PART 1 of 2

Evaluating Transmission Opportunities in Integrated Resource Plans

# Part 1: How to Incorporate Transmission in IRP Models

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## Authors and Acknowledgements


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INTERWEST
ENERGY ALLIANCE

### About Interwest Energy Alliance

Interwest Energy Alliance is a 501(c)(6) nonprofit regional trade association representing developers of large-scale renewable energy, storage, and transmission in six states in the Desert Southwest and Intermountain West. Interwest's mission is to create market opportunities for utility-scale renewables across the Interior West through policy and regulatory intervention.

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# Executive Summary

As electric utilities in the Interior West respond to rising demand and cost pressures, integrated resource planning must thoroughly evaluate the role of transmission in delivering reliable, least-cost generation portfolios. Yet many integrated resource plans (IRPs) still focus primarily on generation and either omit transmission completely or treat it as a fixed constraint rather than a flexible investment choice. This limits utilities' ability to identify lower-cost solutions and better manage reliability risks.

Well-planned transmission investments can reduce total system costs, improve reliability, and enable access to high-quality renewable resources. However, many utilities do not comprehensively model transmission constraints or evaluate expansion options in their IRP, and instead conduct separate transmission planning in response to generator and load interconnection requests. While separate generation and transmission planning may have sufficed in the past, it is no longer adequate for today's more complex grid characterized by tighter reserve margins and increasing geographic diversity of supply. With their detailed modeling, scenario analysis, and regulatory oversight, IRPs are well-suited to support integrated evaluation of both transmission and generation.

This report is the first in a two-part series. In Part 1, we provide a detailed review of modeling methods that utilities can use to incorporate transmission into integrated resource planning. Part 2 offers an in-depth review of five recent IRPs, with specific examples of how utilities implement each method. The utilities reviewed in Part 2 include Arizona Public Service, NV Energy, PacifiCorp, Public Service Company of New Mexico, and Salt River Project (see *Evaluating transmission opportunities in integrated resource plans Part 2: A review of Interior West utilities*).

By comparing utility approaches to incorporating transmission in IRPs, we aim to help regulators and utilities advance integrated planning for a more affordable and reliable grid. We hope this review prompts utilities to evaluate transmission expansion as they determine their least-cost investment portfolios in future IRPs. Where utilities do not do so voluntarily, regulators play a critical role in ensuring planning reflects evolving system needs and delivers cost-effective outcomes. By requiring IRPs to evaluate transmission, regulators and lawmakers can foster more robust planning, reduce system costs, and enhance long-term reliability.

## Recommendations for Evaluating Transmission Opportunities in IRPs

Utilities can use two basic steps to evaluate transmission expansion opportunities in their IRPs: 1) represent transmission constraints in IRP models, and 2) quantify the value of transmission expansion opportunities. This report explains five specific modeling and analytical methods utilities can implement to accomplish these steps:

| Method | Recommendation |
|---|---|
| Step 1: Represent Transmission Constraints in IRP Models | |
| **Resource Expansion Limits** in Capacity Expansion Models | Constrain new resource additions by zone based on known transmission capacity. |
| **Transfer Limits** in Production Cost Models | Apply transfer limits between load/resource zones and market zones to reflect known transmission constraints. |
| Step 2: Quantify the Value of Transmission Expansion Opportunities | |
| **Transmission Scenarios** | Model scenarios with specific transmission changes (e.g., new lines or rebuilds) to assess impacts on portfolio cost and composition. |
| **Transmission Expansion Options** in Capacity Expansion Models | Allow the model to exceed zonal limits by incurring costs that reflect necessary transmission upgrades. |
| **Transmission Planning Studies** Explicitly Integrated with the IRP Analysis | Use transmission planning studies to ensure that IRP models include accurate transmission constraints and upgrade options and that the final portfolio evaluation includes transmission costs required to deliver new resources. |

These methods can be implemented within existing IRP frameworks and have already been used successfully by several utilities in the West. However, other utilities have yet to adopt even basic practices for modeling transmission constraints in IRPs.

The following table summarizes the results of our utility-specific assessment, as presented in our Part 2 report.

### Which Western utilities best evaluate transmission opportunities in their IRP?[1]

| Rank | Utility | IRP Year |
|---|---|---|
| 1 | PacifiCorp (PAC) | 2025 |
| 2 | Public Service Company of New Mexico (PNM) | 2023 |
| 3 | Salt River Project (SRP) | 2023 |
| 4 | NV Energy (NVE) | 2024 |
| 5 | Arizona Public Service (APS) | 2023 |

[1] Interwest Energy Alliance, *Evaluating transmission opportunities in integrated resource plans Part 2: A review of interior West utilities*, 2025.

# 1. Introduction

**Should Transmission Be Studied in IRPs?**

The U.S. must double the grid's transmission capacity by 2050 to ensure it can reliably and affordably meet expected electricity demand.[2] In the Western U.S., the grid will need at least 15,000 miles of new high-voltage or regional transmission lines.[3] Many recent studies call for significant investments in new transmission as the most cost-effective strategy for achieving a reliable electricity system.[4] These studies show that investing in transmission can save consumers money by reducing overall system costs through savings on fuel, reductions in the overall need for generation and storage capacity, access to lower-cost and cleaner generation, and greater reliability, among other important benefits.[5] It is therefore essential that utilities adequately assess the benefits and value of expanded transmission connectivity.

Evaluating the full benefits of transmission upgrades that expand the electrical grid requires considering them in close coordination with plans to increase generation capacity. Planning for future generation needs typically occurs in a utility's integrated resource plan (IRP),[6] but IRP modeling has historically omitted key aspects of the transmission grid. For example, many IRPs lack a detailed representation of transmission constraints in the

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[2] Under current trends and policies, the lowest-cost electricity system portfolios require a U.S. transmission system that is 2.1 to 2.6 times larger in 2050 than in 2020 (DOE, *National transmission planning study*, 2024). Approximately 5,000 miles of new high-voltage transmission would be needed every year to meet the DOE study's targets, but only 322 miles were added in 2024 (Grid Strategies, *Fewer New Miles*, 2025).

[3] This transmission is in addition to large projects already underway, including NVE's Greenlink, PSCo's Colorado Power Pathway, and merchant projects like SunZia Transmission. If utilities planned regionally for a 2045 decarbonized grid, the West would need 110 GW of new inter-regional transmission capacity in addition to planned projects (Energy Strategies, *The Connected West study*, 2024).

[4] Estimates suggest every $1 invested in well-planned, high-capacity transmission produces between $3.80 and $4.70 in benefits for U.S. consumers (Grid Strategies, *Large-Scale Transmission Deployment Saves Consumers Money*, 2025). Two high-voltage transmission portfolios approved through MISO's *Long-Range Transmission Planning* produced $2.60-$3.80 and $1.80-$3.50 in benefits for every $1 invested. Similarly, a review of seven operating regional and interregional transmission projects found ratepayers saved between $1.10 and $3.90 for every $1 spent, and savings exceeded planning estimates (RMI, *High Voltage, High Reward Transmission*, 2025). Modeling of the lower 48 U.S. states found that eliminating interregional transmission constraints would have reduced generation costs by $5.8–7.1 billion in 2022 and $3.4–5.0 billion in 2023 (Ham et al., *Power Flows Part 2: Transmission Lowers US Generation Costs, But Generator Incentives Are Not Aligned*, 2025).

[5] Transmission provides a wide range of benefits that can lead to electricity system cost savings, but in this report we focus on the two most directly related to the core considerations in an IRP: the economic benefits that transmission can provide by reducing production costs and the capital costs of the generation portfolio required to meet resource adequacy standards.

[6] Some utilities use different labels for their integrated planning efforts, like Salt River Project's recent "Integrated System Plan" (ISP) and the "Electric Resource Plans" (ERP) of the Colorado utilities. For simplicity, we use "IRP" to reference all utility resource planning processes.

models used to simulate the economic dispatch of a portfolio of generation resources. IRPs also often rely on overly simplified cost assumptions for transmission upgrades that could expand access to new generation.[7]

An IRP that does not adequately reflect the transmission system cannot assess the value of transmission grid investments that support the least-cost generation portfolio. As a result, IRPs may understate the benefits of transmission expansion, leading to investment decisions with higher overall costs than would be realized through a more integrated and coordinated evaluation of transmission and generation investment opportunities together.

Figure 1 below contrasts the legacy approach to IRPs, in which transmission is generally not integrated, with our recommended approach of integrating transmission options into the planning framework from the beginning. The figure also reflects our recommendation that the IRP serve as the basis for post-IRP planning and investment that proactively incorporates IRP investments into transmission planning.

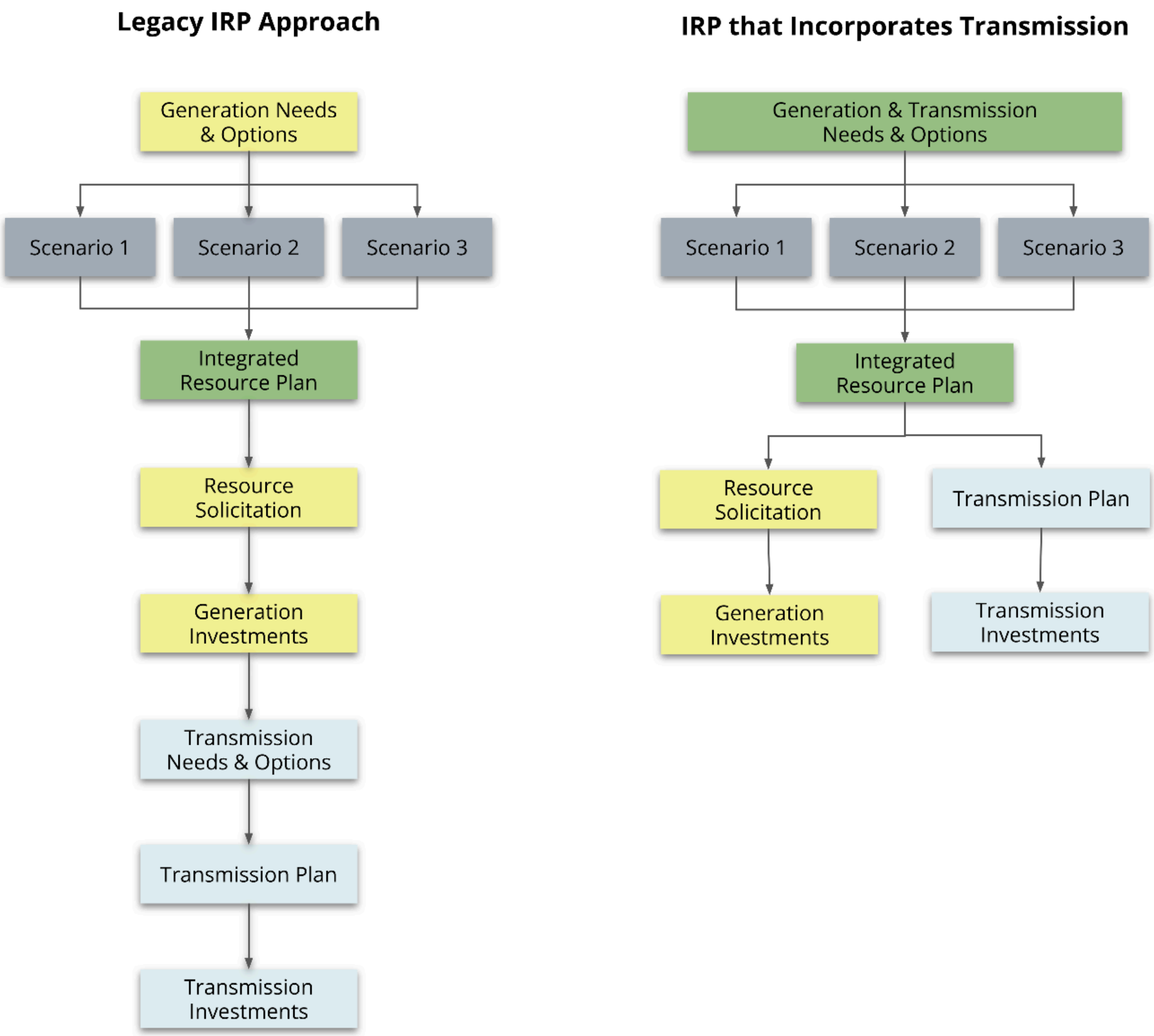
**Report Structure**

This report is the first half of a two-part series about evaluating transmission opportunities in IRPs. Part 1 describes the primary methods available for incorporating transmission into an IRP. Readers are encouraged to start with Part 1 for a review of how utilities can incorporate transmission in capacity expansion models, production cost models, and IRP scenarios and analysis. Readers familiar with IRP modeling may wish to skip to *Part 2: A review of utilities in the Interior West*, where we provide a detailed review of five recent IRPs and compare how well each incorporates transmission using specific examples.

Part 1 follows our recommendations for how utilities should set up an IRP to jointly evaluate generation and transmission expansion opportunities using two basic steps. First, utilities should configure their capacity expansion and production cost models to represent known transmission constraints on their system (see *Section 2: How to Represent Transmission Constraints in IRP Models*). Once the models include transmission constraints, the IRP analysis should quantify the costs and benefits of potential upgrades to the transmission system (see *Section 3: How To Quantify the Value of Transmission Expansion*). After explaining each method in detail, we summarize our general recommendations for evaluating transmission expansion opportunities in an IRP (see *Section 4: Summary of Recommendations*).

[7] Limited coordination between transmission and resource planning is a result of many factors, including legacy organizational barriers and the fact that each planning discipline has its own team of experts, vocabulary, datasets, modeling tools, and regulatory requirements.

Figure 1: Legacy planning evaluates transmission needs after the IRP identifies a generation portfolio. Evaluating transmission and generation together leads to coordinated investments and lower total system costs.



## 2. How to Represent Transmission Constraints in IRP Models

The purpose of an IRP is to provide a roadmap for a utility to reliably and affordably meet expected electricity demand over an extended time horizon, often 20 years or more. Constructing such a roadmap requires an integrated evaluation of a range of attributes and costs for three distinct parts of the electrical grid: generators that produce electricity, the transmission and distribution grid that delivers electricity, and customer programs that promote demand flexibility and efficiency. A successful IRP should identify a portfolio of investments—including generation, transmission, customer programs, and, ideally, distribution—that maintains a reliable grid and meets public policy goals at the lowest cost.[8]

Utility transmission planners routinely study how much electricity can flow on the transmission system under different conditions. However, this information is often excluded from IRP models. As a result, IRPs may overestimate the deliverability of remote generation or underestimate the value of transmission upgrades. The first step to ensure an IRP adequately evaluates transmission expansion opportunities is to include known transmission constraints in the IRP models.

A utility's IRP staff should work closely with their transmission planning colleagues to identify transmission constraints relevant for the two primary models that form the core of the IRP analysis: capacity expansion models and production cost models.[9] Typically, a capacity expansion model is used first to create alternative portfolios of generation resources that could meet the projected electricity demand under a wide range of system conditions while accounting for future uncertainties and policy goals. Then, a production cost model is used to simulate the hourly performance and optimal dispatch for each generation portfolio over the entire planning horizon to evaluate each portfolio's performance and cost.

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[8] For additional IRP best practices, see Synapse & Berkeley Lab, *Best Practices In Integrated Resource Planning*, 2024 or RAP, *Putting It All Together: Options for Modernizing Integrated Resource Planning*, 2025.

[9] Resource adequacy (RA) models are a third type of model essential to IRP analyses. We excluded them from our assessment due to the extremely limited information about their use in the IRPs we reviewed. However, it will be increasingly important for RA models to also reflect transmission constraints, especially when used at large scales for regional resource adequacy assessments such as the Western Resource Adequacy Program. RA models produce the effective load carrying capability (ELCC) of different generation types by simulating the ability of a resource portfolio to meet forecasted demand for a particular electrical system across a broad range of weather conditions. Typically, an RA model is used before a capacity expansion model to establish the ELCC values and planning reserve margin (PRM) used in the capacity expansion model.

Both models can be employed without including any representation of the relevant transmission system, resulting in what are often called "copper plate" models.[10] However, modern versions of these models can be configured to represent transmission constraints, which is the first step to evaluating transmission expansion opportunities in an IRP.

## 2.1. Define Resource Expansion Limits in Capacity Expansion Models

**Capacity Expansion Models**

A capacity expansion model chooses from a set of candidate generation and storage resource options to determine the least-cost mix of generation that can satisfy a set of specified constraints over a long-term horizon of 20 years or more. The constraints commonly specified may include a target planning reserve margin (PRM) and limits on pollution. Capacity expansion models usually use a set of representative days for each year to reduce the computational size of the optimization problem they aim to solve (this is different from a typical production cost model, which simulates every hour in the study period). Utilities use the output of a capacity expansion model to calculate the total costs of the least-cost generation portfolio, including fixed costs (such as capital costs or fixed operations and maintenance) and variable costs (including fuel, purchases and sales of energy, and variable operations and maintenance). However, the representation of variable costs is often simplified due to the model's simplified representation of time. It is therefore not as accurate or detailed as it is in a production cost model.

**Resource Expansion Limits**

A key input to a capacity expansion model is the menu of new candidate generation resource options the model may select from. This menu is key because the costs and performance attributes of the candidate resources can significantly impact the model's results. A capacity expansion model that omits transmission constraints can often select any quantity of any generation resource, without consideration of the feasibility of delivering that resource's output to load. To incorporate transmission constraints in a capacity expansion model, utilities can define the menu of generation resource options to reflect the transmission system's limits. We refer to the model parameters used to do this as ***resource expansion limits***, which are used to constrain the *quantity* (in megawatts, MW) or *timing* (first available year) of the generation options from which the capacity expansion

[10] The term "copper plate" suggests unlimited connectivity and deliverability between all generation and all load, as if connected by a copper plate.

model can choose, based on the transmission system's existing ability to deliver generation to load.[11]

### Single-Resource Limits vs. Comprehensive Zonal Limits

Many recent Western utility IRPs only represent transmission constraints by limiting the quantity and timing of one or two resource options, such as out-of-state wind or geothermal in a specific location.[12] However, this approach ignores transmission constraints that may limit the addition of other resource types or on other parts of the system.

A more comprehensive approach is to define resource options by zone and limit the maximum quantity of resource additions in every zone to reflect the transmission system's capacity to deliver resources from that zone to load.[13] In most cases, utilities already use zones to plan their system, or the IRP team can define these zones with help from transmission planners based on known transmission constraints.[14] In addition to being more comprehensive, this zonal approach allows for spatial differentiation of candidate generation options (such as different capacity factors for wind or solar in each zone).

### Resource Expansion Limits Can Change Over Time

Utilities should initially set resource expansion limits to reflect the maximum new generation in each zone that the existing transmission system could deliver to load centers. However, there are two important reasons these limits might change. First, suppose the utility plans to upgrade its transmission system. Those upgrades will affect transfer limits, and these changes should be programmed to occur in the model corresponding to the timing of the planned construction of the upgrades. Second, utilities can allow the model to exceed existing limits by incurring a cost representing the transmission network upgrades that could enable delivery of additional generation. Providing the model with the ability to

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[11] We are focused on resource expansion limits that reflect transmission constraints, but utilities may also limit the type, quantity, or timing of generation resource options for other reasons (e.g., technology availability, development timelines, etc.).

[12] Approaches are discussed in detail in Part 2 of this report; see Interwest Energy Alliance, *Evaluating Transmission Opportunities in Integrated Resource Plans Part 2: A review of Interior West utilities*, Section 2.1 (Resource Expansion Limits).

[13] Capacity expansion models can also be configured to include a zonal topology with transfer limits similar to a production cost model (whereas the approach we describe incorporates zones only indirectly through the menu of candidate new resources). However, most utilities use a zonal concept to set candidate resource limits rather than a zonal model topology because the latter approach increases the amount of data and calculations involved and leads to longer model run times.

[14] Defining zones requires planners to aggregate substations and associated transmission lines into contiguous zones that simplify the model. Utilities should explain how they determined the zones they use in IRP models.

consider transmission upgrade options allows it to evaluate tradeoffs between resource expansion options and transmission upgrade options (and the interaction between different options), potentially identifying a lower-cost overall portfolio of investments than would be identified with a model that ignores transmission constraints. We discuss approaches to evaluating these tradeoffs in *Section 3.2*.

**Resource Expansion Limits Summary**
Utilities can take the following steps to represent transmission constraints in capacity expansion models:

1. Define candidate resource options by zone. Zones should be defined based on known transmission constraints.
2. Limit the type, quantity, and timing of new resources in each zone to reflect known transmission system capacity.
3. Enable the model to exceed limits by incurring the appropriate costs (see transmission cost adders).

## 2.2. Define Transfer Limits in Production Cost Models

**Production Cost Models**
A production cost model simulates the detailed performance of a specified generation portfolio at an hourly or sub-hourly timestep for the complete chronology of a year or longer. The generation portfolio simulated by the model is a user-defined input and is often sourced from the output of a capacity expansion model. The attributes of each generating resource in the production cost model are represented with a high level of detail, including ramp rates, start-up costs and times, minimum up or down times, outage rates, scheduled outages for maintenance, and round-trip efficiency or leakage rates for energy storage resources.

For each hour in the study period, the production cost model simulates the level of load, price of power, generation outages, and renewable generation output. It then determines the generation levels from dispatchable resources and energy purchases (or sales, which generate revenue that offsets total costs) that can collectively meet the required energy and ancillary service needs at the lowest total cost over the study period, which can be a representative year or multiple years. Utilities use the output from a production cost model to calculate the total variable costs of using the simulated generation portfolio to meet the load requirements, including fuel consumption, emissions, and other performance attributes of interest.

### Transfer Limits

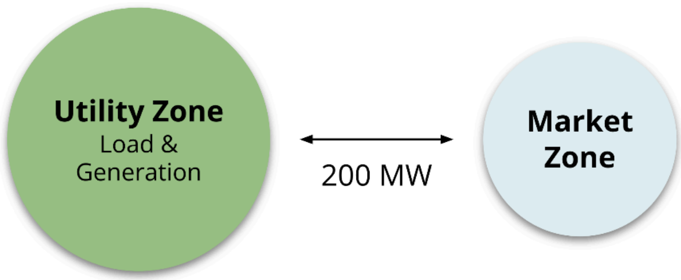
A production cost model that omits transmission constraints will represent hourly load with a single value (MW) required to be served in each hour, and it will assume all generators in the portfolio can be used to meet this load. In reality, transmission limits can constrain the dispatch of the generation portfolio. For example, limits on the transmission system's ability to deliver generation located far from load may require curtailment of that resource and an offsetting increase from generation at a plant closer to the load, even if it costs more.

Utilities can represent transmission constraints in a production cost model first by segmenting the utility's generation and loads into multiple zones. The connectivity between zones can then be defined with ***transfer limits*** representing the maximum quantity (MW) of power the model allows to flow between two zones at any given time.[15] The location and number of zones in a production cost model can vary significantly and should be tailored to each utility's system.

In practice, many utility production cost models contain only one utility zone and one market zone, which means they do not represent any internal transmission constraints within the utility's system. Figure 2 depicts an example of this, where the model represents the utility's entire generation and load within the single utility zone, and the market zone simply represents the price at which the utility may buy or sell power from the wholesale market (typically, no modeled generation or load is included in the market zone). Transfer limits between utility and market zones can specify the maximum amount of power that can be bought or sold during each period, though sometimes these transfers are not limited in the model.

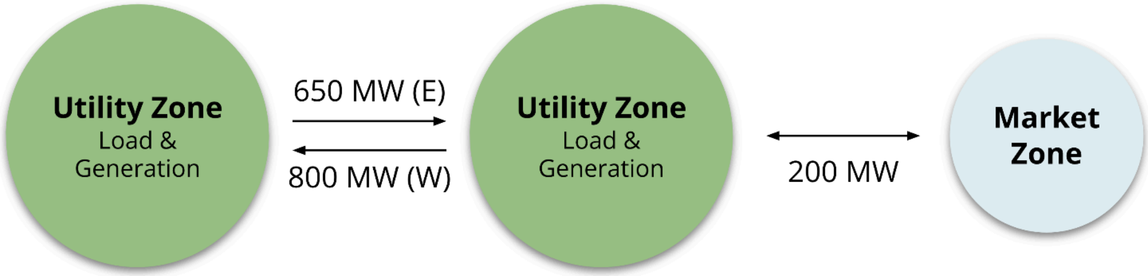
[15] As an alternative to using zones, it is possible to conduct nodal production cost modeling in which every line and substation on the bulk power system is modeled. However, this is computationally intensive and none of the utilities we reviewed currently use nodal production cost models.

Figure 2: The simplest production cost models only limit market transfers and don't represent any internal transmission constraints on the utility's system. Here, we show an example of a 200 MW market transfer limit.




More detailed configurations are possible by defining multiple utility and market zones and including transfer limits representing constraints between the zones. Figure 3 shows an example of this. Utilities with larger transmission networks are more likely to need multiple zones in their production cost model. Transfer limits between zones can be bi-directional or different in each direction (e.g., "650 MW west to east").

Figure 3: Defining two or more utility zones is required to represent internal transmission constraints as transfer limits between utility zones, and can represent different limits in the east-to-west and west-to-east directions. The transfer limit values shown here are examples.




**Import Limits**

Utilities often set transfer limits between utility and market zones based on estimates of market depth provided by their operations teams.[16] These estimates are typically drawn from past experience and do not always account for transmission constraints. IRPs should clearly state whether import and export limits are based on available transmission capacity or on assumptions about how much energy can realistically be purchased from

[16] Market depth refers to the maximum volume of wholesale energy that the utility could expect to purchase from other utilities or market participants.

neighboring systems. These assumptions directly influence the IRP analysis of new transmission connecting the utility to neighboring systems. Defining external transfer limits is increasingly important because transmission between balancing authority areas will become more valuable as utilities increase regional collaboration through day-ahead markets and resource adequacy agreements.

**Production Cost Impacts**

Using transfer limits in a production cost model enables utilities to ensure their simulations realistically reflect how transmission constraints affect the dispatch of the generation portfolio and the associated operational costs. However, it is insufficient to represent transfer limits without evaluating their impacts. Utilities should report the extent to which transmission constraints impact production costs for each modeled portfolio. This information is critical to understanding potential production cost benefits of transmission expansion, which should be considered alongside costs when evaluating transmission upgrades as part of the IRP portfolio.

**Transfer Limits Can Change Over Time**

Most utilities set fixed transfer limits. However, as we discuss in *Section 3.2*, a zonal capacity expansion model can be provided with transmission upgrades as an option that the model can select. Transmission upgrades that increase transfer limits increase access to additional generation and may reduce production costs by enabling greater use of lower-cost generation. Quantifying these production cost savings may require iterative capacity expansion and production cost modeling, because cost savings enabled by transmission upgrades should be incorporated into the capacity expansion model's optimization. Utilities can also manually configure transfer limits to change at future dates to reflect planned transmission upgrades. In all cases, it is first necessary to define multiple zones in the production cost model and set transfer limits between them based on existing transmission constraints.

**Transfer Limits Summary**

Utilities should take the following steps to represent transmission constraints in production cost models:

1. Define multiple utility zones and market zones based on known transmission constraints (ideally, these are the same zones used to define resource options).
2. Apply transfer limits between zones.
3. For transfer limits to/from market zones, clarify the roles of transmission capacity and assumptions about market depth in determining the limits.
4. Quantify and publish the impact of transfer limits on production costs.
5. Configure transfer limits to change at future dates when appropriate to reflect planned upgrades.

# 3. How To Quantify the Value of Transmission Expansion

After capacity expansion and production cost models are configured to include an electrical grid's important transmission constraints, utilities can analyze the benefits of transmission upgrades that relieve those constraints. This section explains three methods some utilities use to quantify the value of transmission expansion in their IRP: transmission scenarios, transmission expansion options in the capacity expansion model, and transmission planning studies.

## 3.1. Use Transmission Scenarios to Compare Total Portfolio Costs With and Without Transmission Upgrades

A simple way to quantify the economic value of a transmission investment is to compare the total cost of the IRP portfolios created with and without a transmission upgrade in place.[17] Scenarios are common in IRPs, though they are rarely used to evaluate transmission expansion opportunities. Instead, utilities typically use IRP scenarios to analyze the impact of uncertain external variables such as load growth, state and federal policies, or technology cost trajectories. However, some utilities have begun including scenarios designed to evaluate the benefits of transmission expansion.

We use the term ***transmission scenario*** to refer to any IRP scenario in which changes are made to how the transmission system is represented, relative to a base case or other comparison scenario.[18] By changing assumptions about the future transmission grid in one scenario, planners can isolate the impact of that change on system costs and performance.

Transmission scenarios can answer questions such as:

- How did the optimal generation portfolio change when the transmission upgrade was added?
- How did the upgrade impact total system costs, including production costs?
- Do the costs saved by adding transmission justify the investment?

[17] We are focused here on the economic value that transmission upgrades can provide via production cost savings or reductions in the total cost of generation capacity, which are the values most commonly studied in an IRP. Transmission can provide other electricity system cost savings, but those are rarely addressed in IRPs and are not addressed in this report.
[18] Some transmission scenarios we discuss could also be considered "sensitivities," which typically refers to changing only a single variable (e.g. "technology costs") rather than a set of variables as is typical of IRP scenarios (e.g. "Strong Climate Policy," which lowers technology costs and increases other costs such as the cost of carbon, electrification levels, and gas prices).

**Example:** Imagine a utility considering a new transmission line that could increase deliverability by 800 MW from one zone (say, a "West Zone") and be in service by 2035. The utility could run a capacity expansion scenario with the transfer limit between the West Zone and its load center increasing by 800 MW in 2035. In this scenario, the capacity expansion model could select up to 800 MW of new generation in that zone without the transmission expansion cost (the cost will be addressed in *Section 3.2*). In addition to adding more generation resources, this adjustment would likely change the optimal resource mix the model selects in all zones. The utility could then run the resulting portfolio through its production cost model, which would also have the 800 MW increase in deliverability from the West Zone. The utility would compare the results of these models with those from a scenario that did not include the increase in West Zone deliverability, and the difference in total costs would be attributed to the value created by the transmission investment.

Utilities can combine transmission scenarios with co-optimization methods such as transmission cost adders discussed in *Section 3.2*. While both are useful for quantifying the value of transmission expansion options considered in an IRP, scenarios may sometimes be more actionable and easily understood by stakeholders. Scenarios can inform investment decisions by isolating a known potential transmission project and showing whether it produces net portfolio benefits by reducing costs or improving reliability.

**Transmission Scenarios Summary**

Utilities should:

- Include scenarios with specific transmission changes (e.g., new lines, rebuilds, timing adjustments) to evaluate the impact on portfolio composition, cost, and performance.
- Use multiple scenarios to evaluate different conceptual transmission upgrades or portfolios of upgrades.

## 3.2. Include Transmission Expansion Options in the Capacity Expansion Model

**Manual vs. Model-Selected Transmission Expansion**

Constructing transmission scenarios requires IRP planners to manually adjust transmission constraints in the models to reflect potential upgrades and then compare results from the models with and without the changes. In contrast, transmission expansion options can be included in the capacity expansion model's menu of candidate options alongside new generation resources, allowing the model to directly select or "co-optimize" the least-cost combination of generation and transmission investments. Utilities can include transmission expansion options in a capacity expansion model in two ways: 1) using transmission cost adders in a capacity expansion model that does not have zones defined, and 2) defining transmission upgrade options directly in a zonal model.

**Transmission Cost Adders**

*Transmission cost adders* represent the cost of transmission upgrades needed to exceed resource expansion limits in the capacity expansion model and thereby increase delivery of new generation to load.[19] Transmission adders are expressed as a $/MW cost added either to individual resource options in the capacity expansion model or comprehensively to all resources in a zone. Utilities should derive transmission adders from high-quality cost estimates for the conceptual transmission projects the utility could pursue if the model selects upgrades as part of the least-cost portfolio.

By applying different transmission cost adders to resource expansion options in multiple zones, the capacity expansion model can consider the cost of transmission upgrades jointly with its decisions about which new generation resources to add. Ideally, resource options are differentiated by geography (e.g., wind generation in different zones might have different capacity factors). The model may then reveal that a resource requiring expensive transmission upgrades has other offsetting benefits—such as a high capacity factor or geographic diversity—and the model can factor this into its optimization.

[19] Transmission cost adders are distinct from interconnection costs, which cover the local upgrades needed to connect a generator to the transmission grid, are typically included in the base capital cost of a resource, and which do not impact transfer limits between zones.

**Example:** Consider a utility with 300 MW of transmission capacity available to deliver resources from its North Zone to its primary load center. The capacity expansion model should be limited to selecting up to 300 MW of new resources in the North Zone. However, for $300 million, the utility could build a new transmission line that would be in service by 2030 and increase deliverability by 600 MW. Starting in 2030, the model could be given the option to select up to 600 MW of additional resources in the North Zone, but with an added cost of $500/kW to reflect the new line.[20] The amount of generation the model selects beyond the initial 300 MW limit will provide evidence about the cost-effectiveness of the new transmission line's ability to increase access to new generation.

**Transmission Upgrade Options in Zonal Capacity Expansion Models**

Transmission cost adders are the simplest and most common way to consider transmission and generation investments in capacity expansion modeling jointly. However, utilities can also configure zonal capacity expansion models to include ***transmission upgrade options*** that the model can select alongside resource expansion options. Including transmission upgrades explicitly requires use of a zonal topology in the capacity expansion model, such that transmission options can either add interconnection capacity (enabling more resource additions in a particular zone) or transfer capacity (relaxing transfer limits between zones), or both.[21]

Similar to cost adders, including transmission upgrade options allows the model to select additional generation resources if the value they add justifies the cost of necessary transmission upgrades. However, cost adders and transmission upgrade options have important differences. In addition to requiring a zonal capacity expansion model, transmission upgrade options are typically modeled as all-or-nothing choices (the model must select the entire upgrade or no upgrade). In contrast, models that use transmission cost adders can incrementally add any quantity of new resources with the associated $/kW cost added. Modeling all-or-nothing choices is computationally more difficult than incremental additions, but it also produces more accurate results because the model must either select or not select a specific transmission upgrade as part of the least-cost plan. When transmission cost adders are used to indirectly represent transmission upgrades, the

[20] $500/kW is the added capacity divided by capital and maintenance costs in this simple example.

[21] Only one of five IRPs we reviewed included transmission upgrade options in the capacity expansion model; see Interwest Energy Alliance, *Evaluating Transmission Opportunities in Integrated Resource Plans Part 2: A Review of Interior West Utilities*, Section 2.4 (Transmission Cost Adders).

capacity expansion model may only select a portion of the new generation that a transmission upgrade could deliver (and therefore a portion of the transmission upgrade), requiring utilities to separately examine if the complete transmission upgrade is worth the investment. However, both methods allow the capacity expansion model to jointly consider transmission and resource investment options when determining the least-cost portfolio.

**Production Cost Benefits**

To effectively evaluate transmission expansion options in an IRP, it is essential to accurately reflect both the costs and benefits of the underlying transmission upgrades. To do this, transmission cost adders should be offset by any production cost savings the upgrade enables. If the capacity expansion model selects transmission upgrades or generation that includes transmission cost adders, transfer limits should be relaxed accordingly in the production cost model. This step is necessary to ensure that the total portfolio cost includes both the costs of transmission upgrades and any production cost savings that those changes enable.

A more advanced way to account for potential production cost benefits of transmission expansion is to iterate between the capacity expansion and production cost models. Suppose the initial capacity expansion model run selects a transmission upgrade. In that case, the utility should include that transmission expansion in the production cost model as relaxed transfer limits, which reduces production costs relative to portfolios without the upgrade. In a subsequent capacity expansion run, these production cost savings can be applied as a credit to the transmission option to partially offset the cost. Applying this credit encourages the capacity expansion model to select cost-saving transmission upgrades in subsequent model runs. Further iteration between the models can be used to refine the production cost benefits and the resulting transmission/generation portfolio, to ensure they converge upon consistent results.

**Transmission Expansion Options Summary**

Utilities can take the following steps to include transmission expansion options in capacity expansion models:

- Allow the capacity expansion model to exceed resource expansion limits by incurring an additional cost equivalent to transmission upgrades that increase deliverability.
- Work with the transmission planning team to estimate accurate transmission expansion costs and transfer capacity improvements.
- Offset transmission costs with credits based on the production cost savings the upgrade creates (this may require iterative capacity expansion and production cost modeling).
- As an alternative to transmission cost adders, include transmission upgrade options the capacity expansion model can select (this requires a zonal model).

## 3.3. Use Transmission Planning Studies for Accurate Inputs and Portfolio Evaluation

**Transmission Planning Studies**

Utilities routinely conduct transmission planning studies as part of reliability planning and generator interconnection processes, and these studies may help inform the resource expansion and transfer limits included in capacity expansion and production cost models. Transmission planning studies can also be used to identify potential transmission upgrades for IRP models to evaluate using scenarios or transmission options in the capacity expansion model. IRPs may use information from existing transmission planning studies or studies conducted specifically to inform the IRP analysis.

Conceptual transmission upgrades modeled by the transmission planning team—such as a new line or rebuild that the utility considered during a prior transmission planning process—are more useful in IRP analyses than generic proxies because they provide more realistic information. Projects studied through a transmission planning process are also more actionable, providing a clear investment direction if the IRP indicates that adding that transmission upgrade is part of the least-cost solution.

After the initial IRP modeling, transmission planning studies can also help refine cost estimates for the transmission upgrades required to deliver selected generation portfolios. Even when the capacity expansion model includes transmission cost adders, the underlying estimates are often simplified. Once IRP planners have identified several candidate generation portfolios, utilities can conduct additional transmission planning studies to determine the specific upgrades required for each portfolio. The results can then be used to update previous transmission cost estimates when finalizing the preferred plan.

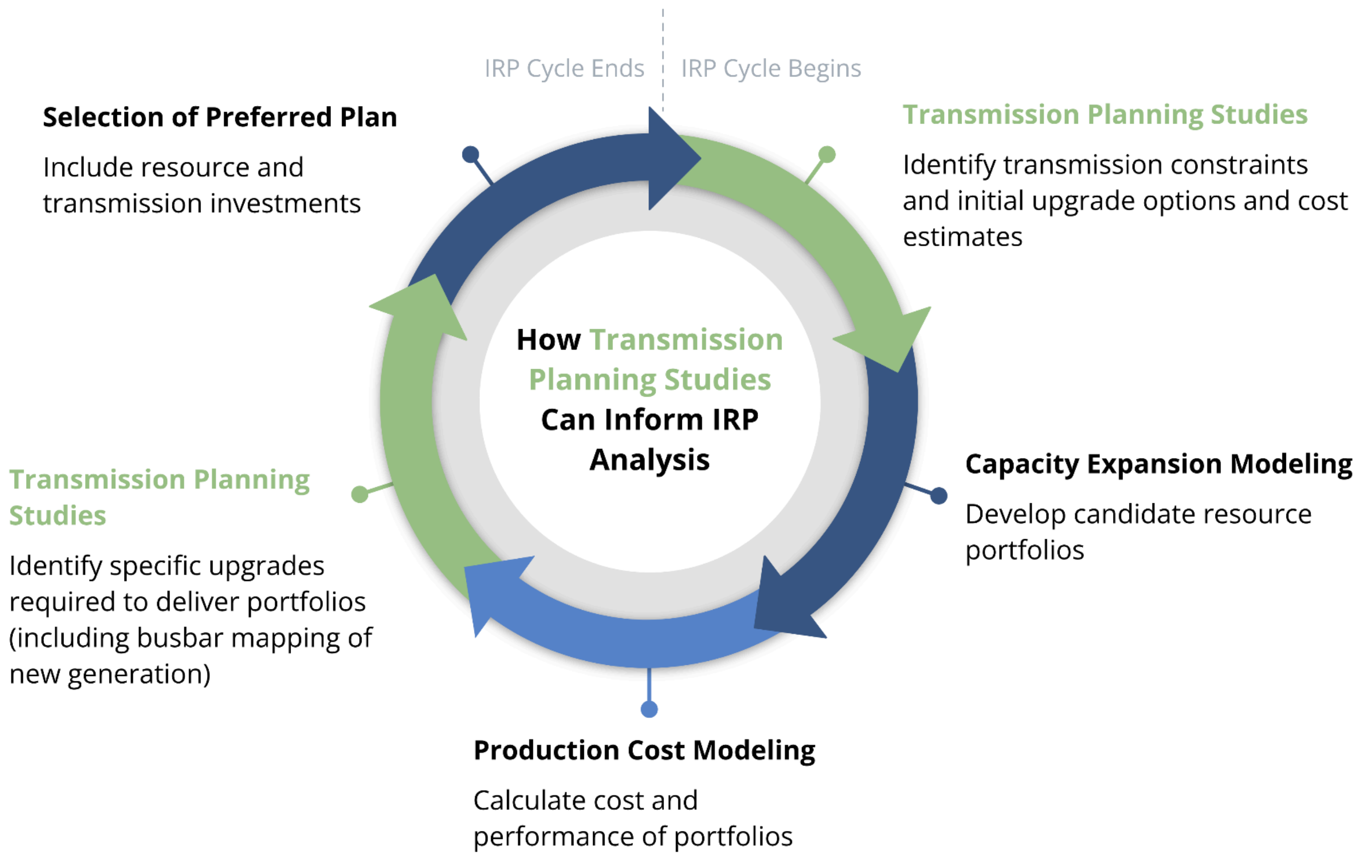
**Coordinating Transmission and Resource Planning**

Because the bulk power grid is highly interconnected and its capabilities depend on complex interactions among its transmission topology and generation characteristics, resource selection and transmission system expansion are highly interdependent. IRPs may, therefore, need to allow for iteration between portfolio modeling and transmission planning studies to arrive at a truly least-cost plan. The IRP process should be closely coordinated with a utility's transmission planning function so that transmission studies can inform IRP modeling and vice versa.

Figure 4 illustrates one way that utilities can incorporate transmission planning studies into an IRP process to inform the initial representation of transmission constraints in IRP models and then again to evaluate the transmission upgrades needed for a full portfolio of generation additions selected in an IRP or resource procurement process.

Finally, transmission planning should account for IRP results. If transmission scenarios or capacity expansion model results indicate that transmission upgrades enable the least-cost portfolio, utilities should include these upgrades in the IRP action plan and subsequent transmission plans. Given the accelerating pace of projected load growth, it is increasingly important that utility transmission planning processes proactively incorporate the outcomes of IRPs, rather than waiting for downstream procurement activities, to ensure timely and cost-effective infrastructure development.

Figure 4: Transmission planning studies can inform IRP model inputs and indicate upgrades required to deliver candidate portfolios developed through capacity expansion and production cost modeling.



**Transmission Planning Studies Summary**

Utilities should:

- Use transmission planning studies to ensure the accuracy of model inputs, including zonal interconnection capacity, transfer limits, and transmission upgrade options and costs.
- Model transmission upgrades required to deliver resource portfolios considered in the final stages of IRP analysis to ensure accurate cost estimates inform the selection of a preferred plan.
- Establish and publish clear procedures for coordinating transmission and resource planning, including timelines and data sharing.

# 4. Summary of Recommendations

The following table summarizes our detailed recommendations for each method for evaluating transmission expansion opportunities in an IRP. Part 2 of this report contains tailored recommendations for the five utilities we reviewed (see *Evaluating transmission opportunities in integrated resource plans Part 2: A review of Interior West utilities*).

We encourage utilities, regulators, and lawmakers to use these recommendations to support more effective transmission modeling and analysis in future IRPs.

## Detailed Recommendations for Evaluating Transmission in IRPs

| Method | Recommendations |
|---|---|
| Step 1: Represent Transmission Constraints in IRP Models | |
| **Resource Expansion Limits** in Capacity Expansion Models | • Define candidate resource options by zone. Zones should be defined based on known transmission constraints.<br>• Limit the type, quantity, and timing of new resources in each zone to reflect known transmission system capacity.<br>• Enable the model to exceed limits by incurring the appropriate costs (see transmission expansion options). |
| **Transfer Limits** in Production Cost Models | • Define multiple utility load/resource zones and market zones based on known transmission constraints (ideally, these are the same zones used to define resource options).<br>• Apply transfer limits between zones.<br>• For transfer limits to/from market zones, clarify the roles of transmission capacity and assumptions about market depth in determining the limits.<br>• Quantify and publish the impact of transfer limits on production costs.<br>• Transfer limits should change at future dates when appropriate to reflect planned upgrades. |
| | |

| Step 2: Quantify the Value of Transmission Expansion Opportunities | |
|---|---|
| **Transmission Scenarios** | ● Include scenarios with specific transmission changes (e.g., new lines, rebuilds, timing adjustments) to evaluate the impact on portfolio composition, cost, and performance.<br>● Use multiple scenarios to evaluate different conceptual transmission upgrades or portfolios of upgrades.<br>● Use the scenario results to inform transmission planning. |
| **Transmission Expansion Options** in Capacity Expansion Models | ● Allow the capacity expansion model to exceed resource expansion limits by incurring an additional cost equivalent to transmission upgrades that increase deliverability.<br>● Work with the transmission planning team to estimate accurate transmission expansion costs and transfer capacity improvements.<br>● Offset transmission costs with credits based on production cost savings the upgrade creates (this may require iterative capacity expansion and production cost modeling).<br>● As an alternative to transmission cost adders, include transmission options the capacity expansion model can select (this requires a zonal capacity expansion model).<br>● If transmission upgrades are part of the least-cost portfolio, include them in the IRP action plan and the utility's transmission plans. |
| **Transmission Planning Studies** Explicitly Integrated with the IRP Analysis | ● Use transmission planning studies to ensure the accuracy of model inputs, including zonal interconnection capacity, transfer limits, and transmission upgrade options and costs.<br>● Model transmission upgrades required to deliver resource portfolios considered in the final stages of IRP analysis to ensure accurate cost estimates inform the selection of a preferred plan.<br>● Establish and publish clear procedures for coordinating transmission and resource planning. |

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