

FORTISALBERTA INC.

2026 DISTRIBUTION SYSTEM PLAN

AUGUST 31, 2026

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1. INTRODUCTION

1. FortisAlberta Inc. (FortisAlberta or the Company) is an owner of an electric distribution system and provides the following 2026 Distribution System Plan (DSP) and attached 2026 FortisAlberta DSP Workbook pursuant to the Alberta Utilities Commission's (AUC or the Commission) DSP Guidelines for Submission (DSP Guidelines). In accordance with section 20.3 of AUC Rule 001: *Rules of Practice*, FortisAlberta notes that it used generative artificial intelligence in preparing this DSP to support review and drafting of this submission, including readability and consistency, and assisting with document organization. The DSP and the data underlying the 2026 FortisAlberta DSP Workbook have been prepared, verified, and validated by FortisAlberta personnel to confirm accuracy. The information, analysis, and conclusions in this DSP remain those of FortisAlberta.

2. This DSP and the 2026 FortisAlberta DSP Workbook are provided to the Commission on the understanding that these documents will not to be used for any purpose other than for the Commission's information. The 2026 FortisAlberta DSP Workbook contains detailed feeder level information, including the number of customers and the amount of load connected to the segment. In some instances, only one customer is connected to the feeder, thereby disclosing individual customer usage information. Further, the feeder level information could be used by bad actors to determine what feeders would be most negatively impacted by a physical or cybersecurity threat. The Company has therefore provided a version of the 2026 FortisAlberta DSP Workbook with the utilization tab redacted. The unredacted version has been provided directly to the Commission.

2. OVERVIEW OF FORTISALBERTA

3. The Company operates a geographically dispersed distribution system that serves a large and diverse service area, including rural, agricultural, and resource-based regions. FortisAlberta delivers electricity to more than 600,000 customer sites across central and southern Alberta, comprised of residential, farm, commercial, and industrial loads. A detailed customer breakdown, by rate class, is provided in Table 2-1, below.

Table 2-1 FortisAlberta Customer Segmentation by Rate Class	
Rate Class	**Number of Sites**
Residential	481,404
Farm	34,779
Irrigation	8,257
REAs	36,649
Street Lighting	7,715
Small General	62,111
Oil and Gas	12,278
General Service and EV Charging	9,701
Large General Service	222
Transmission Connected Service	74

4. The Company's service area includes the top eight fastest-growing communities in Alberta within what is already one of the fastest-growing provinces in the country. FortisAlberta is also experiencing a level of growth in distributed energy resources (DERs) relative to the size of the system that is almost unparalleled elsewhere in North America. FortisAlberta operates in varied terrain, including environmentally sensitive areas such as federal and provincial parks, forest protection areas, and habitats for species at risk. The Company's diverse service area presents unique planning and operational challenges not typically encountered by more urban utilities. These include areas subject to heightened regulatory oversight from various agencies,[1] constrained access, and elevated environmental risk, which requires more complex and site-specific solutions. As a result, distribution system planning must incorporate environmental considerations, vegetation management requirements, DER operational challenges, and regulatory obligations related to land use and environmental protection.

[1] Examples of applicable regulatory requirements include federal and provincial environmental legislation such as the *Fisheries Act*, *Species at Risk Act*, *Migratory Birds Convention Act*, *Water Act*, and *Environmental Protection and Enhancement Act*, among others, as well as operating requirements across multiple jurisdictions, including municipal franchise agreements and First Nations consultation and land use arrangements.



Figure 2-1 FortisAlberta Service Area

5. FortisAlberta's service area has highly variable customer density, which creates distinct planning and operational challenges. Low-density rural areas require longer lines and more rights-of-way. This increases capital and operating costs and makes fault identification and response more time consuming and resource intensive. At the same time, higher-density pockets can create congestion and capacity constraints. These differing density patterns also add complexity to load forecasting and demand management because consumption patterns and peak timing vary across the service area. As a result, solutions must be tailored to the needs of rural, low-density areas and more urban, higher-density areas.

6. The Company's service area is also subject to wildfire risk and extreme weather conditions, including high winds and storms. Over the 2015 to 2025 period, FortisAlberta recorded over 2,500 wildfire ignition events[2] across its service area. Wildfire risk is influenced by environmental

[2] Events counted include ignition events both inside and outside the Forest Protection Area, pole top fires that did not spread to the surrounding environment, and fires that did not meet the magnitude threshold to be included in provincial wildfire statistics.

conditions such as vegetation, weather patterns, and topography, and utility equipment can act as an ignition source under certain conditions, particularly in dry environments with abundant fuel. These factors influence asset design, maintenance practices, and capital investment planning, including targeted system hardening, vegetation management, and asset monitoring to reduce risk and maintain safe and reliable service. The frequency of wildfire ignition events, combined with the associated safety, environmental, and customer impacts, including damage to natural areas, service interruptions, and increased restoration complexity, requires ongoing and targeted investment to mitigate wildfire risk and support reliable system operation.

7. Approximately 40% of FortisAlberta's service area is within Alberta's Forest Protection Area, where wildfire risk is persistent and must be actively managed. Planning in these areas requires explicit consideration of vegetation fuel loading, topography, and weather patterns, recognizing that utility infrastructure can act as an ignition source under certain conditions. These risks drive the need for targeted system hardening investments, enhanced inspection and monitoring programs, and adaptive operating practices during high-risk periods, such as high-wind and low-humidity events. In addition, FortisAlberta is required to develop, file, and obtain approval of an annual Wildfire Control Plan with provincial forestry authorities for infrastructure within the Forest Protection Area, reflecting formal regulatory oversight and reinforcing the need for disciplined proactive wildfire mitigation, vegetation management, and operational planning.

8. Maintaining acceptable reliability across a large, low-density service area presents operational challenges, including access constraints and extended restoration times in certain locations. To address these challenges, FortisAlberta undertakes targeted investments in system improvements, asset replacement, and grid modernization, including the use of monitoring, automation, and remote operation capabilities to improve outage response and restoration performance. The map below displays the distribution infrastructure density of the FortisAlberta system.

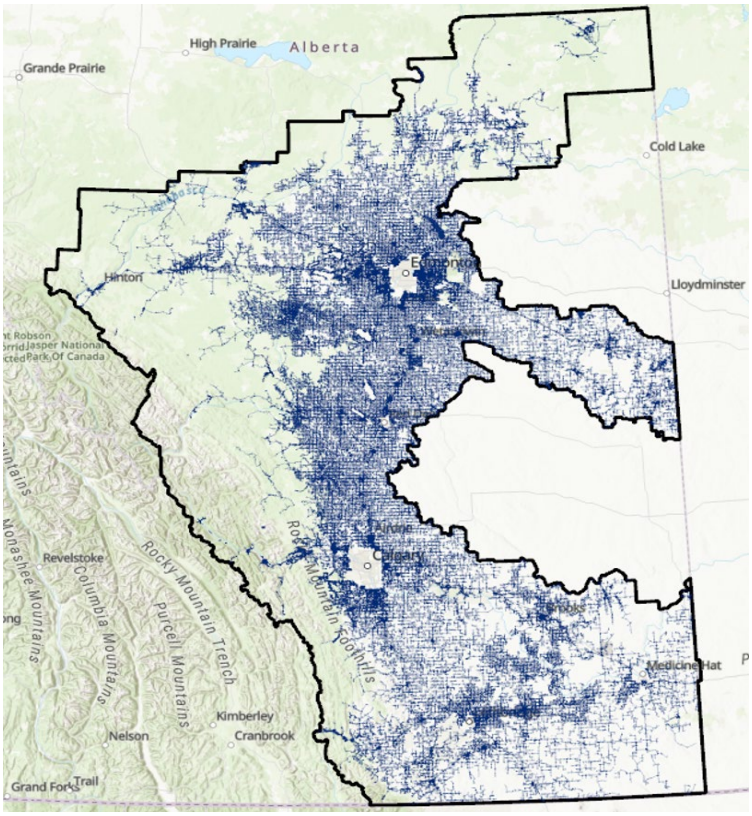


Figure 2-2 FortisAlberta Service Area Distribution Infrastructure Density

9. The Company delivers electric distribution service to critical emergency service providers, such as first responders, hospitals, and essential infrastructure operators, including municipal governments, water services, and airports. Providing reliable service supports the ability of first responders and critical infrastructure operators to respond to emergencies every day, as well as during extreme events. FortisAlberta's ability to meet its obligations to provide reliable, resilient, and safe service to its customers is dependent upon the quality and condition of its distribution assets, as well as the Company's ongoing maintenance practices and investment to address weather events, wildfires, cybersecurity threats, and physical security threats. FortisAlberta must ensure that existing facilities are compliant with legislation, such as the *Alberta Electrical Utility Code* (*AEUC*) and sections 105 and 127 of the *Electric Utilities Act* (*EUA*), and that it remains in compliance with the minimum service standards set out in AUC Rule 002: *Service Quality and Reliability Performance Monitoring and Reporting for Owners of Electric Distribution Systems and for Gas Distributors* (AUC Rule 002). FortisAlberta prioritizes expenditures to align with these obligations.

10. FortisAlberta plans and delivers its capital program consistent with good utility practice. The Company proactively identifies and prioritizes projects that address critical safety and reliability concerns. Capital programs are also initiated as distribution system conditions change, including in response to climate change, evolving customer needs, cybersecurity risks, and emerging technologies.

11. FortisAlberta's distribution system planning must accommodate evolving requirements driven by customer growth, changing load characteristics, and increasing operational complexity. The Company is observing growth in both large, discrete customer loads and DERs, resulting in greater variability in the magnitude, location, and timing of load. FortisAlberta has experienced industry-leading DER penetration, with installed DER capacity representing 48% of coincident peak load on its distribution system, and expects interconnections to continue to increase over time. These trends require the Company to plan for more dynamic loading conditions, two-way power flows from intermittent and non-dispatchable renewable resources, localized system constraints, protection and coordination requirements, and maintaining voltage fluctuations within acceptable limits. These trends are no longer only operational considerations; they are emerging drivers of capital investment, as higher variability and bidirectional flows can require targeted feeder upgrades, adaptive and flow-dependent protection and voltage-control modifications, enhanced monitoring and control capability, and supporting systems such as advanced distribution management systems (ADMS) to maintain safe, reliable, and efficient system operation.

3. 10-YEAR OUTLOOK

12. FortisAlberta's capital planning incorporates both operational and economic considerations. The Company's evaluation of these factors is informed by local experience, as well as independent third-party assessments of prevailing economic conditions and industry trends. Growth-related investment is expected to be concentrated in areas experiencing elevated residential development, large load, industrial and resource-based activity, and continued DER adoption within FortisAlberta's service area, consistent with broader economic, demographic, and technology adoption trends.

13. Over the 10-year outlook period, FortisAlberta expects electricity systems across Canada to face increasing cost pressure as demand growth, electrification, and evolving supply and technology requirements drive higher infrastructure investment needs. For distribution utilities, these trends

are expected to increase the pace, scale, and complexity of required system investment, particularly as customer load shapes evolve and new technologies place additional demands on planning, operations, and asset capability. Looking ahead, continued investment in generation, transmission, and distribution infrastructure is expected to be required to meet future demand, maintain reliability, and integrate emerging technologies. While this growth contributes to upward pressure on capital requirements and customer costs, it also reflects the role of the distribution system as an economic enabler by supporting new development, business activity, electrification, and customer connections across the service area.

14. In Alberta, future electricity costs are also expected to remain sensitive to broader market conditions, including wholesale price dynamics and market design features that are outside the control of distribution utilities. Those broader bill pressures reinforce the importance of prudent distribution planning and disciplined capital investment to support affordability over time.

15. These trends reinforce the importance of a disciplined distribution planning approach that can accommodate increasing uncertainty, evolving load patterns, and rising system complexity. As the primary interface for customer connections, electrification, and DERs, the distribution system must continue to adapt to changing operational and infrastructure requirements.

3.1 CUSTOMER GROWTH AND REGIONAL INVESTMENT TRENDS

16. Canada is expected to experience continued population growth over the long term under all projection scenarios published by Statistics Canada. While population projections are not guaranteed, they provide a useful planning framework for understanding potential future demand drivers and regional differences across provinces. Under the medium growth scenario, Canada's population increases steadily through the projection period, with western provinces accounting for a growing share of the national population.[3]

17. Economic analysis prepared by ATB Economics, based on Statistics Canada's medium growth scenario, highlights that Alberta's population growth moderates over the projection period relative to recent peak years, while remaining above the national average.[4] Statistics Canada's base case projections also indicate that Alberta is expected to become the third most populous province over

[3] Population Projections for Canada (2025 to 2075), Provinces and Territories (2025 to 2050)
[4] ATB - Population Projection - Alberta

this period, reinforcing the overall scale of growth despite the moderation from recent peaks.[5] This outlook reflects a return to more typical growth patterns following exceptional post-pandemic migration inflows, rather than an assumption that recent short-term growth rates persist indefinitely.

18. Alberta is projected to experience population growth that exceeds the national average across all Statistics Canada scenarios, resulting in an increasing share of Canada's total population over time. This growth is driven by a combination of natural increase and sustained net in migration, including both interprovincial and international sources, and has direct implications for long-term distribution system planning, including increased customer connections and targeted system investment in areas experiencing elevated growth.

3.2 ENERGY TRANSITION AND ELECTRIFICATION TRENDS

19. In addition to population-driven customer growth, FortisAlberta expects the energy transition to remain a material driver of distribution system growth over the 10-year outlook period. Trends associated with decentralization, digitalization, and decarbonization change how customers consume and produce electricity. Over time, these trends are expected to increase the complexity of distribution system planning and operation, and contribute to the need for continued modernization of the distribution system.

20. Over the next decade, increasing electrification of customer loads, including electric vehicles (EVs), electric heating, DERs, is expected to influence load profiles and contribute to growth in peak demand across FortisAlberta's distribution system. The pace and magnitude of electrification will depend on a range of factors, including customer adoption, technology availability, infrastructure development, economics, and government policy. As electrification advances, the Company expects it to become a more significant consideration in distribution system planning, particularly where localized load growth creates additional capacity requirements for feeders, transformers, and related infrastructure.

21. FortisAlberta has evaluated a range of electrification scenarios to assess the future impacts on its distribution system. EV adoption represents an evolving source of load growth for the distribution system over the next ten years, with the potential to materially affect feeder and transformer

[5] Statistics Canada. Table 17-10-0057-01 Projected population, by projection scenario, age and gender, as of July 1 (x 1,000).

capacity where adoption becomes concentrated or coincident with existing peak demand. The pace and magnitude of EV adoption remain uncertain and will depend on several factors, including customer economics (e.g., incentives), vehicle availability, charging infrastructure, customer preferences, and government policy (e.g., emissions targets and broader electrification strategies). While managed charging, time-varying rates, and demand side management (DSM) programs may improve system utilization and help moderate peak demand growth, FortisAlberta expects that increasing EV adoption will nonetheless require ongoing monitoring and targeted infrastructure investment to maintain reliable service.

22. FortisAlberta's analysis indicates that widespread electrification will place increasing pressure on distribution infrastructure, with transformer overloading emerging as the most immediate and pervasive constraint under most scenarios. As adoption accelerates, impacts are expected to include feeder congestion, substation capacity limitations, and localized voltage performance issues, particularly on low voltage distribution assets. While managed charging strategies may partially mitigate peak impacts, they are not sufficient to fully offset infrastructure capacity requirements under higher electrification trajectories.

3.2.1 Agricultural Electrification

23. FortisAlberta has also worked with Alberta Innovates and industry stakeholders to assess the electrification of agricultural sector operations. The assessment identified that electrification is currently most feasible for passenger vehicles, light-duty trucks, and lower-horsepower equipment, with broader electrification of larger or specialized farm equipment remaining limited by technology availability and cost. Adoption of these electrified technologies is expected to increase over time, driven by economic, policy, and technical factors, and has been assessed through a range of potential adoption scenarios.

24. The Company's analysis of the increasing electrification of agricultural operations indicates that this phenomenon will, over time, result in material incremental growth in rural electricity demand that places additional pressure on rural distribution systems, particularly along longer single-phase feeders serving dispersed customers. FortisAlberta further identified that this load growth may result in voltage regulation challenges and thermal capacity constraints under higher adoption conditions, requiring system mitigations such as equipment upgrades, conductor enhancements,

and voltage support. These impacts are consistent with, and additive to, the broader system impacts anticipated with continued adoption of EVs, electric heating, and DERs in rural Alberta.

25. Overall, growth in agricultural electrification will require a sustained increase in capital investment, with a larger share of future work being driven by asset replacement, capacity upgrades, and targeted system reconfigurations. FortisAlberta will use adaptive planning, continuous refinement of forecasts, monitoring actual adoption trends, and the alignment of investment timing to emerging system needs to optimize the timing and amounts of required investments.

3.2.2 Data Centre Interconnection

26. FortisAlberta has experienced a significant and unprecedented increase in large, discrete load interconnection requests, predominantly from data centre developments. Alberta's competitive electricity market structure, favourable climate conditions, land availability, and the provincial government’s support of technology-sector investment have all contributed to increasing activity in the data centre customer segment. As of May 2026, the Company has received interconnection requests from 19 data centre projects totaling approximately 426 MW of requested distribution-connected capacity, with individual project sizes ranging between 1 MW and 75 MW. Of this total, 48.6 MW have been connected and are in service, 117.8 MW have been accepted and are in the active interconnection process, and approximately 260 MW are in the assessment stage. These requests illustrate the pace and scale at which large-load growth can be expected to emerge in Alberta’s market.

27. The Commission has asked FortisAlberta how much of the 426 MW of data center development is currently reflected in FortisAlberta’s load actuals and forecasts. The 48.6 MW of connected and 117.8 MW of accepted projects are reflected in the load actuals and forecast. The 260 MW of projects in the assessment stage are not reflected in the load forecast.

28. The pace, scale, and geographic concentration of these requests represent a material shift in load growth patterns relative to FortisAlberta's historical experience, with data centre loads now accounting for the majority of total requested capacity increases in certain areas of the distribution system. The Company expects data centre and other large discrete load growth to remain a significant planning consideration over the 10-year outlook period. This type of load growth will have material implications for distribution system infrastructure investment required to make the

associated necessary capacity and reliability available to customers. It also has the potential to impact upstream transmission planning; increasing "high-density" load growth may accelerate the need for broader transmission system upgrades to ensure sufficient upstream capacity is available to support the load growth occurring on the distribution system.

3.3 TECHNOLOGY AND PROCESS ADVANCEMENTS

29. FortisAlberta's approach to technology and process adoption considers both changing distribution system conditions and external requirements that influence how the system must operate over time. These external drivers include evolving government policy direction, compliance obligations, industry-led market reforms, and Commission-directed initiatives. As a result, technology and process investments may be required not only to improve efficiency or defer infrastructure where practical, but also to maintain safe and reliable service, meet emerging operational requirements, support market and policy implementation, and preserve flexibility as the distribution system continues to evolve.

30. Over the 10-year outlook period, FortisAlberta expects that new distribution technologies will continue to be developed and made available to meet emerging customer needs and enable system optimization through process improvements. Technologies including digitization, enhanced planning tools, next generation Advanced Metering Infrastructure (AMI), and ADMS will provide greater visibility into feeder and customer-level conditions, improve monitoring and situational awareness, and support system planning and operations. These technologies improve FortisAlberta's ability to identify emerging system constraints, respond to outages, and manage increasingly dynamic power flows and system operating conditions.

31. Adoption of technologies and related processes is also expected to be influenced by industry initiatives and market evolution. In particular, the Company expects to make the necessary investments to comply with changes in meter data management arising from the design choices in the restructured energy market.

32. The pace and scope of technology implementation may also be influenced by Commission initiatives such as the implementation of time-varying rate designs. Investments in AMI, interval data capabilities, and associated data management systems are expected to be required to enable time-varying rates and to provide customers with actionable information.

33. In addition to external policy and market drivers, FortisAlberta's technology adoption over the 10-year period will be influenced by enterprise resource planning (ERP) requirements. The Company's ERP is critical to the ongoing support of core business functionality, regulatory compliance, data governance, integration between operational and financial systems, and protection against evolving cybersecurity threats. It is also necessary to enable the effective implementation and ongoing use of grid-facing technologies such as AMI and ADMS. The ERP will improve the quality, accessibility, and integration of the data and processes on which those technologies depend.

34. As discussed above, electrification trends, including EV adoption, are expected to increase demand for distribution infrastructure over time. The operational and planning implications of these trends are discussed in Section 3.2. Technology investments described in this section support FortisAlberta's ability to monitor, operate, and manage the resulting increase in system complexity.

4. LOAD FORECASTING

35. In this section, FortisAlberta distinguishes between the load forecasting methodology it uses for distribution system planning and investment decisions, and additional forecast information provided in response to the DSP Guidelines. Section 4.1 describes the bottom-up forecasting methodology FortisAlberta uses to identify future distribution system capacity needs and to inform investment decisions. That methodology is based on historical feeder and substation peak loading, committed customer contracts, known large discrete load additions, coincidence factors, load transfers, and engineering judgement, together with the treatment of observed DER impacts and the targeted analysis the Company has undertaken in relation to electrification and DER adoption.

36. Sections 4.2 and 4.3, by contrast, describe forecast information provided in the 2026 FortisAlberta DSP Workbook in response to the DSP Guidelines. This information is not used by FortisAlberta to inform distribution system planning investments. Where the Commission has requested forecast information that FortisAlberta does not prepare as part of its distribution system planning process, the Company identifies that limitation directly and provides the best available explanation, assumptions, and supporting data for the information it does provide.

4.1 LOAD FORECASTING FOR DISTRIBUTION SYSTEM PLANNING

37. FortisAlberta's distribution system planning is based on an established, deterministic planning process that is applied consistently across the Company's service area.

38. Consistent with this planning process, FortisAlberta employs a bottom-up load forecasting approach that starts with annual peak demand measured at each feeder using interval meter data, aggregates upwards to substation transformers, and then to substations using coincidence factors to account for the non-simultaneous nature of peak loads across feeders. The forecast for each feeder and substation is built from three core inputs: (1) historic peak demand from feeder meters, measured over a March 1 to February 28 planning year; (2) a trend-based prediction formula applied to the historical peak demand series to produce a 90th-percentile forecast scenario; and (3) committed load aggregation, incorporating known new customer contracts at their contracted demand level and scheduled in-service date.[6] These inputs are supplemented by professional engineering judgement, which is applied to validate and adjust forecast outputs where statistical trends alone do not adequately reflect known operational conditions, planned system reconfigurations, or atypical customer profiles. Load transfers between areas and different parts of the network are considered in the forecasting approach. Permanent transfers are differentiated from temporary transfers to ensure accurate peaks are selected and the forecast will reflect the permanent configuration.

39. FortisAlberta's load forecast is based on capacity requirements rather than demand. The forecast aims to determine the level of system capacity that must be in place to reliably serve customers across a reasonable range of future conditions. The Company uses a 90th-percentile scenario for its upper-bound loading condition, which accounts for the combined variability of weather, economic activity, and customer behaviour. FortisAlberta considers that other approaches, such as planning to a median forecast (i.e., the 50th percentile) would introduce unacceptable reliability risk in years when actual demand exceeds average conditions and could result in insufficient system capacity to accommodate existing or new aggregate customer load.

40. Accordingly, comparisons between the forecast and actual demand observed in any single year should be interpreted with this context in mind. While actual demand in a mild-weather, low-

[6] Growth from known, new customer contracts, including large discrete loads, is approximately 400MW in the next five years across the system.

growth year may fall well below the forecast, this does not indicate that the forecast was inaccurate; conversely, a year that approaches or exceeds the 90th-percentile threshold validates the planning margin. The relevant measure of forecast quality is whether the methodology consistently identifies the correct timing and location of capacity needs over an extended period, not whether it accurately predicts the precise peak demand in a given year.

41. The key inputs, data sources, and assumptions used in FortisAlberta's load forecasting methodology and their impact on the forecast are summarized in Table 4-1 below.

Table 4-1
Load Forecast - Key Inputs and Assumptions

Input/Assumption	Source	Method	Impact on Forecast
Feeder Peak	Substation feeder level interval meters, measured over a March 1 to February 28 planning year	Identification of individual feeder peak demand under normal system configuration	Provides baseline for forecast
Prediction Formula	FortisAlberta developed formula using historical peaks	Statistical (90th-percentile scenario)	Provides base growth rate for forecast
Customer Loads	Customer Contracts	Incorporation of committed customer contract demand into the forecast	Additional committed load aggregated to feeder and substation level
Coincidence Factor	Historical load diversity analysis	Applied at customer to feeder, and feeder-to-substation aggregation	Ensures feeder and point of delivery (POD) peaks reflect realistic coincident demand

42. FortisAlberta has analyzed potential impacts of EVs, solar photovoltaic (PVs), Energy Storage, and building electrification on growth but has not, to date, modified its forecast methodology based on this work. This is because the potential impacts identified in the Company's analysis were not considered sufficiently reliable to be incorporated into the forecast methodology, given the uncertainty associated with how industry trends may evolve.

43. As actual adoption of EVs, PVs, Energy Storage, and building electrification occurs on FortisAlberta's distribution system, efficiency offsets are implicitly accounted for in the forecasting formula through historical trends. Actual adoption of these technologies is inherently captured in the breaker loading data and therefore is included in trended forecasts.

44. FortisAlberta does not undertake customer site sampling as part of its forecast methodology. The Company understands customer site sampling to mean the collection of data from a smaller subset of customer sites and extrapolation of those results to a broader population. At this time, FortisAlberta does not consider that approach sufficiently reliable for distribution system planning, given limitations in available data and supporting technology.

45. The Company relies instead on feeder and substation loading data, known customer additions, and engineering judgement, as described above. For DER treatment within that framework, distributed generation (DG) with interval meters has its metered output removed from the feeder peak data used for forecasting, so that the forecast reflects gross load. By contrast, micro-generation (MG) is inherently captured in the breaker loading data and therefore offsets the metered feeder peak. This approach supports planning for the worst-case loading scenario in circumstances where intermittent, non-dispatchable generation is unavailable.

4.1.1 Load Forecast Scenarios and Sensitivities

46. FortisAlberta does not incorporate broad scenarios and sensitivities into the load forecasting methodology it uses for distribution system planning and investment decisions. The Company uses a deterministic framework based on historical loading, known and committed customer additions, and engineering judgement to identify when capacity constraints are expected to occur. Consistent with this framework, FortisAlberta does not currently employ probability-based analysis, such as load duration curves or probabilistic exceedance modelling, in its distribution planning processes.

47. Actual impacts of these technologies, including EV load, are inherently captured in measured feeder loading and reflected in the metered data used as the foundation of the forecasting methodology as they materialize. As a result, increasing electrification and associated load growth are incorporated into future load forecasts through the experienced evolution of feeder peak demand and load profiles over time. FortisAlberta has assessed EVs, PVs, Energy Storage, and building electrification, including baseline and alternative growth scenarios, to better understand potential future impacts. However, the results of those assessments are not incorporated into the load forecasting methodology used for distribution system planning.

48. FortisAlberta's approach supports practical and transparent distribution planning because local system constraints are driven by feeder and substation-level peaks and contractual/confirmed growth. Planning decisions can be updated through regular planning cycles as conditions change.

In Alberta's climate, extreme winter conditions can drive sustained and highly coincident peak demand; planning to probabilistic conditions would risk underestimating these peaks and exposing customers to unacceptable reliability impacts. A deterministic approach ensures the system is designed to meet these worst-case conditions, guarding against equipment ratings being exceeded and the associated risk of asset damage and premature aging that can occur during overload events.

4.2 DER FORECAST INFORMATION PROVIDED IN THE 2026 FORTISALBERTA DSP WORKBOOK

49. This section, 4.2, describes the DER forecast information provided in the 2026 FortisAlberta DSP Workbook in accordance with the DSP Guidelines and provides context regarding FortisAlberta's view of potential DER adoption and related system impacts. Please note that the forecast information provided is not used by FortisAlberta to inform its distribution system planning investments. The availability, reliability, and granularity of DER forecast information vary by resource type. Where FortisAlberta does not prepare forecast information in the form requested, the Company identifies that limitation directly and provides the best available explanation and supporting assumptions.

50. Forecasting DER adoption presents unique challenges because the factors that drive deployment vary significantly by resource type. Accordingly, FortisAlberta applies different forecasting approaches to DG and MG. DG growth is generally associated with larger commercial and industrial project developments, interconnection requests, market structures and programs, and energy prices. MG growth is more closely correlated with customer-level DER adoption trends, DER economics, customer sentiment, and policy incentives. Forecast uncertainty is further influenced by differences in project size, development timelines, and interconnection schedules, which can materially affect the timing and magnitude of DER growth.

51. The DER forecast information included in the 2026 FortisAlberta DSP Workbook reflects the best information available to FortisAlberta at the time of this filing. FortisAlberta forecasted DG growth for the 2026 to 2030 period primarily based on the projects currently in its interconnection queue and customer-provided in-service expectations. The forecast assumes that project size, scope, and timing remain consistent with the information available at the time of the assessment. FortisAlberta forecasted MG growth based on the historical average capacity growth trend observed over the 2021 to 2025 period. This approach reflects the limited visibility available for

forecasting customer-level MG adoption and the absence of a more reliable forward-looking indicator. Because DER adoption is dynamic and affected by a wide range of external factors, the forecast information in the 2026 FortisAlberta DSP Workbook is subject to change over time and should be understood in that context.

52. The uncertainty associated with DER forecasting also creates challenges for FortisAlberta in estimating the capital and operating resources required to support DER interconnection and operation. As DER adoption levels, locations, technology types, and interconnection timing can change materially over time, the Company must accept a certain degree of inherent uncertainty in forecasting future expenditures related to distribution system upgrades, interconnection infrastructure, operational technologies, and support services. For example, some MG project applications have been received in areas where transmission substation transformers are already constrained by reverse power flow limitations, requiring further engineering analysis and potentially additional cost and lead time. As a result, the evolving nature of DER penetration adds complexity to both operational planning and financial forecasting.

4.2.1 Electric Vehicles

53. FortisAlberta does not rely on forecasts of EV adoption to inform its system or investment planning. The pace of EV adoption is subject to variability depending on government policies, incentive programs, and other customer-specific drivers that may impact a decision to purchase an EV. While the Company has undertaken analysis to better understand a range of potential electrification scenarios, including EVs, electric heating, and DERs, these scenarios are used for stress testing and risk awareness rather than as predictive inputs into load forecasting. Although increasing electrification has been identified as a potential driver of peak demand growth and infrastructure constraints, FortisAlberta's planning approach remains grounded in observed load growth including that associated with EV charging, interconnection requests, and demonstrated customer demand, rather than attempting to forecast the pace or scale of EV adoption. The 2026 FortisAlberta DSP Workbook shows modest growth in known actual numbers of EVs interconnected on the FortisAlberta distribution system.

4.2.2 Residential and Commercial Solar

54. The solar forecast information provided in the 2026 FortisAlberta DSP Workbook for the 2026 to 2030 period is based on the observed growth in residential and commercial MG solar capacity over

the 2021 to 2025 period. Over that period, residential solar capacity increased from 11 MW in 2021 to 74 MW in 2025, while commercial solar capacity increased from 47 MW to 92 MW. Historical growth in MG capacity and connections is illustrated in Figure 4-1.

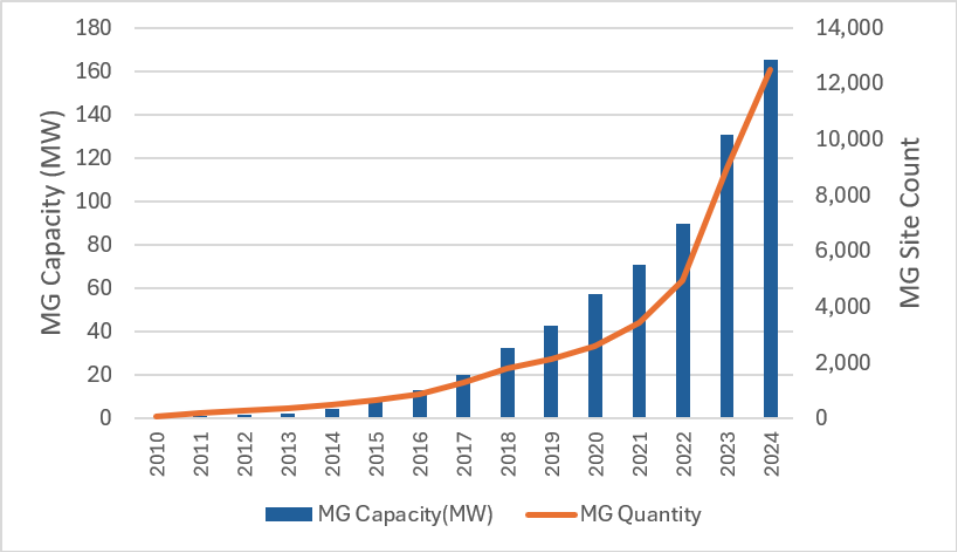


Figure 4-1 Cumulative MG Capacity & Interconnections

55. The forecast reflects a continuation of these historical trends, with residential solar capacity increasing to 154 MW and commercial solar capacity increasing to 151 MW by 2030. This approach provides a practical and stable basis for the forecast given the variability in annual adoption levels, including the stronger growth observed in 2024. Absent significant new government or market-driven incentives, FortisAlberta has not assumed annual additions above recently observed levels.

4.2.3 Residential and Commercial Energy Storage

56. FortisAlberta has not provided residential or commercial energy storage forecast values in the 2026 FortisAlberta DSP Workbook. Forecasting behind-the-meter energy storage adoption remains challenging due to limited visibility into customer installations, operating characteristics, and adoption drivers. Energy storage systems may be deployed without triggering utility planning or interconnection processes and may not require additional service capacity, which limits FortisAlberta's ability to track installation volumes and usage patterns. In addition, adoption is influenced by a range of external factors, including technology costs, customer economics, incentive programs, reliability requirements, and the pace of DG/MG adoption. As a result,

FortisAlberta does not currently have a sufficiently reliable basis to prepare residential and commercial energy storage forecast information in the form requested.

4.2.4 Direct Connected Generation and Energy Storage

57. The direct connected generation forecast information provided in the 2026 FortisAlberta DSP Workbook for the 2026 to 2030 period is based primarily on projects currently in FortisAlberta's interconnection queue and customer-provided in-service expectations. Historical direct connected generation capacity increased from 546 MW in 2021 to 1,177 MW in 2025, and the forecast shows further growth to 1,512 MW by 2030. Historical growth in DG capacity and connections is illustrated in Figure 4-2.

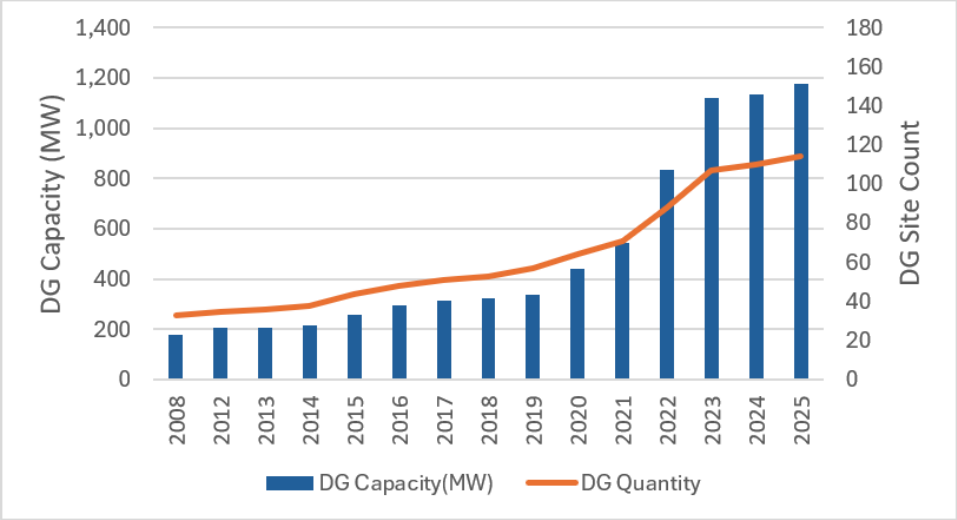


Figure 4-2 Cumulative DG Capacity & Interconnections

58. The forecast assumes that project capacities, scope, and anticipated commissioning schedules remain consistent with the information available at the time of the assessment. However, direct connected generation forecasts may change materially due to changes in project viability, scope, timing, technology, site conditions, financing, and broader economic conditions.

59. The 2026 FortisAlberta DSP Workbook also includes direct connected energy storage information. Historical direct connected energy storage capacity increased from 21 MW in 2021 to 141 MW in 2024 and remains at 141 MW through the forecast period to 2030. The forecast reflects the best information available to FortisAlberta at the time of filing based on currently known projects and project status.

4.3 CUSTOMER FORECAST INFORMATION PROVIDED IN THE 2026 FORTISALBERTA DSP WORKBOOK

60. Section 4.3 describes the customer load forecast information provided in the 2026 FortisAlberta DSP Workbook in response to the DSP Guidelines. The forecast values themselves are provided in the 2026 FortisAlberta DSP Workbook. This information includes forecast information related to Demand Transmission Service (DTS), Supply Transmission Service (STS), and other customer load components requested by the Commission. While this information provides additional context regarding expected customer load and transmission service requirements, it is not used by FortisAlberta to inform distribution system planning investments. Distribution system planning investments are informed by the bottom-up methodology described in Section 4.1.

4.3.1 Demand Transmission Service

61. DTS refers to the contracted transmission capacity at FortisAlberta PODs used to supply the Company's distribution system load from the Alberta transmission system. DTS represents a contracted service limit rather than a physical transmission capability determined by FortisAlberta planning analysis. The historical DTS levels provided in the 2026 FortisAlberta DSP Workbook reflect the combined DTS contract capacity for each distribution POD substation as at the end of each year.

62. FortisAlberta's 2026 to 2030 DTS forecast was developed by aggregating the current DTS contract levels and planned DTS contract increases.

63. The 2026 FortisAlberta DSP Workbook shows that historical DTS remained relatively stable over the 2021 to 2025 period, with future years including DTS increase requests that are with the AESO or currently under development. While system-level DTS values appear relatively stable in the 2021 to 2025 period, the forecast increases are concentrated in localized, high-growth areas. In regions such as Airdrie/Balzac and Chestermere, DTS requirements have increased materially over a relatively short period, reflecting significant localized load growth. As a result, aggregation of DTS values can obscure the magnitude and timing of emerging constraints at specific PODs.

4.3.2 Supply Transmission Service

64. STS refers to transmission service associated with the delivery of energy from generation sources through the Alberta transmission system to serve customer load on FortisAlberta's distribution system.

65. Historically, the measurement and calculation of STS have evolved in accordance with AESO metering requirements. Prior to the implementation of the AESO's Adjusted Metering Practice (AMP), STS values were determined at the substation level, reflecting aggregate net power flows between the distribution and transmission systems. This approach was subsequently refined to a substation transformer-level measurement and more recently modified under AMP to a feeder-level measurement framework. Under the current AMP approach, STS is determined based on metered flow at individual feeder breakers, which are then aggregated to determine the Point of Service STS value. This change in measurement basis results in STS values that no longer directly reflect net power flow to the transmission system; rather, these values represent summed feeder-level measurements at the substation interface.

66. As a result of these changes in methodology, historical STS values are not directly comparable to current or forecast values, as differences may arise from changes in measurement approach rather than underlying system conditions.

67. For the purposes of STS forecasting, only DG facilities are explicitly considered in the assessment of potential impacts to STS based on the existing DG interconnection projects queue. MG resources are not separately evaluated due to the challenges associated with forecasting their contribution to system load reductions. As behind-the-meter resources, MG facilities primarily offset customer consumption, and currently FortisAlberta does not have sufficient visibility into how generation output will align with individual customer load profiles over time. Consequently, the magnitude and timing of any resulting impacts on STS demand are difficult to reasonably quantify.

68. The 2026 FortisAlberta DSP Workbook shows that historical STS increased from 506 MW in 2021 to 1,130 MW in 2025. STS is forecast to remain at 1,130 MW in 2026 and then increase more gradually to 1,301 MW by 2030, reflecting the DG-related assumptions incorporated into the forecast.

4.3.3 Distribution Customer Load Forecasts by Rate Class

69. The 2026 FortisAlberta DSP Workbook includes forecast information by rate class for billing demand, number of sites, and energy consumed. These forecasts have been developed in

accordance with the Company's approved forecasting methodologies for ratemaking purposes[7] and are intended to provide directional customer and load context in the format requested by the Commission. They are not used by FortisAlberta to inform distribution system load forecasts, which are developed using the methodology described in Section 4.1.

70. For each metric, the forecast reflects the best available historical data, known customer information, and applicable forecasting assumptions by rate class. Variations from historical trends generally reflect changes in customer mix, expected growth by rate class, known customer additions, differences in usage patterns, or the mathematical effect of changes in the number of sites on average values.

Peak Demand

71. Peak demand represents the non-coincident peak (NCP) by rate class, with actual values provided for 2021 through 2025. The Company does not develop NCP forecasts by rate class for planning or ratemaking purposes and, consequently, cannot provide the requested forecast data.

Billing Demand

72. Annual billing demand forecasts by rate class reflect the forecast demand quantities used for customer billing under the applicable tariff structures, for those rate classes subject to demand-based charges. Monthly billing demand is estimated based on the forecast number of demand-billed customers in each rate class and the expected monthly demand per customer, as derived from historical data analysis. Annual billing demand for each rate class is subsequently determined by aggregating the corresponding monthly forecast values.

Contracted Demand

73. Contracted demand is calculated by aggregating the contract minimum demand values for the customers in rate classes for which such contract demands apply to all customers, with actual values provided for 2021 through 2025. FortisAlberta does not prepare contracted demand forecasts by rate class and, consequently, cannot provide the requested forecast data.

[7] FortisAlberta's billing determinant forecast methodologies were described in the Company's 2026 Annual Rates Application (Exhibit 30274-X0001, PDF pp. 24-26, paras. 62-65), and approved in Decision 30274-D01-2025, FortisAlberta Inc. 2026 Annual Performance-Based Regulation Rate Adjustment, December 17, 2025, PDF p. 11, para. 32.

Number of Sites

74. The number of sites forecast by rate class reflects expected customer growth based on historical connection activity and forecast trends within each class. These forecasts incorporate the effects of residential development, agricultural activity, commercial and industrial growth, and known customer additions, as applicable to each rate class. The Company's approved forecast methodology applies linear regression based on historical actuals or, where appropriate, average historical growth. Differences between forecast site growth and recent historical trends generally reflect expected moderation or acceleration in development activity, shifts in economic conditions, or updated expectations regarding customer connections in specific rate classes or service areas.

Energy Consumed

75. Energy consumed by rate class reflects annual electricity usage within each customer class. Forecast aggregate energy consumption is impacted by growth in the number of sites, expected changes in customer usage patterns, and the composition of load within each class. Average energy consumption forecasts are also influenced by changes in the number of sites, which may moderate or amplify changes in expected aggregate usage across the system. FortisAlberta's approved forecast methodology primarily applies linear regression based on normalized monthly historical energy data and other relevant drivers. Forecast variations from historical trends reflect shifts in customer mix, weather-normalized usage patterns, electrification-related impacts, efficiency effects embedded in historical trends, and known customer developments affecting specific classes.

5. INVESTMENT CRITERIA GUIDELINES

76. Investment criteria are the measures the Company uses to determine when capital or operating expenditures are required and how available funding is allocated across competing needs. These criteria operate at two distinct but complementary levels. At the capital category (program) level, FortisAlberta applies a structured risk assessment framework to evaluate relative risk exposure across investment categories and to inform the allocation of limited funding within the Parameters for the Third Generation Performance Based Regulation (PBR3) Plans environment. At the individual project level, investment decisions are driven by defined technical, operational, and regulatory criteria, with projects initiated when specific planning thresholds or obligations are met.

77. A significant portion of FortisAlberta's capital investment is non-discretionary and must proceed for the Company to meet statutory, regulatory, or customer-driven obligations. These requirements are therefore the first claim on available capital funding within the PBR3 funding envelope.

78. After accounting for non-discretionary requirements, FortisAlberta applies its structured risk assessment and ranking methodology to capital work where the Company has discretion over timing, scope, or sequencing. This methodology assists in directing the residual available capital funding to areas of highest risk and customer impact, while recognizing that some lower-priority work may still be necessary over time and cannot be deferred indefinitely.

79. FortisAlberta categorizes its capital expenditures into three primary groups, reflecting the extent to which risk assessment informs prioritization.

    i) **Non-Discretionary Expenditures:** Non-discretionary expenditures are those required to meet legislative, regulatory, or externally driven obligations, or that arise from unavoidable operational requirements. These include, but are not limited to, the Company's Customer Growth, Externally Driven, Urgent Repair, Information Technology (IT) Lifecycle, and Metering capital programs. Due to their nature, non-discretionary expenditures are not subject to risk-based prioritization, as they must proceed to meet these obligations. However, these investments remain subject to technical optimization and cost-effective solution selection.

    ii) **Priority Programs/Projects:** For non-mandatory projects, a formal risk assessment is undertaken to evaluate the consequences of deferral. Programs or projects assessed as having a high or extreme level of risk are classified as Priority Projects, reflecting the most significant potential impacts to the Company and its customers if not advanced. These include, but are not limited to, FortisAlberta's Forestry Protection, Transportation Equipment and critical IT programs.

    iii) **Risk Prioritized Programs/Projects:** Programs or projects assessed as having lower relative risk and are of a nature that allows FortisAlberta to phase, sequence, or defer capital work are categorized as Risk Prioritized. These projects are ranked primarily based on their risk ratings, with prioritization occurring first between risk bands and then within bands to establish a more refined ordering. These include, but are not limited to,

the Company's Pole Management, Cable Management, SCADA, and Worst Performing Feeders programs.

80. Under this framework, risk is defined as the likelihood of adverse consequences arising if a project does not proceed in the applicable planning period. The assessment considers both the likelihood of occurrence and the severity (consequence) of impacts, ensuring a comprehensive evaluation of the risks associated with deferral.

81. Likelihood is assessed using a standardized qualitative scale ranging from "Very Unlikely" to "Very Likely," supported by defined probability ranges and indicative event frequencies.

82. Consequences are evaluated across multiple risk domains, including financial, stakeholder, legal and regulatory compliance, operational performance, health and safety, environmental impact, reliability, and IT security. This multi-dimensional assessment ensures that the full range of potential impacts to the Company and its customers is captured.

83. Overall, the program-level composite risk assessment indicates that risk exposure across the DSP is concentrated within a subset of core programs, with variability observed across individual risk categories. Capital categories such as Forestry Protection, General Support, and Environment, Safety and Reliability exhibit comparatively higher composite risk scores across multiple categories. These results indicate that these categories contain programs that are key contributors to overall risk exposure and support continued focus on mitigation and investment in these areas.

84. Distribution utilities operating under PBR3 use I-X escalated base PBR revenues as well as those determined by the K-bar mechanism to fund investments required to provide utility service to customers. Utility capital programs necessarily include significant amounts of non-discretionary work driven by the statutory obligation to serve. FortisAlberta estimates that 75% to 85% of capital investment is non-discretionary on a yearly basis. Non-discretionary capital programs include, but are not limited to, Customer Growth, Distribution Line Moves, Metering, Capacity Increases, and Urgent Repairs. While FortisAlberta has relatively more opportunities to flexibly manage the timing, size, and scope of its remaining priority and risk prioritized capital programs, work under these programs is nonetheless necessary and cannot be deferred indefinitely. Long-term deferrals are untenable in many cases and present real risks of both compounding negative reliability impacts and creating the conditions for inefficient development of the distribution system.

85. The Commission has asked FortisAlberta to provide more specific information about setting investment levels or criteria for reliability system improvement projects (Section 5.3.4); power quality (Section 5.3.5); resiliency (Section 5.3.6); and grid modernization (Section 5.3.7). The Commission notes that the DSP discusses prioritization of projects but does not actually set investment levels and timelines and asks the Company to provide more information in those areas.

86. Given the limitations presented by the capital funding mechanisms within the PBR3 plan, FortisAlberta cannot preset investment levels for reliability system improvement projects, power quality initiatives, resiliency work, or grid modernization activities. Reliability investments are driven by evolving system conditions, operational experience, emerging risks, asset performance, reliability outcomes and technological developments but are subject to the available funding available within the PBR3 term. The funding for reliability investments is, in large part, informed by FortisAlberta's non-discretionary, customer growth-related investments. For example, system growth investments, while forecasted based on known and anticipated load increases, are unavoidably subject to actual customer behaviour in a given year. Put another way, required investments in customer connections are both externally driven and non-discretionary. As the need for system growth investments materializes, FortisAlberta must proceed with the required investments to meet its obligation to serve. This impacts the remaining funding available for reliability system improvement projects, power quality initiatives, resiliency work, and grid modernization. As a result, while FortisAlberta continuously assesses future reliability, resiliency, and modernization needs, it cannot reasonably identify in advance the funding that will be available in future years to support reliability projects, nor establish predetermined investment levels and timelines in the manner contemplated by the question. Instead, investment decisions are made through ongoing planning and risk assessment processes that respond to the conditions and priorities identified on the system over time, taking into account the available funding and resources in a given year.

87. FortisAlberta does not maintain standalone programs specifically dedicated to power quality, resiliency, or grid modernization. Rather, these are objectives and outcomes that are advanced through a variety of broader capital and maintenance programs. Investments are generally initiated based on identified system needs, including customer growth, reliability performance, asset condition, safety requirements, wildfire risk, operational requirements, and compliance

obligations. As those needs are assessed, FortisAlberta evaluates technically viable alternatives and selects the solution that most effectively addresses the identified need while balancing safety, reliability, compliance, operational requirements, risk reduction, and cost-effectiveness.

88. For example, FortisAlberta has undertaken initiatives to replace wood crossarms with fiberglass crossarms. While this work enhances system resiliency by improving resistance to environmental conditions, it also provides reliability and safety benefits. Similarly, investments in monitoring, automation, sensing, and communications infrastructure may improve outage response, support DER integration, enhance situational awareness, and advance grid modernization objectives at the same time.

89. Because these investments are driven by underlying system needs rather than by separate resiliency, power quality, or grid modernization programs, and because individual projects commonly deliver multiple overlapping benefits, it is not practicable to isolate and quantify what portion of forecast investment relates exclusively to any one of these objectives. Nor is it practicable to establish predetermined investment levels for these categories independent of the broader planning, risk assessment, and capital prioritization processes through which the underlying investment needs are identified.

5.1 FUTURE INVESTMENT CRITERIA AND RISK TOLERANCE

90. Over the 10-year outlook period, FortisAlberta will continue to evolve its investment criteria and risk tolerance as system conditions, customer needs, technology, and external requirements change. Capital decisions are expected to be increasingly informed by the structured assessment of adverse outcomes across relevant risk categories, taking into account existing controls and the level of residual risk that remains. This approach supports consistent decisions regarding the timing and scale of investment required to maintain safe, reliable, and cost-effective utility service.

91. Changes in external requirements, including evolving Alberta Reliability Standards and related North American Electric Reliability Corporation and Western Electricity Coordinating Council frameworks, may also influence FortisAlberta’s investment criteria and risk tolerance over the planning horizon.

5.2 CUSTOMER GROWTH CRITERIA AND RISK TOLERANCE

92. Customer growth is a core, non-discretionary driver of FortisAlberta's distribution system investment. As the owner and operator of an electric distribution system, the Company is statutorily obligated to connect customers and accommodate new load requests within its service area. These investments are externally driven, occur in response to customer actions, and must be undertaken regardless of prevailing economic or regulatory conditions. Customer growth investments include the extension and reinforcement of overhead and underground distribution facilities required to connect new service locations and accommodate incremental load increases associated with residential, commercial, agricultural, and industrial development. The timing, location, and scale of these investments are inherently uncertain and depend on population growth, housing development, economic activity, and customer-specific service requests within FortisAlberta's service area.

5.2.1 Investment Criteria for New Customers Connections to the Distribution System

93. FortisAlberta connects new customers in accordance with its statutory obligation to serve. These investments are therefore not subject to discretionary prioritization against other capital needs. However, they remain subject to FortisAlberta's technical assessment, cost-effective solution selection, and applicable contribution policies. In that context, certain AUC requests framed around comparative investment prioritization or discretionary screening are not directly applicable to individual connection investments.

94. When a new customer connection request is received, FortisAlberta assesses whether the existing distribution system can accommodate the connection while maintaining applicable planning criteria. The distribution system must deliver voltage within the limits of CSA Standard C235:19 at the customer's utilization point. FortisAlberta's planning criteria require a minimum primary voltage of 115 V for three-phase service and 113 V for single-phase service under peak load conditions, and a maximum of 127 V under light load conditions, expressed on a 120 V base. Distribution equipment, including overhead conductors, underground cables, transformers, and voltage regulators, must be operated within 100% of rated capacity. Maximum feeder loading during normal operations is limited to 13 MVA (300 A at 25 kV). Primary-side voltage fluctuation at the service transformer must not exceed 5%, consistent with CSA Standard C61000-3-7. Maximum three-phase fault current is limited to 8,000 A RMS symmetrical and maximum single-

line-to-ground fault current is limited to 5,000 A RMS symmetrical on the 25 kV system. Corrective action is required when a proposed connection would cause any of these criteria to be violated.

95. Where a deficiency is identified, FortisAlberta evaluates technically viable alternatives to address it. Typical solutions include load transfers between feeders, phase balancing, voltage regulator installation or upgrade, conductor upgrades, new feeders, or substation capacity increases. The selected solution must be technically viable and remain suitable over at least a five-year planning horizon.

96. Investments required to connect new customers are undertaken as needed to meet FortisAlberta's obligation to serve. As a result, these investments are not subject to comparative prioritization against other capital needs, and timing is generally driven by customer connection requirements and practical implementation considerations.

5.2.2 Link Between Load Forecasting and Investment Decisions

97. FortisAlberta's load forecasting methodology is a capacity requirement forecast rather than a demand prediction. Its purpose is to determine the infrastructure that must be in place to reliably serve customers across a reasonable range of future conditions.

98. The use of a 90th-percentile planning scenario reflects the need to plan for credible upper-bound loading conditions, recognizing variability in weather, economic activity, and customer behaviour. Distribution infrastructure must be planned with sufficient lead time, and planning to a median forecast would increase the risk of capacity constraints during higher-load conditions.

99. Accordingly, forecast outputs are used to identify when system capacity is expected to exceed established planning criteria. Where forecast conditions indicate that a violation of thermal, voltage, or operational criteria is expected to occur, mitigation is required to maintain safe, reliable, and compliant operation. This establishes a direct linkage between forecast outcomes and investment requirements, and serves as the basis for initiating capacity-driven investment, as described in Section 5.2.3.

100. As illustrated in Figure 5-1, distribution system planning is conducted through an annual, iterative process that integrates load forecasting, system modelling, deficiency identification, and the

development and evaluation of mitigation options. The process shown in Figure 5-1 is further discussed below.

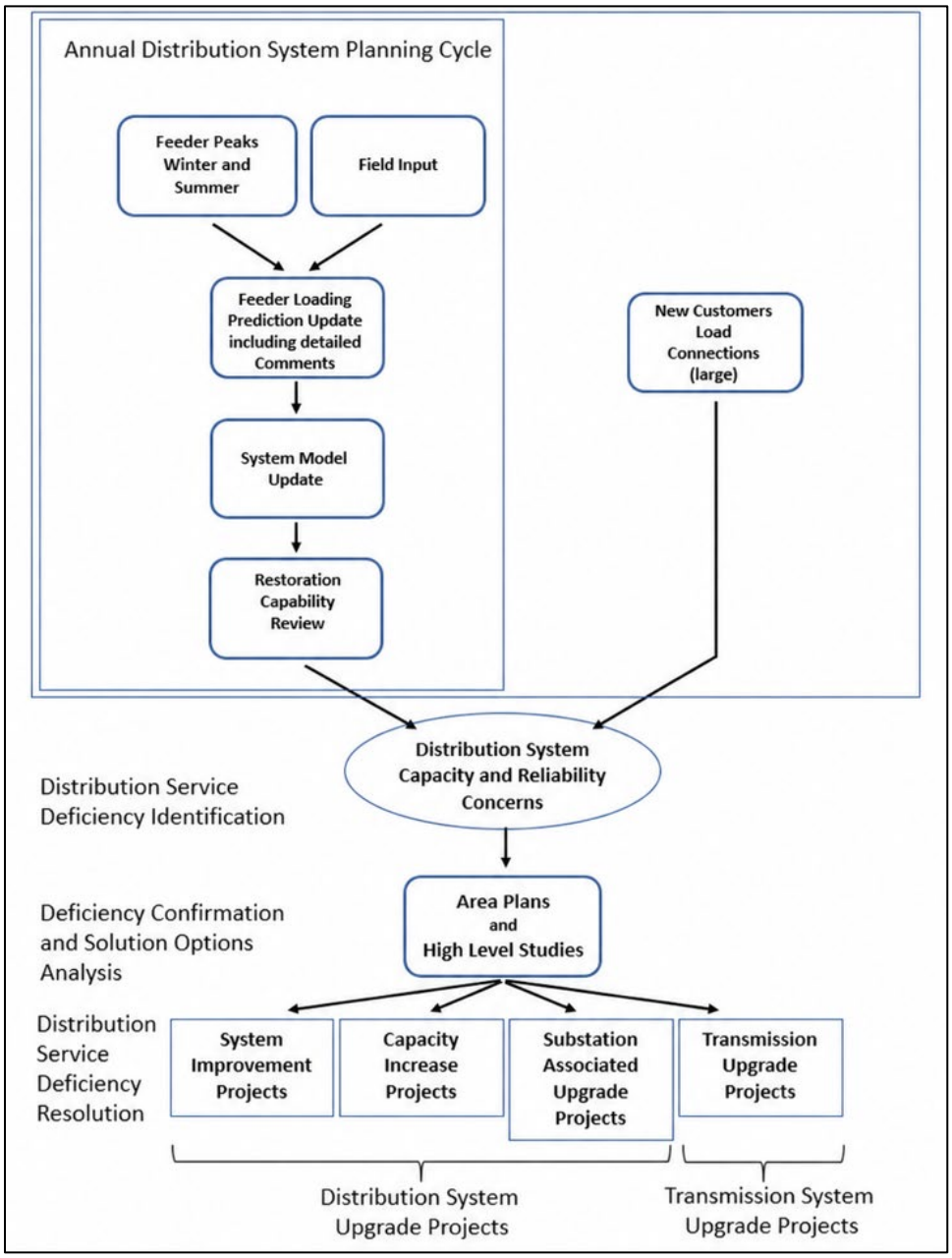


Figure 5-1 Annual Distribution System Planning Cycle

101. In practice, this process results in the identification of location- and timing-specific system constraints at the feeder and substation level. Each identified constraint is assessed to determine whether it represents a violation of planning criteria under forecast conditions, and if so, what mitigation is required to address it.

Illustrative Example – Voltage Constraint Under Forecast Growth

102. For example, in a developing area experiencing sustained customer growth, forecast loading on a feeder may result in primary voltage falling below the minimum limits defined in CSA Standard C235:19 under peak conditions. This represents a violation of planning criteria and requires mitigation prior to the forecast year in which the violation would occur. In response, FortisAlberta evaluates technically viable distribution-level alternatives, including load transfers to adjacent feeders where capacity and system configuration permit, installation or relocation of voltage regulation equipment, phase balancing, localized conductor upgrades, and feeder reconfiguration. The Company will implement the lowest cost solution that is capable of resolving the deficiency within planning criteria and over the planning horizon. Where lower-cost measures are not technically viable, more capital-intensive solutions, such as feeder upgrades or new feeder construction, are advanced. The selected solution must resolve the identified constraint under forecast loading conditions and remain effective over the planning horizon.

Feeder Loading Prediction Update and Forecasting Methodology

103. FortisAlberta applies a structured, deterministic distribution system planning process to identify future capacity and reliability requirements, and to determine the need for distribution and transmission system investments. As part of this process, FortisAlberta completes a feeder loading prediction update on an annual basis. This update provides the latest recorded actual peaks for each of the Company's 25 kV distribution feeders and generates a forecast value of the potential capacity requirement for a 10-year period to support the identification of future distribution system constraints within the planning horizon. This feeder loading prediction update also forms the basis of the distribution forecasts provided to the AESO to support transmission planning.

104. FortisAlberta performs this capacity requirement forecasting on all the Company's 25 kV distribution feeders that are connected to POD substations. The peak demand for each feeder is examined separately to ensure that the capacity ratings of the electric system facilities are adequate for future loading requirements. A bottom-up load forecast approach is consistently utilized, as described in Section 4.1.

System Model Update

105. Upon completion of the annual feeder loading prediction update, base distribution feeder models are updated in power-flow modeling software. The models are based on the most current distribution system configuration and most recent recorded peak load values. A distribution feeder base model is used to evaluate system performance under existing conditions, committed loading scenarios, and forecast loading conditions over the planning horizon to identify potential thermal, voltage, and operational constraint violations under both normal and contingency conditions.

106. In addition to the distribution feeder base model, two additional models are produced for each distribution feeder. The first model is a contract load model that incorporates committed contract load values and is used to assess the system's ability to meet existing contractual obligations under near-term operating conditions. The second model forecasts capacity requirements out 5 years (i.e., Year 0 + 5) to identify potential future capacity constraints under forecast growth conditions.

107. These models provide complementary perspectives on system capability. Together, they enable planners to distinguish between current system limitations in meeting the Company's contractual obligations and emerging future constraints, support the timing and prioritization of mitigation measures, and ensure that required system upgrades address longer term needs.

Restoration Capability Review

108. Once updated models are available, FortisAlberta planners assess restoration capability under relevant N-1 contingency conditions. This internal planning review evaluates whether unsupplied load[8] could arise following the loss of key system elements and where service can be restored through alternate supply paths, switching arrangements, adjacent feeders, or available substation capacity. The review supports the identification of restoration-related constraints and is applied consistently with the backup criteria described in Section 5.3.2.

Deficiency Issue Identification, Mitigation Alternative Analysis, and Distribution Deficiency Resolution

109. Once the above steps are completed, area plans and high-level engineering studies are completed to identify distribution system deficiencies and assess mitigation approaches. These assessments

[8] Unsupplied load is the amount of customer demand that cannot be served under a given contingency.

consider both capacity and reliability deficiencies identified through forecasting, modelling, and restoration analysis. Mitigative solutions are prioritized for delivery based on the timing and severity of identified planning criteria violations and system risk. Higher priority is given to mitigation of capacity deficiency issues. The solutioning of reliability deficiency concerns identified during the restoration capability review is subsequently prioritized based on a ranking of historical outage events, customer count, the magnitude of unsupplied load, and available resources.

110. Deficiencies may be addressed under three possible programs: Distribution Capacity Increase, Substation Associated Upgrade, and Distribution to Transmission Contributions (i.e., transmission upgrades), with projects initiated when planning analysis identifies that system performance is expected to exceed established thermal, voltage, or reliability criteria within the planning horizon, at which point investment becomes non-discretionary as described in Section 5.2.3.

111. This process supports the timely identification of capacity and reliability constraints and the development of coordinated distribution and transmission solutions.

5.2.3 Investment Criteria for Distribution Load Growth

112. In addition to individual service connections, customer growth also gives rise to broader system investments required to support forecast distribution load growth. These investments are managed through the Capacity Increase (CI) component of the Distribution Capacity Increase program. As with new customer connections, these investments are not discretionary once a forecast violation of established planning criteria is identified. Accordingly, AUC requests directed to risk-prioritized prioritization, comparative ranking, or probability-based screening do not apply to this category.

113. CI investments are initiated when planning studies indicate that forecast loading is expected to exceed the thermal, voltage, or operational limits of existing distribution assets within the planning horizon. The same planning criteria described in Section 5.2.1 are applied in these assessments, including voltage limits, equipment loading limits, maximum feeder loading of 13 MVA (300 A at 25 kV), and applicable fault current limits. Operating within these limits avoids premature asset deterioration and supports prudent use of customer-funded infrastructure.

114. Projects are identified through a structured planning process in which feeder load flow models are developed using forecast peak loads five years into the future. When modelling indicates that a

distribution asset would exceed its rating, or that voltage would fall outside acceptable limits, the shortfall is addressed before the year in which the violation is forecast to occur. Typical solutions include load transfers between feeders, phase balancing, conductor upgrades, voltage regulator installation or relocation, new feeders, converting customer services from lower voltage classes to 14.4 kV, or increasing transmission capacity where necessary. In selecting a solution, FortisAlberta undertakes a holistic assessment of technically viable distribution alternatives and selects the option that addresses the identified deficiency at the lowest overall cost while remaining suitable over at least a five-year planning horizon.

115. When evaluating substation transformer capacity, coincident peaks are used to avoid overstating capacity limitations. Capacity driven projects use predicted exceedance of the nameplate capacity of equipment as a violation trigger for investment. Where feasible, FortisAlberta considers operational alternatives, including load transfers between feeders or substations, to defer investment where sufficient capacity and operational flexibility exist. These opportunities are generally limited to areas with interconnected or looped configurations, available switching capability, and adjacent system capacity. Where such conditions are not present, capital investment is required.

116. A violation trigger occurs when projected peak demand in the upcoming planning year is expected to exceed the nameplate or applied rating of equipment. This assessment is based on modeled peak usage rather than the duration of exceedance. When such a violation is identified, FortisAlberta evaluates operational flexibility and deferral options, including load transfers, voltage management, system reconfiguration, and reactive power compensation, where sufficient system capacity and configuration permit. Where deferral is feasible, projects may be delayed until forecast loading can no longer be accommodated within system capability.

117. Where multiple projects are identified in the same planning cycle, sequencing is informed by the year in which the violation is expected to occur, together with practical considerations such as constructability, coordination with other planned work, and resource availability. In limited circumstances, a project may be advanced where changing system conditions create a more urgent need for investment.

5.2.4 Future Transmission Upgrades

118. FortisAlberta identifies the need for transmission-related investment where forecast aggregate distribution load, including existing connected load and committed customer additions, is expected to exceed available substation or POD capacity, as defined by contracted DTS and confirmed system conditions, and when no distribution-level alternative can resolve the deficiency in a cost-effective manner. A transmission upgrade may also be pursued where FortisAlberta's planning analysis determines that a transmission solution may be delivered at a lower overall cost than the available distribution alternative over the planning horizon.

119. FortisAlberta does not have authority over the planning or execution of transmission upgrade projects. Transmission system upgrades are planned and executed by the AESO and the transmission facility owner (TFO). FortisAlberta's role is to identify distribution system needs and work with the AESO, in conjunction with the incumbent TFO (AltaLink), through the AESO connection process to determine whether the optimal solution is distribution-based, transmission-based, or a combination thereof. If a distribution solution is determined to be the optimal solution, or a component thereof, the Company completes the required work as part of one of its established capital programs. If a transmission solution is identified as the most technically and economically viable option, the work is completed by the TFO. FortisAlberta may be required to make contributions on account of transmission upgrades in its capacity as a DFO market participant as and when required under the Independent System Operator tariff framework.

120. Potential future transmission investment needs are identified in FortisAlberta's annual distribution system planning process, which includes area plans and high-level engineering studies. These plans and studies assess whether identified deficiencies are best addressed through load shifting, distribution upgrades, or transmission upgrades. Where a high-level study determines that a transmission upgrade is the optimal solution, FortisAlberta initiates a System Access Service Request through the AESO connection process.

121. Transmission upgrades are only pursued where a distribution-level solution is not technically viable or, if a distribution solution exists, where a transmission solution will be more cost-effective over the planning horizon. The following subsections describe potential future transmission developments identified through that process by planning region.

5.2.4.1 City of Airdrie Area

122. FortisAlberta identified the need for a DTS increase, expected in 2026, for the following transmission PODs in the area:

- 199S East Airdrie – driven by aggregate distribution load growth and contracted distribution loads.
- 186S Dry Creek – driven by aggregate distribution load growth and contracted distribution loads.
- 391S Balzac – driven by aggregate distribution load growth and contracted distribution loads. In addition, multiple large distribution customer load requests in the area.
- In the Airdrie-Balzac area, there are numerous residential and commercial subdivisions in development that will drive continuing aggregate load growth in future years.

123. Through the AESO connection process, FortisAlberta was informed that DTS increase in the area would be limited as overloading of the 138 kV transmission system in the Airdrie area may occur under N-1 scenarios. Reinforcement of the transmission infrastructure is expected to be required in the near term to address the current load growth limitations in the area. The AESO is currently working with FortisAlberta and the TFO to determine the optimal solution.

5.2.4.2 City of Chestermere Area

124. FortisAlberta identified the need for a DTS increase, expected in 2028, for the following transmission POD in the area:

- 419S Chestermere – driven by a single large distribution customer load request in the area.
- In the Chestermere-Strathmore area, FortisAlberta engaged with multiple customers with large distribution load requests, including a commercial subdivision development in the Shepard area, with potential of driving continued aggregate load growth in future years.

125. Through the AESO connection process, FortisAlberta was informed that the DTS increase request in 419S Chestermere POD requires a transmission study, the result of which will provide guidance on the potential optimal transmission solution to the current constraint of the 138 kV transmission

line connecting 419S Chestermere POD. The AESO is currently working with FortisAlberta and the TFO to determine the optimal solution.

5.2.4.3 Cadomin Area

126. The Cadomin area is served by 983S Cadomin substation, supplying a remote region with growing load requirements. This has driven the need to upgrade the existing transformer to a higher capacity to ensure the substation can continue to reliably serve current and forecast customer demand.

127. FortisAlberta has engaged the AESO to advance a solution to increase available capacity and support area load growth. The AESO is currently working with the Company and the TFO to approve and deliver this transmission upgrade.

5.3 RELIABILITY INVESTMENT CRITERIA AND RISK TOLERANCE

128. FortisAlberta's reliability investment decisions are informed by a comparative, risk-based, and cost-effectiveness assessment rather than fixed prescriptive thresholds or a defined dollar value that customers are willing to pay for incremental improvements. Investments are advanced where local reliability performance, outage consequences, or residual risk indicate a need for mitigation relative to system-average performance and acceptable risk levels, after considering existing controls, operational alternatives, and the practical ability to mitigate risk through lower-cost measures.

129. In FortisAlberta's experience, customers have a low tolerance for outages and are generally dissatisfied when they receive what they perceive to be poor reliability, particularly where interruptions are frequent or prolonged. Approaching reliability from the perspective of how much customers are willing to pay introduces inherent limitations, as customers are not typically well-positioned to directly assess or monetize the value of reliability in advance of experiencing an outage. For many customers, the relationship between reliability improvements and incremental cost is abstract and difficult to evaluate, particularly where outages are infrequent or their impacts are uncertain. In practice, customer preferences are often revealed *ex post*: a customer who experiences a particularly inconvenient or disruptive outage may reasonably conclude that they would have been willing to pay a modest amount more to avoid that specific interruption. However, this retrospective willingness does not readily translate into clear, *ex ante* signals about acceptable rates or investment levels, as customers generally evaluate cost and reliability separately rather than as a continuous trade-off. As a result, framing the issue solely in terms of willingness to pay

risks oversimplifying customer preferences and understating the challenges customers face in meaningfully connecting reliability outcomes to rate impacts.

5.3.1 Customer Feedback

130. FortisAlberta considers direct customer feedback as one input to its reliability planning. Customer surveys provide quantitative information regarding outage experience, restoration timeliness, and communication, while written comments and complaints provide qualitative insight into how customers experience service interruptions, field activities, and restoration efforts. Appreciated as a whole, this feedback helps identify areas where reliability performance and customer experience may warrant further review beyond what is reflected in system metrics alone.

131. The Commission has asked FortisAlberta to provide more details regarding how customer feedback informs the Company's reliability planning and the types of survey questions asked. Customer feedback is an important input into FortisAlberta's continuous improvement efforts, including initiatives related to service reliability and the customer experience. Twice a month, the Company distributes an online customer survey to customers who have had an interaction with FortisAlberta within the previous 15 days. These interactions include, among other things, customers who have experienced a power disruption or outage.

132. The survey is designed to gather both quantitative and qualitative feedback. Customers are asked questions regarding their perception of FortisAlberta as a company and the Company's performance in relation to their most recent interaction. The survey also includes open-ended questions that allow customers to provide additional comments, such as identifying ways FortisAlberta could make it easier for customers to work with the Company.

133. Survey results are reviewed regularly throughout the organization. A summary of the quantitative survey results, together with verbatim customer feedback, is provided to operational leaders on a monthly basis and shared more broadly with all leaders on a quarterly basis.

134. In addition to customer survey feedback, FortisAlberta receives customer complaints directly and through the Utilities Consumer Advocate and the AUC. These complaints can identify localized service quality or reliability concerns that may not be readily apparent through broader system performance metrics. When a complaint raises a concern regarding electric service reliability, FortisAlberta will often dispatch a power line technician to investigate conditions in the affected

area, assess how service is being impacted, and determine whether any corrective action or maintenance work is required. While individual complaints are not generally a direct input into system-wide reliability planning, they nonetheless inform reliability-related decision-making by helping the Company identify, assess, and address site-specific reliability concerns experienced by customers.

5.3.2 Transmission and Feeder Backup Criteria

135. FortisAlberta's distribution planning criteria require that adequate backup supply be available for N-1 contingency events, subject only to switching time, where practical. These events include the loss of a substation transformer, feeder breaker, or other substation elements that limit the capacity available from the POD. During those events, FortisAlberta seeks to provide full restoration capability through remaining substation elements, alternate source transformers, adjacent substations, and/or interconnected distribution feeders, recognizing that such outages can affect a broad geographic area and a large number of customers. FortisAlberta's distribution planning criteria on substation service restoration (N-1 contingency) requires the following:

- Full restoration capability via the distribution system; and/or
- An alternate source transformer within the POD substation; and/or
- An alternate source transformer at adjacent substation(s).

136. In support of this objective, all 138 kV and 25 kV buses must have adequate switching points and protection to minimize the frequency and duration of outages associated with the maintenance or failure of components upstream of the 25 kV bus. For substations with multiple source transformers, failure of one upstream component should not result in a total station outage.

137. FortisAlberta's feeder backup criteria target the ability to restore 100% of peak demand from an adjacent feeder where doing so is technically feasible, operationally practical, and justified by the associated reliability benefit. For this purpose, a "distribution feeder" refers to a main three-phase circuit originating from a substation breaker. These feeders are often interconnected through normally open tie points that enable alternate supply and switching-based restoration during contingency events.

138. The N-1 backup criteria do not apply to radial tap or branch circuits. Taps and branches, which may be either single-phase or three-phase, are radial extensions of the main feeder and generally

do not have alternate feed capability. Where a tap or branch circuit is lost, only the customers supplied by that lateral are affected, and service is restored through fault isolation and repair rather than by transfer to an alternate source.

139. The scope of the N-1 criteria is therefore focused on the main feeder backbone, where a single contingency event has the potential to affect a large number of customers across a wide geographic area, and where alternate supply through interconnected feeders can be established through switching operations.

140. Backup capability implementation is prioritized in areas where it provides the greatest benefit in terms of unsupplied load, customer count, and historical reliability performance. FortisAlberta does not apply a fixed outage duration threshold; restoration performance depends on system conditions, including accessibility, extent of damage, alternate supply availability, and the number of customers affected. The Company's target restoration times for main feeder contingencies are generally one hour or less in urban areas and four hours or less in rural areas, where alternate supply is available through switching.

141. Applicable regulatory requirements, including AUC Rule 002, provide a framework for monitoring reliability performance and support the Company's approach to balancing restoration timelines, customer impact, and system conditions.

142. FortisAlberta's distribution back-up criteria apply to all main feeder contingencies as well as transmission substation element failures, which would be a high-impact event. Losing a single transmission substation element without distribution system back-up could lead to outages on a much larger scale than those resulting from a single feeder contingency. While FortisAlberta's distribution backup criteria focus on localized redundancy where practical, transmission system backup is managed by the AESO and TFOs and reflects broader system reliability requirements. As a result, backup approaches at the transmission level differ from those at the distribution level due to differences in scale, configuration, and planning responsibility.

143. FortisAlberta's distribution backup criteria apply to single-contingency (N-1) planning conditions only. The Company does not plan for N-1-1 or N-2 conditions in its distribution planning because the distribution system is predominantly radial and the incremental planning value of those scenarios is limited relative to the transmission system.

5.3.3 Reliability Triggers, Investment Levels, and Prioritization

144. FortisAlberta does not apply fixed numerical reliability thresholds or a single prescriptive model that automatically triggers capital investment. Reliability metrics such as the system average interruption duration index (SAIDI), the system average interruption frequency index (SAIFI), and worst-performing feeder indicators are used as diagnostic and comparative tools to identify deteriorating performance, elevated customer impact, and areas requiring further review. Investment decisions are informed by a comparative assessment of outage likelihood, outage consequences, customer impact, system configuration, asset condition, and the expected benefit of available mitigation options.

145. FortisAlberta considers reliability outcomes to be acceptable where they remain within applicable regulatory requirements, including AUC Rule 002 service quality standards, and where localized outage frequency, duration, restoration capability, customer impact, and safety or environmental consequences can continue to be managed through existing controls or operational measures.

146. Reliability investments are advanced where observed performance, outage consequences, or residual risk indicate that those conditions can no longer be maintained. This assessment considers the number of customers affected, the magnitude of unsupplied load, restoration capability, safety and environmental exposure, and the criticality of the load served. It is supported by planning, engineering, and field judgment informed by outage history, inspection findings, and area-specific operating knowledge.

147. FortisAlberta does not allocate a fixed percentage of total capital spending to reliability improvements. Investment levels are determined based on identified system need, relative risk, and customer impact, and projects are advanced where reliability improvement and risk reduction are required to maintain system performance. Where multiple reliability projects are identified, timing and sequencing are informed by the relative urgency of the issue, the effectiveness of interim mitigation measures, constructability, and resource availability. Lower-risk issues may be phased or deferred where acceptable performance can be maintained through operational or incremental solutions.

148. Consistent with its deterministic planning framework, FortisAlberta does not use load duration curves or asset failure rates to trigger reliability investment for N-1 conditions. Reliability investment is grounded in observed performance, actual loading, and identified system needs.

Once a reliability need has been identified, FortisAlberta evaluates the underlying cause, customer impact, available mitigation options, and expected benefits before determining whether capital investment is warranted.

5.3.4 Reliability Improvement Programs

149. FortisAlberta addresses identified reliability needs through several established programs, including the Worst-Performing Feeder (WPF) program, the System Improvement (SI) component of the Distribution Capacity Increase program, and a number of additional reliability-focused programs within the Environment, Safety and Reliability and Rebuilds, Replacements and Life Extensions capital categories. These reliability-focused programs include, but are not limited to, conductor management, pole management, bird proofing, protective coatings, porcelain switch replacement, and related targeted ageing facilities initiatives. These programs address system needs in areas where customers are experiencing poor reliability or where localized conditions create elevated reliability risk.

150. The WPF program includes three primary components. First, on an annual basis, the WPFs by SAIDI are identified for review. Second, trouble switch analysis identifies feeder segments where protective devices have operated repeatedly due to unplanned outages. Third, the customers with multiple outages initiative identifies situations where 50 or more customers have experienced repeated interruptions that are not otherwise captured through feeder-level screening. These components help identify localized service issues that may not be evident from system-average performance alone.

151. The SI program includes projects undertaken to maintain service reliability and power quality where load growth, system configuration, or restoration limitations may compromise service quality. These investments include upgrades to distribution components or the installation of new components to address alternate feed limitations, improve sectionalizing, reduce the impact of interruptions on customers, and support planned maintenance or contingency restoration. Accordingly, SI investments are not limited to feeders with below-average historical SAIDI or SAIFI performance. The investment need may instead be driven by the expected consequence of a contingency event, including the magnitude of unsupplied load, the number of customers affected, the absence of practical backup supply, and the cost and feasibility of establishing alternate supply. SI projects are ranked using factors such as project cost against the number of

customers affected, historical feeder reliability, and magnitude of unsupplied load. Isolated or non-recurring events, such as foreign interference, are reviewed with field personnel and do not automatically justify capital investment.

152. The inclusion of a feeder, circuit, or asset within a reliability improvement program does not automatically result in a capital project. Once an issue is identified, FortisAlberta evaluates the underlying cause, the expected consequence of continued deferral, the available mitigation options, and the relative cost-effectiveness of intervention. A capital project is advanced where this assessment indicates that acceptable reliability outcomes cannot reasonably be maintained through existing controls or operational measures.

Illustrative Example – Customers with Multiple Outages (CMO)

153. The CMO program is a component of the Company's WPF program intended to identify localized reliability issues that may not be evident from feeder-level SAIDI or SAIFI screening alone. Under this program, FortisAlberta identifies sections of line supplying 50 or more customers that have experienced six or more sustained outages over a 12-month period. This approach recognizes that, in a large and predominantly rural distribution system, customers on specific line sections may experience repeated interruptions even where the broader feeder does not rank among the WPFs on a system-wide basis. The CMO component therefore complements the WPF and trouble-switch screening processes by identifying concentrated pockets of poor customer reliability and enabling targeted corrective action:

- small repairs such as re-insulating and re-tying conductors, adding wildlife or bird protection, replacing defective crossarms, insulators, switches, or other localized components, improving grounding, or correcting deficiencies identified through field patrols;
- targeted vegetation management, including tree removal or right-of-way work where tree contact or environmental exposure is a material contributor to repeated outages; and
- targeted line section rebuilds or relocations, including rebuilding cross-country line along developed rights-of-way where existing alignment, access, asset condition, or recurring outage causes make localized repairs insufficient.

154. Once a CMO location is identified, outage causes are reviewed and the affected line section is patrolled to determine whether the recurring interruptions are associated with equipment condition, conductor issues, wildlife contact, lightning exposure, adverse weather, tree contact, access constraints, or other localized factors. The mitigation solution selected is based on the identified cause and the least-cost option that is expected to address the prevalent outage drivers and maintain acceptable reliability. Where localized repairs can reasonably address the issue, FortisAlberta will pursue those lower-cost interventions. Where the underlying condition reflects multiple compounding issues, such as deteriorated poles or crossarms, aged or poorly performing conductor, numerous splices, recurring vegetation exposure, poor access, or an undesirable alignment, a more comprehensive rebuild or relocation may be required to provide a durable reliability improvement. This approach ensures that CMO investments are not triggered solely by the number of outages, but by a cause-based assessment of whether targeted intervention is required and what scope of work is justified by the expected reliability benefit.

5.3.5 Power Quality

155. FortisAlberta undertakes targeted reliability investments to address localized power quality issues where those issues are persistent, measurable, and materially affect customer service, safety, or system performance. These investments are required to provide and maintain service that is safe, adequate and proper, and may address issues such as voltage deviation, flicker, harmonics, or frequent momentary interruptions and are typically localized to specific feeders or assets rather than driven by system-wide power quality targets.

156. Whether investment is warranted depends on the number of customers affected, the frequency and recurrence of the issue, the severity of the impact on customer operations or equipment, and whether corrective action is cost-effective relative to available alternatives. As with other reliability investments, FortisAlberta relies on localized engineering and planning assessment rather than a single standardized cost-per-unit metric.

5.3.6 Resiliency and Key Business Risks

157. Consistent with industry usage, FortisAlberta understands resiliency to refer to the ability of the distribution system to anticipate, absorb, recover from, and adapt to disruptive events, particularly

high-impact, low-frequency events.[9] The Company undertakes resiliency-related investment, but resiliency is not currently a standalone capital category. Instead, resiliency considerations are embedded within existing investment drivers, primarily reliability, asset replacement, and asset design. FortisAlberta considers environmental exposure, asset vulnerability, and consequences of failure when identifying and prioritizing investments, with a particular focus on wildfire risk, extreme weather, and public and worker safety.

158. Risk reduction and public safety benefits are not determined by using fixed quantitative thresholds. Instead, they are assessed comparatively using available information such as hazard exposure, outage history, inspection results, asset condition, and planner and field judgment. Mitigation measures may include system hardening, asset-level protection, selective monitoring and control technologies, wildfire mitigation activities, and operating practices such as enhanced protection settings and public safety power shutoff.

159. FortisAlberta also evaluates investments related to other key business risks, including physical security, cybersecurity, and operational resilience, using a risk-based and business-impact-driven approach. These investments are informed by threat intelligence, regulatory expectations, asset criticality, vulnerability exposure, and the operational, safety, financial, and reputational consequences of service disruption or security incidents. Particular focus is placed on protecting critical infrastructure, control systems, field operations, facilities, and essential business services from both intentional and unintentional threats that could impact safe operations or grid reliability. Investments are prioritized based on their ability to reduce enterprise risk, improve prevention and detection capabilities, strengthen incident response and recovery processes, and enhance the resilience of both IT and Operational Technology environments.

5.3.7 Grid Modernization

160. Grid modernization investments are focused on improving how the distribution system is monitored, operated, and managed as system complexity increases. These investments include advanced monitoring, automation, field sensing, voltage support, and control capabilities that provide greater visibility into feeder conditions, enable more effective voltage management, support faster fault identification, enable more targeted switching, and improve restoration

[9] Integrated System Resilience - NARUC

performance. Technologies such as ADMS, dynamic wildfire risk modelling, weather intelligence, and expanded field sensing support a more active operating model by improving situational awareness at both the control centre and field level.

161. FortisAlberta advances grid modernization through the integration of these capabilities, rather than through stand-alone point solutions. Integrated systems that combine external data sources, system models, and operational platforms support coordinated decision-making and adaptive operating responses during high-risk conditions, including wildfire events, extreme weather, increased DER penetration, two-way power flows, and localized system constraints. These capabilities support reliability and resiliency by providing situational awareness to quickly identify extraordinary weather events and operating conditions, reducing reliance on manual intervention across a large and geographically dispersed system, and improving operational response where access constraints or longer restoration times increase customer impact.

162. FortisAlberta evaluates modernization initiatives based on their expected safety, operational, reliability, efficiency, and risk-reduction benefits over the lifecycle of the asset or system. Quantifiable benefits, such as reduced outage duration, improved restoration performance, avoided operating costs, and deferred traditional infrastructure investment, are considered where practicable, alongside practical operational benefits such as faster fault isolation, improved coordination, reduced field exposure, enhanced visibility, resilience, and safety, including the identification, prevention, and mitigation of hazards. Investment decisions are supported by the best available quantitative information, demonstrated operational need, comparative engineering judgment, and the requirement to maintain safe and effective system operation as distribution system requirements continue to evolve.

5.3.8 Optimization and Deferral

163. FortisAlberta optimizes reliability investment by first considering lower-cost operational, maintenance, and targeted asset interventions where those measures can maintain acceptable performance and risk levels. Depending on local system conditions, these measures may include reconfiguration, switching changes, targeted component replacement, re-insulating, re-tying, re-sagging of lines, crossarm and insulator replacement, life-extension treatments, and other focused corrective work.

164. These measures may enable the deferral or avoidance of higher-cost capital investment where they are able to provide a practical and durable means of managing reliability risk. However, deferral is not pursued where residual risk would become unacceptable or where system performance is expected to deteriorate materially in the near-term. A "do nothing" alternative is considered as a baseline but is generally not viable where it would lead to worsening outage performance, degradation of voltage and power quality (particularly in the context of increasing DER penetration), increasing safety or environmental exposure, or higher long-term lifecycle cost.

165. FortisAlberta does not currently incorporate DERs as a primary reliability resource in its reliability planning. While DERs may provide incidental reliability benefits, they are generally not credited as firm reliability resources because of their non-dispatchable nature and uncertain output. The Company has implemented limited non-wires solutions, such as the Waterton battery energy storage pilot, and may consider temporary supply arrangements such as portable generation or temporary feeder configurations in specific outage or restoration scenarios where customer impact and system conditions warrant.

166. FortisAlberta continues to evaluate non-wires and demand side solutions as potential tools to defer or optimize traditional infrastructure investment in limited circumstances. However, broader application remains constrained by the absence of an established Alberta policy and regulatory framework for evaluating these alternatives, including a common cost-benefit methodology for assessing utility system benefits, customer impacts, and potential upstream infrastructure deferral. As policy and regulatory direction evolves, clearer evaluation frameworks may improve the practicality of incorporating these tools into future distribution planning.

Illustrative Example – Reliability Optimization and Line Rebuild Assessment

167. For example, a poorly performing portion of a distribution feeder may be identified through detailed line patrols, outage history, customer feedback, pole testing, or other asset management activities. Once identified, FortisAlberta first assesses whether the reliability, safety, or asset condition concern can be addressed through lower-cost targeted interventions. These may include localized repairs, re-insulating or re-tying conductors, replacing individual crossarms or insulators, targeted vegetation work, or other focused corrective work that can extend asset life or improve performance without requiring a full rebuild. These alternatives are considered first because they can often be delivered more quickly and at lower cost while maintaining acceptable risk.

168. In some circumstances, however, localized interventions are not sufficient because the feeder segment presents multiple compounding issues. For example, a line section may include aged or deteriorated poles, a high concentration of failed or substandard pole-test results, deteriorated crossarms, aged conductor with numerous splices or recurring conductor failures, clearance concerns, poor access, environmental constraints, or an alignment that limits efficient maintenance and restoration. In these circumstances, treating or replacing individual components may only address isolated symptoms and would be expected to result in continued reliability issues, repeated field intervention, higher long-term lifecycle costs, and ongoing safety or compliance risk.

169. Where those conditions exist, FortisAlberta evaluates whether a broader rebuild, replacement, or realignment is the more appropriate optimized solution. This assessment considers the condition and age of the facilities, outage history, customer impact, employee and public safety, accessibility, constructability, environmental or land-use constraints, the ability to improve future maintenance and restoration, and whether the work can be coordinated with other planned activities in the area. A rebuild is advanced only where lower-cost alternatives are not expected to provide an effective long-term solution or where the cumulative condition of the assets supports addressing the line segment as an integrated project rather than through repeated incremental repairs.

170. Although a line rebuild has a higher upfront cost than targeted repairs, it may be the lowest-cost lifecycle alternative where it addresses several related deficiencies at the same time, reduces repeat site visits, improves access or alignment, restores compliance with current standards, and materially reduces residual safety and reliability risk. This approach is consistent with FortisAlberta's broader approach to reliability: targeted interventions and life-extension measures are used where they can maintain acceptable performance, while more comprehensive rebuilds are pursued where the asset condition, reliability history, and operational constraints indicate that incremental repairs would not adequately address the underlying risk.

5.3.9 Criteria for New Facilities

171. FortisAlberta considers the need for new facilities when reliability performance cannot be adequately addressed through targeted maintenance, operational changes, or incremental asset upgrades. Relevant considerations include sustained reliability issues, repeated or widespread outages, limited restoration capability, capacity or loading constraints, single points of failure, and system configurations that no longer provide an acceptable level of reliability risk. Decisions are

informed by outage probability, customer impact, cost-effectiveness, and long-term system performance.

5.4 ASSET REPLACEMENT INVESTMENT CRITERIA AND RISK TOLERANCE

172. Asset replacement decisions are made within the PBR3 framework, under which the Company is incented to manage costs through prudent maintenance, asset life-extension, and efficient timing of replacements, while continuing to meet its statutory obligation to serve and maintain safe and reliable service. Where FortisAlberta has discretion over the timing, scope, or sequencing of intervention, asset replacement investments are prioritized by balancing asset condition and failure likelihood with consequence of failure, available mitigation measures, and the practicality and cost of deferral. Failed assets, urgent safety requirements, and mandatory compliance work proceed as non-discretionary needs.

5.5 ASSET CONDITION AND FAILURE LIKELIHOOD ASSESSMENT BY ASSET CLASS

173. The Commission has asked for more details of what informs the asset condition and probability of failure metrics used for different asset classes for FortisAlberta's asset replacement investment criteria. Table 5-1, below, summarizes the principal condition, failure-likelihood, consequence, and intervention considerations applied to major distribution asset classes.

Table 5-1
Asset Condition and Failure Likelihood Assessment by Asset Class

Asset class	Condition information	Failure-likelihood information	Consequence information	Intervention criteria
Wood poles	Visual inspection; sounding and probing; core testing; shell condition; structural capacity; climbability; decay; wildlife damage	Inspection outcome; local failure experience; vintage, species, treatment cohorts; exposure; time to next inspection	Safety; line function; customer exposure; wildfire; accessibility; clearances	Treat where deterioration can be arrested; replace where structural criteria are not met; act immediately where imminent failure is identified; assess rebuild where failures are concentrated across a line segment

UG cable	Diagnostic test results; insulation condition; neutral condition; splice quantity; corrosion; failures	Cable vintage; fault history; test category; electrical stresses; previous rejuvenation performance	Number of customers or amount of load served; restoration time; winter excavation; source proximity; safety and environmental exposure	Rejuvenate where technically viable and expected to manage risk at lower lifecycle cost than replacement; replace where condition, repeated failures, neutral deterioration, or splice density makes rejuvenation ineffective
Large transformers (over 2,500 kVA)	Dissolved gas analysis (DGA); oil quality; infrared results; visual inspection; leakage; operating condition	DGA trends; loading and thermal history; failure experience; manufacturer information; age as a supporting input	Customer and load impact; criticality; redundancy; safety; oil release; replacement lead time	Increase monitoring for adverse trends; refurbish where effective; replace proactively where deterioration and consequence create unacceptable residual risk
Transformers (under 2,500 kVA)	Visual condition; leakage; damage; loading; outage or failure history	Observed failure performance; loading; environmental exposure; known cohorts	Local customer impact; environmental release; availability of spares; restoration time	Permit run-to-failure only where consequence is low and prompt replacement is feasible; proactively replace leaking, damaged, non-compliant, or elevated-risk units
Overhead conductor	Corrosion; strand loss; splices; clearances; sag; inspection findings	Recurring conductor failures; vintage/material cohort; weather exposure; observed deterioration	Customers/load; access; wildfire; public safety; restoration duration	Repair localized defects; replace or rebuild where multiple compounding deficiencies indicate incremental repair is not durable

Switches and apparatus	Operational checks; maintenance history; inspection; alarms; mechanical condition; contamination	Operation count; failed operations; known defect cohorts; test history	Isolation capability; customers affected; safety; restoration flexibility	Maintain or refurbish where condition is recoverable; replace where safe operation or dependable isolation is no longer assured

174. FortisAlberta assesses asset condition and likelihood of failure using criteria tailored to the failure modes, available condition information, and operating role of each asset class. Age is not used as a stand-alone replacement trigger. It may, however, be used as a screening, inspection-planning, population-forecasting, or failure-likelihood input where experience demonstrates a relationship between asset vintage and deterioration.

175. FortisAlberta does not calculate a uniform numerical annual probability of failure for every distribution asset. For asset classes with repeatable test results and sufficient historical failure information, condition and historical performance may support a quantitative or categorical estimate of failure likelihood. For other asset classes, likelihood is assessed on a relative basis using inspection results, observed condition, failure history, loading and operating experience, environmental exposure, known failure mechanisms, manufacturer information, and engineering judgment. FortisAlberta uses the term “likelihood of failure” where a numerical probability has not been established.

176. Asset condition represents the observed physical, electrical, mechanical, or operational state of an asset. Depending on the asset class, condition information may include visual inspection results, structural or material testing, diagnostic test results, operating or maintenance history, failure and outage records, environmental exposure, and field observations. The assessment also considers the quality and age of the available information. Where condition information is incomplete or requires confirmation, FortisAlberta may undertake additional inspection, testing, monitoring, or field review before approving a material capital intervention.

177. Condition and likelihood information is combined with consequence of failure. Consequence considerations include public and worker safety, wildfire ignition and propagation potential, customer interruption magnitude and duration, critical customer service, environmental impact,

regulatory and code compliance, asset criticality, system configuration, restoration capability, and availability of replacement equipment. Assets with similar condition may therefore receive different priorities where their consequences of failure differ materially.

5.5.1 Risk Treatment and Tolerance

178. FortisAlberta applies a lower tolerance to risks affecting public and worker safety, legal and regulatory compliance, wildfire ignition potential, environmental release, and service to critical customers. Risks in these areas may require immediate control, accelerated maintenance, or proactive replacement even where an asset has not reached an expected service life.

179. For other risks, FortisAlberta evaluates whether maintenance, life extension, monitoring, operational changes, reconfiguration, refurbishment, or replacement provides the most cost-effective and durable means of managing the risk. Deferral is permitted only where the residual risk after existing and planned controls remains within the applicable tolerance and where the asset continues to meet safety, reliability, environmental, and compliance requirements. The deferral decision is revisited when new inspection, testing, failure, operating, or environmental information becomes available.

180. Run-to-failure may be appropriate where failure consequences are limited, customer impacts are localized and short in duration, failure can be detected and safely isolated, replacement equipment is readily available, and restoration can be completed promptly. It is not appropriate where failure could produce material safety, wildfire, environmental, compliance, extended-reliability, or system-operability consequences.

181. Required replacements may be like-for-like where the existing design remains suitable and continues to be available. In other cases, like-for-like replacement may not be practical or appropriate because the original asset type, material, equipment configuration, or construction standard is no longer manufactured or supported under current standards. For example, FortisAlberta's pole management practices include life-extension measures such as pole stubbing, wrapping, and internal treatments where they can cost-effectively extend service life. However, poles that no longer satisfy minimum structural thresholds must be replaced, and line sections with high pole failure rates, limited access, clearance issues, or deteriorated vintage assets may require rebuild or realignment rather than one-for-one replacement. Similarly, asset replacement work may require upgrading deteriorated, defective, or non-standard distribution equipment identified

through inspections, technical reviews, or routine operations, such as rebuilding overhead lines to accommodate aged conductor replacement under current electrical codes and construction standards, replacing outmoded equipment, or adding missing or upgraded system neutrals where existing facilities cannot accommodate the required conductor or clearance. In these circumstances, FortisAlberta selects the replacement approach that appropriately addresses the underlying asset condition, safety, compliance, reliability, and lifecycle risk, while balancing risk reduction, system performance, constructability, and long-term sustainability.

5.5.2 Life Extension, Decommissioning, and Reconfiguration

182. FortisAlberta uses a range of life-extension, reconfiguration, and targeted mitigation measures to defer or avoid higher-cost replacement where those measures can maintain acceptable safety, reliability, compliance, and environmental risk levels. These measures include pole stubbing, pole wrapping, internal treatments for wood poles, cable testing and rehabilitation, bulk lamp replacement, apparatus refurbishment, grounding-system work, and other targeted repairs.

183. System reconfiguration is also considered where it provides a lower-risk or lower-cost alternative to direct replacement. Reconfiguration may include targeted conductor upgrades and other localized measures that allow existing assets to continue operating within applicable reliability criteria. These alternatives are pursued where they provide a practical and durable means of managing asset condition or system performance risk without requiring immediate replacement. However, reconfiguration is not an alternative to replacement where the underlying asset condition, safety hazard exposure, compliance requirement, or lifecycle risk can no longer be effectively managed through operational or targeted mitigation measures. In those circumstances, FortisAlberta proceeds with the replacement, rebuild, or upgrade necessary to maintain safe and reliable service.

184. Assets are decommissioned only where they are no longer required to support reliable service, customer supply, safety, compliance, or system operation. Asset replacement deferral is pursued only where risk remains manageable and where future system changes or lower-cost interventions are expected to provide a reasonable alternative to immediate replacement.

5.5.3 Investment Levels, Timing, and Prioritization

185. FortisAlberta determines asset replacement investment requirements using available condition information, inspection findings, failure history and trends, asset-class failure-likelihood

assessments, historical performance, and consequence of failure. There is no single quantitative replacement threshold or fixed percentage of total spending applicable across all asset classes. Failed assets, urgent safety needs, and mandatory compliance requirements proceed as non-discretionary work. Other replacement needs are prioritized based on relative risk and the effectiveness of available maintenance, life-extension, monitoring, or operational controls.

186. FortisAlberta's risk tolerance varies by consequence category. The Company maintains a low tolerance for risks that could adversely affect public or worker safety, regulatory compliance, wildfire ignition potential, or critical customer service. Accordingly, assets presenting elevated exposure in these areas are generally prioritized for replacement or other mitigating action before lower-consequence assets with similar condition characteristics.

187. Timing and prioritization are determined by the combined failure likelihood and consequence of failure, the immediacy of the risk, and the extent to which maintenance, life extension, monitoring, or other interim measures can continue to maintain residual risk within applicable tolerance.

188. Assets or programs with higher and more immediate risk are advanced first, while lower-risk work may be phased or deferred where appropriate. FortisAlberta does not allocate fixed percentages to individual replacement programs; program funding varies over time based on identified need and relative risk across the asset base.

6. ASSET DESIGN

189. Design standards establish the technical parameters and configurations used once a system need has been identified, ensuring that assets are constructed in a manner that supports safe operation, reliability performance, and cost-effective lifecycle management. FortisAlberta maintains standard design levels for transformers, feeders, and customer service infrastructure to support consistent, efficient, and reliable system development. The Company’s design standards are applied consistently across all distribution system construction projects, rather than acting as independent drivers of investment decisions.

190. Design levels are established based on reliability requirements (including backup capability), historical system design practices, and cost-effectiveness considerations, balancing standardization with the need to accommodate location-specific load characteristics. Design levels are reviewed periodically to determine whether consolidation or expansion of standard sizes would

improve efficiency. A limited set of standardized capacity levels supports efficiency in design, procurement, and construction; increasing the number of standard levels may improve optimization in limited specific cases but would introduce additional complexity and cost overall. The selection of standard capacity levels reflects a deliberate balance between design efficiency and system performance. Standardization reduces engineering effort, supports consistent and repeatable construction practices, improves inventory management and emergency response capability, and enables efficient procurement through bulk purchasing. A broader set of standard levels could in theory allow more precise sizing for individual locations; however, the resulting increase in engineering complexity, inventory carrying costs, spare equipment requirements, and construction variability would outweigh the incremental optimization benefit for a geographically dispersed service area. Asset design also considers environmental and operating conditions (e.g., temperature, loading, and exposure), consistent with applicable standards, to ensure assets perform reliably under expected system conditions.

191. Transmission transformers are operated within their manufacturer-specified nameplate capacity limits, or otherwise as determined by the TFO. FortisAlberta does not select or specify the standard capacity level for transmission transformers at its PODs. Transmission substation transformer sizing, configuration, and procurement are the responsibility of the TFO and are determined through the AESO connection process. FortisAlberta's role is to identify the distribution capacity requirement through its planning process and to initiate a System Access Service Request where a DTS increase or new POD is required. The resulting transformer capacity is determined by the AESO and TFO based on the system access request, transmission system configuration, and applicable transmission planning criteria. Accordingly, FortisAlberta does not maintain standard design levels for transmission transformers and does not determine their effective capacity or operating limits. To optimize system utilization and defer higher-cost transmission upgrades where feasible, FortisAlberta may implement load transfers between substations or PODs, consistent with the planning and operational approaches described in Sections 4 and 5.

192. FortisAlberta applies a standard 13 MVA maximum normal condition load for three phase feeders, corresponding to a maximum loading of 300 A at 25 kV. For the purposes of asset design, a "three-phase feeder" refers to a main three-phase circuit originating from a substation breaker, consistent

with the definition described in Section 5.3.2. These feeders form the backbone of the distribution system and are the circuits to which the N-1 backup criteria apply.

193. At the substation egress, three-phase feeders are constructed with a capacity of approximately 26 MVA, using 477 ACSR conductor for overhead segments and 750 AL MCM cable for underground segments. This 26 MVA egress capacity is deliberately established at twice the 13 MVA operating load limit to provide the capacity margin required for N-1 backup. Under normal operating conditions, each feeder is loaded to a maximum of 13 MVA. Under contingency conditions, the feeder can accept up to its full 26 MVA egress capacity to accommodate load transferred from an adjacent feeder through normally-open tie points. This design ensures that adjacent feeders have sufficient capacity to accept transferred load during planned or unplanned outages while maintaining voltage and thermal performance within acceptable limits.

194. Beyond the substation egress, conductor sizing and capacity are not maintained at the full 26 MVA egress standard along the entire length of the feeder. Instead, the feeder is progressively optimized to serve the current and forecast load under both normal and N-1 conditions at each point along the circuit. Conductor selection, voltage regulation placement, and system configuration downstream of the egress reflect the actual and forecast loading requirements of the area served, consistent with the planning criteria described in Section 5.2.1. This approach avoids over-investment in conductor capacity where it is not required by local load, while ensuring that the feeder backbone maintains sufficient capacity and operational flexibility to support switching and load transfer during contingency events.

195. Three-phase feeders are distinct from three-phase taps. A three-phase tap is a radial three-phase line that branches off a main feeder to serve local distribution load. Three-phase taps do not originate from a substation breaker and do not have alternate feed capability through normally-open tie points. They are designed and sized to serve the specific load they supply, with conductor selection optimized for that load rather than built to the main feeder egress standard. As described in Section 5.3.2, three-phase taps, like single-phase taps, are not subject to the N-1 backup criteria. Typically, service to customers on a three-phase tap is restored through fault isolation and repair rather than through switching to an alternate supply source. Within this standard, feeder design may be optimized through conductor selection and voltage regulation, taking into account existing

and committed loading conditions. These design choices support efficient system utilization while maintaining alignment with the planning criteria described in Section 5.

196. Single-phase tap capacity is determined primarily by conductor characteristics and system configuration rather than a defined standard capacity level. These taps are typically radial extensions off the three-phase systems and are designed and optimized based on localized loading conditions, consistent with the broader feeder design approach. Single-phase taps are optimized by right-sizing the conductor for existing and forecast loads, and are not subject to the N-1 backup criteria described in Section 5.3.2. Instead, the design is tailored to the specific load being served, which supports cost-effective construction and avoids over-investment in conductor capacity that would not be fully utilized. FortisAlberta standard conductor size for new single-phase construction is #2B Haddock ACSR overhead conductor and #1Al underground cable. Voltage regulation is also used to optimize single-phase taps in the same way as three phase feeders.

197. Distribution transformers are selected based on customer load requirements and are operated within defined capacity limits. FortisAlberta maintains a defined set of standard distribution transformer sizes for overhead (pole-mount) and underground (pad-mount) applications, covering a range of single-phase and three-phase configurations. Standard sizes are selected to efficiently serve connected customer load while providing reasonable headroom for near-term load growth and operational flexibility. Standardized sizing practices are applied to ensure efficient utilization of assets, support inventory management and rapid replacement, and reduce engineering effort associated with site-specific design. Any customer-specific, non-standard configuration requirements are addressed through customer contributions, consistent with FortisAlberta's connection practices described in Section 5.

198. To support distribution system reliability and restoration capability, FortisAlberta installs switching cubicles outside the substation fence at feeder egress points. This design approach enables feeder-level backup capability and operational flexibility that is independent of the internal substation bus configuration determined by the TFO. By locating switching capability outside the TFO fence, FortisAlberta can perform feeder switching, load transfers, and contingency restoration without requiring access to, or coordination with, the transmission substation bus, consistent with the N-1 feeder backup criteria described in Section 5.3.2.

199. As a DFO, FortisAlberta does not determine the low voltage bus configuration at transmission substations. Bus configurations at FortisAlberta's PODs are the responsibility of the TFO and are designed in accordance with the AESO's functional specifications and the TFO's engineering standards. FortisAlberta's distribution planning criteria requests that all 138 kV and 25 kV buses at its POD substations have adequate switching points and protection to minimize the frequency and duration of outages associated with the maintenance or failure of substation components upstream of the 25 kV bus, as described in Section 5.3.2. For POD substations with multiple source transformers, failure of substation components upstream of the 25 kV bus must not result in a total substation outage. FortisAlberta communicates these requirements to the AESO and TFO through the connection process and relies on the AESO to implement appropriate bus configurations to meet these performance expectations.

200. FortisAlberta's asset design standards incorporate resilience considerations through compliance with applicable regulatory and industry standards rather than through utility-specific probabilistic withstand thresholds (e.g., one-in-100-year event criteria). The Alberta Electrical Utility Code, which adopts CSA C22.3 No.1 (Overhead Systems) and CSA C22.3 No.7 (Underground Systems), establishes minimum design requirements that include weather withstand criteria for wind, ice, and combined loading conditions applicable to overhead structures and conductors. These standards are developed by the Canadian Standards Association and reflect national engineering consensus on appropriate design margins for the environmental conditions encountered in Canadian utility service areas. FortisAlberta designs all distribution assets to meet or exceed these requirements. In addition to code-based withstand requirements, FortisAlberta incorporates resilience considerations into asset design through targeted system hardening in wildfire-prone areas, the use of materials and configurations appropriate for the Company's varied terrain and climate conditions, and the application of design practices that reduce exposure to common failure modes such as vegetation contact, wildlife interference, and moisture ingress. These practices are described further in Sections 5.3.6 and 7.8.

201. Asset designs utilize standardized materials and engineered configurations that align with applicable regulatory and industry standards, including the Alberta Electrical Utility Code, which adopts the CSA C22.3 No.1 Overhead Systems and CSA C22.3 No.7 Underground Systems standards. These standards establish minimum performance requirements, including weather

withstand criteria, and support consistent, reliable asset performance under varied operating conditions.

6.1 ASSET RATING DETERMINATIONS

202. Asset ratings define the technical operating limits of distribution system equipment and are applied within the planning and design processes described in this Section and Section 4. These ratings do not independently drive investment decisions but are used to assess whether identified system needs result in violations of planning criteria, as described in Section 5.

203. The determination of asset ratings is dependent on the type of asset and its material. Thermal limits for materials are based on the point at which degradation or failure begins to occur. Transformers, conductors, and cables are subject to thermal constraints, along with certain other equipment such as regulators. In general, distribution assets are planned and designed using standard steady state thermal ratings, with emergency thermal ratings considered to a more limited extent.

204. The Commission has asked FortisAlberta to elaborate on how emergency thermal ratings are "considered to a more limited extent". Emergency thermal ratings are used in limited circumstances, primarily during off-normal system conditions or contingency events where they may be required to restore the greatest practical customer load that could not otherwise be restored. Emergency ratings are not used as a basis for normal system planning and are generally intended for short-duration operation until the system can be returned to a normal configuration or a permanent solution can be implemented. Operating assets at or near emergency ratings can accelerate asset deterioration, reduce expected asset life, and increase the likelihood of equipment failure. Accordingly, FortisAlberta plans and designs its system based on normal continuous ratings and uses emergency ratings sparingly and only when necessary to support system restoration or contingency operations.

205. Transformers are rated by the manufacturer, with capacity dependent on internal oil and coil temperatures. In contrast, cable and conductor ratings are determined using engineering calculations that account for ambient temperature, load current, soil resistivity, wind conditions, emissivity, and duration of loading. For planning purposes, a conservative ambient temperature assumption (e.g., 40°C) may be applied together with maximum design loading to establish standard equipment ratings. This assumption represents a conservative upper-bound condition and ensures that asset ratings remain valid under adverse operating conditions. FortisAlberta considers

this assumption to be appropriately conservative from a risk tolerance perspective, as it avoids reliance on favourable short-term environmental conditions and ensures that planning decisions are robust under peak loading scenarios.

206. The Commission has asked FortisAlberta to elaborate on which asset ratings consider seasonal temperature variation. FortisAlberta plans to annual peak loading conditions and does not generally apply separate seasonal summer and winter ratings in its distribution planning assessments. While seasonal rating adjustments are not generally used for distribution planning, seasonal temperature effects may be considered when evaluating additional loading on existing transformers. For example, when evaluating additional loads on existing transformers, lower ambient temperatures in winter may allow for a defined level of short-term overload above the standard design rating. Overloading and overheating are time-dependent phenomena and limited-duration exceedances may be acceptable depending on the asset type and associated risk tolerance. This approach allows FortisAlberta to make informed use of available capacity under favourable conditions without compromising asset integrity or long-term performance. Seasonal adjustments for transformers are determined using manufacturer information and engineering assessment and are not based on real-time dynamic monitoring of cooling conditions.

207. Not all assets are constrained by thermal limits. Other factors, such as mechanical strength, condition, and operational requirements, may be more relevant in determining acceptable operating limits.

208. In addition to thermal constraints, voltage limits are determined through load flow analysis using system models and impedance values of assets. FortisAlberta plans and operates its distribution system to maintain voltage within the limits of CSA C235:19 at the point of connection. FortisAlberta's planning criteria require a minimum primary voltage of 115 V for three-phase service and 113 V for single-phase service under peak load conditions, and a maximum of 127 V under light load conditions, on a 120 V base, as described in Section 5.2.1.

209. The difference between the three-phase and single-phase minimum primary voltage reflects the CSA standard's utilization point limits, which permit a normal operating minimum of approximately 110 V for three-phase and 108 V for single-phase service. FortisAlberta's primary voltage criteria are calibrated to these utilization point limits by accounting for voltage reduction

through the service transformer, secondary conductors, and customer wiring, generally assumed to be 3 to 5 volts under peak loading conditions and 1 to 2 volts under light load conditions.

210. The minimum primary voltages are assessed with the source substation voltage set at 123.5 V, while maximum voltages are assessed at 126.5 V, reflecting the typical operating bandwidth of substation voltage regulation equipment. For medium-voltage systems (e.g., 25 kV), CSA establishes a steady-state operating range of ±6% of nominal voltage at the point of connection. Voltage limits are verified through load flow modelling and are assessed under both normal and contingency operating conditions.

211. In addition to steady-state voltage limits, FortisAlberta applies applicable industry standards for voltage fluctuation and rapid voltage change (e.g., CSA/IEC 61000-3-7 and IEEE 1453) in assessing power quality impacts.

7. FIVE-YEAR CAPITAL INVESTMENT PLAN

212. FortisAlberta has included a five-year capital investment plan in the 2026 FortisAlberta DSP Workbook, presented consistently with the capital categories determined in Proceeding 26615.[10]

213. FortisAlberta's capital investment plan is constrained by funding considerations that can materially affect the scope and timing of deliverable programs. Under the PBR framework, utilities recover prudent costs within a funding envelope established through formulaic rate-setting. Given that a significant portion of the Company's annual capital program is non-discretionary, capital spending levels and the allocation across categories are largely determined by the volume and timing of these requirements. During the PBR3 term, elevated customer growth expenditures, together with significant non-discretionary investments in AMI replacement, have required the prioritization of these programs within the available funding envelope.

214. As a result of these pressures, capital capacity available for risk-prioritized and condition-based maintenance programs was constrained during the earlier years of the PBR3 term. This led to the deferral of certain system maintenance and asset renewal activities, with the associated work accumulating over time. While customer growth is expected to moderate over the remainder of the PBR3 term, the need to address previously deferred maintenance, in addition to ongoing non-discretionary requirements, contributes to a higher forecast of capital expenditures in the latter

[10] Proceeding 26615, ATCO Electric and FortisAlberta 2023 Cost-of-Service Review.

years of the period, particularly in 2029 and 2030, as the Company works to maintain system reliability and asset condition.

7.1 CUSTOMER GROWTH

215. The Customer Growth category captures non-discretionary investments required to connect new customers and accommodate incremental load across FortisAlberta's service territory. These investments include the extension and reinforcement of overhead and underground distribution facilities and are driven by customer connection requests and the need to maintain acceptable voltage and loading conditions.

216. Customer growth investment is influenced by residential development, commercial and industrial expansion, agricultural activity, and large customer-specific service requests. Over the last five years, both the scale and composition of growth have shifted, with sustained population growth and increased economic activity driving higher volumes of connection-related investment.

217. Table 7-1 shows the actual additions for 2021 to 2025 and the forecast capital additions for 2026 to 2030 for the Customer Growth category.

Table 7-1
Customer Growth
Capital Additions
($ millions)

	Actual					**Forecast**				
	2021	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Capital Expenditures	91.0	134.5	162.2	210.5	230.8	230.3	220.8	220.4	223.3	229.5
CWIP	5.1	(2.5)	4.4	6.5	(0.1)	2.8	(1.6)	(0.8)	0.5	0.7
Capital Additions	**86.0**	**137.0**	**157.9**	**204.0**	**230.9**	**227.6**	**222.4**	**221.1**	**222.8**	**228.8**

**Minor variances due to rounding*

218. From 2021 to 2025, Customer Growth capital additions increased materially following a period of reduced activity during the COVID-19 pandemic. Growth accelerated from 2022 onward, driven primarily by residential development supported by strong population growth and migration, as well as increased commercial and industrial activity.

219. Customer Growth capital expenditures are forecast using a three-step approach:

    1. Forecast the number of new service locations by rate class based on historical trends and supporting economic and demographic indicators.

2. Estimate average unit costs using recent historical data, adjusted for current conditions.
3. Calculate total forecast expenditures by applying unit costs to projected service additions.

220. Capital additions over the 2026 to 2030 period are expected to remain elevated, reflecting continued customer growth, while moderating from peak levels observed in 2024 and 2025. This outlook reflects expectations of more normalized population growth and development activity, with customer growth remaining the largest driver of FortisAlberta's capital program.

7.2 SYSTEM MODIFICATIONS FOR GROWTH

221. FortisAlberta does not have a distinct and separate category of "System Modifications for Growth". Expenditures that would otherwise be captured within this category are included within FortisAlberta's Externally Driven System Modifications category. This approach reflects the Company's established capital program structure and ensures consistency with prior submissions, whereby system modifications arising from customer-driven growth and third-party activities are treated as externally driven investments.

7.3 DISTRIBUTION TO TRANSMISSION (D TO T) CONTRIBUTIONS

222. This category captures FortisAlberta's capital contributions toward the construction of transmission facilities under the AESO customer contribution policy. These contributions arise where transmission solutions are required to address capacity or reliability needs identified through the Company's distribution system planning process.

223. FortisAlberta has not forecast capital additions in this category for the 2026 to 2030 period. Consistent with Commission direction, AESO customer contributions are expensed in the year incurred rather than capitalized.[11] Forecasted D to T Contributions for the 2026 to 2030 period included in operating and maintenance (O&M) expense and flowed through to customers via Y Factor, have been included in Section 7.14.

[11] In Decision 29006-D01-2025 the Commission found that AESO customer contributions should continue to be expensed in the year incurred and approved the use of deferral accounts and amortization consistent with the approach established in Decision 26521-D01-2021.

7.4 EXTERNALLY DRIVEN SYSTEM MODIFICATIONS

224. The Externally Driven System Modifications category captures investments required to respond to customer-driven load growth and third-party requests, including asset relocations and system modifications outside of FortisAlberta's direct control. This category includes the following programs:

- **Distribution Line Moves:** Relocation or replacement of distribution facilities in response to third-party requests, including municipal, provincial, transmission-related, and customer-driven activities.
- **Distribution Capacity Increases:** Projects required to address load growth, including voltage and thermal constraints, and to maintain acceptable reliability and power quality.
- **Substation Associated Upgrades:** Distribution facilities required to connect new or expanded substations to the existing system.
- **Independent Power Producer Interconnections:** Infrastructure required to safely integrate customer-driven generation, funded through customer contributions.
- **High Load Corridor Clearances:** System modifications to enable safe transport of oversized loads and reduce reliance on high-load escorts.
- **DER Integration:** Investments to monitor, manage, and support increasing levels of DERs.
- **Distribution Voltage Management:** Projects to address voltage and power quality impacts arising from DER adoption and changing load characteristics.

225. These investments are largely non-discretionary in nature, as they are driven by external requirements and obligations.

226. Table 7-2 shows the actual additions for 2021 to 2025 and the forecast capital additions for 2026 to 2030 for the Externally Driven System Modifications.

Table 7-2
Externally Driven System Modifications
Capital Additions
($ millions)

	Actual					Forecast				
	2021	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Capital Expenditures	54.0	46.0	72.9	65.4	58.4	59.7	73.9	81.4	80.3	89.4
CWIP	5.1	(3.4)	(0.3)	(3.3)	0.8	0.4	1.2	0.8	(0.1)	1.6
Capital Additions	**48.9**	**49.4**	**73.2**	**68.8**	**57.6**	**59.3**	**72.7**	**80.7**	**80.4**	**87.7**

**Minor variances due to rounding*

227. Capital additions in this category are variable and do not exhibit a consistent trend, reflecting the timing and scope of externally driven projects, including government infrastructure initiatives, customer requests, and DER-related requirements.

228. The 2026 to 2030 forecasts are based on a combination of project-specific estimates and historical averages, escalated to reflect expected cost levels and anticipated activity.

7.5 ENVIRONMENT, SAFETY AND RELIABILITY

229. The Environment, Safety and Reliability category captures investments required to maintain the safety, reliability, and compliance of FortisAlberta's distribution system. These investments address deteriorated, defective, or non-standard assets identified through inspections, operational experience, and technical assessment. This category includes the following core programs:

- **Compliance, Safety, Aging Facilities & Reliability:** Replacement or upgrade of assets identified through inspection and operational activities to address safety, reliability, and compliance risks.
- **SCADA:** Investments in monitoring and control systems that support system visibility, operational efficiency, and improved outage response.
- **Worst Performing Feeders:** Targeted upgrades to address feeders with the poorest reliability performance, based on outage frequency, duration, and customer impact.

230. Deferral of these programs is limited, as risks associated with safety, compliance, and deteriorated assets cannot be effectively mitigated through alternative measures.

231. Table 7-3 shows the actual additions for 2021 to 2025 and the forecast capital additions for 2026 to 2030 for the Environment, Safety and Reliability category.

Table 7-3
Environment, Safety and Reliability
Capital Additions
($ millions)

	Actual					Forecast				
	2021	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Capital Expenditures	80.8	85.4	75.9	38.7	41.3	45.3	46.1	71.8	74.5	76.9
CWIP	(4.3)	3.0	9.8	(0.8)	(0.8)	(8.5)	(0.6)	15.1	2.5	1.8
Capital Additions	**85.1**	**82.4**	**66.1**	**39.6**	**42.0**	**53.8**	**46.7**	**56.7**	**72.0**	**75.2**

**Minor variances due to rounding*

232. Capital additions in this category vary over time, reflecting changes in capital allocation across competing non-discretionary priorities. Higher investment levels in 2021 and 2022 were facilitated by lower customer growth in those years, while reduced levels in 2024 to 2027 reflect the prioritization of customer growth and AMI-related investments.

233. Forecast increases in 2028 to 2030 reflect a rebalancing of capital to maintain system safety, reliability, and asset condition. Forecast capital additions are primarily based on escalated historical spending levels, supplemented by project-specific estimates where required.

7.6 REBUILDS, REPLACEMENTS, AND LIFE EXTENSIONS

234. This category captures investments required to replace or extend the life of distribution assets based on condition, performance, and risk. These investments are driven by inspection results, asset failures, and technical assessments, and are necessary to maintain safe, reliable, and cost-effective service.

235. The category includes the following core programs:

- **Bulk Lamp Replacements:** Time-based replacement of streetlight bulbs and controls.
- **Pole Management:** Activities to extend pole life, including treatments, stubbing, and targeted replacement based on condition.
- **Urgent Repairs:** Immediate repair or replacement of failed or high-risk assets to restore service or address safety concerns.

- **Cable Management:** Life extension or replacement of underground cable and associated components based on condition, performance history, and failure risk.
- **Apparatus Predictive Replacement:** Refurbishment or replacement of equipment based on testing, condition, and operational thresholds.
- **LED Streetlights:** Replacement and upgrade of streetlighting to LED technology.

236. Deferral of these programs is limited, as it would increase failure risk, safety exposure, and long-term costs.

237. Table 7-4 shows the actual additions for 2021 to 2025 and the forecast capital additions for 2026 to 2030 for the Rebuilds, Replacements and Life Extensions category.

Table 7-4
Rebuilds, Replacements and Life Extensions
Capital Additions
($ millions)

	Actual					Forecast				
	2021	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Capital Expenditures	49.6	53.7	60.0	51.9	49.8	48.5	59.4	61.1	63.5	65.8
CWIP	2.7	(3.3)	0.0	(0.9)	(0.5)	0.8	0.9	0.2	0.2	0.0
Capital Additions	**47.0**	**56.9**	**60.0**	**52.8**	**50.3**	**47.7**	**58.5**	**60.9**	**63.3**	**65.7**

**Minor variances due to rounding*

238. Capital additions in this category are variable because the timing and pace of rebuild, replacement, and life-extension work can be managed to some extent within the PBR funding envelope, provided safety, reliability, compliance, and asset condition risks remain acceptable. Unlike non-discretionary capital work, these programs generally allow FortisAlberta to phase, sequence, or defer lower-risk work where life-extension, maintenance, or targeted mitigation measures can continue to manage the underlying risk. However, it is important to note that this work is not optional over the long term because sustained deferral increases failure risk, safety exposure, and lifecycle costs.

239. The 2026 forecast reflects a temporary reallocation of capital within the available PBR funding envelope to accommodate non-discretionary elevated customer growth and metering expenditures. Forecast capital additions for 2027 to 2030 reflect a return toward more typical levels of condition-

driven investment, informed by escalated historical averages and the need to address ongoing asset replacement requirements.

7.7 METERING

240. The Metering category captures investments required to support accurate billing, load settlement, and customer service through the provision of reliable consumption data. This includes the installation and replacement of revenue metering and the associated systems and communications infrastructure required to collect, validate, and deliver metering data.

241. Expenditures in this category during the 2024 to 2029 period are primarily driven by FortisAlberta's AMI Program. The program is required because FortisAlberta's current Power Line Carrier (PLC) AMI vendor has discontinued the sale of PLC meters and will cease operational support for the PLC System after 2029. As the PLC technology is proprietary, FortisAlberta does not have alternative sources of meter supply, network equipment, or ongoing support for that system. In addition, certain existing PLC meter communication modules are no longer approved for use in Canada and must be removed from service by December 31, 2029. FortisAlberta must therefore replace the existing PLC System in order to continue meeting its metering, billing, and load settlement obligations. The AMI Program includes implementation of the head-end system, deployment of Radio Frequency and cellular AMI meters, associated communication networks, and lifecycle replacement of existing customer meters by the end of 2029. The new AMI System will provide a fully supported, reliable, and secure metering platform and will enable interval-capable metering, improved meter read performance, customer usage information, and future capabilities such as sub-hourly load settlement, evolving rate structures, outage management integration, and distribution system optimization.

242. Table 7-5 shows the actual additions for 2021 to 2025, and the forecast capital additions for 2026 to 2030 for the Metering category.

Table 7-5 Metering Capital Additions ($ millions)										
	Actual					**Forecast**				
	2021	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Capital Expenditures	15.8	7.6	20.5	20.2	43.5	50.2	62.1	61.7	48.1	16.9
CWIP	0.8	0.0	2.4	(4.3)	(0.0)	-	-	-	-	-
Capital Additions	**15.1**	**7.6**	**18.1**	**24.5**	**43.5**	**50.2**	**62.1**	**61.7**	**48.1**	**16.9**

**Minor variances due to rounding*

243. Capital additions over the 2021 to 2025 period reflect the timing and scale of meter replacement activities and the ramp-up of AMI-related investment. Additions are forecast to increase through 2029 as AMI deployment progresses, followed by a decline in 2030 upon program completion. Forecast capital additions are based on current vendor pricing and FortisAlberta's experience with AMI deployment and associated services.

7.8 FORESTRY PROTECTION

244. The Forestry Protection category captures investments required to reduce the occurrence and severity of powerline-caused wildfires and to comply with FortisAlberta's obligations under the Agreement for the Reduction and Prevention of Wildfires in the Forest Protection Area. This category includes the following programs:

- **Previously Trimmed Tree Removal:** Removal of trees near distribution lines to reduce recurring trimming requirements and improve reliability.
- **Forest Protection Area Maintenance:** Vegetation management and right-of-way widening within the Forest Protection Area to maintain compliance with regulatory obligations and reduce wildfire risk.
- **Wildfire Mitigation:** Risk-based investments guided by FortisAlberta's Wildfire Risk Mitigation Plan, including wildfire risk assessment models to inform the identification and prioritization of high-risk fire areas, targeted inspections, system hardening, vegetation management, and operational practices to support public safety and system reliability.

245. Table 7-6 shows the actual additions for 2021 to 2025 and the forecast capital additions for 2026 to 2030 for the Forestry Protection category.

Table 7-6
Forestry Protection
Capital Additions
($ millions)

	Actual					Forecast				
	2021	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Capital Expenditures	7.9	10.0	16.3	20.2	16.0	9.7	18.8	20.9	21.8	22.5
CWIP	0.3	0.2	1.3	(1.7)	0.1	0.3	0.6	0.1	(0.3)	0.1
Capital Additions	**7.6**	**9.9**	**15.0**	**21.9**	**16.0**	**9.5**	**18.2**	**20.8**	**22.0**	**22.5**

**Minor variances due to rounding*

246. Capital additions in the Forestry Protection program from 2021 to 2024 reflect the implementation of several wildfire mitigation projects approved in Proceeding 26615.[12] Lower investment levels in 2025 and 2026 reflect prioritization of customer growth expenditures. Investment is expected to remain relatively stable from 2027 to 2030. The forecasts for Previously Trimmed Tree Removal and Forest Protection Area Maintenance are based on escalated historical averages, while Wildfire Mitigation investment forecasts are developed using a bottom-up approach in 2026 and 2027 and escalated for 2028 to 2030.

7.9 GENERAL SUPPORT

247. The General Support category captures investments required to support FortisAlberta's ongoing operations, including facilities, equipment, tools, and IT systems. These investments enable the safe, reliable, and efficient operation, maintenance, and administration of the distribution system and are largely lifecycle-driven or compliance-related. The category includes the following core programs:

- **Facilities:** Maintenance and improvement of FortisAlberta's distribution and corporate facilities, including offices, shops, storage, and yard space required to support field operations, inventory management, and equipment storage.

[12] Decision 26615-D01-2022 – ATCO Electric Ltd., FortisAlberta Inc. 2023 Cost-of-Service Review, July 28, 2022, PDF p. 63, paras. 260, 262.

- **Tools and Instruments:** Replacement and acquisition of tools and specialized equipment used in construction, operations, and maintenance activities. Many of these assets are subject to mandatory testing and recertification requirements and are therefore non-discretionary.
- **Transportation Equipment:** Replacement and addition of fleet vehicles and specialized equipment required to support field operations. Investment is primarily driven by lifecycle replacement and operational requirements.
- **Information Technology – Hardware and Software:** Lifecycle replacement and enhancement of IT systems that support core business functions, including operational systems, communications infrastructure, cybersecurity, and enterprise applications and are therefore largely non-discretionary.

248. Table 7-7 shows the actual additions for 2021 to 2025 and the forecast capital additions for 2026 to 2030 for the General Support category.

Table 7-7
General Support
Capital Additions
($ millions)

	Actual					Forecast				
	2021	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Capital Expenditures	49.3	89.2	84.2	118.0	96.4	108.0	103.5	111.4	123.7	117.1
CWIP	5.6	(4.2)	10.4	2.6	18.7	(8.3)	(5.2)	7.5	22.5	(37.0)
Capital Additions	**43.7**	**93.4**	**73.8**	**115.4**	**77.7**	**116.3**	**108.7**	**103.9**	**101.2**	**154.1**

**Minor variances due to rounding*

249. Capital additions in this category are variable and reflect the timing of lifecycle replacement cycles, program-specific initiatives, and business requirements. Variability across years is primarily driven by the staging of cyclical replacement programs and the timing of larger projects. Forecasts are developed using a combination of escalated historical averages, lifecycle replacement schedules, and project-specific estimates, depending on the nature of each program.

7.10 SYSTEM PURCHASES

250. The System Purchases category captures investments associated with the transfer of electric distribution systems from third-party owners, including REAs and municipalities, that elect to

discontinue operations. These transfers ensure continued provision of safe and reliable distribution service to affected customers. Transfers proceed where agreed upon by the parties and subject to required regulatory approvals, including AUC approval of service area changes and prudence review for inclusion in rates.

251. Table 7-8 shows the actual additions for 2021 to 2025 and the forecast capital additions for 2026 to 2030 for the System Purchases category.

Table 7-8
System Purchases
Capital Additions
($ millions)

	Actual					Forecast				
	2021	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Capital Expenditures	-	-	-	8.2	-	-	-	-	-	-
CWIP	-	-	-	-	-	-	-	-	-	-
Capital Additions	**-**	**-**	**-**	**8.2**	**-**	**-**	**-**	**-**	**-**	**-**

**Minor variances due to rounding*

252. System Purchases are irregular and driven by third-party decisions and, therefore, cannot be forecast.

7.11 PILOT PROGRAMS - DEMAND SIDE MANAGEMENT

253. The DSM category captures pilot initiatives that influence customer electricity consumption to improve system efficiency, manage peak demand, and optimize use of existing infrastructure. These programs are customer-focused and support evolving distribution system needs.

254. FortisAlberta has implemented limited DSM pilots, including an approved Managed EV Charging Pilot. These initiatives provide insights to inform potential future programs.

255. Table 7-9 shows the actual additions for 2021 to 2025 and the forecast capital additions for 2026 to 2030 for the DSM category.

Table 7-9 Demand Side Management Capital Additions ($ millions)										
	Actual					Forecast				
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Capital Expenditures	-	0.1	0.1	0.0	-	-	-	-	-	-
CWIP	-	0.1	0.1	0.0	0.0	-	-	-	-	-
Capital Additions	**-**	**-**	**0.2**	**0.0**	**0.0**	-	-	-	-	-

**Minor variances due to rounding*

256. DSM expenditures to date have been minimal, reflecting the pilot nature of these initiatives. FortisAlberta is not forecasting any capital additions associated with DSM from 2026 through to 2030.

7.12 RIDER E

257. The Rider E category captures investments associated with the construction of distribution facilities dedicated to serving the specific requirements of an individual customer. These projects are externally driven and initiated at the request of a customer where dedicated infrastructure is required. Under Rider E arrangements, FortisAlberta designs, constructs, owns, and maintains the facilities, with the associated revenue requirement, including capital, operating, maintenance, and related costs, recovered directly from the customer through a Rider E charge. These arrangements are structured so that the costs and associated revenues are fully attributable to the customer and are not borne by other customers.

258. Table 7-10 shows the actual additions for 2021 to 2025 and the forecast capital additions for 2026 to 2030 for the Rider E category.

Table 7-10 Rider E Capital Additions ($ millions)										
	Actual					Forecast				
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Capital Expenditures	0.8	8.2	27.6	12.7	12.0	14.3	14.8	15.4	16.0	16.6
CWIP	0.0	5.0	9.2	(13.8)	0.5	4.0	0.2	0.2	0.2	0.2
Capital Additions	**0.8**	**3.2**	**18.3**	**26.5**	**11.5**	**10.3**	**14.6**	**15.2**	**15.8**	**16.4**

**Minor variances due to rounding*

259. Rider E capital additions are variable and reflect the timing, scope, and volume of customer-initiated projects. Forecast capital expenditures are based on a five-year average of 2021 to 2025 actuals, escalated over the forecast period.

7.13 Z FACTOR

260. FortisAlberta does not forecast Z Factor capital expenditures. Z Factor items are addressed through established regulatory processes as they arise and are not included in base capital forecasts. Accordingly, no Z Factor investments are included in the 2026 to 2030 forecast, as such costs are inherently uncertain, externally driven, and not associated with routine distribution system planning activities.

7.14 D TO T Y FACTOR (OPERATING EXPENSE)

261. Table 7-11 shows the D to T O&M expense historic actuals for 2021 to 2025 and the forecast for 2026 to 2030.

Table 7-11
D to T Y Factor
(Operating Expense)
($ millions)

	Actual					Forecast				
	2021	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Operating Expense	(1.9)	-	(1.0)	(0.0)	0.1	0.8	0.9	35.9	6.5	-

**Minor variances due to rounding*

262. As discussed in Section 7.3, D to T contributions are expensed in the year incurred and flowed through to customers through the Y Factor mechanism. D to T contributions associated with transmission upgrades for a specific distribution customer are billed directly to that customer and are not included in the Y Factor flow-through. FortisAlberta has forecast D to T expenditures and anticipated timing based on the best information currently available, including potential transmission upgrades in the areas discussed in Section 5.2.4.

8. METRICS

8.1 ASSET/SYSTEM UTILIZATION

263. FortisAlberta has provided the asset and system utilization data as requested in the 2026 FortisAlberta DSP Workbook.

264. The Company submits that the asset and system utilization data should be interpreted with caution, as the requested format reflects certain simplifying assumptions that are not representative of FortisAlberta's planning and operating practices. For example, minimum feeder demand values have not been adjusted to account for feeder transfers, outages, or missing data, while only absolute peak values have been adjusted to show peak loading conditions with the system in its normal operating state. Additionally, the various capability values reported in Tab 3 (including asset capability, planning capability, and constrained capability) represent different constructs used for screening and planning purposes and should not be interpreted as uniformly available capacity across all nodes of a feeder and its associated taps. As a result, calculated average loading metrics and average-to-peak ratios may be distorted by off-normal conditions and should not be relied upon in isolation without corroborating engineering analysis.

265. Similarly, the planning capability values presented for POD substations reflect the contracted DTS capacity associated with each location, rather than an independently derived physical capability assessment. DTS represents the maximum transmission capacity made available to serve the distribution system at each POD and is subject to review and approval by the AESO. Accordingly, FortisAlberta, in its role as DFO market participant, cannot and does not assume, or model, transmission system capability beyond the substation and is therefore limited to planning within the bounds of the existing DTS contract.

266. FortisAlberta also notes that system utilization metrics based on aggregate feeder, substation, rate-class, or system-level values should not be interpreted as complete indicators of available distribution system capacity or efficiency. Distribution planning cannot assess capacity constraints in isolation from voltage limits, power quality requirements, feeder configuration, equipment ratings, phase balance, and the location of load along the feeder. Power-flow studies must confirm not only that thermal capacity is available, but also that customers can be served at the meter with acceptable voltage and power quality under applicable planning and operating conditions. This distinction is particularly important for FortisAlberta's predominantly rural and radial distribution system, where long feeder lengths, geographically dispersed customers, and low customer density can create localized constraints that are not apparent from aggregate utilization metrics.

267. The requested indicators are also affected by diversity and aggregation. As individual customer demands are aggregated from the meter level to transformers, feeders, substations, and the overall

system, diversity generally reduces coincident peak demand relative to the sum of non-coincident customer demands. While aggregated metrics may be useful for high-level reporting, they can obscure the localized demand, capacity, voltage, and power quality requirements that drive distribution investment. FortisAlberta must design and operate facilities to meet service obligations at the customer meter, not only at an aggregate feeder or substation level. Accordingly, customer-level demand, localized load characteristics, and kilometres of line required to serve customers across a rural service territory are important considerations in assessing the true use of FortisAlberta's system. Metrics based solely on aggregate demand, energy, customer count, or contracted capacity do not fully reflect the infrastructure required to provide safe, reliable, and adequate electric service.

268. The 11.7 MW[13] planning capability shown in the Feeder Data table should be understood as a planning requirement derived from N-1 reliability requirements at the substation egress, rather than a representation of uniformly available capacity. In practice, FortisAlberta does not apply an arbitrary planning derate to this value; rather, feeder loading is limited based on the rated capability of the underlying equipment, with the nominal 13 MVA operating level preserving an equivalent margin to support contingency transfer conditions (i.e., up to approximately 26 MVA under N-1 conditions as described in Section 6). Any reduction in available capacity relative to this planning level arises from localized system conditions, such as downstream conductor sizing, voltage constraints, or configuration, which must be assessed on a feeder-specific basis consistent with the planning criteria described in Section 5.2.1. Where feeder-level capability exceeds the available POD DTS, overall system capability remains constrained by the DTS value, reflecting potential upstream transmission system limitations that are unknown to FortisAlberta, and outside the Company's direct control. Similarly, the calculated utilization ratios (e.g., peak-to-capability and average-to-peak) included in Tab 3 do not capture feeder-specific constraints, operational flexibility, or contingency transfer requirements, and therefore should not be used in isolation to assess available capacity or system performance.

269. Finally, while percentile-based metrics can provide a high-level screening tool in more homogeneous or meshed systems, their application to a predominantly radial and geographically dispersed network is inherently limited. The distribution system is characterized by non-uniform

[13] 11.7 MW is derived from the 13 MVA planning capability with a 90% power factor applied.

capacity, localized constraints, and variability in data quality, such that percentile statistics do not inherently reflect meaningful utilization or capacity headroom without detailed engineering context. Accordingly, these metrics are best understood as descriptive summaries of the reported dataset rather than definitive indicators of system performance or efficiency. This context, together with the data limitations described above and the fundamental differences between FortisAlberta's system characteristics and those of dense urban utilities, underscores the need to interpret the Commission's requested utilization metrics cautiously and in conjunction with supporting engineering analysis. In addition, certain customer classes within FortisAlberta's service area (e.g. irrigation) exhibit highly seasonal and weather-dependent demand profiles. These loads may result in low average annual utilization factors despite requiring significant system capacity to be designed and available during relatively short peak operating periods. Notwithstanding lower measured utilization over the course of a year, FortisAlberta remains obligated to provide sufficient infrastructure to reliably serve these loads at the time and location they materialize, consistent with its statutory obligation to serve and planning criteria. As a result, lower utilization metrics in these areas should not be interpreted as excess capacity, but rather as a function of load characteristics and service obligations inherent to a geographically dispersed and rural-based system.

270. Consistent with FortisAlberta's planning practices, assessment of system capacity, risk, or investment needs requires supplementary engineering analysis that considers local system configuration, equipment ratings, and planning criteria as outlined in Section 5.2.1.

8.2 TREND ANALYSIS

271. Based on the Commission's notation in the Distribution Plans Data Schedules template, FortisAlberta understands that the Commission will calculate the prescribed trend analysis metrics using the data provided. Accordingly, these calculations have not been reproduced in the 2026 FortisAlberta DSP Workbook. However, FortisAlberta provides the following discussion of the Commission-identified metrics, describing each ratio in terms of its underlying components and discussing the extent to which the numerator and denominator exhibit a meaningful economic or operational relationship. FortisAlberta has included this discussion alongside the data to help ensure that the metrics are interpreted within their proper context(s), such that their true informational content can be understood.

8.2.1 Growth Net Additions / New Customers

272. This metric compares growth-related capital additions to the change in the number of customers within each rate class and appears to be intended to approximate the average capital investment required per incremental customer connection. In the Company's view, this metric will not produce a reliable measure of the average capital cost of connecting a new customer to FortisAlberta's system.

273. The denominator is the simple change in average number of customer sites, not a count of new customer connections. Customer sites are calculated on an average basis and may not align with the timing or magnitude of capital expenditures in a given year. The number of customer sites by rate class is also impacted by rate-class reclassifications, customer buy-downs, and removal of salvaged sites, all of which are unrelated to growth capital additions in the period. For closed rate classes, including Rates 21, 23, 33, and 44, there are no new customers being added and, therefore, the calculated change in sites may be zero, or negative where salvages or rate-class reclassifications have occurred. As a result, the DSP workbook formulas may show reductions rather than additions in customer counts for certain rate classes, generating negative results.

274. The numerator is also affected by the location, load characteristics, and system configuration associated with individual customer connections. Connection costs vary materially based on distance from existing facilities, load size, system configuration, and whether upstream reinforcement is required. As a result, growth capital additions do not vary proportionately with the number of customer sites added. For example, the cost of connecting a residential customer in a low-density or remote area may be materially higher than the cost of connecting a residential customer in a denser urban area where the customer can be interconnected to existing infrastructure.

275. The metric is also affected by project timing. Large growth projects, such as subdivisions or industrial developments, may require upfront infrastructure investment before all customers are energized. This can increase the ratio in one period, when capital additions are recorded before the corresponding customer additions, and reduce the ratio in later periods as customers connect to facilities already constructed.

276. For the same reason, the metric should not be interpreted as a marginal cost measure. The cost of the next connection depends on whether existing distribution facilities have available capacity or

whether the connection triggers the need for a system upgrade investment. In many cases, a single connection can be accommodated at relatively low cost where existing facilities have available capacity. In other cases, a single connection or development may trigger a step change in required facilities, such as a feeder extension, conductor upgrade, voltage regulator, or transformer upgrade.

8.2.2 Non-growth Net Additions / Depreciation

277. This ratio compares non-growth capital additions, such as sustainment and replacement investments, to total depreciation expense. FortisAlberta understands that the AUC may use this metric as a high-level proxy for potential rate pressure. However, the Company considers that the proposed relationship between non-growth capital additions and depreciation expense may create the appearance of an affordability concern where none actually exists. FortisAlberta's view is that the results of this metric are not evidence of over-investment, under-investment, or indicative of whether future customer rates will increase or decrease.

278. Depreciation is the accounting mechanism used to allocate the cost of utility assets over the periods in which those assets are expected to provide service. It appropriately reflects recovery of historical capital investment over estimated useful life, but it does not represent the amount of capital investment required in the same period to sustain, replace, or harden the distribution system. For distribution utilities, depreciation is largely determined using group depreciation methods because distribution assets are numerous, geographically dispersed, and impractical to track solely on an individual asset basis. As a result, depreciation expense reflects the average cost recovery profile of broad asset groups; it does not identify whether specific assets require replacement, life extension, refurbishment, or continued operation in a particular year.

279. The proposed comparison is also problematic because the denominator is total depreciation expense across the full depreciable asset base, not depreciation associated only with non-growth assets or programs. Total depreciation includes depreciation on assets installed for customer growth, system capacity, metering, facilities, fleet, tools, technology, and other capital programs. As a result, the denominator is not a direct measure of cost recovery for the assets reflected in non-growth capital additions.

8.2.3 Revenue-Based Metrics

280. The Commission has prescribed several metrics that use distribution revenue as the numerator and various output or capacity measures as the denominator, including number of customers, energy,

demand, peak demand, and AESO contracted capacity. The primary limitation is that the relationship between the numerator and the denominator is overly complex such that the resulting ratio cannot be easily interpreted.

281. Collectible rate revenues for Alberta's distribution utilities are determined by a ratemaking construct that intentionally delinks them from the costs utilities actually incur to provide service (i.e., invest in and operate utility infrastructure), notwithstanding COS rebasing years. Furthermore, utility revenue generally reflects the full revenue requirement, including O&M costs, income taxes, and regulatory true ups. These components of the revenue requirement cannot be directly attributed to capital investment or to the cost of serving a particular customer, rate class, MWh, MW of demand, or unit of contracted capacity.

282. The denominators used in the prescribed metrics reflect different customer usage, or system requirements, including MWh, peak demand, billing demand, and contracted capacity. These measures may be relevant for planning or operational purposes but, as previously mentioned, they do not have a uniform or direct relationship with collectable distribution revenue. For example, revenue per MWh may increase when delivered energy declines due to weather, customer conservation, DER adoption, or changes in load factor, where the underlying cost to provide distribution service has not declined. Conversely, peak demand or contracted capacity may increase before associated revenues reflect the timing or magnitude of new load.

283. Accordingly, the individual revenue-based metrics may describe mathematical relationships between distribution revenue and selected customer, usage, demand, peak demand, or contracted-capacity measures, but they do not provide a reliable basis for assessing operational efficiency, cost causation, or whether customer growth is self-funding. Customer counts, delivered energy, billing demand, rate-class non-coincident peaks, and AESO contracted capacity each measure different aspects of customer or system activity, and none has a uniform or direct relationship to distribution revenue. Changes in these ratios may therefore reflect rate design, billing determinants, customer mix, load factor, weather, customer conservation, DER adoption, localized growth, contracted capacity changes, or timing differences between infrastructure investment and revenue recognition, rather than changes in efficiency, prudence, or the cost of providing distribution service.

8.3 RELIABILITY

284. FortisAlberta provides five-year rolling SAIDI and SAIFI reliability metrics in accordance with the AUC's data guidelines. These metrics, shown in Table 8-1 below, are calculated using the annual values presented in the Company's historical Rule 002 Reports. The five-year rolling averages smooth the effects of year-to-year variability and provide a longer-term view of reliability performance trends. Consistent with AUC Rule 002, the metrics are presented both with and without major event days.

Table 8-1
Reliability Metrics
(5-Year Rolling Average)

	2021	2022	2023	2024	2025
SAIDI (without major events)	1.77	1.67	1.64	1.61	1.63
SAIDI (with major events)	2.48	1.97	1.99	1.92	1.93
SAIFI (without major events)	1.24	1.16	1.10	1.08	1.08
SAIFI (with major events)	1.44	1.26	1.21	1.18	1.18

285. SAIDI represents the average outage hours per customer experienced during the year, with a targeted service standard of 4.28 or less, excluding major events. SAIFI represents the average number of outages per customer experienced during the year, with a targeted service standard of 2.30 or less, excluding major events.

286. Over the reporting period, the five-year rolling average SAIDI and SAIFI metrics generally improved through 2024, reflecting sustained reliability performance over time. The increase in the five-year rolling averages in 2025 reflects the inclusion of more recent outage experience and demonstrates the influence that significant weather and outage events can have on long-term reliability trends. Notwithstanding year-to-year variability, FortisAlberta's reliability performance has remained well within the applicable AUC Rule 002 service standards throughout the reporting period.

287. As discussed in Section 5.3 of this submission, these metrics, together with WPF indicators, support FortisAlberta's system optimization efforts by enabling targeted identification of underperforming areas, informing prioritization of capital and operational investments, and assessing whether reliability outcomes are being maintained in a cost-effective manner.