Proposal to Develop Optimal Transmission Planning in Alberta

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NOTICE

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I. OTP Options Paper Outline

The purpose of this document is to provide options to AESO and its stakeholders for designing an optimal transmission planning ("OTP") framework that (1) aligns with the AESO's objectives and design principles, (2) builds on the available "best practices" across the industry for improving transmission planning, and (3) prepares the AESO and stakeholders for the upcoming OTP stakeholder consultation.

II. Key Decisions in Designing Transmission Planning Processes

This section discusses key decisions for AESO and its stakeholders to consider when designing an optimal transmission planning process that complies with the Alberta government's OTP policy directive. A well-designed transmission planning process seeks to balance technical precision, economic efficiency, and stakeholder inclusivity to deliver a portfolio of transmission solutions that cost-effectively supports long-term energy needs across a range of future scenarios. There are a variety of planning processes across the United States, Australia, and Europe that implement aspects of "optimal" transmission planning in different ways, as discussed in this section.

The topics in this section step through several decisions related to the process design and analytical approach that will impact the design of AESO's OTP framework and ultimately determine how effective the AESO OTP will be at planning the transmission system. For each decision, this section summarizes the key considerations relevant to the decision, options for how OTP could be implemented, examples from relevant jurisdictions, and the advantages and disadvantages of the proposed options.

A. Planning Process Options

1. How Should “Optimal” be Defined in the OTP – Narrowly or Broad?

Historically, AESO transmission planning has sought to resolve reliability criteria violations and relieve all anticipated congestion. Under this framework, a transmission need arose when either (1) predefined reliability requirements—such as thermal, voltage, and stability limits—were expected to be violated; or (2) congestion was projected. This ensured that the system remained compliant with established reliability standards and the Alberta congestion-free mandate, which was designed to encourage new generation investments and more competitive market outcomes.

One way to implement OTP is to replace the “zero congestion” standard with a similarly simple standard that defines acceptable levels of congestion. By addressing congestion if it exceeds a certain threshold, the OTP will require minor modifications to the existing transmission planning process, but AESO would need to determine the non-zero threshold to set for addressing congestion in future planning studies. This method is unlikely to achieve optimal planning outcomes that create the most value and lowest overall cost for Alberta’s electricity industry in either the near- or long-term as it does not evaluate the benefits of resolving congestion and other system impacts, nor the costs of the solutions for resolving the needs.

An alternative approach to implementing OTP is to consider a multi-value transmission planning framework. This approach assesses the broader economic, environmental, legislative requirements, and operational benefits associated with transmission investments. By this definition, a multi-value analysis is performed to assess the benefits associated with alternative transmission solutions and compare the benefits to the costs of the transmission solutions. Such a multi-value analysis aims to reduce the total cost of generating and transmitting electricity in Alberta, in addition to meeting all applicable reliability standards. This option enables the development of transmission projects that sustain a reliable grid at least cost and provide the most value to the province.

In designing the “optimal” process, AESO transmission planners have to decide whether the OTP process should be based on congestion thresholds or be implemented as a multi-value planning framework:

1. Design OTP by replacing the congestion-free mandate with **congestion thresholds**. Under this approach transmission projects would be planned to (1) meet all applicable reliability requirements and (2) limit congestion to predetermined target levels.

   – Existing planning based on reliability criteria remains unchanged

   – Congestion-relief projects are planned to limit congestion to predetermined levels

   – In the context of the AESO system, moving away from the congestion-free requirement as mandated by the government, the congestion-free metric could be reconfigured to consider thresholds of congestion costs (annual dollar value) or the number of congested hours on the system. Transmission expansion would be triggered only when congestion (either levels or costs) exceeds a prespecified threshold. The transmission solution would reduce the expected congestion to below the target level.[1]

   We are not aware of examples from other jurisdictions with this approach.

2. Design OTP broadly based on a **multi-value planning framework** that is focused on reducing total electricity system costs in Alberta. Under this approach the AESO would perform a holistic benefit-cost analysis to identify transmission solutions that reduce system-wide costs, analyzing a comprehensive set of long-term transmission needs and values (i.e., benefits based on overall cost savings).

   – Several drivers are evaluated to determine the needs of the system, including reliability, economic, transmission asset renewal projects, legislative requirements, etc., as well as both near-term and long-term drivers of transmission solutions.

   – The total benefits of transmission solutions are compared to their costs to justify the need for transmission and selecting the most optimal solution (while maintaining system reliability).

   Examples from other jurisdictions include Australia's Integrated System Plan (ISP), CAISO's Transmission Economic Analysis Method (TEAM), MISO Multi-value Projects (MVP) process,

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[1] The Alberta Ministry of Affordability and Utilities proposed adjustments to the zero-congestion policy in its 2023 "Transmission Policy Review: Delivering the Electricity of Tomorrow" green paper. The proposals, described as "mutually exclusive," included optimal transmission planning or increasing the level of allowable congestion (see pp. 14). In the July 2024 direction letter, the Minister announced the decision to "move away from the current zero-congestion transmission planning standard to an optimally planned transmission planning standard." Based on discussions with the AESO staff, we believe this may exclude the threshold approach as a viable option.

SPP's proposed new Consolidated Planning Process (CPP) and multi-value benefits assessments, NYISO's Public Policy Transmission Planning Process (PPTPP), Europe's Cost-Benefit Analysis (CBA) Guidelines for transmission planning.

The choice between these two approaches—threshold-based congestion relief versus a multi-value planning framework—will fundamentally shape the new transmission planning process. A threshold-based approach provides straightforward criteria for transmission development. However, it overlooks opportunities for transmission investments that deliver broader economic and operational efficiencies that reduce total costs and may identify the need for upgrades that increase total system costs (similar to the existing zero-congestion standard). A multi-value framework enables a more holistic assessment of transmission expansion opportunities through comprehensive assessment of transmission needs and the development and selection of solutions (transmission alternatives) that can most cost-effectively address these needs from a total cost perspective.

Options	Pros	Cons
1. Replace congestion-free mandate with pre-determined congestion thresholds	• Simple reconfiguration of existing process • Congestion thresholds create predictability in triggering upgrades	• Largely ineffective in other jurisdictions • Overlooks broader benefits, leading to outcomes that are not cost-efficient • May lead to uneconomic outcomes (transmission over-build or under-build) • Would have to determine "acceptable" level of congestion
2. Multi-value planning framework	• Optimizes system to ensure investments create overall system savings • Considers how transmission solutions can provide reliability, resilience, economic, and legislative benefits to Alberta's market participants and customers • Proven approach in other jurisdictions	• Higher analytical burden, requiring a comprehensive benefit-cost methodology • Because project selection depends on broader cost-benefit analysis, investment triggers may be less clear than in threshold-based system

2. How Should Transmission Needs be Assessed – Separate or Holistically?

Transmission planning processes are typically designed to address three primary drivers: reliability, economic, and legislative requirements. These drivers of transmission needs encompass considerations such as end-of-life asset replacement, expected load growth, intertie restorations, and the likely location and size of future generator additions and retirements. Along with transmission service requests for generator and load interconnection, transmission infrastructure necessary to address these needs are often planned in separate processes, but in some cases are planned holistically across several drivers of transmission needs.

The planning approach to address these transmission needs can either (a) use separate, sometimes sequential, planning processes for the individual driver of transmission needs, or (b) consolidate these processes into a consolidated multi-driver planning process that holistically considers all needs and develops solutions that most effectively address the full set of identified needs.

AESO transmission planners will need to decide between these two types of approaches for assessing transmission needs:

1. The first approach is to **maintain separate planning processes** for each type of transmission need. Under this approach, transmission planning studies for each driver remain separate and solutions are developed for specific needs (e.g., one solution, or set of solutions to address reliability needs, while other solutions are developed to mitigate congestion or address legislative requirement needs). Reliability-driven planning focuses on identifying and mitigating violations of established reliability criteria, such as thermal overloads, voltage instability, and system contingencies. This process ensures compliance with reliability standards and prevents system disruptions under a limited set of system conditions. Legislative requirement-driven planning supports broader policy goals, such as increasing renewable integration, increasing transfer capacity with neighboring systems, or meeting other legislated mandates. Finally, economic-driven planning seeks to identify transmission investments that alleviate congestion to improve market efficiency and allow for a more cost-effective generation dispatch.

   In most jurisdictions, existing transmission planning processes separately address reliability and other needs.

2. Alternatively, a **consolidated, multi-driver planning process** integrates several drivers of transmission needs, including reliability, economic, legislative requirements, and generator interconnection requests, into a consolidated (or well-coordinated) framework. This approach evaluates all needs holistically, seeking transmission solutions that simultaneously solve violations of reliability criteria, reduce system costs, accommodate generator interconnection or pending transmission service requests, and support legislative requirements. By taking a comprehensive, system-wide view, a consolidated process can identify transmission investments that most cost-effectively address multiple needs rather than pursuing separate projects for each driver, thereby reducing overall system costs. This approach can also reduce duplication and delays by streamlining analysis and decision-making across different planning objectives.

   In a consolidated process, there may be solutions that only address specific needs (e.g., reliability violations). However, when AESO identifies a solution to address a reliability violation they will also want to consider whether that solution or an alternative can cost-effectively address other drivers as well (e.g., economic efficiency, future generator interconnections, etc.). This approach may result in a different solution that cost-effectively solves the original reliability violation and additionally provides benefits by reducing congestion or accommodating new resources onto the grid.

   For example, given a future reliability need, the planning process could identify a transmission development that solves that reliability need at least cost and implement that solution. Separately, the process could identify the least cost solution to accommodate new generator interconnection. This is the approach that is common in many jurisdictions today. In contrast, a consolidated (coordinated) planning approach would assess the potential to deviate from the least-cost solution for the reliability need to also address generator interconnection, and other needs. In this case, the optimal solution may be upsizing the transmission upgrade that only solves a near-term reliability so that it also solves a generation interconnection need and alleviates congestion. While this approach may increase the cost of the transmission solution, it can deliver lower overall costs by alleviating congestion and helping to interconnect future new resources while avoiding the need for additional transmission upgrades later.

   Examples of consolidated transmission planning processes from other jurisdictions include:

   - SPP’s Strategic and Creative Re-engineering of Integrated Planning Team (SCRIPT) was created in 2020 to consolidate the existing planning approaches to “streamline the planning process, enhance coordination, and improve the efficiency of the transmission system."[2] The Consolidated Planning Process Task Force (CPPTF) now leads the design and development of the consolidated planning process (CPP) and associated cost-sharing mechanisms as recommended by SCRIPT and approved by the SPP Board of Directors.[3]

- CAISO's new transmission planning process simultaneously considered multiple near- and long-term needs. While the planning process assesses reliability, public policy, and economic needs in sequential order, an iterative process ensures that if a project identified in a subsequent analysis can also address the need resolved by a previous proposed projects and provide additional benefits, it is considered for approval to incorporate multiple benefit streams.[4]
- MISO's Long-Range Transmission Planning (LTRP) process uses a multi-driver planning process for long-term planning (while maintaining separate processes for near-term reliability needs, economic needs, and generator interconnection).[5]
- The Australian (AEMO) Integrated System Planning (ISP) provides an excellent example of a multi-value planning process that optimizes transmission investments through a comprehensive scenario-based planning process that recognizes planning uncertainties and values flexible transmission solutions through a risk-minimizing least-regrets planning approach.[6]

An example of separate but coordinated planning processes is the NYISO's Comprehensive System Planning Processes. NYISO's process includes the Public Policy Transmission Planning Process (PPTPP) that recognizes multiple transmission related benefits to address public policy needs and separate planning processes for reliability, economic, and generator interconnection needs.[7]

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2 See SPP, "SCRIPT C1 CPP Phase 1 Assessment Inclusion and Transmission Plan Recommendation Report," (January 2024).

3 Consolidated Planning Process Task Force - Southwest Power Pool

4 See CAISO 2023-2024 Transmission Plan (2024), pp. 18 [PDF 24 of 173].

5 See MISO Transmission Expansion Plan (MTEP24) and MISO Long Range Transmission Planning

6 See AEMO Integrated System Plan Methodology.

7 See NYISO Update on NYISO Comprehensive Planning Process, Overview of the Coordinated Grid Planning Process, and NYISO M-36 Public Policy Manual

While the consolidated multi-value planning framework provides an optimal approach to evaluating transmission needs and prioritizing investments, not every transmission need and associated solution may require a holistic, multi-value assessment. Selecting a consolidated planning approach should not preclude the AESO from identifying some transmission projects (e.g., immediate reliability needs or essential reinforcements) without a holistic assessment of multiple needs, specifically if these projects address a narrow need in a part of the grid where no other near- or long-term needs exist. Other jurisdictions apply a multi-driver assessment to certain proposed solutions, while limiting the analysis where a proposed solution does not deliver certain benefits, or the quantification of multiple value drivers is not necessary to justify the cost of the project. For example, the CAISO analyzes multiple economic benefits for transmission solutions that are deemed to provide such benefits. CAISO then quantifies only the major economic benefits that are expected to be provided by the project, while qualitatively discussing others.[8]

Options	Pros	Cons
1. Separate planning processes for each type of need	• Easier to add to existing planning methodologies without the complexity of integrating the analysis of multiple drivers • Straightforward compliance with distinct mandates of reliability planning and congestion mitigation	• Addressing each need in isolation may fail to identify projects that could more cost-effectively solve multiple needs together • Potential for "piecemeal" transmission upgrades, leading to inefficiencies and redundancies
2. Consolidated, multi-driver planning process	• Enables development of "optimally scaled" solutions for multiple needs that can achieve lower cost outcomes • Successful examples in other jurisdictions	• Potentially increased planning effort to assess interplay between different transmission needs • May not be necessary for all projects, such as urgent reliability needs

8 See CAISO 2023-2024 Transmission Plan, Appendix G, pp. G-5 and Table G.2-1.

3. Over What Planning Horizon Should OTP be Applied – Long-term or Near-term?

Transmission planning typically considers both near-term needs (e.g., known changes in load/generation, unexpected reliability violations, end-of-life considerations, etc.) and long-term system needs (e.g., future resource integration, policy considerations, and major infrastructure investments). While the definition of "near-term" and "long-term" planning horizons differ across planning jurisdictions, stakeholders in Alberta will need to provide input on how to apply OTP to AESO's near-term and long-term planning processes.[9] For example, if OTP includes a multi-value framework for assessing transmission solutions, will that apply only to its existing Long-Term Planning process, or also to near-term needs?

In other jurisdictions, when a multi-value framework is integrated into transmission planning, it is nearly always applied to long-term (10-20 year) planning. However, it is not always applied to near-term (less than 10 year) planning. When addressing near-term needs, even if the full multi-value framework is not applied, it is essential to ensure that solutions necessary to address urgent near-term needs do not pre-empt more holistic solutions that could more cost-effectively address multiple near- and long-term needs.

AESO transmission planners have two options:

1. Apply OTP **only in long-term planning**. For this option, AESO would apply OTP only in the long-term planning processes that focus on strategic system development. This approach recognizes that longer-term planning tends to focus on larger-scale transmission solutions that are necessary to move the grid toward legislative goals and react to changing economics of power generation, broader economic trends, and the demographic evolution of the province. Applying OTP to long-term planning allows planners to optimize the system to meet expected future demand, integrate new generation, and assess future congestion. Applying OTP only to long-term planning may avoid the complexity and resource burden of applying the holistic analyses to all potential transmission solutions. However, the risk of applying OTP only to address long-term needs is that it can result in the implementation of solutions necessary to address near-term needs that pre-empt more cost-effective solutions that holistically address long-term needs, ultimately leading to higher overall costs.

[9] In the current AESO transmission planning process, "near-term" planning is for infrastructure investments expected in five or fewer years and "long-term" planning is for those happening in years six through 20 in the future.

Most jurisdictions apply economic (and multi-value) frameworks to long-term planning processes with 10-to-20-year horizons. FERC's Order 1920 also only mandates multi-value planning for long-term (10-20 year) planning without requiring that the same approach be applied to existing shorter-term planning processes.

2. Apply OTP **in both near-term and long-term planning.** While this approach may require additional modeling and analysis for near-term needs, it ensures that all transmission investments made to address near-term needs also align with longer-term trends, policies, and other drivers of future transmission needs. By applying OTP to both near-and long-term solutions, transmission investment and benefits are optimized across the planning horizons and the risk of inefficient outcomes is reduced (such as the pre-emption of more efficient long-term solutions through projects that only address short-term needs or missed opportunities for efficiently upsizing transmission projects to address long-term needs).

   Examples from other jurisdictions include the Australian ISP Australian (AEMO) Integrated System Planning (ISP) process, which starts with a 30-year outlook to identify long-term needs and transmission solutions able to address these needs but combines the long-term planning with near-term decision making by distinguishing between "actionable projects" for which the need has become certain enough now to move forward and future projects that are likely needed at some point (but a decision does not yet need to be made), additionally emphasizing projects that can be built or expanded in stages and undertaking "early works" to develop shovel-ready projects that can be constructed quickly in the future.

Options	Pros	Cons
1. Apply OTP only in long-term planning	• Reduces resource burden of applying a multi-value framework in near-term planning • May allow for quicker resolution of near-term needs	• Without applying OTP to near-term planning, solutions to urgent needs may preempt more cost-effective, holistic solutions • If near-term investment decisions do not consider long-term needs, costly additional investments may be needed later
2. Apply OTP in both near-term and long-term planning	• Maximizes the overall efficiency of transmission planning in Alberta • Results in identifying solutions that achieve lower cost outcomes for the province	• Requires additional analyses by planning staff • Added complexity may delay near-term solutions

B. Benefits and Metrics Options

1. What is the Appropriate Overall Benefits Perspective – Total Cost or Ratepayer?

Under OTP, transmission planners will need to determine from what perspective "benefits" (or cost savings) should be calculated to assess the relative value of alternative transmission solutions.

To achieve an efficient outcome may necessarily require a electricity-system-wide perspective, evaluating all costs and benefits of transmission solutions and their ability to reduce total electricity system costs—including externalities—and maximize overall value to the Province. A system-wide "total cost perspective" accounts for direct costs for both transmission and generation, operational efficiencies, avoidable costs, and long-term economic and environmental impacts[10] to ensure that the transmission system is planned and operated in a way that provides the greatest total value to Alberta.

Within this framework, the total cost perspective (which is sometimes also referred to as a "societal" perspective because it includes both consumer and producer costs) can be defined different ways, leading to alternative conclusions about what benefits should be considered and prioritized. In this context "total cost" is generally limited to users of the electricity (i.e., all participants, customers and generators in the electric power system).

As an alternative to a total electricity system cost perspective, the transmission planning process could be targeted to positively impact individual groups of electricity market participants, such as electricity customers (even if customer benefits come at the expense of other electricity market participants, such as generators). This would not preclude other groups from benefiting as well from transmission planning, and in fact many transmission solutions may benefit all stakeholder groups to some degree. However, doing so raises the possibility that benefits to one group of market participants (e.g., customers) would come at the expense of other groups (e.g., generators).

The question of the appropriate benefits perspective of OTP (and operations) in Alberta is an important choice to be made by AESO tranmission planners. The two most common choices are:

1. Assess and select transmission solutions to **minimize total electricity system cost.** Assessing transmission solutions based on total benefits (cost savings) to the Alberta electricity system implies that planners will analyze the total value of transmission solutions and select the solution that delivers the highest overall value, so it yields the lowest overall costs.

   Under this option, the planners would not focus on the distribution of the transmission-related benefits to stakeholders in the study region (i.e. this option considers total economic surplus compared to costs). Planners may find, for example, that a transmission solution that eliminates a congested generation pocket on the grid increases revenues to generators in that pocket while reducing revenues to generators in other parts of the grid. Under the total cost approach, planners will ignore these kinds of distributional effects and focus only on whether the solutions decrease overall electricity system costs in Alberta.

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[10] Environmental impacts may include costs arising from both macro impacts, such as meeting future greenhouse gas and air pollutant emissions regulations, and local impacts, such as reduced environmental disturbance and costs in siting.

Lower system-wide costs will tend to benefit consumers because they ultimately pay for all costs incurred in the long run.

Most jurisdictions in North America use a system-wide perspective to assess potential transmission alternatives. Similarly, the transmission planning process in Australia uses a total cost perspective. The Australian Energy Regulator created guidelines for the AEMO that requires it to consider the total market benefit of any proposed transmission development alternative using both "consumer and producer surplus" along with a variety of other metrics. Any transfer of surplus between consumers and producers is explicitly prohibited from inclusion in the calculation of benefits.[11]

2. **Assess and select transmission solutions to maximize customer net benefits.** Under this approach, the AESO would select transmission solutions that maximize cost reductions specifically for electricity customers in the province (i.e., maximizes "consumer surplus").

   Transmission planners and policy makers in some jurisdictions have determined that this approach may be justified because ratepayers ultimately pay for transmission costs. For example, when CAISO adopted its economic planning framework, it shifted the focus on the ratepayer perspective because "[c]ost recovery of transmission upgrades is ultimately collected from ratepayers."[12] Others, however, have explained that a customer perspective—which often focuses on wholesale market price impacts—can yield unstable, volatile benefit metrics.[13] High customer savings may also not be sustainable in the long run if these savings come at the expense of generators such that it would deter necessary generation investments or shift generation additions to different locations.

In addition to selecting one of the two options above, the transmission planning process in Alberta could be designed to consider both the total cost and ratepayer benefit perspectives when selecting among alternative transmission solutions. This may be appropriate, if one of the metrics (e.g., impacts on total electricity system cost) is selected as the primary metric, while the other metric is calculated for informational purposes or is used as a tiebreaker. ERCOT recently added a customer cost metric to its economic planning process along with the existing total cost metric.

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[11] See AER Cost Benefit Analysis Guidelines (November 2024), pp. 22.

[12] See CAISO Transmission Economic Assessment Methodology (2017), pp. 10 [PDF 14 of 37].

[13] See, for example, NY DPS, Congestion Cost Examples: Societal Cost Approach vs. Load Payments Approach (2003), available at: https://www.nyiso.com/documents/20142/1391561/cong_cost_examples.pdf

Options	Pros	Cons
1. Assess and select transmission solutions to minimize total electricity system cost	• Optimizes for economically efficient outcomes, yielding lowest overall costs for the province • Captures the fact that, in the long-term, customers will have to pay for total costs	• Ignores distributional effects despite lowering overall system costs
2. Assess and select transmission solutions to maximize customer net benefits	• Focuses on reducing electricity costs for customers • Because ratepayers bear the costs, emphasizing their benefits can make transmission investments more publicly acceptable	• May overlook efficiencies that benefit the electricity system as a whole, leading to sub-optimal long-term outcomes • Metric is more volatile • If transmission investment decisions consistently prioritize lower customer cost at the expense of generators, it may discourage new generation investment, leading to higher costs in long-term

2. What Criteria Should be Used to Evaluate and Select Solutions – Net Benefits, Benefit-to-Cost Ratios, Least Regrets, or a Combination?

After quantifying costs and benefits of proposed transmission solutions, AESO transmission planners must use a selection criterion to evaluate the alternative transmission solutions. The most common approaches are to either maximize net benefits (total benefits less the cost of a transmission solution) or selecting solutions with the highest benefit-cost ratio. A selection based on benefits can be combined with risk analyses (such as through least-regrets planning) to identify solutions that offer better risk mitigation.

AESO transmission planners have to decide whether they will:

1. Select solutions based on **largest net benefits.** This criterion prioritizes and selects solutions that deliver the largest overall benefits (e.g., system-wide cost savings) after subtracting the transmission project costs. The focus is on maximizing total value to the system, even if

project costs are high. Project selection based on greatest net benefits is often used for solutions that provide high absolute economic or reliability gains, even if they have lower benefit-cost ratios then smaller-scale project. For example, the in Australia the AEMO's ISP employs an expected net benefits approach that weighs the benefits results for individual scenarios (additionally applying a 'Least-Worst Regrets' approach to select project that perform best across multiple scenarios of plausible futures).[14]

2. Select solutions based on the **highest benefit-to-cost ratio.** This approach prioritizes projects that offer the most value per dollar invested. The approach emphasizes efficiency, selecting projects with the greatest benefits relative to their costs. It ensures that every dollar spent yields the maximum value, which is particularly useful in budget-constrained environments. However, given the focus on the ratio of benefits and costs this approach may under select larger-scale, higher-impact investments in favor of lower-cost solutions, resulting in higher total system costs.

3. Select solution based on **<u>both</u> the highest benefit-to-cost ratio and largest net benefits.** Transmission planners can use both approaches to assess potential transmission solutions. Both approaches effectively identify transmission solutions that decrease overall costs for market participants by channelling investment into transmission solutions that provide higher value to the system than cost. However, given the different types of solutions each approach may favor, planners may decide to analyze options under both approaches and make selections based on a combination of the two approaches.

4. Additionally perform a **"Least Regrets" evaluation of transmission alternatives**. Regardless of the benefits selection criteria, the planning process may additionally consider a "least-regrets" approach to evaluate how well projects perform under different scenarios of plausible futures. In the context of transmission planning, a well-designed least-regrets approach can minimize the risk of both over-building and under-sizing the grid, should the future turn out differently than anticipated.

   By evaluating a range of future scenarios, as is already done in the AESO LTO and LTP processes now, planners can use a "regrets analysis" to test the robustness of proposed solutions across several futures to not only maximize the expected (e.g., weighted average of) benefits across the scenarios, but additionally to minimize the possible regrets of either over-building or under-sizing transmission solutions. Adding a least-regrets approach can

[14] See AEMO ISP Methodology (2023), pp. 91.

identify the "option value" of more flexible (scalable) transmission solutions given future uncertainties that can adjust as long-term uncertainties resolve themselves over time—such as by spending slightly more to construct a new single circuit transmission line on double circuit towers to create a low-cost expansion opportunity should demand turn out to be higher in the future.

As noted earlier, the Australian Integrated System Planning process applies this type of least regrets approach to select transmission solutions (and the added value of flexible options) that perform best across multiple scenarios of plausible futures.[15]

Options	Pros	Cons
1. Select solutions based on greatest net benefits	• Prioritizes projects that maximize total system value	• May not be ideal in budget constrained situations
2. Select solutions based on the highest benefit-to-cost ratio	• Maximizes efficiency of investment decisions, ensuring that the dollars available for investment yield the highest relative benefit	• May overlook larger-scale projects with high upfront costs but significant system benefits
3. Select solutions based on <u>both</u> the highest benefit-to-cost ratio and overall net benefits	• Balances efficiency with impact, supporting both large-scale projects with high net benefits and smaller, cost-effective projects • Planners can select the best transmission solution for different contexts	• Planners may need to navigate trade-offs between net benefits and cost-benefit ratios, adding a potential additional layer of analysis
4. Add a "least regrets" evaluation of transmission alternatives	• Ensures that selected projects also perform well across a range of uncertain future outcomes, reducing the risk of over- or under-building	• Added complexity • Requires well-specified scenarios representing a plausible range of future outcomes

[15] See AEMO ISP Methodology (2023), pp. 91.

3. How Should Potential Solutions be Assessed – Project-based or Portfolio-based?

When evaluating alternative transmission solutions, planners must also decide whether to assess solutions individually or as part of a broader portfolio of transmission investments. Under a project-by-project approach, each potential transmission solution must demonstrate cost-effectiveness and justification on its own merits. While this method provides a clear and transparent evaluation on each individual solution, it may overlook synergies between different projects, where the portfolio of projects offers greater benefits than the sum of benefits from individual projects.

A portfolio-based assessment considers the interactions between multiple transmission solutions to identify a group of solutions that can solve multiple needs with complementary benefits and potentially reduced overall investment costs. However, the portfolio-based approach requires modeling interactions of multiple projects and may take additional time to optimize the entire portfolio.

To strike the balance between efficiency and adaptability, planners can implement a combined approach that utilizes portfolio of projects for developing a comprehensive transmission plan while assessing individual projects within the portfolio to optimize the portfolio and fast-track some clearly beneficial projects needed in the near-term.

AESO transmission planners have three approaches to choose from:

1. **Project-based approach.** This method involves assessing benefits of individual transmission solutions. This approach is commonly used in many jurisdictions in North America, including the current AESO process as well as in SPP as well as MISO and PJM for "economic" projects.

2. **Portfolio-based approach.** Under this approach, potential solutions for identified needs are evaluated as portfolio. This approach considers how the potential solutions interact and complement each other to meet local, regional, or interregional needs. By assessing several solutions at the same time, the portfolio-based approach can avoid misrepresenting the benefits of one transmission solution due to the sequencing of how solutions are analyzed and approved in the planning process. For example, if an area of the grid is facing several near-term and long-term needs, the first transmission solution assessed may show very large benefits, leading planners to select it. However, the sequencing of how different transmission solutions are assessed may make certain solutions seem less beneficial, and

lead to a different set of transmission solutions being selected. A portfolio-based approach focused on optimizing the overall portfolio can help avoid distortions based on the sequence of how transmissions solutions are assessed in the planning process from driving outcomes.

The portfolio-based approach is used in MISO as part of its LRTP evaluation of multi-value projects (MVPs). It is also used by NYISO solutions to address public policy needs, which often are composed of a portfolio of individual projects.

3. **Combined approach.** Under this approach, transmission planners would have the option to (a) evaluate multiple projects as a portfolio to capture the interdependence of transmission solutions and optimize the overall system; and (b) to assesses individual projects that are not expected to interact with other transmission solution or to assess individual projects within that portfolio on an incremental/decremental basis to optimize the design of the portfolio. With this optionality, planners may choose to differentiate between immediate short-term reliability needs that can be solved with a low-cost solution and longer-term needs composed of multiple drivers, including reliability, economic efficiency, and policy drivers. Finding solutions to multiple needs may be better suited to a portfolio of solutions.

Options	Pros	Cons
1. Project-based approach	• Straightforward process, as each transmission solution is assessed on its own merits	• Overlooks synergies between projects that may lead to addition cost savings and efficiency gains (unless synergistic projects are combined)
2. Portfolio-based approach	• Better suited for addressing multi-driver needs • Planners can avoid approving solutions that become less valuable when additional projects are implemented	• Requires the evaluation of different portfolios and portfolio designs to identify optimal portfolios
3. Combined approach	• Allows transmission planners to optimize the portfolio of transmission projects in the plan by evaluating some projects on a project-specific basis, while preserving the ability of portfolio approach to address multiple needs	• Determining which projects should be considered independently, incrementally, or decrementally is challenging but necessary to identify optimal portfolios

4. What Benefits Should be Considered and Calculated – Prescriptive or Flexible?

To identify optimal transmission solutions, planners must consider all potential benefits provided by proposed solutions. These benefits can be quantified (e.g., production cost savings, congestion relief benefits, and the avoided cost of smaller reliability upgrades) or assessed qualitatively (e.g., improvements in resilience, flexibility, or legislative requirements or goals). The scope and methodology for evaluating benefit metrics plays a crucial role in how planners choose between proposed transmission solutions and how regulators approve the transmission plans established by the planning authorities.

Table 1 presents a more comprehensive "checklist" of potential benefits applicable to the Alberta market that transmission solutions can provide the grid based on an industry-wide review of available experience (although some projects may offer additional benefits not included in Table 1).[16] AESO transmission planners will need to determine which benefits are most applicable to Alberta in the context of designing the OTP.

TABLE 1. TRANSMISSION-RELATED BENEFIT METRICS APPLICABLE TO AESO MARKET

Benefit Category	Transmission Benefit
1. Traditional Production Cost Savings	Adjusted Production Cost (APC) savings as currently estimated in most planning processes
2. Additional Production Cost Savings	i. Impact of generation outages and A/S unit designations
	ii. Reduced transmission energy losses
	iii. Reduced congestion due to transmission outages
	iv. Reduced production cost during extreme events and system contingencies
	v. Mitigation of typical weather and load uncertainty, including the geographic diversification of uncertain renewable generation variability
	vi. Reduced cost due to imperfect foresight of real-time system conditions, including renewable forecasting errors and intra-hour variability
	vii. Reduced cost of cycling power plants
	viii. Reduced amounts and costs of operating reserves and other ancillary services
	ix. Mitigation of reliability-must-run (RMR) conditions
3. Reliability and Resource Adequacy Benefits	i. Avoided/deferred cost of reliability projects (including aging infrastructure replacements) otherwise necessary
	ii. Reduced loss of load probability
4. Generation Capacity Cost Savings	i. Deferred generation capacity investments
	ii. Access to lower-cost generation resources
5. Market Facilitation Benefits	i. Increased competition
	ii. Increased market liquidity
6. Environmental Benefits	i. Reduced expected cost of potential future emissions regulations
	ii. Improved utilization of transmission corridors
7. Public Policy Benefits	Reduced cost of meeting public policy goals and legislative requirements
8. Other benefits	i. Avoided other transmission needs
	ii. Increased export revenues and reduced import costs
	iii. Increased storm hardening and wild-fire resilience
	iv. Increased system flexibility (risk mitigation)

Sources and Notes: Based on The Brattle Group and Grid Strategies, "Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs," October 2021.

16 "Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs," (2021), summarizing industry experience with transmission benefit-cost analysis in various jurisdictions, such as SPP's Benefits for the 2013 Regional Cost Allocation Review (posted at 20120913 mtf report_approved.pdf) and SPP's updated benefits metrics in its 2016 Regional Cost Allocation Review (RCAR II) (posted at https://www.spp.org/documents/18175/20120913%20mtf%20report_approved.pdf)

Many of these benefits listed in Table 1 can be quantified through the standard modeling tools used by transmission planners, including the AESO.[17] These tools, such as nodal production cost models, may need to be refined and improved to fully capture many of the benefits described on the list (see next section). Some of the benefit metrics listed in Table 1 are more difficult to quantify but can be considered qualitatively as transmission planners select between options and as regulators approve the development of solutions.

In Alberta, the design of OTP will need to provide direction for AESO transmission planners regarding the benefit metrics to be considered when assessing different transmission solutions. There are two different approaches that have been used in other jurisdictions, (1) a prescriptive approach that explicitly specifies the list of benefit metrics that need to be calculated for all transmission solutions, and (2) more a flexible approach that establishes guidelines (approved by stakeholder, regulators and policymakers) for use by the transmission planners, but provides some flexibility to (a) determine what benefit metrics are relevant for a particular transmission solution and (b) expand the list of benefit metrics and improve analytical approaches to quantifying these benefits over time.

AESO transmission planners will have to decide between:

1. **Prescriptive Approach**. The prescriptive approach would identify a pre-specified set of benefit metrics, as approved by the AUC, which are quantified by AESO transmission planner uniformly across all potential solutions. Under this approach, the AUC approves the set of benefit metrics to be calculated, and likely the methodology on how to quantify them, and the AESO would apply that methodology to all transmission solutions it assesses. Additional benefits or alternative quantifications would be allowed *only* with rule modifications and approval by the AUC. A prescriptive approach would ensure consistency of benefit calculations across all potential transmissions solutions but could also create unnecessary work for transmission planners as some benefit metrics are not applicable to all transmission solutions. The risk of this approach is that benefits of transmission solutions may be understated if the prescriptive list of benefit metrics established by the AUC is not fully comprehensive, potentially resulting in beneficial projects not being approved.

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[17] For a summary of approaches that have been used successfully to quantify each of the listed benefits, see "Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs," (2021), Appendices B-D.

A prescriptive approach to transmission benefit calculation is applied in several North American jurisdictions, including the "economic planning processes" in PJM, NYISO, ISO-NE, and MISO.

2. **Flexible Approach with Guidelines.** Under a flexible approach the AUC would provide guidelines to AESO that allow the transmission planners to specify certain benefit quantifications as necessary for each proposed solution. For example, the AUC may establish a comprehensive list of transmission benefits, such as the one presented in Table 1, that AESO should consider (and be able to supplement) for each transmission solution, allowing AESO planners to determine which benefits are most applicable and should be quantified for a particular transmission solution. The AUC may also provide guidelines on the methodologies to be used for quantifying certain benefit metrics. The list of transmission benefits and quantification methodologies established by AUC can be expanded over time with stakeholder input based on growing experience and improved quantification techniques. Under this approach, the AUC may decide to establish a minimum set of benefit metrics (similar to those in FERC's Order 1920) that should be assessed and a remaining set of metrics and quantification methods that can be applied when applicable.

   A flexible approach allows for already-existing guidelines for benefit metrics and quantification approaches to be adapted, refined, and expanded over time. Transmission solutions can yield a diverse array of benefits, and the flexible approach ensures that planners can identify and quantify only the relevant metrics for specific projects from the full spectrum of potential benefits.

   A flexible approach to benefit calculation is used by CAISO,[18] SPP,[19] MISO for its LRTP process, and in Europe (through periodically updated Cost-Benefit Analysis Guidelines).[20]

[18] See CAISO Transmission Economic Assessment Methodology (2017), pp. 21 [PDF 25 of 37] and CPUC Decision 07-01-040 Section III ("Project Benefits"), January 25, 2007, Opinion Granting a Certificate of Public Convenience and Necessity.

[19] See SPP Regional Cost Allocation Review Report for RCAR II, July 11, 2016; and SPP Metrics Task Force, *Benefits for the 2013 Regional Cost Allocation Review*, July, 5 2012.

[20] See 4th ENSTO-E Guideline for cost-benefit analysis of grid development projects (2024).

Options	Pros	Cons
1. Prescriptive approach	• Ensures consistency by requiring all transmission solutions to be evaluated against the same criteria	• Will not fully capture all relevant benefits as projects with unique benefits emerge • Makes it more difficult to modify benefit metrics as experience is gained in Alberta and other jurisdictions over time
2. Flexible approach with guidelines	• Allows for learning by doing • Avoids having to quantify every benefit metric for every project when specific benefits do not apply	• Flexibility in benefits identification and quantification may lead to inconstancies and disagreements

5. How to Capture a Realistic Level of Congestion Costs in Planning – Scaling or Refine Model?

One of the objectives of OTP is to replace the current "zero congestion" paradigm used in transmission planning in Alberta and replace it with a planning process that seeks to "optimize" congestion (i.e., invest in new transmission solutions to reduce congestion to the optimal extent in the province). To achieve this objective, the modeling tools used to analyze system congestion and the impact of new transmission solutions on alleviating congestion will need to accurately determine congestion costs on the grid, including expected future congestion costs, so that those costs can be incorporated into benefit-cost analyses for new transmission solutions.

Unfortunately, the economic modeling tools (including nodal production cost models) that are used in most transmission planning processes typically do not fully capture the full level of congestion in the system and thus tend to significantly understate the benefit of congestion relief. This is typically the case because production cost models used in transmission planning tend to have perfect foresight, analyze only normalized system conditions, and assume an intact transmission grid (e.g., N-1 contingency constraints assuming no existing transmission outages). More specifically, the models used in transmission planning tend not capture challenging grid conditions and extreme weather events that may account for only 5% of all hours in a year but represent 50% of transmission related value.[21] These conditions may include transmission outages, unanticipated drops in renewable generation and generation outages that occur close to real-time, daily fuel price variances and basis differentials (including occasional spikes), extended renewable generation draughts, and other uncertainties.[22] The cost of congestion is unlikely to be captured under these modeling assumptions.

As Alberta moves away from the "zero congestion" standard in transmission planning it will become increasing important for transmission planners to utilize economic modeling tools and approaches to realistically quantify congestion on the grid, including not only the frequency of congestion (as is needed under the zero congestion standard) but also the cost that congestion imposed on the grid (needed to assess the benefit of transmission solutions that alleviate congestion).

We identified three options for AESO transmission planners to consider to more fully capture congestion and more accurately assess costs associated with congestion in economic market simulations:

1. **Apply scaler for missing congestion**. Run the existing nodal production cost model for several recent years and quantify the percentage of congestion cost missed by comparing simulated congestion from the AESO's transmission planning models compared to actual congestion on the grid. Then apply that percent value as a single "scaler"—or multiple scalers that account for individual factors missed in the simulations—to the model's projected future congestion costs when simulating future years. This "true up" of modeling results for observed missed congestion based on calibration to historical years is a relatively easy approach to account for the inadequacies of simulation models in fully estimating congestion on the grid.

[21] See Julie Kemp, Dev Millstein, Will Gorman et al., "Electric transmission value and its drivers in United States power markets," *PREPRINT (Version 1) available at Research Square*, Lawrence Berkeley National Laboratory (March 2024). https://doi.org/10.21203/rs.3.rs-3957695/v1.

[22] For example, see [NYISO 2023-2042 System & Resource Outlook, Appendix I: Transmission Congestion Analysis](), pp. 3: "When comparing historic congestion costs to projected congestion costs, it is important to note that there are significant assumptions not included in projected congestion costs using production cost simulations. Such assumptions include: (a) virtual bidding, (b) transmission outages, (c) price-capped load, (d) generation and demand bid price, (e) Bid Production Cost Guarantee payments, (f) co-optimization with ancillary services, and (g) real-time events and forecast uncertainty."

See also Section 4.1 of SPP's Benefits for the 2013 Regional Cost Allocation Review (posted at 20120913 mtf report_approved.pdf), summarizing the limitations of standard (nodal) production cost simulations.

It is important to note that this option is **fundamentally a calibration process** based on observed historical data, **rather than an arbitrary or speculative adjustment**. To determine the amount of calibration (i.e., the percent adder), the adjustment factor is derived from actual congestion costs that were missed by the model instead of an assumption about future congestion. This approach enhances accuracy, ensuring that a more realistic view of congestion costs is used in decision making.

This approach is used by the NYISO, based on guidance from the NY PSC, by calibrating their models against historical congestion data and adjust to estimate future congestion costs by analyzing past market operations to identify areas with recurring congestion patterns, which then informs their projections for future transmission constraints and associated costs.[23] It is also used by SPP to account for just the amount of understated congestion due to transmission outages.[24]

2. **Refine model to quantify missing congestion**. This option improves the production cost model used in transmission planning to more accurately capture the factors that drive system congestion that are usually not captured in nodal production cost models. Under this approach, the AESO would need to invest in improving and calibrating its modeling tools to assess congestion, especially to consider extreme weather events, unexpected deviations in resource output, net load volatility, daily gas price volatility, real-time uncertainties, etc.

3. **Apply scaler while incrementally refining model to quantity congestion**. Borrowing elements from both of the above approaches, a third option is to apply an adder to simulated congestion costs based on a calibration against historical years while simultaneously working to refine the production cost simulations over time, so that they capture a larger share of the actually observed congestion. In this approach, the adder

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[23] See NYISO Manual 35, "Economic Planning Process Manual," (November 2023). See also Benefit-Cost Analysis of Proposed New York AC Transmission Upgrades, Section V.B. (developing multipliers ranging from 6% to 56% to account for understated simulation results for congestion, market heat rates, and clean energy values). The New York Market Monitors' independent analysis of transmission benefits similarly concluded that a 40% adder is appropriate to account for understated simulation results (Potomac Economics, Market Monitoring Unit for the NYISO, NYISO MMU Evaluation of the Proposed AC Public Policy Transmission Projects, dated February 2019, at 16).

[24] See Section 7.6.4 of SPP's 2016 Regional Cost Allocation Review Report for RCAR II (available at rcar 2 report final.pdf).

applied to the simulated results will decline over time as the nodal simulation models improve.

Options	Pros	Cons
1. Apply scaler for missing congestion	• Requires minimal changes to existing modeling tools, making it a practical short-term solution	• Does not improve the fundamental models, which may be important if future congestion drivers differ from historical
2. Refine model to quantify missing congestion	• Addresses fundamental model deficiencies by incorporating real-world congestion into simulations	• Potentially resource-intensive and complex model enhancements • Longer implementation timeline
3. Apply scaler while incrementally refining model to quantify congestion	• Balances short-term practicality with long-term accuracy • Flexibility in implementation, providing continuous learning and improvement	• If model refinements do not progress as expected, reliance on historical congestion scaler may be needed for longer than expected

6. How Should Generation Investment Cost be Considered – Excluded or Included?

In addition to mitigating congestion, reducing operating costs, and avoiding or deferring other transmission investments, certain transmission projects can reduce the future cost of generation investments. Even in jurisdictions without integrated resource planning, reductions in generation investment costs materialize through: (1) reducing energy losses during peak demand periods and therefore reducing the amount of generation capacity needed to serve peak load; (2) deferring investments needed to construct additional generation for resource adequacy by geographically diversifying generation or enabling increased imports from neighboring areas with excess capacity; and (3) ensuring there is sufficient transmission capacity to support the development and integration of more cost-effective generation resources (e.g., create transmission capacity to interconnect more generation in low-cost areas of the Province).[25] Well-planned transmission can allow generation to be sited where it is most cost-effective, reducing overall expenditures on new generation resources.

When detailing the range of benefits to be assessed, it is important for AESO transmission planners to decide whether to quantify generation investment cost reduction.

1. **Ignore reduced generation investment costs when assessing transmission solutions.** Not considering generation investment cost implications of transmission solutions reduces the administrative burden and modeling complexity of the planning process. Incorporating generation investment cost reduction as a benefit metric for transmission solutions requires a modeling approach that considers generation investment outcomes that are co-optimized with transmission investments to reduce total system costs, rather than pre-specifying generation buildout as a fixed input into transmission planning. However, ignoring the reduction in generation investment cost potentially created by transmission solutions risks understating the benefits of transmission investment and failing to select efficient solutions in the planning process.

   Generation investment cost savings are not quantified for solely "economic projects" in MISO, PJM, NYISO, and ISO-NE. They are also not mandated by FERC's Order 1920 (other than the investment cost savings associated with a reduction of transmission losses during peak load periods).

2. **Quantify generation investment cost savings where relevant.** Under this approach, transmission planning would need to either (a) utilize tools that can co-optimize efficient investment in transmission and generation assets; or (b) evaluate different transmission capabilities in generation expansion simulations. In addition, resource adequacy simulations would be used to evaluate the extent to which different generation expansions (or the expansion of interties with neighboring systems) would reduce overall generation investment needs. This would require the close coordination of (a) transmission planning with (b) the development of location-specific (e.g., zonal) generation capacity expansion scenarios in the LTO. In this approach, there is an optimal mix of generation, enabled by transmission expansion, which produces the lowest overall system cost, including both investment and operational costs. In performing this analysis, the proposed location of generation resources is not set prior to long-term planning and dispatch modeling. Rather,

[25] For a detailed discussion of how transmission investments can reduce generation investment costs, see The Brattle Group and Grid Strategies, "Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs," 2021, Section 2.a.4 Generation Capacity Value, pp. 43.

the optimal mix of generation locations with transmission investment is iterative. This option may require close collaboration with the Alberta government, regulators, and permitting agencies to pre-specify desirable generation development zones to which transmission expansions can be optimized (e.g., as was done in Texas for planning transmission to Competitive Renewable Energy Zones, CREZ, and as is being done in Australia through the AEMO Integrated System Plan, which also pre-specifies Renewable Energy Zones).[26]

If planners decide to quantify generation investment cost savings (where relevant), they will need to determine how to coordinate transmission planning with LTO-level generation capacity expansion scenarios to co-optimize transmission expansion with likely future generation investments. There are two primary approaches to achieving this coordination: (a) **an iterative approach**, where transmission planning and capacity expansion modeling inform each other in sequential rounds of analysis, or (b) an **integrated co-optimization approach**, where capacity expansion modeling incorporates at least some transmission investment decisions (e.g., between defined zones) directly within a unified optimization framework. MISO's Regional Generation Outlet Study presents an example of an iterative approach in which several generation development sites were developed with high-level transmission overlays to determine which combination produced the lowest total system costs.[27]

In the co-optimized modeling approach, it is important to note that there will be some iteration between exploration of high-level transmission expansion (e.g., within the LTO's capacity expansion modeling) and detailed transmission studies and the development of specific transmission project alternative (which requires reliability studies and more detail nodal modeling). When the capacity expansion model that is able to co-optimize generation and transmission selects adding new generation resources to a per-defined zone, it simultaneously evaluates the cost and benefits of corresponding interzonal transmission upgrades needed to support them. The optimization process determines the best mix of zonal generation and transmission investments that minimize total system costs,

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[26] See ERCOT CREZ Analysis Report (2006) and AEMO Integrated System Plan Methodology, Section 2.3.4.

[27] See MISO Regional Generation Outlet Study (2010). Fourteen different generation siting options were considered for new wind generation development. The sites ranged from local generation (typically requiring less transmission development) to regional generation (typically sited where wind generation has the strongest potential) and included a combination of local and regional generation. In each generation siting scenario, transmission expansion was developed with stakeholders and total system costs were calculated. The resulting "Bathtub Curve" shows the least cost approach contains a combination of local and regional generation.

considering factors such as the cost of interzonal transmission expansion, congestion, resource availability, load growth, and legislative targets. The resulting co-optimized zonal generation expansion scenarios can then be used to form the basis for detailed (nodal) transmission planning efforts.

An example of state-wide co-optimization of generation and transmission investment is the California planning approach in which the CPUC is using a zonal capacity expansion model that co-optimizes zonal generation and transmission investments. The results of these co-optimized zonal simulations are then used by CAISO for transmission planning using nodal reliability and production cost models.[28] Similarly, the SPP Strategic Planning Committee's recent Future Energy and Resource Needs (FERNS) presents an example of co-optimized zonal generation and transmission expansion.[29] The U.S. Department of Energy's National Transmission Planning Study also uses co-optimization of generation and transmission expansion in their modeling to find the optimal mix of new generation, storage, and transmission options to meet future scenarios.[30] The AEMO ISP provides another example of co-optimized zonal generation and transmission modeling as the first step in a more detailed multi-value transmission planning process.[31]

Generation investment cost savings are quantified in most jurisdictions that utilize multi-benefit transmission planning, including CAISO (for projects that are expected to offer such

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[28] See Slide 28 of CAISO's "Overview of the CPUC's IRP Cycle," February 2025.

[29] See Future Energy and Resource Needs Study (FERNS): Preliminary Update, July 2024.

[30] The U.S. DOE's National Transmission Planning Study (2024) uses the National Renewable Energy Laboratory's Regional Energy Deployment System (ReEDS) to perform co-optimization of generation and transmission. The process continues with resource adequacy simulations (to make sure the buildout scenarios are adequate), followed by detailed power flow and reliability modeling (to identify reliability needs for the buildout), and finishing with nodal production cost modeling to identify economic transmission needs (and evaluate available solutions).

[31] See AEMO Integrated System Plan Methodology, Section 2.

benefits),[32] SPP,[33] in MISO's LRTP,[34] in NYISO's public policy planning process,[35] as well as in Australia[36] and Europe.[37] Note that none of these grid operators perform integrated resource planning (IRP) or are able to make actual generation investment decisions. Rather, they attempt to select transmission investments that create beneficial location-specific grid capabilities, which will either facilitate investment in lower-cost generation or offer reliability benefits by reducing the need for generation investments

Options	Pros	Cons
1. Ignore reduced generation investment costs when assessing transmission solutions	• Reduces computational and planning burden	• Understates the benefits that certain transmission solution can offer to the province by ignoring potential reductions in generation investment costs
2. Quantify generation investment cost savings where relevant	• Enables planners to co-optimize generation and transmission investments, leading to lowest combined cost for the system	• Requires enhanced modeling tools to co-optimize generation and transmission (including from a resource adequacy perspective)

[32] See CAISO DPV2 benefit-cost analysis in CPUC Decision 07-01-040, January 25, 2007, Opinion Granting a Certificate of Public Convenience and Necessity.

[33] SPP Regional Cost Allocation Review Report for RCAR II, July 11, 2016; and SPP Metrics Task Force, *Benefits for the 2013 Regional Cost Allocation Review*, July, 5 2012

[34] MISO has used different sets of benefit metrics in different planning cycles, all of which included avoided generation capacity savings as one of the benefits. For their most recent set of benefit metrics, including the avoided generation cost savings, see LRTP Tranche 2.1 Benefit Metrics Development (2024)

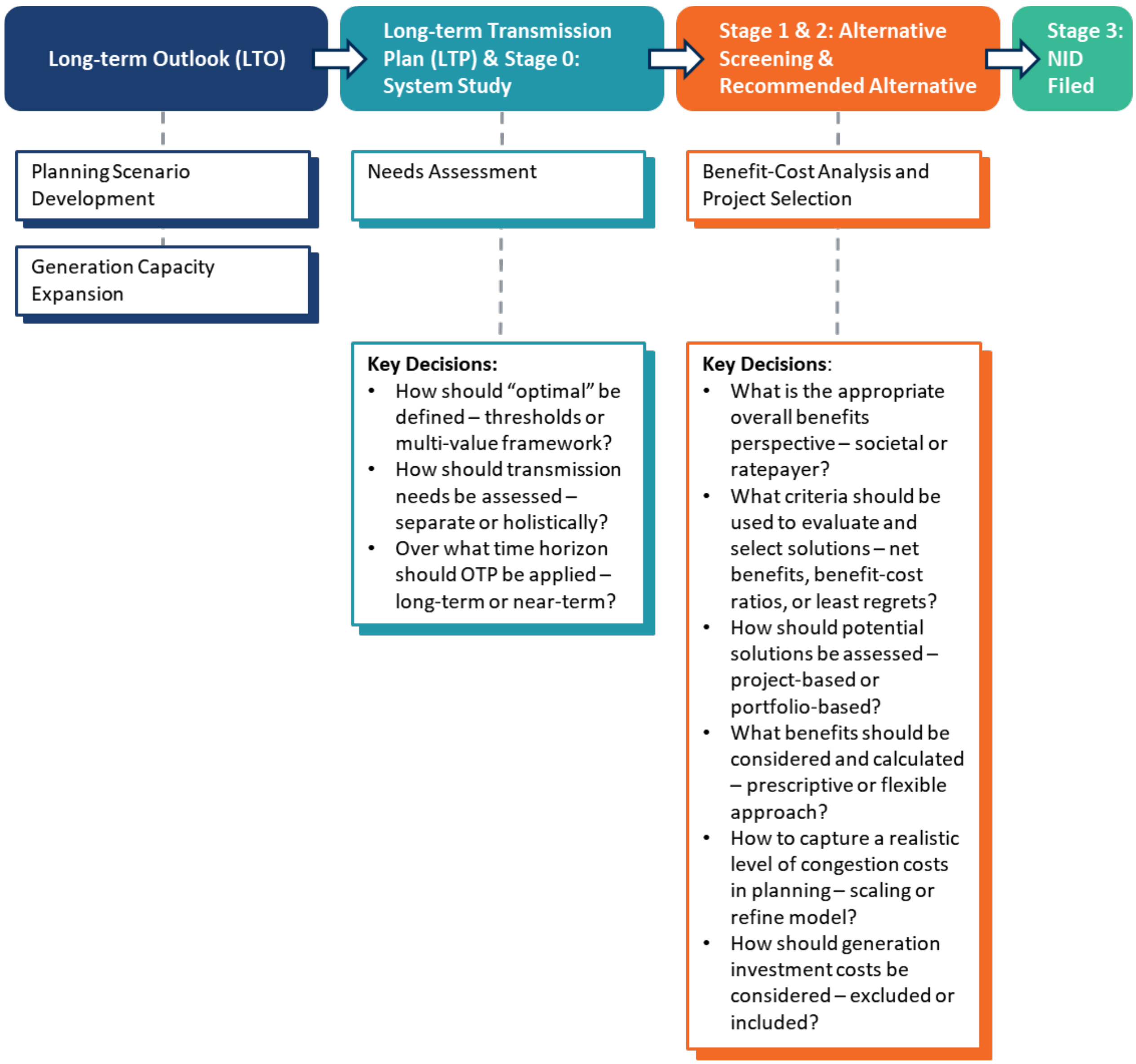
[35] See Benefit-Cost Analysis of Proposed New York AC Transmission Upgrades, September 15, 2015

[36] See AEMO Integrated System Plan Methodology, Section 5.2.

[37] See 4th ENSTO-E Guideline for cost-benefit analysis of grid development projects (2024).

III. OTP Decisions in Existing AESO Processes

The key decisions to be made in designing the OTP (as discussed above) can be mapped to the existing AESO transmission planning processes, as shown below.



IV. OTP Best Practices

Our review of planning practices in other jurisdictions[38] shows that the AESO has the opportunity to create an optimal planning process that proactively addresses multiple near-term and long-term transmission needs through solutions that improve reliability and reduce the total system-wide cost of electricity in Alberta. Based on this review of transmission planning processes in other jurisdictions and their effectiveness, we find that "best practice" proactive planning processes tend to include:

- The evaluation of "economic needs" is undertaken from a total system-wide cost perspective in addition to (and simultaneously with) reliability and public-policy needs
- Multiple transmission alternatives are identified and evaluated for a range of plausible long-term scenarios (rather than just a base case) that capture and bracket future uncertainties
- A wide-range of transmission-related benefits is quantified to estimate the extent to which alternative transmission solutions help reduce system-wide costs (while maintaining reliability and addressing public-policy goals and mandates)
- In addition to comprehensive benefit-cost analysis of alternative solutions that identified the best solution across multiple scenarios, a "least regrets" evaluation of the alternatives to is used to identify the most flexible, most robust solution that (in addition to reducing overall costs) also mitigates the risks associated with near- and long-term uncertainties (i.e., by avoiding higher-cost outcomes associated with over-building or under-sizing of the transmission system)
- The consolidation or close coordination of separate transmission planning processes (e.g., network planning, generator interconnection, etc.) so that the best "holistic" transmission solution can be selected that simultaneously and most cost effectively addresses multiple needs.

[38] See, for example, Pfeifenberger, Gramlich, et al., Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs, 2021 at 31, Table 4 and appendices B, C, and D).

See also Order 1920 Compliance: An Opportunity to Improve Transmission Planning beyond Mandates - Brattle (2024).

V. Background: US FERC Order No. 1920

In May 2024, the U.S. Federal Energy Regulatory Commission (FERC) has issued its "Order 1920" (which was confirmed and clarified in "Order 1920-A").[39] Since the Order addresses economic transmission planning and the quantification of multiple transmission-related benefits, it is relevant background for Alberta's OTP effort.

As we have explained in an MIT working paper,[40] the Order is intended to improve transmission planning processes to make them more holistic and proactive by addressing anticipated long-term transmission needs over at least 20 years, considering long-term uncertainties through at least three plausible scenarios.[41] It requires grid planners "to conduct and periodically update long-term transmission planning to anticipate future needs; … to consider a broad set of benefits when planning new facilities; … to identify opportunities to modify in-kind replacement of existing transmission facilities to increase their transfer capability, known as 'right-sizing'; customers [to] pay only for projects from which they benefit;" it also expands the role of U.S. states in planning, selecting, and determining how to pay for transmission. These scenarios must incorporate categories of factors identified by the Commission including resource retirements, integrated resource plans, utility needs, and federal, state, and local laws regarding the future resource mix and decarbonization.[42] The planning process must include a process for the transmission planner to select long-term projects, based on an assessment of at least seven mandatory benefits identified by the Commission.[43] To allocate the costs of these long-term projects, planning regions must have a default allocation method to recover the costs from various states.[44]

The FERC Order recognizes that holistic long-term transmission planning is desirable to avoid the inefficiencies created by the current planning processes. Planning that holistically considers more than one transmission driver simultaneously is referred to as "multi-value" or "multi-

[39] Building for the Future through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection (2024). See Fact Sheet | Building for the Future Through Electric Regional Transmission Planning and Cost Allocation | Federal Energy Regulatory Commission and FERC Strengthens Order No. 1920 with Expanded State Provisions | Federal Energy Regulatory Commission

[40] Regulation of Access, Pricing, and Planning of High Voltage Transmission in the U.S. - CEEPR

[41] Order 1920 at 559

[42] Order 1920 at 387

[43] Order 1920 at 667, 911

[44] Order 1920 at 1291

driver" planning, enabling solutions that enhance the existing grid, upsize existing lines, or add new lines to simultaneously and more cost-effectively address multiple needs. Holistic planning is particularly valuable now as the need to refurbish or replace transmission infrastructure originally deployed during the rapid expansion of the US electric grid during the middle of the 20th century logically drives a significant portion of today's high level of local transmission investments.

To achieve such holistic planning outcomes, FERC's Order 1920 requires that a 20-year planning horizon and benefit–cost analyses that consider a wide range of transmission-related benefits as well as a broad set of solutions, including grid-enhancing technologies and the upsizing of aging existing lines. The mandatory subset of transmission-related benefits that FERC Order 1920 requires include: (1) avoided or deferred reliability transmission facilities and aging infrastructure replacement; (2) either reduced loss of load probability or reduced planning reserve margin; (3) production cost savings; (4) reduced transmission energy losses; (5) reduced congestion due to transmission outages; (6) mitigation of extreme weather events and unexpected system conditions; and (7) capacity cost benefits from reduced peak energy losses.[45]

As FERC also recognized, but did not mandate in Order 1920, additional benefits of transmission investment exist beyond those mandated. They include: (8) diversification of weather and load uncertainty; (9) deferred generation capacity investments; (10) access to lower-cost generation; (11) increased competition; and (12) increased market liquidity.[46] This list of benefits is derived from successful examples of existing multi-value transmission planning efforts by RTOs/ISOs and a growing amount of industry experience.[47]

FERC's Order 1920 is somewhat limited in scope. First, while it mandates a new long-term, multi-value transmission planning processes, it does not provide much guidance on how the new planning process should be coordinated or integrated with existing planning processes (although Order 1920-A clarifies that planning for the refurbishment of aging transmission infrastructure has to explore upsizing opportunities). Second, and as noted above, the mandated list of transmission-related benefits to be considered in planning is not a complete

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[45] Order 1920 at 667.

[46] Building for the Future through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection, Notice of Proposed Rulemaking (NOPR), 2022, 179 FERC ¶ 61,028 at 185

[47] Pfeifenberger, Gramlich, et al., Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs, 2021 at 31, Table 4 and appendices B, C, and D).

list of all transmission-related benefits. Third, while Order 1920 requires interregional coordination of regional transmission planning, it does not require interregional planning. Fourth, it does not prescribe how scenario-based planning should be used to develop least-regrets transmission solutions that perform best across the range of planning scenarios. This means there are opportunities to improve transmission planning beyond the strict mandates of Order 1920.[48]

Although Alberta is not mandated to follow FERC orders, through the development of the OTP framework, AESO has a unique opportunity to create a transmission planning process that is not only consistent with the minimum mandates of FERC's Order 1920 but, by taking advantage of best practices from around the world, exceeds those requirements.

48 For example, see Order 1920 Compliance: An Opportunity to Improve Transmission Planning beyond Mandates (October 2024) and Transmission Cost Allocation for Order 1920 Compliance (December 2024).