point of the example above is that models commonly assume a single time horizon and that different answers can easily be obtained even in small problems when multiple time horizons are considered. In large systems that have thousands of buses, considering multiple time horizons can alter both the location of new transmission investment and its size. Thus, the relevant questions that non-technical stakeholders can ask to understand modeling limitations resulting from temporal simplifications include: “What time horizons were modeled?” and “How did the results vary across different time horizons?”

A second common temporal simplification in models, and example two in our study, is to consider few operational hours. Production cost modeling—using programs such as PROMOD, GE MAPS, Grid View, or PLEXOS—traditionally include the full 8,760 hours in each year; however, modeling the full 8,760 hours in a year for planning models is too computationally demanding. As a result, a select few hours are modeled. In some cases, only a single peak hour is modeled. The logic behind this selection is intuitive: if a primary goal of transmission expansion planning is to meet demand at the

lowest possible price, why not choose the most demanding hour? Simply put, overemphasizing demand and thus generation costs throughout the course of a year biases the system toward overdevelopment. Relevant questions here for modelers are: “Which hours were modeled?”, “How reflective are these hours of both peak and non-peak load hours?”, and “How do the results change if a different subset of hours is modeled?”

Take, for example, our three-bus system now modified to show two different demand levels. In **Figure 4**, the system has a peak load of 1,250 MW and an off-peak load of 500 MW. If only the peak hour is considered, the lowest-cost option is to build the larger 1,500 MW line. This configuration and its cost calculation are given in **Box 2**; the cost of the system with different configurations is given in **Table 2**. This large line allows the full peak load of 1,250 MW to be met using the lower cost plant at Bus B. If, however, peak conditions are assumed to exist for 10 percent of load hours and the remaining 90 percent are non-peak, the lowest-cost option now becomes building the smaller 750 MW line. The smaller line becomes a lower cost option because 90 percent of the year the demand can be met with the lower cost generator at Bus B. The more expensive plant at Bus C is required only during the remaining 10 percent of peak hours.

Figure 4. Test System for Hourly Demand Simplifications

Table 2. Investment Costs and Capacities for Hourly Demand Simplifications

	Line Cost (MUSD)	Capacity (MW)	Peak Hour Only System Cost (MUSD)	Peak and Off-Peak System Cost (MUSD)
Line A–B <i>Medium</i>	5	750	347	157
Line A–B <i>Large</i>	7.25	1,500	336	158

The simple problem shown in **Figure 4** also provides insight into one of the fundamental issues in transmission expansion planning. The annual generation costs in Table 2 are two orders of magnitude larger than the annualized transmission costs. This is not an artifact of the example selected. In existing power systems, transmission costs are typically less than 10 percent of the total system cost. As a result of this difference in costs, transmission expansion planning models will often select more transmission lines to access lower-cost generation than exists in current systems. These modeled plans

represent the most economic transmission expansion plans, but they do not account for institutional barriers such as siting or cost allocation. These institutional barriers can be partially incorporated into transmission expansion planning if an interactive process is used. For example, if a line selected by a planning model will encounter an area with known siting issues, the line can be rerouted and the model rerun with the new capital cost or removed from the set of options that the model can select.

Box 2. Cost Calculation Example for Temporal Simplification 2, Peak Hour Only

Output: 1,250 MW

Cost: \$30/MWh

Output: 0 MW

Cost: \$50/MWh

Total Cost Annual:

$$\begin{aligned}
 \text{Cost} &= \text{Transmission Cost} + \text{Operational Cost} \\
 \text{Cost} &= 5,000,000 \cdot x_{\text{medium}} + 7,250,000 \cdot x_{\text{large}} + \text{generation_cost} \cdot \text{hours} \\
 \text{Cost} &= 5,000,000 \cdot x_{\text{medium}} + 7,250,000 \cdot x_{\text{large}} + 8760(30 \cdot \text{gen}_A + 50 \cdot \text{gen}_B) \\
 \text{Cost} &= 0 + 7,250,000 + 8,760(30 \cdot 1250 + 50 \cdot 0)
 \end{aligned}$$

Demand:

	Demand(i)=	generation(i)	+	non-served energy(i)	+	flow in(i)	-	flow out(i)	
A:	1,250	0	+	0	+	1,250	-	0	
	=								
B:	0	=	1,250	+	0	+	0	-	1,250
C:	0	=	0	+	0	+	0	-	0

IV. Uncertainty Simplifications

Almost all transmission planning models consider specific scenarios with perfect knowledge. That is, the modeler assumes that all future demands, fuel prices, generator locations, and reliability issues are known. In reality, of course, we have very imperfect knowledge about the future. Natural disasters destroy infrastructure and cause major changes in fuel prices. Technological breakthroughs produce new generation types not

known to today's planners. Market developments can shift supply and demand over time. To capture some of this uncertainty, planning models can try to produce transmission plans that have low costs across a variety of different futures. An example of such a multi-scenario approach is the *WECC Long-Term Planning Scenario Report* (WECC 2013).

Take the three-bus example, the third in our series of six examples, now shown in **Figure 5**. In this iteration of the model, a new low-cost power plant may be constructed at Bus C with three different investment options presented by the planner (given in **Table 3**). The total system costs for each transmission and generation scenario are given in **Table 4**. If the planner had perfect foresight and knew that the plant would not be built, the lowest-cost investment option would be to build Line A–B and Line B–C. Note that because the system is networked, the most intuitive solution, building Line A–B only, is not the lowest-cost option in any scenario. Instead, building the additional line between Bus B and Bus C allows the lower-cost plant to meet the entire load at a lower cost by sending power across both the new lines and the existing line between Bus A and Bus C. On the other hand, if the planner had perfect foresight and knew the new generator would be built, the lowest-cost option would be to build only the additional capacity between Bus A and Bus C. If the planner assumed the generation is built and added only Line A–B, but the generation developer pulled out, the system would become very expensive to operate, by nearly a factor of five more.

Figure 5. Test System for Generation Location Uncertainty

Table 3. Transmission Costs for Generation Uncertainty System

	Cost (MUSD)	Capacity (MW)
Line A–B	5.0	750
Line A–C	5.0	750
Line B–C	3.0	500

It is clear based on the disparity among potential costs in the example above that the preferred objective is to find a plan that does well across a variety of possible futures. In the example above, if there is a 50 percent probability that the generation will be developed, the transmission plan that has the highest **expected value** build-out includes Line A–C and Line B–C. Expected value is the modeling term for weighted average, and it implicitly assumes that the decision maker is neutral. In the example here, if the probability of new generation increased to 60 percent, the expected cost for the build-out including Line A–C and Line B–C build-out would decrease from 248 MUSD to 231 MUSD, as shown in **Table 5**.

Table 4. Generation Uncertainty System Costs Given Different Generation and Transmission Scenarios

System Costs	New Generator (MUSD)	No New Generator (MUSD)	Expected Value (MUSD)
Line A–B	268	369	318
Line A–C	104	500	302
Lines A–B, B–C	161	336	248

Table 5. Calculation of Expected Cost for Generation Uncertainty System

<i>New Generator</i>			<i>No New Generator</i>		
Scenario Cost (MUSD)	* Probability of Scenario	+	Scenario Cost (MUSD)	* Probability of Scenario	= Expected Cost (MUSD)
161	* 0.5	+	336	* 0.5	= 248
161	* 0.6	+	336	* 0.4	= 231

With a risk-neutral decision metric, it does not matter how the transmission plan performs in individual scenarios as long as on average it performs well. A plan selected with a risk-neutral decision metric could have one scenario under which the plan performs very well and under all other scenarios performs very poorly. Likewise, the plan could have on average very good performance but a very poor outcome in a single scenario. Other decision metrics exist to differentiate between risk-averse and risk-seeking plans (see Binz et al. 2012 for a useful discussion on managing and minimizing risk in system-wide planning), but expected value is the most common modeling metric.

The simplifications thus far have been presented individually. In reality, however, the effects are not easily separable. In the test system presented in **Figure 6**, uncertainty regarding the construction of a new generator is considered (similar to that in Figure 5), but two time periods are now also considered. The test system shown in Figure 6, our fourth example, includes two existing generators, with costs of \$30/MWh and \$45/MWh, as well as two existing 400 MW capacity transmission lines. Three possible lines may be constructed: a large line from Bus A to Bus B, a medium line from Bus A to Bus B, and a medium line from Bus A to Bus C. In this example, the effects of uncertainty and multi-period modeling are combined.

Figure 6. Test System Combining Uncertainty and Multi-Period Modeling

A myopic view of the test system shown in Figure 6, one that considered only the first period, would always select only the medium-sized Line A–B. The medium-sized line allows the demand at Bus A to be met at the lowest possible cost in the near term. This solution, however, is blind both to the development of new generation and the growth in demand. When both time periods are considered and the planner knows the new generation will not be built, the lowest-cost investment option is the large-sized Line A–B. The large line allows the full demand at Bus A to be met with the cheaper generation available at Bus B across both horizons. When the planner considers both time periods and knows the generation plant will be built, however, the lowest-cost transmission decision in the first period is to build the medium-sized Line A–B in the first period and add Line B–C in the second period.

Table 6. Transmission Characteristics for the Uncertainty and Multi-Period Modeling Test System

	Cost (MUSD)	Capacity (MW)
Line A–B Medium	5.0	750
Line A–B Large	7.5	1,500
Line B–C	5.0	750

Table 7. Minimum Cost of First Period Transmission Investments

<i>First Period Transmission Investment</i>	New Generation (MUSD)	No New Generation (MUSD)
Line A–B, Medium	363	411
Line A–C, Large	366	400

In this example, the lowest-cost decision depends on whether or not the new generation will be built. Each point shown in **Figure 7** represents the expected total cost for the test system shown in Figure 6 with different transmission investments when the probability of new generation is varied from 0 percent to 100 percent. For example, when the probability of new generation is 10 percent, the expected system cost with the medium line is 396 MUSD and the expected cost with the large line is 406 MUSD. When the probability of a new generator is 90 percent, the large line becomes a less expensive option, with an expected value of 367 MUSD, compared to the medium line, with an expected value of 369 MUSD. As shown in **Figure 7**, building the medium line from Bus A to Bus B is the lowest-cost decision as long as the probability of the new generator being developed is less than 80 percent. Although it is not shown in this small example, using an expected value across scenarios may identify line combinations that have average values in individual scenarios but high expected values when considering multiple scenarios. These lines may not be identified if only the highest value lines from individual scenario analyses are considered.

From a planning perspective, there is some certainty about whether an existing generator will retire or a new generator will come online if its construction has begun. This timescale, however, is mismatched with the transmission planning timescale. A new transmission line takes five to 10 years to plan and build. A new wind power plant,

however, may be permitted and constructed in less than three years. Thinking further into the future and considering the 40-year life span of a transmission investment, it is impossible for a planner to know how the future will evolve. As a result, the planning discussion returns to one of risk. In the example here, the risk of new generation not being developed and the wrong size line being constructed must be weighed against the potential economic benefits if the new generator is constructed. Thus, the additional questions for stakeholders to ask modelers based on these two uncertainty-related examples include: “Which scenarios of future outcomes were considered?”, “What probability or likelihood of occurrence was assigned to each scenario?”, and “What decision metric was used to incorporate risk across scenarios (e.g., expected value)?”

Figure 7. Risk Illustration for New Generation Uncertainty

V. Externalities

Thus far, the costs included in the transmission expansion planning process have not been included in the external costs imposed by the power system. **External costs**, such as land-use impact and air pollution, are those that are not directly priced and that

may be imposed on unwilling or unknowing participants. These costs can greatly influence the lowest-cost transmission plan by accessing different generation resources and rerouting lines.

The goal of an optimization-based transmission planning model is to plan the lowest-cost system. Given the large number of transmission lines under consideration, transmission line costs are often modeled using straight lines between buses. Modelers do not have sufficient geographic or political knowledge to route lines, and when thousands of lines are being considered, it can be untenable to try to route them individually. As a result, plans from transmission expansion models underestimate transmission costs and may produce transmission routes going over mountain peaks or through protected habitat. Correcting these routes may change the optimal decision set.

In the test system shown in **Figure 8**, the fifth in our series of six examples, it has been discovered that a straight-line route must be modified to avoid a sensitive land use. This test system contains two existing generators, two existing 400 MW capacity lines, and two new investment options, one between Bus A and Bus C and one between Bus B and Bus C. Before the rerouting, the lowest-cost solution was to build Line A–B and Line B–C. The solution assumed that a straight line could be drawn between all buses; however, in the example below, it has been discovered that the proposed line between Bus B and C passes through a protected forest. To avoid the sensitive area, the line must be rerouted. The additional cable, right-of-way, and installation required with the new route increases the cost such that the lowest-cost solution becomes to build only Line A–B, as shown in **Table 8** and **Table 9**. Questions that stakeholder can ask to modelers based on this example include: “What external factors that could limit or otherwise affect transmission development were included?” and “Did the model exclude undevelopable areas (e.g., protected lands, areas with large slopes, or residential areas)?”

Figure 8. Routing Externality Test System

Table 8. Transmission and Generation Costs with Rerouted Line B–C

	Rerouting Line B–C (MUSD)
Line A–B	377
Line A–C	337
Lines A–B, B–C	378

Table 9. Transmission Cost Characteristics before and after Routing Line B–C

	Cost (MUSD)	Capacity (MW)
Line A–B	5.0	600
Line A–C	5.0	600
Line B–C (straight line)	3.0	300
Line B–C (rerouted)	9.0	50

Another set of externalities that may affect the results of a transmission expansion planning model are generator pollutant emissions. These include local air pollutants such as NO_x and SO_x as well as greenhouse gas emissions such as CO_2 . There are two

common ways to include these externalities, although it should be reiterated that these pollutants are unlikely to be included in a model unless explicitly stated. The first method is to develop a cost for each type of pollutant. These costs may be set to mirror market costs for the specific pollutant or set to the “social cost” of the emissions. **Social costs** are intended to quantify all external impacts of the pollution both on current and future generations. As an example of costing emissions, CO₂ could be priced at \$50/ton; this type of pricing is often referred to as a carbon tax. In the second method, a cap is set for each pollutant type. For example, a system could be limited to emitting 1 million tons of CO₂ per annum. Both the cap and pricing methods can be calibrated to produce the same generator dispatches and transmission plan results; however, it is difficult to compare the stringency of the imposed cap and cost policies across models. Our goal is not to debate which method, cap, or price, is preferred, but to demonstrate the effect of emission externalities on transmission expansion planning.

In the example shown in **Figure 9**, the last in our series of six, there are two existing generators and two 300 MW capacity transmission lines. The two generators have been assigned both generation costs and emissions rates. In the base case, in which no pollutant externalities are considered, the most economic option is to build Line A–B; this line accesses cheaper generation from the plant at Bus B. If, however, a \$45 emissions price is added, the effective price of the plant at Bus B raises from \$30/MWh to \$97.50/MWh. In this case, the plant at Bus C is now more economic, with an effective price of \$72.50/MWh. The most economical solution to meet demand with a \$45/ton emissions price is now to build Line A–C. As shown in this small example, the inclusion or exclusion of emissions prices has the ability to change the optimal transmission plan. The relevant questions for transmission planning modelers here include: “What externalities costs were included?” and “How did their inclusion or exclusion affect the results?”

Figure 9. Air Pollution Externality Test System

Table 10. Transmission Characteristics for Air Pollution Externality Test System

Transmission Characteristics	Cost (MUSD)	Capacity (MW)
Line A–B	5.0	750
Line B–C	5.0	750

Looking closer at the example problem, there is a pollutant price in which both generators will have the same effective price. At \$40/ton, both generators have an effective price of \$70/MWh. If the pollutant price were \$39.99/ton, the model would select line A-B. If the pollutant price was instead set to \$40.01, the model would select Line A–C. This type of “knife-edge” behavior, in which a small change in an input produces a dramatic change in output, is not unique to pollutant prices. Small changes in fuel prices, line costs, and other inputs can produce widely varying transmission plans. These abrupt changes are a result of the optimization algorithms underlying planning

models. If a small change in input, no matter how small, leads to a solution with a lower cost, the model will adopt the new solution.

This type of sensitivity is not revealed by a single model run, and without a sensitivity analysis there can be a false sense of confidence in the answer provided by the model. **Sensitivity analysis** is the process of changing the model inputs, rerunning the model, and comparing the change in output. If a model shows little sensitivity to varying input parameters, the solution found may be considered more robust. In our example problem above, if the generator at Bus B cost \$75/MWh, building line A–C would be the lowest-cost solution regardless of the emission price or cap. On the other hand, a sensitive model can provide stakeholders and decision-makers with additional insight into the planning problem. Depending on the sensitivity analysis, results may indicate instead that there are many good solutions, each with costs very near one another. The sensitivity analysis may also reveal the drivers of model behavior. One or two inputs, such as the cost of natural gas or the financial discount rate, may drive the results of planning models. Changing more than a single variable at a time reduces the number of model runs to be completed; however, this type of sensitivity analysis does not provide insight into which variable is driving the change in results. Understanding these key drivers can help direct future studies and elucidate the major issues for both stakeholders and decision makers.

VI. Further Technical Simplifications

The six test systems presented here have vastly simplified the physics of the real transmission expansion planning problem. In each of the test systems, we assumed that flow was directable rather than using the DC approximation of the AC load flow presented in Box 1. We also ignored reactive power, transformer costs, and reliability issues, such as N-1 contingencies and stability issues. Non-technical stakeholders should ask transmission planning modelers about the flow type and other technical assumptions and the caveats of these assumptions. The type of modeling presented here provides very valuable insight into the value of future transmission investments; however, it is fundamentally ill suited to identify near-term reliability and power quality issues.

VII. Summary and Conclusions

We need to plan wide-area transmission investments today for an uncertain future. Future natural gas prices will almost certainly fluctuate as a result of demand and supply variations, potential future liquid natural gas terminals, or governmental regulations on shale gas. National carbon policies may result in high penetrations of renewable energy. Potential transmission line routings may change with the discovery of cultural heritage sites. Given these uncertainties and the complexity of transmission expansion planning, models are needed to help inform and guide decision-making processes. Temporal, technical, uncertainty, and externality simplifications and assumptions are made in transmission planning models to reduce an otherwise computationally intractable problem.

Table 11. Summary of Common Simplifications Made in Transmission Expansion Planning Models

Simplification	Shortcomings/Issues	Recommended Practice	Possible relevant modeling questions
Temporal simplification with single investment decision time period	Location and size of new transmission investment depends on time horizon	Consider multiple time horizons	What time horizons were modeled? How did the results vary?
Temporal simplification with subset of operational hours	Overemphasizing demand biases the system toward overdevelopment	Include peak and non-peak load hours	Which hours were modeled? Do they represent peak and non-peak load hours? How sensitive are results to the hours chosen?
Uncertainty simplifications by considering scenarios with perfect knowledge	Transmission plan depends on unpredictable future system developments	Evaluate risk across a variety of different futures according to stakeholder risk preferences	Which scenarios of future outcomes were considered? What probability was assigned to each scenario? What decision metric was used to manage risk (e.g., expected value)?
Externalities simplifications by ignoring external	Externalities can influence lowest-cost transmission plan by	Conduct sensitivity analysis with	What external factors and/or costs that could limit or otherwise affect

costs imposed by the power system	accessing different generation resources and rerouting lines	multiple variables to gain insight into key model drivers	transmission development were included (e.g., right-of-ways, social costs)? Did the model exclude undevelopable areas?
Technical simplifications by ignoring very near-term reliability issues such as power quality and voltage stability	Details of AC flow, reactive power, transformer costs, and reliability issues can impact transmission plans	Conduct system impact studies and facilities studies to address these short-term reliability issues	What line flow type was assumed? What other technical assumptions were made? What implications could they have on the results?

This article highlights the impacts that multiple simplifications can have on the results of transmission planning models, and it presents corresponding questions that non-technical stakeholders in the transmission planning process can ask to modelers to better understand the context of the results for making more informed investment decisions. As we have shown in the six examples presented, these simplifications, as well as the inherent lumpiness of transmission investments, can greatly affect the location, size, and choice of transmission lines. **Table 11** summarizes these findings and relevant modeling questions. Because of modeling simplifications and because of the uncertainty in future power system development, no single model can capture or explore all aspects of the transmission expansion planning problem. The benefit of the models used in transmission planning, however, does not result from considering a single solution but rather by comparing sensitivities and trends across a variety of planning models and combining these results with broader contextual information.

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¹ NB, the Midcontinent Independent System Operator, and Southwest Power Pool have attempted to close these gaps. For example, see the Southwest Power Pools integrated transmission planning reports (http://www.spp.org/publications/20130730_2013_ITP20_Report_clean.pdf)

² Thermal limits and costs from American Electric Power.