Technical Requirements for Connecting to the Alberta Interconnected Electric System (IES) Transmission System

Part 3: Technical Requirements for Connecting Transmission Facilities

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1. Introduction

1.1 *Scope*

This document specifies the general technical requirements for connecting a new (or previously isolated) Transmission Facility[1] to the Alberta Interconnected System (IES)[2] Transmission System[3]. These requirements apply to all transmission facilities which will be directly connected to the IES Transmission System.

This document includes only the technical requirements specific to interconnection of transmission facilities Any contractual, tariff, power pool, auxiliary services, operating agreements or other requirements to complete the interconnection are not in the scope of this document. For information on any commercial or tariff issues, contact the Customer Service Manager, ESBI Alberta Ltd.:

- E-mail: customer-service@eal.ab.ca
- phone: (403) 232-0944

1.2 *Guiding Principles*

The requirements specified in this document are based on the principles set out in the *Electric Utilities Act* (EUA)[4]. The Transmission Administrator advises Transmission Facility Owners to become familiar with this document.

The EUA mandates the Transmission Administrator to create a "level playing field" for all persons seeking to connect any facilities to the IES. The Transmission Administrator's goal is to provide transmission access in the most effective, efficient and economic way possible while still maintaining the safety, reliability, security and integrity of the IES.

The Transmission Administrator shall interconnect facilities to the IES if the facilities satisfy the technical requirements described in this document and other terms outlined in the Transmission Administrator's tariff. The Transmission Administrator will ensure that new transmission facilities do not jeopardize the reliability and security of the IES.

This document specifies the interface between the transmission facilities and the IES, as well as the required information exchange between the facility owner and the Transmission Administrator. This document does not specify the design of equipment within the transmission facility.

1.3 *The Interconnection Process*

The Transmission Facility Owner shall contact the Transmission Administrator's Customer Service Manager to request interconnection:

- E-mail: customer-service@eal.ab.ca
- phone: (403) 232-0944

[1] "Transmission Facility" as defined in the *Electric Utilities Act* (EUA), Statutes of Alberta, 1995, Chapter E-5.5, as amended
[2] "Interconnected Electric System" as defined in the (EUA)
[3] "Transmission System" as defined in the EUA
[4] *Electric Utilities Act*, , S.A. 1995, c.E-5.5.

The Transmission Facility Owner should become informed of the requirements in this document and prepare the specified information to expedite the interconnection process.

1.4 *Definitions of Terms and Acronyms*

For definitions of terms and acronyms not otherwise defined in this document, please refer to the Transmission Administrator Operating Policy (TAOP) OP-01. TAOPs can be reviewed on the Technical Documents page of the Transmission Administrator's internet web site: www.eal.ab.ca.

2. Description of the Proposed Transmission Facility

The Transmission Administrator requires different levels of detailed information throughout the various stages of the proposed project. Five discrete project stages are considered in this document:

1. Preliminary;
2. System Access Application;
3. Construction;
4. Commissioning; and
5. Commercial Operation.

Please Note: The technical information requirements listed in this document are intended to be comprehensive, therefore, not all information will be relevant or necessary for every facility. The Transmission Administrator will work with prospective Transmission Facility Owners to identify the specific information requirements for proposed facilities. Please contact the Transmission Administrator's Customer Service Manager to discuss further:

- **E-mail: customer-service@eal.ab.ca**
- **phone: (403) 232-0944**

2.1 *Preliminary Information.*

Prospective Transmission Facility Owners who wish to have the Transmission Administrator assess possible transmission facility interconnections on a preliminary basis should provide the Transmission Administrator with following information:

- desired point(s) of interconnection to the transmission system;
- type(s) of facilities;
- bus configuration(s); and
- transformer size(s).

2.2 *System Access Application Stage*

At the System Access Application Stage, prospective Transmission Facility Owners applying for System Access Service should provide actual (where known), or best estimate, transmission facility data as listed in Appendix A to the Transmission Administrator. In addition, the prospective Transmission Facility Owner should contact the Customer Service Manager, ESBI Alberta Ltd. to identify any commercial information requirements.

If a Transmission Facility Owner expects to interconnect any generating or load facilities to the IES, the Transmission Facility Owner should refer to the documents *Technical Requirements for*

Interconnecting Generators[5] and *Technical Requirements for Interconnecting Loads*[6], respectively.

2.3 *Construction Stage*

At the Construction Stage, the prospective Transmission Facility Owner should upgrade the information provided in Section 2.2 to reflect the improved level of accuracy based upon more complete design and actual equipment ordered. Transmission facility data requirements are specified in Appendix A. In particular, at this stage the prospective Transmission Facility Owner should provide:

- actual transformer, regulator and breaker nameplate data;
- finalization of protection requirements; and
- planned date to synchronize to grid.

2.4 *Commissioning Stage*

At the Commissioning Stage, the prospective Transmission Facility Owner shall perform on-line tests to verify the estimated parameters provided earlier, and should provide the verified information to the TA to enable final acceptance. In addition, the prospective Transmission Facility Owner should provide the Transmission Administrator with any changes in the project's scope resulting from actual construction.

- adequate visibility to the System Controller;
- actual dates to perform required testing and commissioning of major equipment; and
- preliminary test results from commissioning tests.

2.5 *Commercial Operations – Approved System Access Stage*

After completing the commissioning tests, the Transmission Facility Owner shall provide the Transmission Administrator with final testing, performance and validation reports. Assuming that the results are acceptable to the Transmission Administrator and that the necessary commercial conditions are met, the Transmission Administrator will approve System Access Service and the facility will be able to enter Commercial Operation. After entering Commercial Operation the Transmission Facility Owner should notify the Transmission Administrator of any changes in the technical information pertaining to the facilities.

The Transmission Facility Owner should not unilaterally modify any control equipment parameters (e.g.: protection settings) without the Transmission Administrator's approval.

3. Interconnection Requirements

To be eligible for IES interconnection, a proposed Transmission Facility must comply with the technical requirements outlined below .

[5] *Technical Requirements for Connecting to the Alberta Interconnected Electric System (IES) Transmission System, Part 1: Technical Requirements for Connecting Generators*
[6] *Technical Requirements for Connecting to the Alberta Interconnected Electric System (IES) Transmission System, Part 2: Technical Requirements for Connecting Loads*

The Proposed Transmission Facilities must comply with the requirements of the Canadian Electrical Code Part I and The Alberta Electrical and Communication Utility Code (AECUC).

3.1 *Determination of the Interconnection point*

The Transmission Administrator, , in consultation with the proposed Transmission Facility Owner and with other relevant parties, shall determine the point of interconnection.

In broad terms there are three possibilities, each of which entails different requirements for adequately coordinating interconnection:

1) the Proposed Transmission Facility Owner owns the existing terminal facilities to which the new transmission facility will be connected;
2) the new facility will connect to existing terminal facilities owned by another party; and
3) a new terminal facility must be constructed to connect the new transmission facility to the IES.

3.2 *Line Design Criteria*

New transmission lines should meet the Transmission Administrator's transmission line design standards – see Appendix B.

3.3 *Power Quality*

The Transmission Facility shall comply with the following power quality requirements.

3.3.1 Harmonics

If harmonic distortion emanating from the Transmission Facility affect the power system or other facilities, the Transmission Facility Owner shall take corrective action. The maximum permissible harmonic limits are as defined in IEEE[7] Std 519-1992 *Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems*.

3.3.2 Voltage Unbalance

Any three-phase AC transmission facility shall not increase the phase-to-phase voltage unbalance of the system, as measured with no load and with balanced three-phase loading, by more than 1% at the point of interconnection. Voltage unbalance will be calculated using:

Unbalance (%)= 100 x (deviation from average) / (average)

as derived from NEMA[8] MG1-1993 14.35.

3.4 *Clearances and Access*

Energized parts are to be maintained at safe vertical and horizontal clearances as dictated by the following standards, regulations and code requirements:

- The Alberta Electrical and Communication Utility Code (AECUC); and
- The Canadian Electrical Code Part I.

[7] The Institute of Electrical and Electronics Engineers, Inc.
[8] National Electrical Manufacturers Association

3.5 *Transformer Connections*

The interface transformer connection(s) shall be designed to provide an effectively grounded transmission system at all times.

3.6 *System Protection and Control*

3.6.1 Protection selection process

Protection of transmission systems is a function of many variables. It depends on the role the transmission element is playing, the reliability the transmission system is required to meet and so on. Generally the higher voltage transmission facilities are equipped with faster operating and redundant protection as a reflection of the role they play in the stability of the power and the number of customers that the loss of such an element affects. It is recognized that protection has two key functions: to uphold the reliability of the power system and to avoid or minimize damage to the protected equipment. It is also recognized that the technology of the equipment used to implement protection systems is constantly changing. Given all these considerations, it is not possible to pre-define the protection philosophy and equipment type that is required in each case. However, it is possible to define a process that should be followed to determine what protection philosophy and what specific equipment is required for each particular application. Certain criteria are valid when choosing protection schemes. These are as follows:

- chose a scheme that will adequately protect the subject equipment;
- chose a scheme that will not degrade the reliability of the power system to which it is applied; and
- chose a scheme that will upgrade the reliability of the power system, if that is one of the objectives of the transmission facility being added;

A proposed Transmission Facilities Owner shall follow the process described below when selecting a protection philosophy and scheme for the new transmission facility. The actual choice of relays for the implementation of the protection is the responsibility of the proposed Transmission Facility Owner. The proposed Transmission Facility Owner must demonstrate that it has followed the process and that the selected protection scheme and equipment meet the established requirements. The participants in this process include the proposed Transmission Facility Owner, the owner of the existing transmission facilities (if different) and the Transmission Administrator.

3.6.2 Fault Protections

The Proposed Transmission Facility Owner must provide suitable fault protections to detect and cause proper isolation of all fault current contributions necessary to meet the safety and reliability requirements of the interconnection. A proposed Transmission Facilities Owner must ensure that a single protection system component failure does not jeopardize an interconnected transmission facility’s responsibility to meeting the WSCC Reliability Criteria. As such, suitable redundancy shall be provided in the transmission protection schemes.

High speed relays, high speed circuit breakers and communication aided protection systems should be used where studies indicate that their application will enhance system stability margins.

The protection systems must be coordinated with the neighbouring interconnected systems.

3.6.3 Remedial Action (RAS) or Special Protection Schemes (SPS)

Remedial Action Schemes (RAS), also referred to as Special Protection Schemes (SPS), are control systems that make automatic adjustments or corrections to the power system without Operator intervention. These schemes are usually implemented to alleviate facility overloads or other potential system problems in response to certain operating conditions within a specific time frame. Examples of RAS schemes are underfrequency or undervoltage tie line, load or generator tripping schemes.

Proposed RAS schemes shall be coordinated with other protection and control schemes identified by the Transmission Administrator or other Transmission Facility Owners.

The dependability, security, selectivity and soundness of the RAS schemes should be consistent with other fault type protection schemes. The testing, monitoring and maintenance of these schemes should likewise be similar.

3.6.4 Automatic Control

Automatic transmission line reclosing should be applied where studies indicate that system requires this feature. Single pole tripping and reclosing may be appropriate in certain cases to deliver the needed system stability.

Automatic reclosing during out-of-step swing conditions should be avoided.

The need for synchronism check or synchronizing control of circuit breakers will be determined on a case by case basis

The above parameters are all determined as part of the overall protection scheme selection process.

3.6.5 Transmission Control Devices

Certain transmission devices that provide dynamic control are usually employed as solutions to specific system performance problems or shortcomings. Such devices include phase shifting transformers, HVDC links, unified power flow controllers (UPFCs), static VAr compensators (SVCs), or thyristor controlled series capacitors (TCSCs). The Transmission Administrator will identify the need for such devices.

3.7 *Interchange Metering*

The need for interchange metering will be determined by the Transmission Administrator in conformity with the EUA and the Transmission Administrator’s Tariff.

Included in the metering equipment are the instrument transformers (voltage transformers, current transformers), secondary wiring, test switches, meters and communication interface. Unless otherwise agreed to by the Transmission Administrator, the Transmission Facility Owner shall dedicate separate instrument transformers s to metering purposes only.

3.8 *Supervisory Control and Indication*

The Transmission Administrator will specify the data control and indication requirements of a proposed Transmission facility. These requirements will be determined by a transmission facility’s location , its function and the extent to which the Transmission Facility Owner wishes the System Controller to control the transmission equipment.

A Transmission Facility Owner interconnecting to the IES must equip its facility for supervisory indication. The Transmission Administrator requires supervisory indication capacity to satisfy requirements outlined in WSCC operating policies and to maintain a proper level of system visibility for overall network security. The Transmission Facility Owner shall provide, as a minimum, a Remote Terminal Unit (RTU), capable of exchanging the following supervisory control and data acquisition (SCADA) information with the System Controller:

- Breaker(s) status;
- Status of isolation device(s);
- Line MW and MVAr flows including direction;
- Transformer MW and MVAr including direction;
- Bus Voltages;
- Status of rotating and static reactive sources;
- Operational status of protective relay and remedial action schemes; and
- The tap position of any on load tap changing (LTC) transformer in service connected to the transmission voltage bus(ses).

Transmission Facilities offering other support services require additional SCADA capability.

3.9 *Metering and Telemetry*

The Proposed Transmission Facility Owner shall use metering of a suitable range, accuracy and sampling rate (if applicable) to ensure accurate and timely monitoring of operating conditions under normal and emergency conditions.

3.10 *Disturbance Recording*

To aid in post-disturbance analysis, automatic disturbance oscillographs and event recorders shall be installed at key locations throughout the IES and synchronized to standard time. The Transmission Administrator shall determine the key locations.

3.11 *Communications*

The Transmission Facility Owner shall provide dependable communication channels to handle voice, telemetry, protection and control requirements. Furthermore, the Transmission Facilities Owner shall provide backup channels for critical circuits.

The Transmission Facility owner shall also provide automated channel monitoring and failure alarms for those protective system communications that, if faulty, could cause loss of generation, loss of load or cascading outages.

4. Technical Issues Requiring Commercial Arrangements

Transmission Facility Owners capable of, and interested in, providing or receiving services beyond the minimum requirements in the previous section should contact the Transmission Administrator's Customer Service Manager:

- E-mail: customer-service@eal.ab.ca
- phone: (403) 232-0944

5. Responsibility of the Transmission Administrator

The Transmission Administrator is responsible for overall planning of the IES and is accountable to ensure that all additions to transmission rate base are prudent. The Transmission Administrator maintains a technical database for all IES facilities. The database is publicly available on the TA's website at www.eal.ab.ca. The Transmission Administrator will provide to the proposed Transmission Facility Owner any other specific information as required and appropriate to enable interconnection of the proposed facilities.

5.1 *Contact Organizations*

The Transmission Administrator shall provide the name and telephone number of contact persons at the Transmission Administrator's office, the Alberta Energy and Utilities Board (AEUB), the Power Pool of Alberta and the System Controller.

5.2 *Technical Information*

The Transmission Administrator conducts the planning studies required to assess the security of the IES and to plan for future additions of equipment and services in light of IES security requirements. The Transmission Administrator may choose to make the results of studies available to the Transmission Facility Owner to help establish interconnection parameters, such as voltage level selection, voltage regulation requirements, short circuit capacity impacts, stabilizer parameter determination, participation in special RAS's, and so on.

As they occur, the Transmission Administrator shall provide the Transmission Facility Owner with information relative to any changes in system operating standards and procedures that may affect the operation of the Transmission Facility Owner's facilities.

5.3 *Acceptance of the Interconnection*

The Transmission Administrator shall review and may, at its sole discretion, choose to accept the interconnection of facilities that meet its requirements. The Transmission Administrator shall witness any interconnection commissioning test the Transmission Administrator deems necessary and shall keep copies of all interconnection commissioning test results.

5.4 *Agreements*

The Transmission Administrator shall implement the relevant interconnection tariffs, and shall support the Transmission Facility Owner in obtaining any operating agreements required to permit interconnection.

6. Responsibility of Existing and Proposed Transmission Facility Owners

The interconnection of new transmission facilities may require modification of systems and equipment owned by other Transmission Facility Owners. Commercial terms to cover the costs of such modifications will be determined by the Transmission Administrator in accordance with the

Transmission Administrator's Tariff. For more information regarding commercial terms contact the Transmission Administrator's Customer Service Manager:

- E-mail: customer-service@eal.ab.ca
- phone: (403) 232-0944

6.1 *Technical Information*

The proposed Transmission Facility Owner will be responsible for determining the rating (current, real and reactive power, fault throughput, etc.) of all equipment included in the proposed transmission facility. The proposed Transmission Facility Owner shall provide the Transmission Administrator with facility ratings applicable for both normal and emergency operation as required both for real-time system operation and for the modeling of the facilities in transmission studies. The proposed Transmission Facility Owner shall define the standards, practices and assumptions used to establish the proposed equipment ratings. Thermal, short and long term loading and voltage limits should be identified along with seasonal (temperature) characteristics.

6.2 *Operating Authority*

Overall responsibility for ensuring the security and reliability of the IES rests with the Transmission Administrator pre-real time and with the System Controller in real-time. The System Controller will issue dispatch instructions to Transmission Facility Owners based upon real-time requirements in accordance with the Transmission Administrator's Operation Policies and Operational Plans.

In the interest of personnel and equipment safety, each Transmission Facility Owner has final operating authority over their own facilities. Transmission Facility Owners shall follow the System Controller's dispatch instructions except where such instructions pose a threat to the safety of personnel, the public or equipment. For common control or isolation points the affected Transmission Facilities Owners shall jointly agree on an appropriate operating procedure and shall provide this procedure to the Transmission Administrator.

The proposed Transmission Facility Owner shall designate a contact person and provide the Transmission Administrator, the System Controller and the owner of any interconnected transmission facilities the contact person's name and telephone number, for the purposes of operational communication.

Appendix A: Transmission Facility Data

The proposed Transmission Facility Owner shall submit to the Transmission Administrator the following information, as applicable, at a level of accuracy appropriate to the present project stage:

I. Contact names, mailing addresses, phone and fax numbers, e-mail addresses for:
   A. commercial terms;
   B. engineering design; and
   C. operating terms.

II. Siting Information:
   A. detailed map showing the proposed location of the new facilities;
   B. single line (one line) diagrams of each substation;
   C. site plan(s) showing the arrangement of the major equipment at each substation; and
   D. diagram showing the voltage and current rating of each major component.

III. Functional Specification:
   A. description the intended function of the proposed facilities, to an appropriate level of detail for the project stage;
   B. site plan(s) showing the arrangement of the major equipment at each terminal; and
   C. diagram showing the voltage and current rating of each major component.

IV. Interconnection Protection:
   A. complete and accurate protection diagrams;
   B. a description of the proposed protection schemes; and
   C. maintenance plans for the interconnection protective devices and interconnection interrupting devices.

V. Transformers:
   A. MVA base rating;
   B. fan rating, cooling type;
   C. high voltage - nominal voltage, connection;
   D. low voltage - nominal voltage, connection;
   E. tapchanger - on-load or off-load, tap chart; and
   F. ratio and accuracy class of instrument transformers. If multi-ratio, state the available ratios and the proposed ratio.

VI. Voltage Regulators:
   A. MVA base rating;
   B. voltage rating;
   C. voltage setting range;
   D. voltage setting tolerance; and
   E. control information.

VII. Reactive Power Devices: shunt and series capacitors, reactors, synchronous condensors and static compensation systems:
   A. control information, include control block diagrams;
   B. nominal MVAr range;
   C. impedance (60 Hz base);
   D. percent compensation (for series devices);
   E. voltage ratings and ranges;
   F. switching step size, if non-continuous;
   G. switching equipment; and

H. electromagnetic transient control schemes (zero crossing breakers, pre-insertion reactors, etc.).

VIII. AC Transmission Lines:

A. nominal voltage;
B. line length;
C. arrangement (underground /overhead, single / multiple circuit);
D. structure type (lattice, tubular steel, wood, single or double pole);
E. conductor configuration (vertical, horizontal, delta, bundling, dimensions, composition);
F. meteorological and construction mechanical loading design parameters;
G. self and mutual impedances;
H. surge impedance;
I. line charging; and
J. nominal and emergency ratings.

IX. DC (Direct Current) Transmission Lines:

A. nominal voltage;
B. line length;
C. structure type;
D. conductor configuration (vertical, horizontal, delta, bundling, dimensions, composition);
E. meteorological and construction mechanical loading design parameters; and
F. nominal and emergency ratings.

X. HVDC Links:

A. nominal voltage;
B. nominal and emergency power ratings;
C. control information, include control block diagrams; and
D. harmonic filter specifications.

Appendix B: Transmission Line Design Criteria

Reliability Based Design Method

The design criteria set out in this document use a reliability-based approach which recognizes the statistical variations of both loading and strength and provides a consistent and logical way of relating loads and strengths. The approach set out here also recognizes that a transmission line is a system of interconnected components. Hence, the overall performance and reliability depends not only on the strength of a given component, but on the relative strength of key components in the system. The concept of sequence of failure is very important and is addressed in this document.

The reliability based approach provides a way of designing lines for consistent levels of reliability even though the lines may be of different design and be located in different parts of the province. Also, it is relatively easy to increase or decrease the relative reliability of a given line by increasing or decreasing the return period of the design weather loadings.

The design approach set out here recognizes that transmission lines must be designed to withstand loadings other than those associated with weather. These are failure containment, or security loadings and construction and maintenance loadings. These loadings are deterministic in nature and the requirements for them are set out in this document.

The basic load and strength equation, which applies to any of the loadings in this docummnent, is:

γ x effect of loads Q $\leq$ ϕ x strength R_c

where : γ = load factor (taken as 1.0, except for construction and maintenance loads)
Q = loads (dead loads, weather loads, failure containment loads, construction loads, etc.)
ϕ = strength factor, as set out in this document
R_c = characteristic strength of the component. This is the value guaranteed in standards, also called the minimum strength or nominal strength. It is a value that has a high probability of being met. It is not the average strength.

The equation given above is the basis of numerous design standards and practices for steel and wood structures. In recent years, several Canadian and international standards groups have set out proposals for transmission line design based on this methodology.

The implementation set out here is simpler than those proposed elsewhere, but retains the key features and advantages of the approach.

Loadings

Transmission lines shall be designed to withstand loadings of the following four types: dead loads, live loads, failure containment (or security) loads and safety (construction and maintenance) loads.

Provincial Code (Legal) Requirements

In Alberta there is a legal requirement that all electrical power lines be designed to meet the requirements of The Alberta Electrical and Communication Utility Code (AECUC). These requirements are intended primarily to ensure the safety of the general public, as compared to providing for the reliability or security of the line itself. All transmission lines shall be designed to meet the requirements of the AECUC.

Dead Loads

Dead loads are the weight of bare wires, hardware, insulators and supporting structures. Since the magnitude of dead loads can be determined with reasonable certainty, dead loads are treated as deterministic in nature i.e. they are given a single constant value, for a given structure and configuration. The load factor for dead loads shall be taken as 1.0.

Live Loads, or Weather Loadings

Live loads are random loads caused by ice and wind, acting separately or in combination. These loads are to be treated in a statistical manner. When data are available for annual extreme values of wind and/or ice, it is generally accepted that Gumbel extreme value analysis should be used to obtain the loading value corresponding to a given return period. Line reliability is changed by using different return periods for design weather loadings. Using loadings with higher return periods will result in higher reliability, although there is no clear analytical relationship between return period and reliability. The load factor for live loads shall be taken as 1.0.

A 50 year return period shall be used for wind loadings, unless approval is obtained for use of a different value. This wind loading shall be assumed to occur at the mean annual temperature for the general area where the line is being constructed. Appropriate corrections shall be made to adjust the basic wind velocity for the height of the average height of conductors and structures above ground. Wind loading on structures shall take into account the shape of the structural elements (round, flat, etc.). The formulae and methods used for calculation of wind loading shall be obtained from industry recognized sources such as the Canadian Standards Association (CSA), International Electrotechnical Commission (IEC), etc. and shall apply specifically to the design of power transmission lines.

Statistical data for ice loadings may not be readily available. Appropriate design values can be obtained by use of ice modeling computer programs or based on the long term operating experience of the utility. In southern Alberta, wet snow is likely to cause much higher design loadings than glaze ice, and hence is to be used for design purposes in that part of the province. Hoar frost may also constitute a significant loading and should be taken into account in those areas subject to this type of loading. The 50 year return values (calculated or assumed) of ice or wet snow loadings shall be applied as vertical loadings acting without wind. Density values for the ice, wet snow or hoar frost shall be based on published information, or measurements made by the utility over a period of time and for the specific type of deposit. The basis of determination of the 50 year return loading shall be documented by the utility.

Combined ice and wind loadings shall be determined by combining the 50 year return ice (or wet snow) value with a wind loading value equal to 40% of the 50 year return wind loading. Density values for the ice or wet snow shall be determined as indicated above.

The temperature assumed for calculation of conductor tensions, for ice alone or combined ice and wind, shall be -10°C.

Failure Containment Loadings (Security Loadings)

The purpose of failure containment loadings is to ensure that a failure initiated by a single component or structure does not progress far beyond the location of the initial failure. In general, this type of failure takes the form of a longitudinal cascade, where structures fail like dominoes until the failure reaches a deadend tower or other “strong point” in the line. Failure containment loadings are deterministic in nature. The load factor (γ) for failure containment loadings shall be 1.0.

Transmission lines shall be designed with failure containment capability utilizing one of the following two methods:

1.) Each structure shall be designed to withstand a torsional load equal to the residual static load (RSL) caused by the release of tension of a whole phase or overhead ground wire in an adjacent span. The loading conditions shall be taken as 0°C, without any ice or wind. The RSL for suspension structures should be calculated for average spans, taking into account the reduction of load resulting from insulator swing, structure deflection and interaction with other phases or wires.

2.) Use of anti-cascading structures. This is achieved by the insertion at a given interval (typically every 5 km to 10 km) of strong structures called anti-cascading structures. Each structure is typically designed to withstand loads due to the tension release of all conductors under ice or wind conditions. The wind condition would be the 50 yr return wind and the ice condition would be the 50 yr return ice loading, as described previously. Conventional heavy angle or deadend structures often meet these requirements.

Construction and Maintenance Loadings (Safety Loadings)

These loadings are intended to ensure the safety of personnel during construction and maintenance operations. The magnitude of these loads, and the applied overload factors, are set so as to provide a reasonable safety margin relative to failure. The loads are considered constant and are treated in a deterministic manner. There is no requirement to apply ice or wind to the safety loadings, since it is reasonable to assume that the operations included here are not normally conducted during storm conditions.

Provision shall be made for the following construction and maintenance activities, with loadings and overload factors as indicated:

Structure erection – the strength of all lifting points and related components shall withstand at least twice the static loads produced by the proposed erection method i.e. load factor (γ) = 2.0. Where the erection operations are under the direct supervision of an engineer, the load factor may be reduced to 1.5.

Conductor stringing and sagging – structures shall be designed to withstand wire tensions equal to 1.5 times the sagging tension or 2.0 times the stringing (pulling) tension. Tensions shall be calculated at the minimum temperatures likely to be encountered during the stringing and sagging operations for the line. Care shall also be taken to ensure that the tension increase due to conductor overpull for deadending, particularly in short spans between deadend structures, is taken into account. Conductor tie down locations shall be located sufficiently far from tangent structures so as to maintain a load factor (γ) of at least 2.0 for vertical loading.

Maintenance – all wire attachment points shall be able to support at least twice the bare vertical weight of wire on the structure at sagging tensions. Any temporary lifting or deadending points located near permanent wire attachment points shall be able to resist at least twice the bare wire loads at sagging tensions. All structural members that may be required to support a worker shall be designed for a load of 1500 N applied vertically at the center of the member, in addition to the stresses imposed by external bare wire loadings.

Strength

Two items need to be considered in determining the strength of transmission line components. The first is the actual strength of a given component, and its statistical variation. The second is the coordination of strength between the various components within the transmission line system, so as to achieve (as far as reasonably possible) a desired sequence of failure.

Coordination of Strength of Components (Sequence of Failure)

Transmission lines shall be designed with a given sequence of failure in order to minimize, or contain, the damage due to failure of a single component or structure. The following criteria are recommended for establishing a failure sequence:

1) The first component to fail should introduce the least secondary load effect (dynamic or static) on other components, in order to minimize cascading failure.
2) Repair time and costs following a failure should be kept to a minimum.
3) A low cost component in series with a high cost component should be at least as strong and reliable as the high cost component, in particular when the consequences of failure are high.

Application of the above criteria leads to the following preferred failure sequence:

1) Tangent towers
2) Tangent tower foundations and hardware
3) Angle and deadend towers
4) Angle and deadend tower foundations
5) Conductor

Strength of components is coordinated, or adjusted by means of strength factors, so as to achieve the desired failure sequence as indicated in the following paragraphs.

Determination of Characteristic Strength (R_c)

The value of R_c for insulators, hardware and conductors can be obtained from standards or manufacturers' published data. For lattice and tubular steel structures, R_c can be taken as the value obtained from the design formulae. For other components, where the given strength data is the average value or where the statistical strength variation information is provided, the characteristic strength can be determined using the following equations:

$$COV = \sigma_R / R_m$$

$$R_c = R_m (1 - k \times COV)$$

where COV = coefficient of variation of component strength
σ_R = standard deviation of the strength

R_m = mean strength
R_c = characteristic strength
k = statistical factor (=1.28 for normal distributions)

Strength Factor (ϕ)

The strength factor is applied to the characteristic strength to achieve the desired sequence of failure (ϕ_s), or to account for the situation where a significant number of the same component, e.g. structures, are subjected to the maximum load intensity (ϕ_n). One or both of these strength factors may be applied, as required. The value of ϕ_s for the first component to fail shall be 1.0. The value of ϕ_s for the second component to fail (assuming it is an angle structure) is 0.9 and for the third component to fail $\phi_s = 0.8$.

A values of $\phi_n = 1.0$ shall be used for transmission line structures, for the three weather loading cases (high wind, ice alone, and combined ice and wind). This takes into account the fact that structures are generally not loaded to the maximum design values. This fact is assumed to offset the situation where several structures see the maximum value of load at the same time.

Strength factors shall not be applied to the characteristic strength for failure containment loads or for construction and maintenance loads.

Design of Line Components

The basic design equation for reliability based design is:

$$\gamma \text{ x effect of loads } Q \leq \phi \text{ x strength } R_c$$

The following equations show how this basic design equation is applied to specific line components.

Structures: $R_c \geq \dfrac{\text{Structure design loads}}{\phi_s \, \phi_n}$

For typical tangent structures (wood or steel), $\phi_s = 1$, and for angle and deadend structures, $\phi_s = 0.9$. For all structures, $\phi_n = 1.0$. For single pole wood structures, the effect of deflection (P-delta) shall be taken into account.

Foundations: $R_c \geq$ Foundation design loads

$\phi_s \; \phi_n$

For foundations designed with the accepted factors of safety for soil parameters, $\phi_s = 0.9$ for tangent structures and $\phi_s = 0.8$ for angle and deadend structures. The value of ϕ_n can be taken as 0.9, for all foundations.

Conductors and ground wires: $\phi s = \phi n = 1.0$ and maximum conductor tension shall not exceed R_c

Insulators and hardware: The design equation is the same as for structures. $\phi s = 0.9$ for all hardware and 1.0 for insulators. Use a value of $\phi n = 1.0$

Electrical Clearances

Transmission lines shall be designed with electrical clearances in accordance with the requirements of The Alberta Electrical and Communication Utility Code (AECUC).

In addition to meeting the AECUC requirements, the following criteria for clearance between structures and energized conductors shall be met:

1.) For the high wind design loading, the minimum distance between the energized swung conductors and any part of a structure shall be the 60 Hz air gap required for a voltage equal to the nominal line to ground voltage of the line. Conductor shall be assumed to be at final sag, with no ice and at a temperature of 4° C.

2.) For a one year return period wind, the minimum clearance between the energized swung conductors and the structure shall be the air gap required for the switching surge voltage of the line. Conductor shall be assumed to be at final sag, with no ice and at a temperature of 4° C.

Galloping Requirements

In those parts of Alberta subject to wet snow, consideration shall be given to the electrical clearances required between wires (phase conductors and overhead shieldwires) to allow for galloping conditions. This consideration is of particular importance on lines having vertical (or offset vertical) phase configurations. High reliability lines with the above configuration, and in particular if they are of double circuit construction, should have provision for galloping clearances.

For design purposes, the galloping condition can be taken as 12 mm of radial wet snow and 150 Pa wind at 0°C and with final condition wire sags. The path of the galloping wires shall be assumed to be elliptical, with a major axis equal to 1.2 times the conductor sag and a minor axis equal to 0.4 times the major axis. The major axis of the galloping ellipse shall be assumed to be vertical. The electrical clearance between ellipses shall be the 60 Hz flashover value, either phase to phase or phase to ground, depending upon which two ellipses are being compared.

Differential Ice Loading

Differential ice loading provides for the situation where an overhead shieldwire or the higher voltage circuit of a line with underbuild has ice and the other wires are bare. The requirement is as follows:

1.) Overhead shieldwire with 12 mm radial ice (assume 0.9 density) at -20°C and phase conductors unloaded at -20°C, or

2.) Top circuit with 12 mm radial ice (assume 0.9 density) at -20°C and bottom circuit unloaded at -20°C.

The clearances required are the switching surge air gap values.

Radio Interference

Transmission lines shall be designed to meet the requirements for radio noise as set out in the Radiocommunication Act R.S.C. 1985, c. R-2, s.1 with limits measured in accordance with CSA Standard C108.3.1 Limits and Measurement Methods of Electromagnetic Noise from AC Power Systems, 0.15 - 30 MHz.

In order to ensure that transmission lines do not operate in a condition of positive corona, it is recommended that conductor surface voltage gradients meet the limits shown in Figure 1.

Table 1 - Weather Loadings (Reliability Loadings)

Loading Case	Description	Return Period	Load Factor
Dead Load	Weight of bare wires, insulators, hardware and supporting structures. Applied to all weather loading cases. Deterministic in nature.	N/A	1.0
Wind loading	Gust wind loading on wires, structures and other line components. Temperature is mean annual temperature for area where line is to be constructed. Adjust wind velocity for height of structures and wires.	50 yr	1.0
Ice alone	Ice, wet snow or hoar frost loading (choose loading that governs for a given location). No wind. Density based on type of deposit. Temperature -10°C.	50 yr	1.0

Combined ice and wind	Combine 50 yr return value from "ice alone" loading with wind loading equal to 40% of the 50 yr return value of the "wind loading". Both loadings as described above. Temperature -10°C.	As noted	1.0

Table 2 - Failure Containment Loading (Security Loading)
Requirement is Loading A or B

Loading Case	**Description**	**Load Factor**
A)Torsional Load	Each structure designed for torsional load equal to residual static load (RSL) caused by tension release of any one whole phase or any one overhead ground wire in adjacent span. Temperature 0°C with no wind or ice.	1.0
B) Anti - Cascade Structures	Insertion at given intervals (typically every 5 to 10 km) of strong structures designed to withstand loads due to tension release of all conductors under ice or wind conditions. The wind condition would be the 50 yr return wind and the ice condition would be the 50 yr return ice loading, both as described in Table 1.	1.0

Table 3 - Construction and Maintenance Loadings (Safety Loadings)

Loading Case	**Description**	**Load Factor**
Structure erection	Design of all lifting points and related components.	2.0
Conductor stringing and sagging	Design structures to withstand wire tensions = 1.5 x sagging tension or 2.0 times stringing (pulling) tension, whichever governs. Tensions calculated at minimum temperatures expected during stringing and sagging operations for the line. Include effects of conductor overpull during sagging. Vertical loading due to conductor tie downs	As indicated 2.0
Maintenance	All wire attachment points are able to support at least twice the bare vertical weight of wire on the structure at sagging tensions. In addition to the above, all structural members that may be required to support a worker shall be designed for a load of 1500 N applied vertically at the center of the member.	As indicated

Table 4 - Typical Strength Coordination or Sequence of Failure

		Coordination Within Component

	Major Component	Category
To fail first	Tangent tower	<u>Tower</u>, foundation, hardware
Not to fail first (with 90% confidence) of any of these major components	Angle tower	<u>Tower</u>, foundation, hardware
	Deadend tower	<u>Tower</u>, foundation, hardware
	Conductor	<u>Conductor</u>, insulator, hardware

Note: Within each major component category, the underlined component is the weakest.

Table 5 - Typical Values for Coefficients of Variation

Component	COV (%)
Conductors, phase and ground wires	3
Hardware	5
Insulators	5
Steel Poles	5
Concrete Poles	15
Wood Poles	20
Lattice Towers	10
Pile Foundation	25
Foundation with Uncompacted Backfill	30

Table 6 - Strength Characteristics of Wood Utility Poles

Species	MOR (psi)	S_1 (psi)	R_c (psi)
Cedar, Western Red	5555	1054	4206
Fir, Coast Douglas	8175	1020	6869
Fir, Interior Douglas	6834	1038	5505
Pine, Lodgepole, Canada	6553	842	5475
Pine, Lodgepole, US	5000	782	3999
Pine, Southern Yellow	7820	1900	5388

Notes: Data from CSA Standard CAN/CSA-O15-90 Wood Utility Poles and Reinforcing Stubs.
MOR - average modulus of rupture or maximum breaking stress in psi
S_1 - standard deviation of the modulus of rupture found in the sample
R_c - Characteristic strength, psi

Table 7 - Strength Factors

Description	Value
Strength factor for sequence of failure (ϕ_s):	

- tangent structures	1.0
- angle & deadend structures	0.9
- tangent structure foundations	0.9
- angle and deadend structure foundations	0.8
- conductors & ground wires	1.0
- insulators	1.0
- hardware	0.9
Strength factor for number of components subject to maximum load intensity (ϕ_n):	
- structures (wood or steel)	1.0
- foundations	0.9
- conductors & ground wires	1.0
- insulators & hardware	1.0

Appendix C: Revision History

Revision Number	Revision Date	Comment
1.0	1999/12/02	Part 3 of the interconnection document revised to reflect changes in regulations. The Alberta Communications and Utilities Safety Regulation (ECUSR) was rescinded on 1999/11/01, and superceded by The Alberta Electrical and Communication Utility Code (AECUC).