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

Part 1: Technical Requirements for Connecting Generators

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1. Introduction

1.1. Scope

This document specifies the general technical requirements for connecting (or upgrading) a new (or previously isolated) generating facility to Alberta's Interconnected Electric System (IES)[1] and Transmission System[2], either directly, or indirectly through interconnected onsite or distribution facilities.

This document includes only the technical requirements specific to interconnection of generating 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 adhere to the principles set out in the *Electric Utilities Act* (EUA)[3]. Generating Facility Owners are advised to become familiar with the EUA.

The EUA mandates the Transmission Administrator to create a "level playing field" for all eligible persons[4] seeking to connect facilities to the IES. The Transmission Administrator's goal is to provide effective, efficient and economic transmission access while maintaining the safety, reliability, security and integrity of the IES.

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

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

The intent of these technical requirements is to ensure that:

- the generator and AIES operate safely and reliably during system conditions ranging from normal to stressed, to emergency;
- system voltage and frequency is maintained within acceptable limits; and
- generators are dispatched and operated within the physical limits of their capability.

[1] "Interconnected Electric System" as defined in the *Electric Utilities Act,*, S.A., 1995, c. E-5.5, s. 1(1)(p)
[2] "Transmission System" as defined in the *Electric Utilities Act,*, S.A., 1995, c. E-5.5, s. 1(1)(ee)
[3] *Electric Utilities Act*, S.A. 1995, c.E-5.5
[4] "Eligible Person" as defined in s.1(1)(b) of the EUA.

1.3. The Interconnection Process

The Generating 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

The Generating Facility Owner should inform itself of the requirements in this document and prepare the appropriate information as outlined in Section 2 below, 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 TA's internet web site: www.eal.ab.ca.

2. Description of the Generating Facility

The Transmission Administrator requires different detail levels of information throughout the various stages of the. 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 requested information will be relevant or necessary for every facility. The Transmission Administrator will work with prospective Generating Facility Owners to identify the specific information requirements for the 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 Stage

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

- proposed location(s);
- initial and ultimate installed generation megawatt capacity;
- individual generating unit sizes;
- the type of each generator at the facility, (induction, synchronous or other); and
- on site load type and megawatt capacity.

2.2. System Access Application Stage

At the System Access Application Stage, prospective Generating Facility Owners applying for System Access Service should provide actual (if known), or best estimate, interconnection information (Appendix A) and analytical modeling information (Appendix B) to the Transmission Administrator.[5] In addition, the prospective Generating Facility Owner should contact the Customer Service Manager, ESBI Alberta Ltd. to identify any commercial information requirements.

2.3. Construction Stage

At the Construction Stage, the prospective Generating Facility Owner should upgrade the information provided in Section 2.2 to reflect an improved level of accuracy based upon more complete design and actual equipment ordered. Interconnection information is specified in Appendix A and analytical modeling information is specified in Appendix B. In particular, at this stage the prospective Generating Facility Owner should provide:

- finalization of generator, excitation, AVR, PSS, protection requirements;
- final AVR tuning requirements;
- final PSS parameter requirements;
- generator reactive capability;
- generator excitation limiter settings;
  - Under excitation limiter-
  - Over excitation limiter-
  - Volts Hertz Limiter-
- planned date to synchronize to grid;
- planned dates to perform;
  - load rejection tests-
  - VAr rejection tests-
  - reactive capability tests-
  - AVR tests-
  - PSS tests-
- coordination of limiters and protection.

2.4. Commissioning Stage

At the Commissioning Stage, the prospective Generating 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 Generating Facility Owner should provide changes in project scope resulting from actual construction. Specifically, at this stage the Generating Facility Owner should provide:

- adequate visibility to the System Controller;
- actual dates to perform testing and commissioning of generator facilities, including;
  - AVR / PSS commissioning-
  - generator / system protection commissioning-

[5] If the site will include significant loads, the information specified in *Technical Requirements for Connecting to the Alberta Interconnected Electric System (IES) Transmission System, Part 2: Technical Requirements for Connecting Loads* should be provided as well.

- preliminary test results from commissioning tests.

2.5. Commercial Operations – Approved System Access Stage

After completing the commissioning tests, the Generating 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 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 Generating Facility Owner should notify the Transmission Administrator of any changes in the technical information pertaining to the facilities.

Specifically, the Generating Facility Owner should not unilaterally modify any control equipment parameters (e.g.: Governor, AVR, PSS, Limiter or protection settings) without the Transmission Administrator's approval. If settings must be modified to prevent equipment damage before the Generating Facility Owner can notify the Transmission Administrator, then the Generating Facility Owner must notify the Transmission Administrator at the first possible opportunity. The Transmission Administrator may choose to audit any unapproved changes to determine the urgency of change, and the Generating Facility Owner may be liable for any negative consequences imposed upon the system by the unapproved setting changes.

Every 5 years the generating facility model data must be re-validated in accordance with WSCC requirements.

3. System Conditions at the Point of Interconnection

At the point of interconnection, the Generating Facility Owner can expect the following typical system operating conditions.

3.1. Voltage Level and Voltage Range

Typical operating voltages on the IES vary within ± 10% of nominal voltage level. The voltage range at certain locations can be greater, especially during abnormal or emergency conditions.

3.2. Frequency and Frequency Range

The Alberta Interconnected Electric System operates nominally at 60 Hertz (Hz) Alternating Current (AC).

The expected frequency range on the IES is:

- 59.95 Hz to 60.05 Hz under normal system conditions,
- 59.7 Hz to 60.2 Hz for small system events (occasional),
- 58 Hz to 61 Hz for significant system events (infrequent).

Generators connected to the grid that protect off-nominal frequency operations should have relaying protection that accommodate, as a minimum, underfrequency and overfrequency operation for the following time frames:

Underfrequency Limit	Overfrequency Limit	Minimum Time
60.0-59.5 Hz	***60.0-60.5 Hz***	***N/A (continuous operating range)***
59.4-58.5 Hz	60.6-61.5 Hz	3 minutes
58.4-57.9 Hz	61.6-61.7 Hz	30 seconds
57.8-57.4 Hz		7.5 seconds
57.3-56.9 Hz		45 cycles
56.8-56.5 Hz		7.2 cycles
less than 56.4 Hz	greater than 61.7 Hz	instantaneous trip

In accordance with WSCC requirements, generators that do not meet the above requirements and trip off the grid in a shorter time than indicated shall automatically trip load simultaneously with the generator trip to match the anticipated generation loss, at comparable frequency levels.

3.3. Power Quality

The IES generally complies with industry standards and guidelines for power quality including but not limited to the following:

3.3.1. Voltage Flicker

The maximum permissible voltage flicker limits are defined in IEEE[6] Std 519-1992 "Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems".

3.3.2. Harmonics

Harmonic limits are as specified in IEEE Std 519-1992 "Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems".

Upon request, the TA shall provide the Generating Facility Owner with information describing the specific harmonic-impedance envelope at the proposed point of interconnection.

3.3.3. Voltage Unbalance

The voltage unbalance on the electrical system under normal operating conditions may reach 3%. The voltage unbalance is calculated using:

$$\text{Unbalance (\%)} = \frac{100 \times (\text{deviation from average})}{(\text{average})}$$

as derived from NEMA[7] MG1-14.33.

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

3.4. System Grounding

The Alberta Transmission System is operated as effectively (solidly) grounded.

3.5. Network Protection and Control

Typical transmission protections consist of at least primary and backup protection systems for each protected element such as lines, transformers and busses. For lower voltage transmission systems, 69 kV to 138 kV, the backup protection can take the form of either local or remote protective relaying that operate only if the primary protection should fail or become unavailable. For higher voltage transmission systems, 230 kV to 500 kV which have a greater impact on overall system security, the backup relaying takes the form of a second, fully redundant primary protection. This second primary protection is capable of stand-alone operation in parallel with the first primary protection in a "one out of two" tripping scheme. Communication aided protection may be applied as well on the transmission system to allow coordination, high speed fault clearing and proper clearing of remote faults.

Reclosing relays are often employed with power circuit breakers to permit rapid restoration of service to a transmission line that has been isolated due to the detection of a transient fault condition. Automatic reclosing is appropriate to support continuity of service and to maintain stability of the interconnected system.

Most of the 230 to 275 kV class transmission lines and all of the 500 kV class transmission lines in the IES are equipped with single pole and three pole tripping as well as high speed automatic reclose facilities. This protection may have impact on the proposed generating facility or may require modifications to accommodate the proposed facility. Such impact or modification requires careful consideration so that the proposed facility is not jeopardized, and the reliability of the transmission system is not reduced or compromised as a result of the addition of the facility.

Three pole fault clearing with subsequent automatic three pole reclosing is usually implemented on all other transmission lines at transmission voltage levels.

3.6. Site Specific Information

In most cases the Transmission Administrator shall on a best offers basis, provide the Generating Facility Owner with some or all of the following information for the proposed point of interconnection:

3.6.1. Reliability Indices

- Load interruption frequency;
- Expected duration of load interruption events;
- Total expected (average) interruption time per year;
- System availability or unavailability;
- Mean Time Between Failures (MTBF); and
- Mean Time To Repair (MTTR).

3.6.2. Fault Levels

The most recent three-phase and single-phase-to-ground short circuit infeed levels from the system at the interconnection point, including:

- The initial, forecast maximum future, minimum normal and minimum emergency fault current levels;
- Corresponding source reactance to resistance (x/r) ratios; and
- A clear definition of the power system conditions that were used to calculate the maximum and minimum fault levels and the x/r ratios.

3.6.3. Specific Voltage Level and Voltage Range

The anticipated minimum and maximum operating voltage range at the interconnection point under both normal and emergency conditions.

3.6.4. Remedial Action Schemes

A textual description of any site specific Remedial Action Schemes, including the following as a minimum:

- Purpose of the scheme;
- Input information to the scheme;
- Output (controls out) from the scheme;
- Functional logic of the scheme;
- A functional level block diagram;

3.6.5. Network Protection and Control

- Protection standards;
- Range of clearing times for faults on connecting line(s);
- Protection design requirements;
- Reclosing time on connecting line(s);
- Reclosing details (single pole, three pole, conditional logic); and
- Information necessary to prepare relay settings of the supply line protections.

4. Interconnection Requirements

The following sections describe the technical eligibility requirements for generating facilities to interconnect to the IES. The Generating Facility Owner must comply with all the requirements of the Canadian Electrical Code Part I.

4.1. Interconnection Demarcation Point

The Point of Supply (POS), and when applicable the Point of Delivery (POD) for standby requirements, will be defined by the TA, in accordance with the EUA.

4.2. Voltage Level Selection

The following factors shall be considered when selecting the voltage level of the interconnection:

- Power rating of the generating facility, taken as a complete plant;
- Maximum ultimate power rating of the generating plant;
- Reliability and configuration of the interconnection point prior to the interconnection and after the new required configuration is in place;
- Stability requirements of the generating plant and interconnected system;
- The fault level contribution of the facility being connected and its impact on the surrounding region of the power system; and
- Economic considerations (transformer and other equipment costs, etc.).

4.3. Voltage Regulation Requirements

All generators, whether synchronous, induction or inverter type must be capable of operating continuously in voltage regulation mode within the ± 0.9 power factor range at nominal power output. The TA will dispatch all generators in this range.

Generators are not acceptable for connection if they:

- continuously draw reactive power from the interconnection;
- operate with excitation systems in any mode other than voltage regulation (e.g.: constant VAr or power factor mode); or,
- operate with stator current limiters.

In order to ensure adequate voltage regulation for any load customers islanded with the generator, each shall be equipped with voltage regulation equipment capable of maintaining the voltage range prescribed by the TA at busses that could become islanded with the generating facility.

4.4. Frequency and Speed Governing Characteristics of the Turbo/Generator Unit(s)

Synchronous generators (and non-synchronous generators with stand-alone capability) having a capacity of 10 MW or more must have a speed governor (Governor). The Governor droop setting shall be 5% and while connected to the IES the generator must be operated at all times with the governor system free to respond to system frequency changes.

Every Generating Facility Owner seeking to synchronously interconnect a generator that may become islanded with some portion of the IES load, must ensure that the generator is capable of performing its own speed governing. As a minimum, the islanded generator must be able to maintain frequency within the 59.7 to 60.2 Hz range until the island is able to be synchronized to the main IES grid. Potential electrical islands must be equipped to enable re-synchronizing with the main grid.

Non-synchronous generating facilities that are designed to supply load in an islanded mode shall be equipped with frequency control devices that are capable of maintaining the island frequency within the 59.7 to 60.2 band, until the island is re-synchronized with the main IES grid.

An interconnected generating facility must remain synchronously connected for frequency excursions as specified in the WSCC off-frequency requirements, effective June 1, 1998, per the table in Section 3.2.

4.5. Power System Stabilizer (PSS) Requirements

All synchronous generators shall be equipped with Power System Stabilizers (PSS) as required by WSCC policy. The Generating Facility Owner shall interface with the Transmission Administrator to determine the damping requirements for the proposed facility.

4.6. Power Quality

4.6.1. Harmonics

The Generating Facility Owner will be required to mitigate harmonic currents resulting from non-compliance with IEEE Std 519-1992 "Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems".

4.6.2. Resonance

The Generating Facility Owner must design the facility to avoid introducing undue resonance into the IES. Of particular concern are self-excitation of induction motors, transformer ferroresonance, and the resonant effects of capacitor additions. The Generating Facility Owner must be able to demonstrate that the facility is compliant.

4.6.3. Voltage Flicker

The Generating Facility Owner shall be required to carry out corrective action if the power system or other facilities are affected by voltage depressions in excess of the maximum permissible voltage flicker limits as defined in IEEE Std 519-1992 "Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems".

4.6.4. Voltage Unbalance

Any three-phase generating 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 MG1-14.33.

4.7. Insulation Levels

The Basic Impulse Insulation Levels (BIL) or Switching Insulation Levels (SIL) for the interface facilities should comply with CAN3-C308-M85 "The Principles and Practice of Insulation Co-ordination".

4.8. Lightning (Surge) Protection

The Lightning (Surge) Protection for substation facilities should be designed for the average keraunic level (thunderstorm days per year) for the particular site location.

IEEE P998 provides further background on direct stroke lightning protection.

4.9. 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 Transmission Facility Owner's portion of the interconnection facilities should comply with The Alberta Electrical and Communication Utility Code (AECUC).
- The Generating Facility Owner's portion of the interconnection facilities should comply with the Canadian Electrical Code Part I.

4.10. Interrupting and Isolation Devices

4.10.1. Fault Interrupting Devices

The design of the interconnection facility must consider the fault contributions from both the transmission system and the proposed facility. The interconnection facility must have fault interrupting and momentary withstand ratings that are adequate to meet the maximum expected fault levels, with appropriate margin for future growth.

The choice between circuit breakers or circuit interrupters will depend on the required fault interrupting capability, clearing and reclosing requirements.

Due to the reduced reliability, increased outage times, single phasing and possibility of ferroresonance, the application of high voltage fuses on the transmission system is not recommended.

4.10.2. Isolating Devices

The Transmission Administrator shall define a point or points of isolation. The Generating Facility Owner will provide manually operable isolation switches at all points of isolation. The switches must permit visual verification of electrical isolation. The isolation switch shall have the capability of being locked open with multiple locks. The isolating device will be under the control of a single control authority, as agreed between the Generating Facility Owner and the Transmission Facility Owner.

4.11. Transformer Connection

The interface transformer connection shall be designed to provide:

- a favourable circuit to block the transmission of harmonic currents, and
- isolation of transmission and generator side ground fault current contributions.

The preferred configuration is delta connection on the generator side of the transformer and solidly grounded wye connection on the line side of the transformer. Where this configuration is not possible or practical, the TA shall determine an adequate alternative arrangement.

4.12. Protection and Control Interface

4.12.1. Line Protections

The Generating Facility Owner must provide suitable line protections to detect and cause proper isolation of all fault current contributions from the connected generators for a fault on the connecting transmission line(s).

4.12.2. Bus Protections

When transmission system security is not an issue, such that a single bus differential relay scheme may be applied, then time-delayed remote backup protection will be provided by the remote end overreaching line protections facing the protected bus and generator backup protections. The Generating Facility Owner is responsible for the cost of any necessary backup protections.

4.12.3. Special Interconnection Protections

In some cases special generator-specific protection and controls such as loss of excitation, over-excitation and loss of synchronism protection may be required. Similarly special interconnection and system protection such as reverse power relaying or differential zones of protection may be required to provide additional protection on some facilities. The Generating Facility Owner is responsible for the cost of any necessary special protections and controls.

4.13. Billing Metering

The Generating Facility Owner is responsible for the cost of electric meter installation to measure active energy and reactive energy flowing from the generating facility to the IES.

Metering data shall be submitted to the Transmission Administrator and Power Pool in the format specified in the Transmission Administrator's Measurement Standard, which can be found on the Technical Documents page of the Transmission Administrator's internet web site at www.eal.ab.ca. Metering equipment shall conform to the Transmission Administrator's Measurement Standard.

The Transmission Administrator will determine metering requirements for any load to be served at the generating site, per the EUA definitions.

Metering equipment includes (but is not limited to) the instrument transformers (voltage transformers, current transformers), secondary wiring, test switches, meters and communication interface. Unless otherwise agreed to, the instrument transformers should be dedicated for metering purposes only.

4.14. Supervisory Control and Indication

The Transmission Administrator will specify data indication requirements depending upon the location of the generating facility, the number and size of units, and the extent to which the Generating Facility Owner wishes the System Controller to control the generating equipment.

Generating Facility Owners seeking interconnection with the IES for generators larger than 10 MVA must be equipped for supervisory indication. This is required by the WSCC operating policies as well as by the Transmission Administrator to ensure that the proper level of system visibility is maintained for overall network security. If the Generating Facility Owner wishes to become a participant of the Power Pool and offer energy and system support services into the market place then SCADA (System Control and Data Acquisition) is required in order to receive System Controller dispatches and satisfy Power Pool compliance monitoring requirements. The System Controller uses an automated, computerized dispatching system and requires participants to be able to receive dispatch instructions and monitor generator response to those instructions.

The Generating Facility Owner shall provide as a minimum a Remote Terminal Unit (RTU), capable of exchanging the following SCADA information with the System Controller:

- Generator breaker(s) status (if not installed, then the status of the generator interrupter(s) or isolation device(s) shall be provided instead);
- Generator step-up transformer high voltage breaker status;
- Status of any other high voltage breaker at the generating plant substation;
- Status of the interconnection isolation device(s);
- Generator MW and MVAr;
- Voltage of the bus controlled by the generator(s) (may be its own low voltage bus, or may be the bus at the high voltage terminals of the step up transformer); and
- Receive dispatch messages from the System Controller for energy and any other system support service that the Generating Facility Owner may choose to provide.

Generating Facility Owners offering Automatic Generation Control (AGC) services require additional SCADA capability.

5. Technical Issues Requiring Commercial Arrangements

Generating Facility Owners capable of and interested in providing or receiving services beyond the minimum requirements in Section 4 should contact the Transmission Administrator's Customer Service Manager:

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

6. Responsibility of the Transmission Administrator

The Transmission Administrator shall be responsible to provide the following information to the prospective Generating Facility Owner.

6.1. 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.

6.2. Technical Information

The Transmission Administrator shall conduct planning studies 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 Generating 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.

The Transmission Administrator shall provide the technical information it deems necessary to enable the Generating Facility Owner to specify and purchase power system stabilizer(s), that have the capability to provide the required system damping at the required frequencies.

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

6.3. Acceptance of the Interconnection

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

6.4. Agreements

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

7. Responsibility of the Generating Facility Owner

The Generating Facility Owner shall:

- Become a Power Pool participant (unless all energy produced at the site will be consumed at the site) and comply with all applicable Power Pool requirements.
- Comply with the requirements of the applicable Transmission Administrator tariffs.

7.1. Technical Information

The Generating Facility Owner shall provide all the relevant technical information listed in the **Appendices to this Part** to the Transmission Administrator.

Appendix A: Generator Interconnection Data

The Generating Facility Owner shall submit to the Transmission Administrator information to enable preliminary evaluation of the proposed interconnection. Where applicable, specific information should be provided for each generating unit on site.

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

II. Siting Information:
   - A. map showing location of the proposed generating facility
   - B. single line (one line) drawing of the facility
   - C. site layout plan

III. Prime Mover
   - A. type, make and model
   - B. rating
   - C. inertia constant
   - D. governor droop

IV. Generator
   - A. type (synchronous, induction or other)
   - B. make and model
   - C. nominal MVA rating
   - D. maximum continuous rating
   - E. emergency rating
   - F. nominal voltage rating
   - G. speed

V. Excitation System
   - A. type (static or brushless)
   - B. make and model
   - C. rating (peak voltage / peak current)

VI. Voltage Regulator
   - A. type,digital, analogue
   - B. make and model
   - C. voltage regulator setting range
   - D. voltage regulator setting tolerance

VII. Voltage Regulator Compensator[8]
   - A. type of input(s)
   - B. compensating resistance(s)
   - C. compensating reactance(s)

VIII. Unit Transformers including Step Up transformer, *Excitation system transformer, *Unit service transformer, *Station service transformer (* *if applicable*)
   - A. MVA base rating

[8] Voltage Regulator compensators are required for bus tied generators and can be used to compensate for the generator transformer voltage drop as generator output increases.

B. fan rating, cooling type
C. high voltage - nominal voltage, connection
D. low voltage - nominal voltage, connection
E. Fixed tap ratio (if applicable or tap chart for tapchanger)
F. tapchanger - on-load or off-load, tap chart
G. ratio and accuracy class of instrument transformers. If multi-ratio, state the available ratios and the proposed ratio

IX. On Site Load Information
A. station service load
B. auxiliary or start up power requirements
C. sensitivity to automatic and planned interruptions
D. non-generator related on site loads[9]
E. estimated daily and annual load factor and shape

Appendix B: Generator Analytical Modeling Data

The Generating Facility Owner shall submit to the Transmission Administrator detailed information to model the transient, dynamic and steady-state behavior of the generator. The Generating Facility Owner is responsible for providing the best quality data possible at the time (as appropriate for the particular stage of the project) to enable the Transmission Administrator to derive an adequate mathematical representation of the generating facility's electro-mechanical behavior. Data is adequate if it allows the Transmission Administrator to determine accurately

- the impact of the generating facility on other customers connected to the IES; and
- the impact of the generating facility on the dynamic stability, in aggregate, of the IES as an interconnected system within the WSCC.

Such information shall include:

I. Generator

A. For Synchronous Generators only
1. Speed (RPM)
2. Inertia constant (H)
3. Damping Factor (D)
4. Direct axis synchronous reactance (x_d)
5. Direct axis transient reactance (x'_d)
6. Direct axis subtransient reactance (x''_d)
7. Direct axis transient time constant (T'_{do})
8. Direct axis subtransient time constant (T''_{do})
9. Quadrature axis synchronous reactance (x_q)
10. Quadrature axis transient reactance (x'_q)
11. Quadrature axis subtransient reactance (x''_q)
12. Quadrature axis transient time constant (T'_{qo})
13. Quadrature axis subtransient time constant (T''_{qo})
14. Stator Resistance (R)
15. Stator leakage reactance (X_l)
16. Saturation factor at 1.0 per-unit flux ($S_{1.0}$)*

[9] For load information requirements, see Part 2: Technical Requirements for Connecting Loads

17. Saturation factor at 1.2 per-unit flux ($S_{1.2}$)*
18. Negative sequence resistance (R_2)
19. Negative sequence reactance (X_2)
20. Zero sequence resistance (R_0)
21. Zero sequence reactance (X_0)
22. Excitation system type (AC or DC; rotary, "brushless" or "static"; et cetera) **
23. Excitation system Filter time constant (T_r) **
24. Excitation system Lead time constant (T_c) **
25. Excitation system Lag time constant, (T_b) **
26. Excitation system Controller Gain (K_a) **
27. Excitation system Controller lag Time constant (Ta) **
28. Excitation system Maximum Controller output (V_{rmax}) **
29. Excitation system Minimum Controller output (V_{rmin}) **
30. Excitation system regulation factor (K_c) **
31. Excitation system Rate feedback gain (K_f) **
32. Excitation system Rate feedback time constant (T_f) **

* *Or, submit saturation curves*

** *Or, submit a Laplace-domain control block diagram showing all control blocks with all time constants greater than 0.02s, completely specifying the transfer function from the compensator output voltage (or generator terminal voltage, if there is no compensator) and field current, to the generator field voltage.*

B. For Induction Generators only

1. Speed (RPM)
2. Inertia constant (H)
3. Steady-state reactance (x_d)
4. Subtransient reactance (x'_d)
5. Transient reactance (x'')
6. Subtransient time constant (T')
7. Transient time constant (T'')
8. Stator Resistance (R)
9. Stator leakage reactance (X_l)
10. Saturation factor at 1.0 per-unit flux ($S_{1.0}$)*
11. Saturation factor at 1.2 per-unit flux ($S_{1.2}$)*
12. Negative sequence resistance (R_2)
13. Negative sequence reactance (X_2)
14. Zero sequence resistance (R_0)
15. Zero sequence reactance (X_0)

* *Or, submit saturation curves*

C. For Inverter Generators only

Laplace-domain control block diagrams showing all control blocks with all time constants greater than 0.02s; completely specifying the transfer function from the distribution-system inputs (bus voltage and system frequency), to the producer's outputs to the distribution system (electric Power, terminal Voltage, terminal Current, Angle and Frequency).

II. Governor

A. Governor lead time constant (T_2) *

B. Governor lag time constant(s) (T_1) *
C. Permanent Droop (R) or Governor gain (K) *
D. Fuel Starting delay (T_w or T_4) *
E. Minimum Turbine power *
F. Maximum valve or gate opening velocity *
G. Maximum valve or gate closing velocity *
H. Maximum valve or gate position *
I. Minimum valve or gate position *
J. Turbine damping *
K. Governor non-linearity characteristic curve (Gate position to output power)
L. In addition to A-K, for hydro governors only
    1. Temporary Droop (r) *
    2. Temporary Droop time constant (T_r) *
    3. Filter time constant *
    4. Gate servo time constant *
    5. Turbine Gain *
    6. No-load flow *
    7. Valve positioner time constant *
M. In addition to A-K, for steam governors only
    1. Reheat delay time constants *
    2. Reheat stage gains *

* *Or, submit a Laplace-domain control block diagram showing all control blocks with all time constants greater than 0.02s, completely specifying the transfer function from system frequency or generator speed, to the turbine mechanical power output.*

III. Power-System Stabilizer
A. Type of input(s)
B. Gain for each input *
C. Lead Time constant(s) for each input *
D. Lag time constant(s) for each input *

* *Or, submit a Laplace-domain control block diagram showing all control blocks with all time constants greater than 0.02s, completely specifying the transfer function from the inputs, to the stabilizing voltage input to the voltage regulator*

IV. Voltage Regulator Compensator
A. Type of input(s)
B. Compensating Resistance(s)
C. Compensating Reactance(s)

V. Transformers
A. Positive Sequence Impedance
B. Negative Sequence Impedance
C. Zero Sequence Impedance

Appendix C: Revision History

Revision Number	Revision Date	Comment
1.0	1999/12/02	Part 1 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).