aeso

Optimal Transmission Planning Framework

Methodology and Process

JANUARY 2026

Contents

Executive Summary

The Alberta Electric System Operator (AESO) is adopting an Optimal Transmission Planning (OTP) Framework to develop transmission based on economic efficiency or when required for reliability or by legislation. This framework implements the *Transmission Regulation* (T-Reg) requirement that transmission development benefits must outweigh its costs.

Why OTP is Needed

In 2025 the Government of Alberta amended the T-Reg to improve the grid's economic efficiency by eliminating Alberta's decades-old "zero congestion" transmission planning standard. Under the old standard, the transmission system was required to always have capacity available for in-merit electricity. That meant building transmission even when its cost was far greater than the value of the electricity it allowed to flow.

Under the new OTP Framework, the AESO will move transmission development forward when the overall benefits of the proposed transmission outweigh its overall costs and not to ensure zero congestion.

Purpose of the OTP Framework

The OTP Framework establishes how the AESO will plan and develop Alberta's electrical system in the most economically efficient way. The framework:

- Ensures transmission is only built when it provides a net economic benefit to the system, or is needed for reliability or to comply with legislation
- Aligns Alberta's transmission planning practices with North American and global best practices
- Ensures structured, predictable and transparent grid planning

When Transmission Will Be Built

The OTP Framework includes three transmission project categories:

1. **Economic Projects:** Built when the project's economic benefits outweigh its costs.

- Transmission projects can be economically beneficial by reducing congestion or taking advantage of efficient interconnection opportunities
- Costs and benefits will generally include:
  - Transmission capital, operating and maintenance costs
  - Avoided production costs
  - Avoided reliability upgrade costs

- Avoided ancillary services costs
- Improved capital efficiency for generators (avoided generator investment)

2. **Reliability Projects:** Built when required to serve load in compliance with Alberta Reliability Standards (ARS).

- Under ARS, load must always be served reliably, accounting for transmission and generator outages
- Serving load is not contingent on the load delivering economic benefits to the system

3. **Legislation-Driven Projects:** Built when mandated by provincial legislation.

Public Interest Considerations Built into OTP

The AESO structured the OTP Framework to:

- Maintain grid reliability in compliance with ARS
- Provide loads and generators with reasonable opportunity to access to the system with minimal changes to connection processes or timelines
- Align with the Restructured Energy Market (REM) Design

Anticipating Needs Despite Uncertainty

OTP requires forward-looking cost-benefit analysis in addition to the AESO's traditional engineering analysis. Successful planning means developing transmission projects that generators and developers will need based on a realistic long-term outlook.

We will ensure transmission projects support investment decisions by:

- Developing the AESO's Long-Term Outlook (LTO) and Long-Term Transmission Plan (LTP) in consultation with generators and other stakeholders
- Using the AESO's Connection Project List to identify where there is interest in connecting to the transmission system
- Using market models to predict economically sustainable generation development
- Using scenario-based planning to anticipate a broad range of potential needs
- Seeking transmission project approvals earlier so builds are completed close to when transmission is needed

Supporting Investment in Generation

To support investment in generation, OTP will require the AESO to:

- Publish current and anticipated congestion and system capacity information
- Seek approval for transmission projects early on so project construction can begin when congestion reaches pre-determined levels known to stakeholders in advance
- Use a predictable and transparent planning process so interested parties can anticipate when the AESO might build transmission and/or when developers might build generation
- Evaluate transmission benefits from a system-wide perspective that balances the interests of producers and consumers

Next Steps

The AESO will:

- Develop an ISO Rule to establish OTP—filing with the Alberta Utilities Commission (AUC) expected in 2026
- Prepare a comprehensive Information Document (ID) or guideline to accompany the OTP Rule
- Further engage with stakeholders on transmission planning and forecast development
- Base future LTOs and LTPs on the OTP Framework[1]
- Monitor transmission planning outcomes and refine the OTP Framework through periodic updates

[1] Subject to government approval of the AESO's timelines.

1. Introduction

1.1 Purpose

On July 3, 2024, the Government of Alberta directed the Alberta Electric System Operator (AESO) to implement an Optimal Transmission Planning (OTP) practice that allows for congestion.

On July 9, 2025, the *Transmission Regulation* (T-Reg) was updated:

- The requirement to plan a congestion-free transmission system was repealed
- It was replaced with a requirement to “make arrangements for the expansion or enhancement of the transmission system if the Independent System Operator (ISO) determines that the overall benefits of the proposed development outweigh its overall costs”

The AESO is developing an OTP Framework—comprising process and methods governed by an ISO rule and further described in an Information Document (ID)—to implement these transmission policy changes. The purpose of this document is to explain how the AESO will do optimal transmission planning.

We plan to apply to the Alberta Utilities Commission (AUC) for approval of an ISO rule to govern OTP (the OTP Rule) in 2026. We will develop and consult with stakeholders on the proposed rule in accordance with AUC Rule 017.

- The OTP Rule will require the AESO to plan the transmission system according to a process that is described in the rule at a high level
- An ID will provide more detail on processes and methods

OTP practices are used throughout the world. Other system planners using OTP practices publish guidelines explaining how they plan the transmission system. For example, the California ISO (CAISO) has published its *Transmission Economic Assessment Methodology* and the Australian Energy Market Operator (AEMO) has published its *Integrated System Plan (ISP) Methodology*. The form and content of this document is informed by these and similar publications.

1.2 Guiding Principles

The OTP Framework is based on the following principles:

- **Affordability**: The transmission system supports an affordable delivered cost of energy for consumers and sustainable investment in source assets (including generators, storage and interties)
- **Transparency**: Stakeholders know our plans and understand their basis in assumptions, predictions, models and analysis

- **Predictability**: Stakeholders can reasonably anticipate how changes to assumptions and predictions would change our transmission development plans
- **Practicality**: We will be capable of implementing the OTP Framework, and it will be compatible with the energy market and ISO Tariff
- **Compliance**: The OTP Framework must lead to compliance with applicable laws, regulations, Alberta Reliability Standards (ARS) and ISO rules

1.2.1 Affordability

We will seek to achieve affordability by planning the transmission system to maximize economic efficiency.

We will not exclusively adopt the economic perspective of consumers or producers when analyzing the costs and benefits of transmission. We will not attempt to minimize profit from source assets. OTP must support Alberta's competitive wholesale energy market, which relies on private investment for supply adequacy. Investors should be able to recover their costs and achieve a reasonable rate of return on investment.

The AESO will not forego compliance with laws, regulations, ARS, ISO rules or directives to achieve affordability. Overall affordability therefore depends on affordable compliance costs. We trust the governance process for ARS and ISO rules is adequate to ensure Alberta has rules and standards with appropriately affordable compliance costs.

1.3 Scope

This OTP Framework focuses on the economic and engineering analyses we will use to plan the transmission system. It will not address the following related matters:

- Financial protections related to transmission system congestion fall under the Restructured Energy Market (REM) Design, including financial transmission rights (FTRs), granting FTRs or other protections to incumbent source asset owners or local market power mitigation. Details will be shared through the Congestion Management Framework engagement stream.
- Generator contributions to transmission costs, including recovery of a transmission reinforcement payment (TRP), fall under the ISO Tariff. Details will be shared through the TRP & Supply SAS engagement stream.

1.4 Terminology

We use some specialized language in this document.

Term	Definition
Source asset	Any asset capable of supplying energy, including a generator, energy storage device, dispatchable load, aggregation, intertie or hybrid. Some source assets can be net loads or net producers at different times.
Capacity expansion	The addition of a source asset to the grid or a change to the capacity of an existing source asset.
Congestion	A source asset experiences congestion when it is not dispatched but has lower production cost than another source asset that is dispatched, because of the necessity to satisfy security constraints.
Mandatory dispatch	Occurs when a source asset is dispatched but has higher production cost than other available source assets, because that specific asset (or a higher priced asset) must be dispatched to satisfy security constraints.
Security constraints	Mathematical inequality constraints expressing how transmission equipment must be operated within its ratings and capabilities (e.g., "the loading of transmission line 1201L must be less than 1,200 megavolt-amperes [MVA]"). Such constraints can be present in optimization problems for determining source asset dispatch.
Transmission development	A set of transmission system enhancements, grouped together as a system project, for which the AESO would seek approval from the AUC to implement for a common reason. It might include one or more transmission lines, transformers, substations, reactive support devices or non-wires solutions.
Ancillary service	Contingency reserve, regulating reserve, fast frequency response (FFR), ramping reserve (R_{30}), and other services.

Term	Definition
Milestone	A condition that must be met before the AESO directs a transmission facility owner (TFO) to construct an approved transmission development (e.g., “the AESO will direct construction of this when the two-year outlook shows 10 per cent of energy is not deliverable due to congestion”).
Zonal Model	A production cost model that represents all generators and interties in Alberta, with approximate bulk inter-regional transmission constraints, which we will use for capacity expansion simulations.
Nodal Model	A production cost model that represents the transmission system in detail, which we will use for calculating the economic benefits of transmission upgrades.

2. Process Overview

This section provides a high-level overview of the OTP process. Details are provided in the following sections.

OTP Process Steps
Forecasting (Developing the Long-Term Outlook [LTO])

- Develop several planning scenarios representing how different economic and sociopolitical outlooks might manifest in load growth and source asset projects
  - Engage with stakeholders to establish inputs and assumptions
- Estimate likely source asset additions
  - Perform capacity expansion simulations using the Zonal Model
  - Include approximate inter-zonal transfer limits reflecting the limited capacity of the transmission system
  - Find economic capacity expansion projects, including technology, size, location and in-service date (ISD)
  - Repeat the simulations as needed to reflect the relationship between transmission development and capacity expansion

Modelling

- Develop a Zonal Model (Section 4.2) to forecast source asset additions and retirements
  - It models production costs and offer behaviour for all source assets
  - It includes a set of potential source asset projects and is used to determine whether (when) they are economically viable
- Develop a Nodal Model (Section 4.3) to forecast transmission system utilization and congestion
  - It is built from the Zonal Model and adds a complete network model with security constraints
  - It includes a set of potential transmission developments and is used to determine whether (when) they are economically beneficial
- Calibrate the dispatch results yielded by the Zonal and Nodal models based on observed dispatch, offers and congestion

Transmission System Analysis (Developing the Long-Term Transmission Plan [LTP])

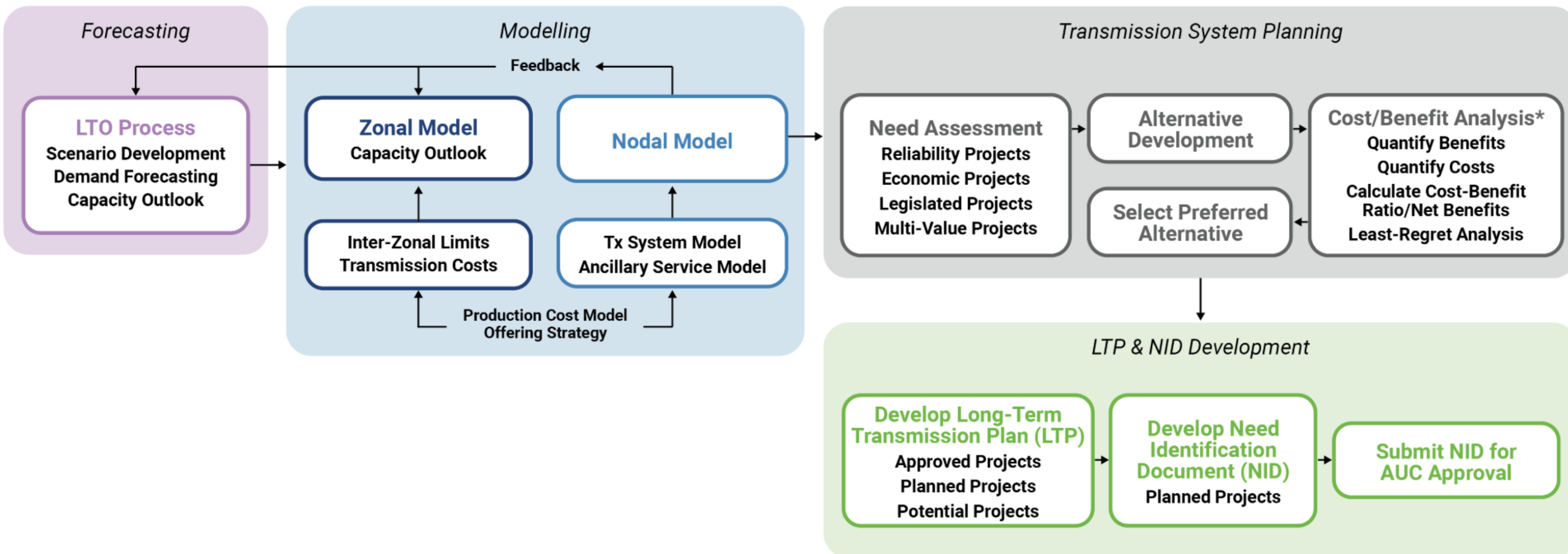
OTP Process Steps
• Perform engineering and economic analysis for each planning scenario – Perform security-constrained economic dispatch (SCED) simulations using the Nodal Model – Identify reliability needs by finding where the ARS cannot be satisfied by the market outcome – Identify potential economic needs by finding material congestion or mandatory dispatch – Identify where a transmission development is required to comply with legislation or directives – Model transmission development alternatives that could meet the reliability, economic and legislated needs revealed in the planning scenario • Perform cost-benefit analysis for each transmission development alternative – Estimate its cost – Find the difference in energy and ancillary services (AS) costs by performing a long-term dispatch simulation – Determine avoided transmission and source asset investment costs • Develop an overall system plan – Identify the most beneficial alternative for each reliability, economic or legislated need – Use least-regret analysis to account for outcomes that vary by planning scenario – Determine reasonable milestones for proposed transmission developments • Test whether the system plan changes forecasted source asset additions and retirements – Determine approximate inter-zonal transfer limits that reflect transmission capacity added by the system plan – Repeat the capacity expansion simulations to determine likely source asset additions – Repeat the transmission system analysis process if the capacity expansion forecast materially changes
Project Development (For Each Need)
• Validate the need for a transmission development, incorporating refinements to the forecast such as the latest information from source asset project developers • Engage with stakeholders, including: – Assessing market participant interest in using added transmission capacity

OTP Process Steps

  - Analyzing stakeholder-proposed alternatives
  - Obtaining asset condition information from transmission facility owners to assess potential avoided costs
  - Gathering information through the AESO's Participant Involvement Program (PIP)
- Develop and analyze a comprehensive set of transmission development alternatives
  - Include variations in topology (such as endpoints), ratings, staging and milestones
  - Perform cost-benefit analysis for each alternative
- Work with potential TFOs to estimate costs and assess environment and land use impacts for each alternative
- Develop a Need Identification Document (NID) and seek approval from the AUC

The AESO plans the transmission system in cycles, ending with the LTP. The OTP process repeats once per planning cycle, which has a two-year duration per the T-Reg. Forecasting and transmission system analysis will iterate to ensure the LTO and LTP align. We plan to publish the LTO and LTP together, preceded by an *Inputs, Assumptions and Scenarios* document that incorporates stakeholder feedback.

Figure 1: OTP Framework Process Diagram



3. Forecasting

3.1 The Long-Term Outlook

The LTO forecasts Alberta's electricity demand growth and source asset expansion for the next 20 years. We base the LTO on assumptions and predictions about parameters and relationships that determine growth. We use scenario-based planning to account for a range of variations in economic, technological and policy drivers.

We use software that simulates the Alberta market by matching load forecast with source asset build-out and dispatch. The capacity expansion forecast seeks to add the most cost-effective source assets to the system, considering fixed and variable costs and anticipated energy revenues. The software incorporates strategic offering, scarcity, asset retirement, emissions costs and regulatory policies to determine when source assets can be built economically to meet demand. The simulation software uses the Zonal Model described in Section 4.2.

3.2 Scenario Development

We use scenario development to explore a range of possible futures, reflecting variations in economic, technological and policy drivers that affect electricity demand and production. The scenario-based approach enables the LTO to answer "what-if questions" and supports transparency by showing the potential OTP build-out and economic outcomes for scenarios proposed by stakeholders. The AESO has a long history of scenario-based forecasting.

The drivers subject to variation across scenarios may include:

- Economic growth expectations
- Federal or provincial policies, pathways or objectives
  - Policy implementation through tax incentives, such as investment tax credits
- Anticipated load growth (considering economic and government policy drivers)
  - Electrification, such as industrial electrification or electric vehicle adoption
  - Efficiency improvements for existing load categories
- Technology costs, capabilities, learning curves and availability
  - Adoption rates for new technologies, such as carbon capture utilization and/or storage (CCUS)
  - Distributed energy resource (DER) adoption, such as rooftop solar
- Industry trends, including hydrogen production or fossil fuel development
  - Potential for large loads, such as data centres, crypto mining or industrial electrification

- Regional intertie development

Scenario development starts by analyzing federal and provincial government policies, market trends and technologies to create a reference case. Additional scenarios are developed by considering shifts in the above factors to create sensitivities to the reference case that account for possible futures. These scenarios will represent variance within reasonable ranges for basic parameters such as economic growth rate or trends that might impact the electricity industry, such as data centre growth, accelerated electrification of industrial processes or electric vehicle adoption.

Stakeholder engagement is essential to ensure the LTO encompasses diverse perspectives, policy and regulatory drivers, industry trends, risk and uncertainties, and real-world constraints.

Through consultation, we:

- Propose an initial set of scenarios to stakeholders and describe how parameters in sensitivity scenarios differ from the reference case
- Gather feedback during a consultation period, which may involve multiple rounds of scenario proposals and feedback
- Choose a final set of scenarios for capacity expansion simulations and transmission planning

3.3 Demand Forecasting

The LTO load forecast is based on an econometric model that represents the interplay between electricity demand, socioeconomic and environmental factors, and the passage of time. It provides hourly load values over the forecast time horizon at several geographical levels.

The load forecast considers:

- Societal or industrial trends, such as the electrification of transportation (electric vehicles) and buildings (heating/cooling)
- Government policy and incentives
- Large discrete load additions, such as data centres, industrial electrification or hydrogen production
- Offsets or reductions to existing demand, such as energy efficiency or DER adoption

We build a reference case and alternative demand forecasts to reflect expectations and variations in these load drivers. The hourly load values in each scenario reflect representative weather patterns.

The model uses the above inputs to predict electricity consumption patterns at multiple levels of aggregation, ranging from Alberta Internal Load (AIL) down to individual points of delivery (PODs) or substations. The Load Forecasting Methodology module in the *AESO 2024 Long-Term Outlook* provides further information.

3.4 Capacity Outlook

Each planning scenario includes a capacity expansion forecast for source assets based on Alberta electricity market simulations. These simulations identify the most cost-effective technologies to meet projected electricity demand and system constraints, considering the economic entry and retirement of source assets.

The objective of the capacity expansion forecast is to identify the technology, timing and location of source asset additions, upgrades and retirements, while meeting demand, emissions limits, policy restrictions, technology availability and transmission system limits based on reliability. Market entry is often represented using proxy units (explained in Section 3.5). Locations are determined on a zonal basis, with a specific point of connection assigned later in the transmission planning process.

The modelling and simulation process uses and produces many inputs and outputs listed in Sections 4.2 and 4.4.

The capacity expansion forecast includes exogenous and endogenous source assets.

Exogenous assets are taken for granted in the capacity expansion simulations. They include:

- Existing assets
- Customer projects that meet inclusion criteria
- Facilities likely to be built for reasons beyond the electricity market, such as:
  - Source assets with power purchase agreements
  - Co-generation tied to industrial growth

Endogenous assets are added when simulations show they are economic. The model includes discrete endogenous source asset development options, and their ISDs are determined based on optimization calculations, subject to constraints on the earliest feasible ISDs.

We will develop cost data for new generators using stakeholder feedback and of public and procured[2] industry reports adapted for Alberta. Fixed and variable costs include financial considerations:

- Inflation
- Lead times and carrying costs between construction start and commercial operations

[2] Sources include but are not limited to:

- The Energy Information Administration (EIA) Annual Energy Outlook
- Pacific Northwest National Laboratory's (PNNL) capital cost and performance data
- Lazard's Levelized Cost of Electricity reports
- Guidehouse's Analyses Regarding Costs and Characteristics of Select Emerging and Advancing Generation and Energy Storage Technologies, procured by the AESO
- 1898 Co.'s Dispatchable Low-Carbon Generation Technology Assessment, procured by the AESO

- Taxes and tax credits
- Technology learning curves, i.e., how costs evolve over time due to improvements in technology

Capacity expansion forecasts are produced using the Zonal Model (Section 4.2), which represents source asset production costs, operating characteristics and capacity addition costs. It will include a simplified transmission system model representing inter-zonal transfer constraints and the zonal locational marginal prices (LMPs) that result from them.[3] LMPs affect our capacity expansion predictions because they affect the relative economics of capacity expansion options with different locations.

The Zonal Model is used to perform dispatch simulations with the objective of minimizing total predicted energy production cost and investment in generation. The simulator tests possible combinations of source asset development options to find the set of options that (approximately) minimizes total cost while meeting the demand forecast. The cost-minimizing set of options becomes the capacity expansion forecast. The simulation process must be repeated for each planning scenario because each scenario has different exogenous assets and endogenous options.

3.5 Customer Projects

In the past, the Generating Unit Owner's Contribution (GUOC) payment determined whether customer projects were included as exogenous assets in forward-looking dispatch simulations. With the shift to TRP, we will revisit project inclusion criteria because the existing criteria will not be applicable. We have not determined the new project inclusion criteria yet. They will be based in part on feedback from the ongoing TRP engagement.

We will model customer projects as follows:

- Customer projects will be included as exogenous assets when they meet the project inclusion criteria (to be determined)
- Planning scenarios will include endogenous asset options representative of customer projects and their existence and ISDs (if ever) will be subject to economic optimization, called "proxy assets"

The purpose of this modelling practice is to predict which projects rational developers will choose to pursue. It is based on the premises that developers will:

- Only complete projects that are reasonably expected to be profitable
- Base their investment decisions on their own projections of market conditions, including their anticipation of the decisions of other developers and the resulting LMPs

[3] As a simplification, we will partition source assets and loads into LMP zones in the Zonal Model. This does not imply the real-time market will have LMP zones—it will have nodal LMPs.

3.6 Iteration Between the LTO and LTP

Initially developed capacity expansion forecasts may change depending on planned transmission developments, as project economics depend on transmission access. Therefore, finalizing an LTO consistent with the LTP may require iteration between planning and forecasting.

The transmission system, including OTP-planned developments, may affect:

- Access to existing and forecasted supply, because transmission constraints can make supply inaccessible
- Demand, because of price sensitivity and the effects of transmission constraints on price
- The economics of adding supply, because transmission constraints and system access costs affect the profitability of capacity expansion options

Therefore, we must iterate between forecasting and transmission planning to establish a self-consistent outlook.

In each iteration:

- The transmission system analysis process will feed inter-zonal constraints back into the Zonal Model, if any incremental transmission developments are planned
- Capacity expansion simulations will then be repeated, and the planning process will continue (or be terminated) if the generation forecast changes (or remains the same)

An iterative forecasting and planning process supports cost-benefit analysis for transmission developments by identifying reduced investment in capacity expansion, enabled by:

- Improved grid access in zones with lower generation development costs
- Improved grid access for existing generators, allowing for investment in new capacity to be deferred

See Section 5.4 for further information.

4. Modelling

4.1 Modelling Objectives

We need models of the electricity market and transmission system to:

- Forecast capacity expansion in the LTO (Section 3.4)
- Assess when transmission development is needed to comply with reliability requirements (Section 5.2.1)
- Quantify the costs and benefits on transmission development (Section 6), including incremental production cost

We will use a Zonal Model to forecast capacity expansion and a Nodal Model to simulate source asset dispatch for reliability assessment and cost-benefit analysis. The two models have many common features, described in Section 4.4.

4.2 Zonal Model

Each scenario within the Zonal Model represents the production costs and dispatch capabilities of all exogenous and endogenous source assets within an LTO planning scenario and the inter-zonal transfer capabilities of the transmission system. It is used to simulate dispatch for a series of time intervals, like every hour in a year.

When the Zonal Model is used to forecast capacity expansion, it solves an optimization problem to minimize total cost over time while solving for:

- The ISD of each endogenous source asset (if ever)
- The unit commitment schedule
- The dispatch in each time interval
- Zonal LMPs and interchange

The simulator applies physical constraints on electricity production (per Section 4.4.1) when determining dispatch, to the extent possible without a full network model.

4.3 Nodal Model

Each scenario within the Nodal Model is based on a capacity expansion result from the Zonal Model and adds a full network model so power flows can be calculated, and security constraints can be evaluated.

In each dispatch interval, a dispatch simulation using the Nodal Model determines the dispatch that minimizes energy cost subject to physical constraints. This dispatch is called the SCED. The physical constraints represented in the simulation include:

- Pre- and post-contingency transmission line loading must not exceed ratings
- System operating limits (SOLs) based on stability limits must not be exceeded
- Electricity production constraints for source assets (per Section 4.4.1) must be respected

The simulator output includes:

- The unit commitment schedule
- The dispatch in each time interval
- Nodal LMPs and shadow prices
- Power flows
- Instances where security constraints could not be satisfied

The Nodal Model includes a full network model with the topology and operating limits of the transmission system and the impedance and rating of each line or transformer it comprises. The network model is a simpler version of that used in alternating current (AC) power system studies, based on linearized power flow equations to allow the use of linear programming methods in optimization.

The linearized power flow equations used in the Nodal Model assume that:

- The system has a flat 1.0 per unit voltage profile
- Voltage angles between adjacent nodes are small[4]
- Reactive power flow is negligible
- Branch resistances are negligible

Based on these assumptions the simulation software determines:

- Power transfer distribution factors (PTDF)
- Line outage distribution factors (LODF)

The simulation software uses distribution factors to calculate system-intact and post-contingency power flows.

- The PTDF matrix operates on the power injections at each node to yield the flows in each branch
- The linearized power flow equations are modelled as equality constraints using the PTDF matrix

[4] I.e., $\sin(\Delta\theta) \approx \Delta\theta$.

- The sum of flows over each branch incident on a node must equal the net injection at the node

- The LODF matrix associated with a contingency operates on the flows in each branch to yield the incremental flows resulting from the contingency
- Security constraints are:
  - Requirements that post-contingency flows must not exceed ratings
  - Modelled as inequality constraints on pre-contingency and post-contingency flows determined by the PDTF and LODF matrices

Constraints apply to post-contingency branch flows because the ARS require the AESO to operate the system in a state of readiness for contingencies.

The linearized power flow model includes an approximation of transmission losses. Losses are calculated as a function of power flow and loss penalty factors are used to calculate the loss component of LMPs and impacts to dispatches.

Security constraints based on voltage cannot be represented directly because of the flat voltage profile assumption. Instead, we must derive SOLs that relate voltage to power flow by performing AC power flow studies (per Section 5.2.1) and represent those SOLs as security constraints.

4.4 Common Features

4.4.1 Production Cost Model

The Zonal and Nodal Models must represent both production costs and offers. Offers are related to production costs, in that generators would offer at marginal cost in a perfectly competitive market. However, the Alberta market allows for strategic offering and generators may have opportunities to exercise market power. Therefore, dispatch is established using offer strategy modelling, but production costs are modelled and used in economic assessments.

The production cost model requires physical characteristics and forecasted input and cost information for existing and potential new source assets.

The physical characteristics incorporated into the model include (but are not limited to):

- Maximum and minimum stable output, including must-run or cycling constraints
- Technology-specific parameters, including:
  - Heat rates, emission rates and emission constraints for gas generators
  - Industrial process constraints for co-generation
  - Storage capacity, losses and recharge rates for energy storage
  - Reservoir state and flow requirements for hydro generators

- Production capability based on wind speed or solar irradiance for wind or solar generators
- Temperature-based derate curves
- Temperature-based transmission line ratings
  - Dynamic line rating, when applicable
- Planned outage dates and durations
- Forced outage probability distributions
- Start-up times and ramp rates

The forecasted inputs required to produce a generator dispatch include (but are not limited to):

- Exogenous demand
- Weather time series data, including location-dependent temperature, wind speed and solar irradiance
- Hydrological data to determine hydro generator production

Required cost data include (but are not limited to):

- Fuel costs
- Costs for compliance with emissions regulations
- Fixed and variable operations and maintenance (O&M) costs
- Startup and cycling costs
- Capital costs and financial costs (for capacity expansion simulations)
- Tax credits and incentives

We collect data from a combination of industry reports from both public and procured sources and adapt this information for Alberta (per Section 3.4).

We will model ancillary service dispatches in dispatch simulations. AS affect dispatch simulations in two ways:

- Transmission capacity must be available to deliver the services
  - Energy and AS dispatches are competing for transmission
  - Congestion impacts the costs of both energy and AS
- AS dispatches reduce the capacity of source assets available to provide energy

4.4.2 Offering Strategy

The Alberta energy market incorporates strategic offering by design. Generators can make offers that materially differ from their production costs. To predict how generators will be dispatched, we must therefore predict their owners' offering strategies.

Strategic offering can theoretically be modelled using:

- **Empirical methods**, where offer strategy is inferred from historical offering behaviour
- **Game-theoretic methods**, where offers are based on equilibria where no source asset can profit more by perturbing its offering parameters

We will use empirical methods, as game-theoretic methods are resource-intensive and complex. Specifically, we will represent offering strategies in generator dispatch simulations, modelled on past market participant behaviour, using:

- Scarcity pricing curves
- Bid adders and multipliers that modify production cost

The empirical approach calls for us to analyze historical data and infer relationships between each asset's production cost and its owner's offers. Relationships between offers, production costs, and selected variables representative of market conditions are determined through regression analyses and used to derive offer strategy parameters. The empirical approach is used by other ISOs. For example, the CAISO recommended this approach in their 2005 Transmission Economic Assessment Methodology (TEAM) paper.

We will model deviation from offer behaviour inferred from historical data when generators can exploit local market power. Local market power exists when generators must produce incremental power (relative to the unconstrained competitive outcome) to satisfy transmission security constraints. When all effective generators must be dispatched to satisfy security constraints, we may assume they will maximally exercise local market power by offering at the applicable cap.

The empirical strategic offering model will be validated by back-testing:

- Offer parameters will be inferred from historical behaviour
- Historical conditions will be provided as inputs to a generator dispatch simulation
  - Including demand, weather, fuel and emissions costs, etc.
- We will adjust offer parameters through iterative simulations until the model yields dispatches close to historical market outcomes
- We will apply correction factors to forward-looking market prices to account for differences between the back-test simulations and their intended outcomes

Explained further in Section 6, we will use the system perspective to decide when economic projects are needed. This perspective is indifferent to money transfers between loads and generators. Decisions are robust to errors in price provided errors in physical output are small.

5. Transmission System Analysis

The AESO develops and publishes an LTP to help stakeholders understand its plans to expand and enhance the transmission system so they can make informed investment decisions. The LTP is based on the LTO and includes transmission developments that might be constructed in the next 20 years.

We will use scenario-based planning to produce the LTP and implement scenario-based planning by:

- Performing engineering and economic analysis for each planning scenario to:
  - identify reliability needs, economic opportunities to lower energy costs by adding transmission, or infrastructure required to comply with legislation
  - identify potentially viable transmission development alternatives
- Performing cost-benefit analysis for transmission development alternatives to identify preferred developments
- Developing an overall system plan, using least-regret analysis to choose alternatives that are expected to provide the best value across planning scenarios
- Testing whether the system plan changes forecasted source asset additions and retirements, and repeating analysis as needed

5.1 Model Preparation

We use the Nodal Model to analyze the transmission system when creating the LTP. The Nodal Model must be prepared as outlined in the following sub-sections before we can use it for this analysis.

5.1.1 Proxy Assets

LTO scenarios include proxy source assets (Section 3.5) that represent economic capacity additions for which the size, technology (fuel) type and zone have been predicted, but are not associated with a specific customer project and point of connection. Points of connection for proxy generators must be chosen based on:

- The customer project list, including the stage of advancement of each project
- Available transmission capacity (as determined in the previous or current planning cycle)
  - Developers are assumed to make reasonable efforts to minimize congestion risk
- Technology-specific siting considerations, such as (when applicable):
  - Wind and solar resource quality

- Alignment with gas supply
- Available land, land use and cost
- Local environmental and social impacts
- Site-specific costs and market opportunities:
  - Congestion
  - Opportunity to profit from mandatory dispatch
  - Connection costs, including the customer contribution and TRP
  - Transmission system losses

We may create sensitivity scenarios with alternate generator locations if engineering judgment suggests they could change planning outcomes. For example, if project capacity exceeds forecasted capacity expansion, we might test different subsets of customer projects to determine how robustly a system project could reduce congestion.

Need assessment may reveal that proxy generators are materially affected by congestion while suitable points of connection exist with available transmission capacity. In such cases, we may revise our proxy generator locations and repeat the assessment.

The proxy generator location assignment process must be repeated for each planning scenario because scenarios have different capacity expansion options. We will generally use consistent locations for source assets that exist in multiple scenarios when possible.

5.1.2 Load Serving

When high load growth is forecasted, power system studies may show a combination of POD capacity exceedances (i.e., transformer overloads) and regional and bulk transmission overloads. The most economical solution may include:

- Expanding existing PODs
- Creating new PODs
- Transferring load between PODs

PODs are generally created when a distribution facility owner (DFO) applies to the AESO through the connection process.

Regional transmission needs may vary depending on whether DFOs plan to create or expand PODs and how they transfer loads within the distribution system. To minimize transmission costs, the AESO and DFOs should coordinate to plan, create and interconnect PODs, and redistribute load to reduce total transmission and distribution expenditures. The AESO cannot do this alone because:

- Distribution planning is largely outside our planning scope and mandate, except to the extent that there are opportunities to co-optimize distribution and transmission
- Distribution planning requires models and data we do not currently gather

Therefore, when we see a long-term insufficiency of load serving capability at the POD level, accompanied by regional or bulk transmission constraints, we will:

- Consult with DFOs to align forecasts and discover their plans for new PODs
- Assess opportunities to serve load in a way that reduces regional transmission build and advise DFOs of such opportunities (if any)
- Represent the joint plans when determining the need for regional transmission to support load growth

The AUC, DFOs and the AESO are engaged in initiatives to improve coordination in distribution planning. We will continue to engage with them to improve planning through better communication channels and information requirements.

5.2 Need Assessment

We will advance transmission developments (system projects) through the project development process when:

- Required to comply with ARS (reliability projects)
- The economic benefits outweigh the costs (economic projects)
- Required to comply with laws, regulations or directives (legislated projects)

Projects might be required for a combination of the reasons above. Such projects are called “multi-value projects.”

The following sub-sections explain how we will determine when projects in each category are needed.

Dispatch simulations using the Nodal Model are the foundation for all need assessments. Dispatch simulations will be conducted for each planning scenario, considering several or all years in the 20-year planning horizon, and accounting for sensitivities in source asset locations and customer project inclusion. The simulations will produce the data required to assess the system’s compliance with reliability requirements and the economic value of transmission development alternatives.

5.2.1 Reliability Projects

5.2.1.1 Reliability Objectives

Our primary reliability objective in planning the transmission system is to ensure compliance with ARS.

The AESO is subject to the ARS, which are based on North American Electric Reliability Corporation (NERC) standards. The ARS require us to plan and arrange to build and maintain transmission to maintain reliability. The transmission planning standards (e.g., the proposed TPL-001-AB-5.1) impose the following reliability requirements:

- The system must meet anticipated peak demand when intact
- The system must continue to meet demand after any single contingency of a transmission element or generating unit (without load shedding or cascading outages)
  - When the starting state is an intact system
  - When starting with an intact system, a generator outage occurs, re-dispatch occurs and a contingency occurs

The system might be unable to meet demand because:

- Transmission elements, including transmission lines or transformers, are loaded above their ratings
- Voltages are outside acceptable operating bounds or voltages are subject to collapse
- Generating units and storage resources become unstable and/or disconnect
- Loads are unable to remain connected to the system due to voltage transients

We will treat reliability requirements as constraints in the OTP process. In other words, the outcome of the OTP process must be a plan that maintains the Alberta grid's compliance with the ARS.

5.2.1.2 Discovery of Reliability Needs

A **reliability need** exists when source assets cannot be dispatched to supply load without violating the ARS. Conversely, there is no reliability need when compliance with ARS can be achieved through security-constrained generator dispatch and reasonable system operating limits. In the REM, dispatching source assets to satisfy reliability requirements is part of normal market operation.[5]

[5] We might implement economic projects, as further explained in Section 5.2.2, to reduce congestion or mandatory dispatch necessary to meet reliability requirements.

Transmission development is required when the forecast predicts a reliability need. A transmission development or non-wires solution that is needed to avoid violations of reliability requirements is deemed a **reliability project**.

We will progress reliability projects regardless of their economic costs and benefits. However, we will apply economic analysis to assess economic benefits, such as avoided production costs, that may differ between transmission development alternatives that meet the same reliability need. Through this process we may discover multi-value project opportunities, where economic benefits and reliability improvements are achieved in the same project.

We will primarily discover reliability needs through dispatch simulations using the Nodal Model. Security constraints will be applied to the dispatch simulation to ensure transmission element loadings are within ratings when contingencies occur and system operating limits are respected. If the dispatch simulation finds an unsatisfiable security constraint in any dispatch interval, then a reliability need exists.

Technical considerations may apply.

Generator Outage Risks

Transmission overloads must not occur due to single contingencies when any one generator is offline (N-G-1 contingencies). We have two strategies to find reliability needs arising from N-G-1 contingencies while avoiding excessive calculations:

1. In many cases, we can infer which generator outage is most strongly associated with reliability needs in an area from generator size and system topology. In such cases, we can repeat the dispatch simulation with that generator out of service, considering only contingencies and security constraints relevant to the area, to identify N-G-1 reliability needs in the area.
2. In other cases, we can screen for reliability needs by modelling N-G-1 events as single contingencies, omitting the redispatch between the generator outage and the subsequent transmission outage. If the screening analysis shows overloads, we can use method (1) for each generator whose outage showed overloads to determine whether a reliability need exists. The screening analysis is conservative in the sense that it can yield false positives but not false negatives.

Voltage Stability Risks

The Nodal Model assumes a flat voltage profile and cannot identify reliability needs arising from abnormal voltages. Abnormal voltages generally occur in extreme system states, such as some combination of:

- Light or peak load

- High or low renewable[6] generator output

To discover voltage stability risks, we will:

- Scan the dispatch simulator output for extreme states and capture AC power flow study cases
- Perform contingency analysis using an AC power flow program to test for abnormal voltages
- Determine proxy system operating limits representative of the transmission loading or generator output at which voltage instability or abnormal voltages will occur

Dynamic Stability Risks

Electromechanical or control stability risks cannot be discovered by dispatch simulations alone. Dynamic or transient simulations are required to assess stability risks. However, conditions that pose the greatest risk of instability are reasonably predictable. Dynamic instability is most likely when:

- System strength or inertia are low
- Generation in an area is high or low relative to transmission capacity, leading to outflows or inflows close to loadability limits

To discover dynamic stability risks, we will:

- Scan the dispatch simulator output for extreme states and capture AC power flow study cases
- Prepare the study cases for dynamic or electromagnetic transient (EMT) simulation
- Perform dynamic or EMT simulations of high-risk contingencies[7] to identify when the system becomes unstable
- Determine proxy system operating limits representative of the transmission loading or generator output at which electromechanical or control instability is likely to occur

Mitigating Voltage or Dynamic Stability Risks

Stability risks or abnormal voltages can often be mitigated by limiting generator dispatch. For example, a dynamic stability study may show instability can be avoided by limiting the total output of a set of generators. Therefore, when a stability risk is discovered, we will:

- Use dynamic or EMT simulations to determine proxy limits for transmission loading or generator output

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[6] Renewable generators do not inherently create voltage stability risks. However, renewable generators on the Alberta grid are clustered in certain geographical areas and have correlated output. Different parts of the grid are stressed when wind and solar output is high or low because of the geographical concentration of these assets.

[7] We will seek to have coverage of most or all contingencies; but each contingency may only be simulated in one (relatively high risk) AC power flow study case.

- The system operating limits should ensure the system is stable when the dispatch complies with them
- Repeat dispatch simulations and test for reliability needs after modelling the system operating limits
  - If no reliability need is found, the stability or voltage-based operating limit may still originate an economic need

5.2.1.3 Solution Proof of Concept

The technical nature of a reliability need determines how potential solutions can be validated.

When a reliability need is caused by a lack of transmission capacity (leading to overloads), we will show a reliability project meets the need by:

- Adding the reliability project to the system model
- Repeating the dispatch simulation
- Showing the load-serving constraint is always satisfied
- Capturing extreme system states (such as load or inter-area transfer extrema) and showing the system meets reliability criteria in AC power flow studies

Solutions for voltage or dynamic stability risks require some additional steps to validate:

- Solutions may include system operating limits, transmission lines, remedial action schemes, reactive support equipment, generator or control system upgrades, AS or a combination of these
- Each alternative must be represented as an equivalent system operating limit and/or ancillary service requirement in dispatch simulations
  - The operating limits must be determined through dynamic or EMT simulations or AC power flow studies
  - Dispatch simulation must show no residual reliability needs when the equivalent operating limit is applied

Lack of transmission capacity is generally the most common need category and the largest driver of spending on transmission development.

5.2.2 Economic Projects

5.2.2.1 Economic Objectives

Our primary economic objective in planning the transmission system is maximizing economic efficiency (i.e., the net value for market participants on the supply and/or demand side).

5.2.2.2 Discovery of Economic Needs

An **economic need** exists when the economic efficiency of the grid can be improved by implementing a transmission development that costs less than its economic benefit. Economic needs generally arise when:

- Low-cost supply is constrained due to lack of transmission outflow capability (congestion)
- High-cost generators experience mandatory dispatch due to lack of load serving capability

We will discover economic needs by:

- Searching dispatch simulation results for frequent occurrences of LMPs that are high or low relative to the system weighted average
  - Frequent low prices indicate lack of outflow capability
  - Frequent high prices indicate lack of inflow capability
- Searching dispatch simulation results for high or low shadow prices
- Performing a counterfactual dispatch simulation where transmission constraints are relaxed and comparing the results between the security-constrained and unconstrained dispatches
  - The results will show output and production cost differences for each source asset
  - The differences in output and production cost will indicate the value of reducing constraints[8]

When simulation results indicate economic project opportunities through high volumes of constrained energy or sustained high or low LMPs, we will test transmission development alternatives to find one that achieves a net economic benefit (when possible). The successful identification of an alternative that yields benefits in excess of costs demonstrates an economic need.

We will investigate economic need when more than five per cent of a generator's output is constrained due to congestion or mandatory dispatch. We may revise this threshold based on experience and may investigate lower levels of congestion.

5.2.2.3 Economics of Reliability Improvement

A reliability project can provide economic benefits by:

- Reducing the need for mandatory dispatch or reducing congestion, thereby lowering average production cost

[8] For example, if a specific generator has a large difference in production when constraints are relaxed because the flow on a specific transmission line, under a specific contingency, is a binding security constraint on its output. Then upgrading the transmission line is at least as valuable as the net present value (NPV) of the sum of (foregone production) × (production cost differential compared to the marginal unit) over all future dispatch intervals.

- Creating opportunities to connect generators at lower cost by increasing the grid's geographical coverage

Conversely, a project motivated by economics can also provide reliability benefits by:

- Increasing load serving capability, thereby averting the eventual need for a reliability project
- Improving system resiliency

We will seek to maximize the benefit of economic projects by any means possible, including by designing them to avert reliability needs when possible.

5.2.2.4 Solution Proof of Concept

When we discover an economic project opportunity, we will:

- Design a set of transmission development alternatives, considering capital cost, system topology and architecture, geography and land use, capacity, constrained energy, and opportunities to avert or defer reliability needs
- Evaluate each alternative using the cost-benefit analysis procedure as described in Section 6
- Select the best alternative based on net economic benefit and/or cost/benefit ratio

When the best alternative achieves a net economic benefit, we have proven the existence of an economic need and found a proof-of-concept solution, which will be further developed through the project development process.

When no alternative provides a net benefit, we have not disproven the existence of an economic need. In such cases, we may consult with stakeholders to ensure we study a comprehensive set of alternatives.

5.2.3 Legislated Projects

We will comply with legislation and regulations that require transmission development by determining the least-cost solution. When several materially different transmission development alternatives exist, we will assess the economic benefits of each alternative and choose the one that maximizes overall benefit, including economic benefit.

The following projects are examples of legislated projects:

- Alberta-BC intertie restoration
- Saskatchewan intertie expansion

Legislated projects are generally limited in scope to their essential elements.

5.2.4 Multi-Value Projects

Projects motivated by both reliability needs and economic benefits are called multi-value projects. Reliability needs and economic benefits often occur together. For example:

- Congestion relief projects can also increase load serving capability, deferring the need for reliability projects
- Bulk system upgrades can increase regional load serving capability while also reducing congestion
- Reliability projects can reduce the need for mandatory dispatch, thereby reducing production cost
- Reliability projects can create connection opportunities for source assets, reducing customer contributions for source asset developers and overall system cost
- Reliability projects can provide opportunities to reconfigure the system, averting the eventual need for inefficient like-for-like replacement of old assets

When we find a reliability need or an economic project opportunity, we will judiciously design transmission development alternatives to maximize net value.

5.3 Asset Management

Transmission developments may have economic value partly because they avert the need for maintenance by replacing elements that would otherwise need to be maintained or are near the end of their useful life.

Parts of the transmission system have been built to support load and source asset dispatch patterns that have changed or will change. We may have the opportunity to design needed transmission developments to eliminate the need for legacy infrastructure by reconfiguring the system while also achieving economic or reliability objectives.

We must know the schedule and cost of maintenance and replacement for existing transmission infrastructure to quantify the benefits above.

We will use three strategies to capture avoided cost opportunities:

1. When reliability or economic needs are discovered, we will investigate whether they can be solved by re-configuring the system or replacing existing transmission in a way that reduces maintenance or like-for-like replacement costs. We will rely on asset condition information supplied by TFOs, including schedules of maintenance and replacement costs, to assess the avoided costs.
2. We will monitor near to medium-term needs for significant investment in rebuilding transmission lines. We will investigate whether there is economic benefit in reconfiguring the system or implementing an alternative to a rebuild that is beneficial to the overall architecture, capacity and

cost of the system. We will ask TFOs to list foreseeable maintenance needs meeting our criteria to enable this analysis. TFOs will be required to estimate approximate replacement dates when they consider rebuilding or replacement a realistic possibility.

3. Where dispatch simulations show low peak and average power flows, we will assess whether the low-utilization transmission lines are needed to comply with reliability requirements, provide operational flexibility or provide economic value through congestion relief that exceeds their ongoing maintenance costs. Transmission that is not needed for reliability, operational or economic reasons could be decommissioned.

Projects that originate from avoided maintenance costs will be economic projects based on cost-benefit analysis. For example, if a radial line is no longer used after a customer decommissions a facility and no new customer projects are proposing to connect to it, then the avoided maintenance costs might warrant salvaging it.

5.4 Feedback Between the LTP and LTO

5.4.1 System Partitioning

Our primary objective when establishing the zones represented in the Zonal Model is to partition the system such that the Zonal Model closely approximates constrained energy compared to the Nodal Model. This is achieved by ensuring that binding constraints occur on transmission lines that cross zonal boundaries to the maximum extent possible.

Our secondary objectives are to:

- Create zones reasonably consistent with past planning practices and publications
- Align zonal boundaries with system operating limits
- Ensure zone definitions support our assumptions about how endogenous resources can have different locations within a zone, accounting for
  - Similar wind and solar resource potential on developable land
  - Access to natural gas
  - Geological and hydrological suitability
  - Co-generation project potential
- Create zones that factor in population density and land use compatibility

5.4.2 Inter-Zonal Transfer Capabilities

We will determine inter-zonal capabilities by finding the maximum power that can flow between zones, based on the system operating limit methodology.[9]

In a simple two zone case, the analysis can be performed by:

- Modelling the transmission system with the most limiting transmission outage in effect
- Including excess zero-cost supply in the source zone and proxy flexible load in the sink zone
  - Ensuring the proxy supply and load are not subject to intra-zonal constraints
- Performing a dispatch simulation to capture variation in system load and supply (including variation in weather)
- Setting the inter-zonal transfer capability equal to the expected interchange yielded by the dispatch simulation

This analysis must be completed twice for a pair of zones with the source and sink zones interchanged to account for import and export limits. The analysis for multiple zones can proceed similarly but is more complex.

[9] Or a simplified version thereof.

6. Cost-Benefit Analysis

6.1 Background

Consumers' willingness to pay (WTP) is the maximum price ($ per MW-h) consumers would pay for electricity. Consumer surplus (CS) is the difference between the consumers' willingness to pay for electricity and the consumer cost (CC).

$$CS = WTP \times L - C$$

Producer surplus (PS) is the difference between the money producers are paid for electricity, the producer revenue (PR), and the production cost (PC).[10]

$$PS = PR - PC$$

Congestion revenue (CR) is the difference between total consumer cost and total producer revenue:[11]

$$CR = CC - PR$$

The Alberta market design allows producers to make strategic offers where energy price is not connected to production cost. Producer surplus is generated when a source asset is more efficient than the marginal source or when strategic offering elevates LMPs.

Assuming inflexible demand, total surplus (TS) is the sum of producer and consumer surplus and congestion revenue:

$$TS = PS + CS + CR = WTP \times Load - PC$$

For a given willingness to pay, total surplus increases when production cost decreases or load increases. We assume economic projects will not change demand. The AESO Connection Process ensures load is provided a reasonable opportunity for system access, and reliability projects ensure all load is served in accordance with the ARS. Therefore, for the purposes of OTP, a transmission development increases total surplus when it decreases production cost:

$$\Delta TS = TS|_{Project} - TS|_{Baseline} = -\Delta PC$$

The benefits of a transmission development extend beyond production cost savings. They also include the avoided or deferred capital investment in source assets, other transmission developments, and maintenance.

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[10] For the sake of simplification, we ignore ancillary service costs and revenues in this and the following section. We will consider AS in our cost-benefit analyses.

[11] For the sake of simplification, we ignore losses in this and the following section. However, we will include avoided losses in our calculation of net benefits, as indicated in Table 2.

6.2 Benefits Perspectives

According to the **system perspective**, an increase in total surplus is considered a benefit. This perspective ignores wealth transfers between market participants: changes in CC and PR caused by changes in price cancel out, per the total surplus identity. The total benefit of a transmission project (ignoring losses) is given by the sum of:

- Avoided production cost (including from AS) (see Section 6.4.1)
- Avoided cost of upgrades, operation and maintenance (see Section 6.4.2)
- Avoided capacity expansion costs (see Section 6.4.3)

According to the **consumer perspective**, the benefit of a transmission project is the increase in CS, as defined in Section 6.1.

According to the **producer perspective**, the benefit of a transmission project is the increase in PS, as defined in Section 6.1.

The AESO will decide whether the benefits of a transmission development outweigh its costs using the **system perspective**, because this perspective:

- Balances the interests of consumers and producers
- Depends on the total cost of transmission development, not how it is allocated to producers or consumers
- Promotes affordability by supporting investment in efficient source assets with lower production costs
  - Reducing production costs also reduces consumer costs in a competitive market
- Appropriately values avoided capital costs

While we will not use the consumer or producer perspectives to determine when to advance a transmission development, we will:

- Include analyses from these perspectives in NIDs and publish them in the LTP
- Assess and publish how transmission developments will affect system access costs for consumers and producers

6.3 Costs and Benefits

Table 1 and Table 2 summarize the components of cost-benefit calculations and how we will calculate them. Further explanation is provided in Section 6.4.

Table 1: List of Economic Costs

Economic Cost	Method of Calculation
Transmission development cost • Capital cost • O&M costs for added infrastructure	• Estimate the capital cost of the system project • Estimate the ongoing O&M costs • Use these estimates to determine the incremental TFO revenue requirement

Table 2: List of Economic Benefits

Economic Benefit	Method of Calculation
Avoided production cost • Cost of congestion • Cost of mandatory dispatch • Cost of losses	• Calculate avoided production costs using dispatch simulations • Compare simulation results between a reference case and selected transmission development alternatives • Measure differences in avoided production cost due to congestion, mandatory dispatch and losses
Avoided AS costs • Achieved when improved grid access leads to more competitive AS markets • Achieved when transmission projects reduce the need for AS	• Include AS in dispatch simulations • Production costs may be associated with providing AS – More efficient energy market dispatch can be achieved by reallocating or procuring more or less AS • AS costs contribute to producer revenue and add to consumer costs.
Avoided or deferred cost of reliability projects	• A transmission development alternative may allow other reliability projects to be avoided or deferred • When it does, credit it with the net present value (NPV) of the avoided transmission development cost or the value achieved by deferral, as appropriate
Avoided or deferred investment in capacity expansion	• Assess how transmission development alternatives might change transfer capability between zones • Compare capacity expansion simulation results between a reference case and selected alternatives

Economic Benefit	Method of Calculation
	• Credit the NPV of avoided capital and O&M costs to the transmission development alternative, when applicable
Avoided cost of cycling	• Count cycles for each generator in each dispatch simulation • Assign owner-stated costs to cycles, accounting for startup costs and loss of life
Avoided cost of transmission operating & maintenance costs, through: • Re-configuration • Replacement (other than like-for-like) • Decommissioning	• Account for O&M costs that can be avoided when transmission development alternatives are implemented • See Section 6.4.2

6.4 Calculation of Benefits

The benefits of a transmission development alternative are calculated by comparing dispatch simulations between cases where it is part of the system and where it is not.

These simulations yield time series for:

- Source asset dispatch, subject to security constraints
- Production cost
- Locational marginal price at every node
- Served and unserved load at every node

Transmission developments can be economically beneficial by:

- Enabling lower production cost energy to reach load
- Reducing capital investment, operating and maintenance costs for transmission or generation

Production cost differences and the resulting differences in consumer and producer surplus are calculated using the simulated time series data. Avoided investment costs are calculated by comparing differences in investment between a baseline simulation where the development is not implemented and trial simulation where the development is present.

6.4.1 Avoided Production Cost

Avoided production cost is often the primary benefit of economic projects and is achieved when a transmission development reduces production cost. Production cost can be reduced by:

- Reducing congestion, where low-cost generators are unable to produce at their maximum potential because of lack of transmission capacity where energy is being produced
- Reducing mandatory dispatch, where high-cost generators are required to produce more than they otherwise would because of lack of transmission capacity where energy is being consumed

Production cost savings are found by comparing the production costs calculated in dispatch simulations with and without a transmission development alternative under evaluation. The dispatches are determined based on generator offers, which can be different from production costs because of strategic offering. The Nodal Model represents offers as modifiers on production cost, and the simulation results include both the LMPs established by offers and the associated production costs.

Gas generators and other emitting generators must pay carbon costs, such as those arising from the *Technology Innovation and Emissions Reduction Regulation* (TIER). Carbon costs add to the marginal cost of energy, like fuel costs. We consider carbon cost to be an element of total production cost.

The AESO will use a back-testing process as described in Section 4.4 to help calibrate our production cost model to yield generator dispatches representative of real market outcomes.

Abnormal conditions can materially affect market outcomes, including LMPs and production costs. The most significant abnormalities include

- Generation and transmission outages, such as for maintenance
- Extreme weather events, such as a heat wave, cold snap or drought

We aim to account for abnormal conditions in our overall assessments of economic value. Our approach will vary situationally, and may include:

- Using a calibration factor to scale the cost of congestion yielded by the Nodal Model so the cost in back-tests matches the real cost
- Using synthetic weather profiles so simulation output represents a range of different weather years in one profile
- Modelling planned or regularly occurring outages
- Simulating each year multiple times using Monte Carlo methods to model transmission and generation outages along with varying weather profiles and averaging the results

6.4.2 Avoided Cost of Upgrades, Operation and Maintenance

Avoided costs must be considered when:

- We are evaluating a primary project (typically an economic project)
- One or more secondary projects are known to be needed for reliability reasons or compliance with legislation
- Some transmission development alternatives considered for the primary project will avert or defer the need for the secondary projects

We will consider cost savings from avoiding or deferring the secondary projects as a benefit of implementing the primary project.

We will treat avoided maintenance like a secondary project. A TFO could avoid maintenance because:

- System re-configuration could allow existing transmission assets to be removed
- The primary project could replace an asset that would otherwise require maintenance or like-for-like replacement

6.4.3 Avoided Capacity Expansion Costs

Investments in transmission can reduce investments in source asset capacity expansion in three ways:

- **Deferred investment**: A transmission development can defer capacity expansion by reducing congestion or mandatory dispatch, allowing energy from constrained assets to reach the grid which would otherwise need to be supplied by new assets
- **Lower development costs**: A transmission development can increase access to lower-cost areas for generation development
  - Development costs can vary between areas for many reasons, including:
    - Better wind or solar resource quality
    - Access to natural gas
    - Lower costs for land or construction
    - Opportunities for carbon sequestration
    - Access to water
    - Geology and terrain
    - Environmental impact and mitigation costs
- **Reduced losses**: A transmission development can reduce system-wide energy losses, so less generation is needed to serve net load (including losses)

We will estimate these cost reductions by comparing capacity expansion simulation outcomes using the Zonal Model with transmission development alternatives present or absent. The difference in total capital and O&M costs between the two runs will be considered a benefit of the transmission development. The effects of transmission development will be captured in the simulation through adjustments to inter-zonal transfer capability operating limits.

6.4.4 Discounting

We will discount future cash flows using discount rates that are appropriate for the benefits and costs considered. We will ensure that, if real cash flows are applied, a real discount rate will be applied.

6.5 Least-Regret Analysis

6.5.1 Procedure

Least-regret analysis[12] is a decision-making process that identifies which transmission development alternatives perform well across planning scenarios, reducing the risk of costly outcomes when the future differs from projections.

Each scenario must be assigned a probability weight to perform least-regret analysis. We may assign weights by:

1. Averaging weight assignments provided by experts (including stakeholders)
2. Deriving the weights from the scenario development process
   - For example, a scenario could be assigned a $P = 0.2$ weight if it represents load growth in less than the 20^{th} percentile or higher than the 80^{th} percentile.)

Method (2) is preferred when scenarios are developed by modelling processes with statistical uncertainty (such as how weather could vary from year to year). Method (1) is preferred when scenarios are developed to analyze scenarios that differ because of deep epistemological uncertainty (such as how pivotal events could change the world).

Transmission development alternatives have different economic performance across scenarios, creating the opportunity for “regret” when a project turns out to be oversized or unnecessary, or conversely, when it fails to enable a beneficial economic opportunity.

The procedure for finding the least-regret alternative is as follows:

1. **Determine net benefit** for each transmission development alternative:

[12] The AEMO is a leading practitioner of least-regret analysis and we have based our approach on theirs. Refer to the AEMO’s Integrated System Plan (ISP) Methodology.

- For alternative $j = 1 \dots n$ and scenario $k = 1 \dots m$, the cost is $C(j,k)$ and the benefit is $B(j,k)$
- The net benefit for each alternative and planning scenario is:

$$N(j,k) = B(j,k) - C(j,k)$$

2. Determine optimal net benefit for each planning scenario:

$$N^*(k) = \max\{N(j,k) | j = 1 \dots n\}$$

3. **Calculate regret** for each alternative and scenario:
   - The regret for choosing alternative j when scenario k occurs is the net benefit foregone by not choosing the optimal alternative for that scenario:

$$R(j,k) = N^*(k) - N(j,k)$$

   - This value must be greater than or equal to zero
   - It measures the difference between the optimal benefit achievable under scenario k and the net benefit actually achieved by alternative j.

4. **Calculate the expected regret** for each alternative:
   - Probability weights[13] $P(k)$ are used for each scenario
   - The expected regret for alternative j is:

$$\bar{R}(j) = \sum_{k=1}^{m} P(k) \times R(j,k)$$

5. Determine the **least-regret** alternative:
   - The least-regret alternative is j^* such that

$$\bar{R}(j^*) = \min\{\bar{R}(j) | j = 1 \dots n\}$$

We will use a combination of least-regret analysis and expected value to choose a preferred transmission development alternative, depending on a subjective assessment of the costs and benefits of the alternatives:

- We will generally prioritize the least-regret alternative when the highest net benefit alternative is determined by a low-probability, high-impact scenario
- We will generally prioritize the least-regret alternative among several alternatives with similar net benefits
- Otherwise, we will prioritize the alternative with the highest expected net benefit or the best cost/benefit ratio

[13] $\sum_k P_k = 1$

6.5.2 Example

Table 3 and Table 4 show how to calculate regret and rank scenarios according to probability-weighted regret. Table 3 shows some hypothetical costs and net benefits for different transmission development alternatives. The green cell in each column shows the maximum net benefit for each scenario and the alternative that provides it.

Table 3: Net Benefit for each Alternative and Scenario

Alternative	Cost ($M)	Scenario 1 (P = 0.2)	Scenario 2 (P = 0.6)	Scenario 3 (P = 0.2)	Expected Value
Alternative 1	$16	$4	$6	$8	$6
Alternative 2	$18	-$5	$15	$20	$12
Alternative 3	$37	-$25	-$5	$60	$4
Alternative 4	$30	-$15	$5	$55	$11

Table 4 shows the regret for each alternative within each scenario: it is the difference in net benefit between the net benefit of each alternative and that of the best alternative for that scenario. The expected regret is the probability-weighted sum of regrets.

Table 4: Regret for Each Alternative and Scenario

Alternative	Ranking	Scenario 1	Scenario 2	Scenario 3	Expected Regret
Alternative 1	#3	$0	$9	$52	$16
Alternative 2	#1 – Least regret	$9	$0	$40	$10
Alternative 3	#4 – Highest regret	$29	$20	$0	$18
Alternative 4	#2	$19	$10	$5	$11

In this example, Alternative 2 both has the highest expected value and the least expected regret. However, it has a higher maximum regret compared to Alternative 4. When we use least regrets analysis to make decisions, we will generally seek to minimize expected regret.

7. Project Development

7.1 The Long-Term Transmission Plan

The LTP will contain a list of projects the AESO has proposed, in three categories:

- **Approved projects**: There is an approved NID and the project is under construction or has an unmet milestone
- **Planned projects**: The AESO has filed a NID or is committed to filing one to meet the optimal ISD
- **Potential projects**: Projects that may or may not be needed in the long term
  - The project may have a positive net benefit in some planning scenarios but not others
  - There is no economic or reliability reason to start construction soon
  - The need will be monitored and reviewed in future planning cycles

We will explicitly designate projects as approved, planned or potential.

When planned or potential projects are included in the LTP, we will publish the following information about each project:

- The need driver (reliability, economics or legislation)
- The anticipated ISD
- The alternatives that were investigated
- Cost-benefit analysis results
  - From the system, consumer and producer perspectives
- Affected system operating limits
  - With and without the project
- Anticipated congestion or mandatory dispatch statistics
  - With and without the project

For economic projects driven by congestion relief, we will publish data showing relationships between congestion and generation capacity and/or load in the area to help developers make informed investment decisions.

When we study economic project opportunities that do not result in planned or potential projects, we will publish some or all of the above (as available). Some information may be unavailable for projects because preliminary analysis may clearly indicate the project cannot be justified.[14]

7.2 The System Project Process

7.2.1 Alternatives and Project Optimization

We may examine several transmission development alternatives when searching for a proof-of-concept solution for an economic or reliability need and publish the proof of concept in the LTP. However, planned or potential projects in the LTP will be subject to further optimization.

We will validate the theory of need using project-specific forecast enhancements, including scenarios representing variation in project progression assumptions and regional economic development. When the need is validated, we will develop a set of transmission development alternatives with the goal of optimizing:

- Incremental capacity and the economic benefits thereof
- Project cost and functional requirements
- System architecture and resiliency
- Interconnection opportunities for customers
- Land use impacts

We will analyze the alternatives using the methods described in Sections 5 and 6 and advance the option that provides the highest expected value and/or least-regret.

Consultation with TFOs is needed at this stage to develop functional specifications, estimate costs, and assess environmental and land use impacts.

In rare cases, analysis conducted after the LTP may indicate a project is no longer necessary. For example, we could change our assessment of an economic project if the capital cost estimate materially increases or economic conditions materially change between LTP publication and NID filing. When this happens, we will publish a stakeholder update and remove the project from the LTP or reclassify it as a potential project.

7.2.2 Need Identification Documents

Each NID will include an update of the information published in the LTP and a detailed comparison of each credible alternative. The NID will meet the information requirements set out in the *Electric Utilities Act* (EUA), the T-Reg and AUC Rule 007.

[14] For example, we might start an assessment by determining the maximum economic value that could be captured by relieving all congestion. If all alternatives cost more than that, there is no need to simulate how much congestion they relieve.

7.2.3 Milestones

In accordance with Section 11(4) of the T-Reg, NIDs may include milestones establishing conditions that must be met before the AESO can direct a TFO(s) to start construction. We may use milestones to balance the risk that regulatory delays could have adverse economic or reliability impacts against the risk that customer projects will materialize more slowly than expected (or never). Milestones will generally be designed to maximize ratepayer value by aligning the ISD with the need.

Milestones may depend on observed or forecasted load, thresholds on observed or forecasted congestion, the capacity of projects committed to energize, or other factors. We will select the most appropriate milestone(s) on a case-by-case basis.

8. Consultation, Transparency and Oversight

8.1 The OTP Rule

We plan to govern the OTP process with an ISO rule and expect to apply for AUC approval of the rule in 2026.

The OTP rule will:

- Define the types of system projects and when they are needed
- Specify the high-level process by which the AESO must conduct OTP
- Specify how the AESO must perform cost benefit analysis and which costs and benefits it must or may consider

We will publish an information document to accompany the OTP rule. It will describe the OTP methodology proposed in this document, subject to modification based on further consultation.

8.2 Stakeholder Consultation

Table 5 summarizes our information requirements and sources, including stakeholder consultation.

Table 5: Information Requirements

Information Requirements	Sources
LTO information requirements: • Advice on scenarios, inputs and assumptions • Scenario probability weights • Location-based capacity expansion costs	Stakeholders via the LTO consultation process
Distribution system plans: • Planned new PODs • Opportunity for moving load • Opportunity to expand existing PODs DFO load forecasts	DFO consultation
Transmission asset condition information:	TFO consultation or information requests

Information Requirements	Sources
• Asset residual life • Maintenance activity and cost schedule • Distribution of time to failure and time to repair	
Capacity expansion costs	• Consultation with developers • AESO estimates • Consultants and industry reports
Demand for transmission capacity	• The AESO project list • Consultation with project developers
System resiliency assessments: • High risk operational scenarios • Susceptibility to extreme weather events	• Consultation with TFO operations and outage scheduling • AESO operational experience
Transmission development alternatives	Call for written feedback based on draft LTP

Table 6 outlines stakeholder input opportunities and the information we will publish during the OTP process.

Table 6: Stakeholder Inputs and AESO Outputs During the OTP Process

When	Process	Stakeholder Input	AESO Output
Pre-OTP	AUC Rule 017 process for the OTP Rule	Written feedback and stakeholder sessions	• OTP Framework Recommendation • OTP Rule • OTP Information Document • Consultation materials
	TFO and DFO consultation	Ability to comply with information requirements Achievable effective dates	
	TRP stakeholder engagement	Stakeholder sessions	• Project inclusion criteria (PIC) • Consultation materials

When	Process	Stakeholder Input	AESO Output
Each cluster	Customer connection process	Connection requests	Project list
Each planning cycle	LTO consultation	LTO information requirements • Advice on scenarios, inputs, and assumptions • Scenario weights • Project development costs • Data needs	• LTO inputs, assumptions, and scenarios document • Supplementary data • Scenario weights • Consultation materials
	DFO consultation for LTO	Load forecasts	
	DFO consultation for LTP	Distribution system plans	Draft LTP • Needs to be evaluated • Transmission development alternatives • Preliminary economic and reliability evaluations
	TFO consultation for LTP	• Transmission asset condition information • System resiliency assessment	
	LTP consultation	Demand for transmission capacity in different locations	
	Review of draft LTP	Written feedback • Recommended transmission development alternatives	
	LTO publication		• LTO • Contribution to Western Electricity Coordinating Council (WECC) production cost modelling

When	Process	Stakeholder Input	AESO Output
			(PCM), available under a nondisclosure agreement (NDA) • Hourly load forecast • Study cases, available under NDA
	LTP publication		LTP, including: • Approved, planned, and potential projects • When planned projects should be constructed, based on congestion or capacity expansion • Economic analysis of projects (multiple perspectives) • System access cost and energy cost impacts for each project and the portfolio • Projects assessed and deemed not viable • System capacity and congestion data • How capacity expansion depends on transmission
Each transmission project	NID process	• TFO asset condition data (as needed) • Distribution system planning options (as needed) • TFO cost estimates, land use impact assessments	NID • Project need (reliability, economic, or legislated) • ARS compliance assessment • Economic assessments of transmission

When	Process	Stakeholder Input	AESO Output
		and feasibility assessments	development alternatives (as needed) • Preferred alternative • Milestones based on congestion (if applicable)

8.2.1 Invitation to Propose Transmission Development Alternatives

As explained in Section 5.2.2, we may develop a theory of need for an economic project based on economic indicators like elevated or depressed LMPs, while being unable to prove the need due to high transmission development costs. In such cases, we may publish details about the theory of need, such as the expected value of alleviating the constraint, and seek input on the lowest cost option to add incremental transmission capacity. We will invite TFOs and other stakeholders to propose transmission development alternatives that can provide better economic value than the options the AESO was able to identify.

8.2.2 TFO and DFO Information

TFOs and DFOs have indicated that:

- Further consultation is required to define reasonable information requirements
- They may need significant time to prepare to meet the AESO's requirements pertaining to asset condition, maintenance and reliability data

We will further consult with TFOs and DFOs before implementing information requirements in the ISO rules to ensure the requirements are reasonably practicable and have appropriate effective dates.

We currently use ad hoc information requests to obtain asset condition information as needed for transmission planning purposes and TFOs are generally able to meet our information requirements. We will continue to use this approach for OTP unless a rule is put in place.

8.3 The AUC Needs Approval Process

The AUC decides on transmission development needs identified by the AESO. The AUC process will remain unchanged when the AESO implements OTP, but we will present different arguments in our NIDs.

NIDs will continue to meet the information requirements and other specifications in the EUA and the T-Reg, notably EUA section 34(1), T-Reg Section 11(3) and 11(4), and AUC Rule 007.

- For economic projects, the "need for improved economic efficiency of the transmission system"[15] may include economic efficiency evaluated according to the requirements in the OTP rule
- The "technical and economic comparison of the options considered"[16] will summarize the results of dispatch simulations and economic analysis showing the NPV of the costs and benefits of each option
  - It will also include a breakdown of contributors to total economic value, such as reduced congestion, avoided mandatory dispatch or avoided transmission maintenance costs, as applicable
- We may seek approval for, and direct construction based on, milestones of the kinds discussed in Section 7.2.3

[15] EUA Section 34(1)(b).

[16] T-Reg Section 11(3)(g).

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