Attachment G: Chugach Electric Technical Specifications

Don Young Port of Alaska
Anchorage, Alaska

4.5 MW / 9 MWh
Battery Energy Storage System
Specification

March 2025

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DEFINITIONS ACRONYMS AND ABBREVIATIONS

Agreement	The documents that comprise the Contract including this Technical Specification, appendices, Request for Proposal, Contract and any electronic data files provided with the RFP.
As Built Drawings	Finalized vendor drawings after commissioning of the BESS.
Battery Management System	Component to manage the operational health of the Project, provide cell-by-cell diagnostics information and assure safe and optimal performance of the BESS.
C-Rate	The measurement of current in which a battery is charged and discharged at. It is a measure of the rate at which a battery is discharged relative to its maximum capacity.
Commercial Operation	When the BESS has been installed, commissioned, energized and in-service
Contractor	Supplier of new Battery Energy Storage System and all subcomponents
Contract Manager	Individual responsible for managing commercial aspects of the Contract. The Contract Manager is responsible for soliciting and facilitating Contract award or Contract modifications.
Final Completion	Final Completion of the Project including punch list items and final documentation.
Manual	Operation and Maintenance Manual for the Project.
Medium Voltage Transformer	BESS step-up transformer connected to the PCS output to step-up the AC voltage to 34.5kV.
Operator	A department or group within Chugach Electric Association, Inc. charged with maintaining, interfacing, setting, or operating the BESS. Typical Operators are Relay and Control, Substation, Communication, Dispatch, or the Engineering Departments.
Owner	The “owner”/”operator” of the BESS for the purposes of this Project will be defined as the Municipality of Anchorage. The Don Young Port of Alaska (POA) is the lead municipal enterprise department for this Project.
SCADA/AGC	Operator’s control system used to interface with the Site Energy Controller.
Point of Interconnection	High-side connection (34.5 kV) on the MV transformers

Power Conversion System	The term “Inverter” will be used synonymously with “Power Conversion System” and means BESS component used to convert DC power to AC power.
Project	Supply of the BESS Equipment for the Port Microgrid Project.
Project Engineer	Individual responsible for the day-to-day management of the Project. The Project Engineer is the primary point of contact for the Project, receiving and tracking all documentation. The Project Engineer is involved in communication with all Project stakeholders and Operators. Other responsibilities include tracking Project costs, change management, involved with Contract negotiation, Project schedule, attending all meetings, attending factory testing, coordinating and monitoring site work, witnessing commissioning and energization and Project closeout.
Project Manager	Individual with the authority and discretion to approve Project changes, Contract negotiation or stop work if required.
Project Site	The BESS will be installed at the Don Young Port of Alaska in Anchorage, Alaska at approximate geodetic coordinates 61o13’53.70” North, 149o53’00.88” West. The BESS will be located approximately 1,800 feet southeast of the marine waters of the Knik Arm of Cook Inlet. The available footprint area for the 4.5 MW / 9 MWh BESS and associated medium voltage transformer(s) is an approximately 45-foot x 75-foot trapezoidal area shown on the Site Plan Drawing provided in Appendix C.
Railbelt	Alaska electrical system spanning from the Fairbanks area to Homer. The system consists of Golden Valley Electric Association, Matanuska Electric Association, Inc., Chugach Electric Association, Inc., and Homer Electric Association, Inc.
Site Energy Controller	BESS component used for control interface with the Operator’s SCADA/AGC
Specification	Battery Energy Storage Project Technical Specification
State of Charge	Nominal Energy Remaining / Nominal Full Pack Energy Available.
Statement of Work	The term “Work” will be used synonymously with “Statement of Work” and means the undertaking of any tasks necessary to accomplish the scope of the Project as described herein.
Substantial Completion	The moment in the Project that the BESS functionally is ready for use by the Owner, but some punchlist items may remain to be completed.

AC	alternating current
ACI	American Concrete Institute
AGC	Automatic Generation Control
ANSI	American National Standards Institute
ASME	American Society of Mechanical Engineers
ASTM	American Society for Testing and Materials
BESS	Battery Energy Storage System
°C	degrees Celsius
CAD	computer-aided design
CFR	Code of Federal Regulations
CT	Current Transformer
DC	direct current
EMI	Electromagnetic Interference
E-Stop	Emergency Stop
FAT	Factory Acceptance Testing
GVEA	Golden Valley Electric Association
HEA	Homer Electric Association, Inc.
HMI	Human Machine Interface
HV	High Voltage
HVAC	Heating, Ventilation, and Air Conditioning
IEEE	Institute of Electrical and Electronics Engineers
I/O	Input/Output
LV	Low Voltage
MEA	Matanuska Electric Association, Inc.
MOA	Municipality of Anchorage
MV	Medium Voltage
MVT	Medium Voltage Transformer
MWh	megawatt hours
NEC	National Electrical Code
NEMA	National Electrical Manufacturers Association
NESC	National Electrical Safety Code
NETA	InterNational Electrical Testing Association
NFPA	National Fire Protection Association
OSHA	Occupational Safety and Health Administration
PCS	Power Conversion System
PDF	Printable Document Format
PF	Power Factor
POA	Don Young Port of Alaska
PQM	Power Quality Meter
psi	pounds per square inch
PT	Potential Transformer
QA/QC	Quality Assurance/Quality Control
QC	Quality Control
RFP	Request for Proposal
RTU	Remote Terminal Unit
SAT	Site Acceptance Testing
SBO	Select Before Operate
SCADA	Supervisory Control and Data Acquisition
SEC	Site Energy Controller
SOC	State of Charge or Energy
SOE	Sequence of Events

TRIR	Total Recordable Incident Rate
UL	Underwriters Laboratory
UPS	Uninterruptible Power Supply
VF	Voltage and Frequency mode
VSI	Voltage Source Inverter/Mode

SCOPE

This Technical Specification (Specification), including Appendices, comprises or constitutes requirements to design, fabricate, ship, assemble, test, startup, commission, warrant and make ready for service a fully functional Battery Energy Storage System (BESS) complete with accessories as required by the Agreement. This Specification defines specific engineering, operating and performance requirements for the Project that is intended to be interconnected on the Chugach Electric Association, Inc. (Chugach) system. The Project is to be designed to be in a restricted access setting and configured to meet applicable standards required of other Chugach equipment with respect to safety, operations, maintenance, and environmental impact.

Don Young Port of Alaska (POA) is deploying a battery energy storage system connected and powered by both the grid to provide backup power to the port and grid ancillary services.

The BESS would be installed at the POA in Anchorage, Alaska and be initially sized at 4.5 MW/9 MWh. The POA intends to deploy a microgrid in the future that could be islanded and as such the BESS shall include grid-forming and blackstart functionality. While the POA intends to purchase the BESS at this time, the microgrid and controller will be designed in the future and this design is not part of this project. BESS output will be stepped-up through a transformer to 34.5kV for tie-in to customer's electrical distribution system via pad-mounted switchgear.

The BESS is intended to be operated at a relatively high state of charge to provide a standby power source during outage instances and can be called upon to provide contingency reserve services to Chugach Electric Association, Inc. (Chugach) at all other times. The POA will own the BESS and it will be operated and maintained by Chugach.

1.0 CONFORMANCE TO SPECIFICATION

1.1 Applicable Standards and Codes

Except as modified herein, the Project, including the energy storage technology, Power Conversion System (PCS), and Site Energy Controller (SEC) shall be designed, manufactured, and tested in compliance with the latest versions (including any issued revisions or local amendments) of the applicable standards and codes including but not limited to the following: American National Standards Institute (ANSI), Institute of Electrical and Electronics Engineers (IEEE), National Electrical Code (NEC), National Electrical Manufacturers Association (NEMA), Occupational Safety and Health Administration (OSHA), American Society for Testing and Materials (ASTM), American Society of Mechanical Engineers (ASME), National Fire Protection Association (NFPA), and Owner or Operator safety practices. See Appendix A for applicable standards and codes.

1.2 Safety

The Project must be compliant with all applicable provisions of IEEE 1547, Underwriters Laboratory (UL) 1642, UL 1741 Supplement A, UL 1973, and NFPA Codes including NFPA 855, Standard for the Installation of Battery Energy Storage Systems. The Project must be able to protect itself from internal failures and utility grid disturbances. As such, the Project must be self-protecting for alternating current (AC) or direct current (DC) component system failures. In addition, the Project must be able to protect itself from various types of external faults and other abnormal operating conditions on the grid.

The Project must be designed in compliance with all applicable federal, state, and local safety standards and regulations with regard to construction and potential exposure to chemicals and with regard to container or enclosure resistance to hazards such as ruptures and exposure to fire.

All Project systems and Equipment must be grounded in accordance with the NEC and adhere to the guidelines in IEEE 80 and IEEE 142.

For all Project Equipment, Contractor shall provide information on all known or reasonably foreseeable safety issues related to the Equipment, including appropriate responses on how to handle the Project in case of an emergency, such as fires or module ruptures. Inspection and testing requirements shall also be included for after an earthquake.

The Project must be designed such as to minimize risk of injury to the workforce and public during installation, maintenance, and operation.

Visual and audible fire alarms should be included as necessary per all applicable fire and safety codes.

A physical Emergency Stop (E-Stop) button is required to be installed at all entrances and exits of the containers. The E-Stop button shall have the ability to open contactors/breakers to the inverter and batteries isolating the DC and AC potential.

1.3 Environmental Requirements

The Project shall be designed for proper operation without de-rating for the following conditions and limits:

- During and after an earthquake the system must maintain functionality (operational)
- Altitude is less than 125 feet above sea level
- Zero gas emissions during normal operating conditions
- Noise produced by any Project operation shall comply with MOA requirements
- Contractor must provide sufficient information specific to their particular product and the Project to facilitate utility personnel training and communications with emergency response and environmental agencies. Safety Data Sheets shall be provided with the Manual

1.4 Seismic

The structural and nonstructural components of all modules, free standing structures, structural Equipment supports, and all associated foundations and anchorages shall be designed and constructed to withstand the effects of earthquake motions and seismic loading in accordance with the requirements of the 2018 International Building Code and American Society of Civil Engineers 7-16. This Project will be designed to Risk Category IV and other geotechnical information will be provided upon request.

All electrical Equipment shall be designed to the ‘High Seismic Qualification Level’ in accordance with IEEE 693 Standard.

For all anchors embedded into concrete that resist seismic loading, the cracked concrete provisions of American Concrete Institute (ACI) 318-11, Appendix D must be considered.

Anchor design must be governed by ductile yielding of a steel element (anchor or attachment), unless the exceptions of ACI 318-11, Appendix D are met.

Post-installed anchors installed into hardened concrete must be an International Building Code Compliant Anchor for Seismic Design Category D and shall be designed and installed in accordance with the cracked concrete provisions.

1.5 Specification Interpretation

Contractor, if in doubt as to the meaning of any part of this Specification, or if Contractor finds discrepancies in or omissions in this Specification, may submit a request for a written interpretation or correction of the Specification. Any request for a written interpretation should be made to the Owner.

Any interpretation or correction of the Specification will be given in writing by the Owner.

2.0 GENERAL REQUIREMENTS

2.1 Proposal Submittals

Contractor shall submit the following supporting documentation with their Proposal:

- Individual BESS component data sheets and overall product literature. Provide typical Equipment setbacks used on past successful projects
- Typical One-Line Diagram showing DC and AC busses of all BESS Equipment being proposed. Indicate where necessary scope is being provided by Owner
- Proposed Project Site plan
- Degradation curves for the BESS based on the cycle duration and 15-year Project life as defined in this Specification.
- Curve showing inherent overload capability as function of time
- Tabulation of recommended spare parts including description, cost, and quantity
- Maintenance Requirements for the BESS
- Training Recommendations – to include onsite training for Dispatchers, Substation Lineman and Substation and Relay Technicians and Engineers
- Detailed Project schedule to include the design submittals, procurement, fabrication, factory testing, transportation, Equipment setting on foundations, impact recorder data/charts and evaluation, on-site commissioning, site acceptance testing, and final closeout documentation
- Initial test plans for both Factory Acceptance Testing (FAT) and Site Acceptance Testing (SAT)
- List of Project team members along with relevant experience for each member
    - Changes to Project team members will require Owner approval
- Related Project experience list

2.2 Meetings

2.2.1 Design Kickoff Meeting

The Contractor's Project team, including the Operator, shall hold a design kickoff meeting in Anchorage with the Owner representative(s), after Contract award and prior to commencing Work. The intent of this meeting is to verify the scope of the Project, operating requirements, the Work plan, Project schedule, site work, outage requirements and information required from the Owner relevant to the Work. Additionally, the Contractor shall use this opportunity to verify site conditions and accuracy of provided documentation.

2.2.2 Progress Meetings

Weekly progress meetings shall be held throughout the duration of the Project. The Owner will determine if the meeting frequency should be changed based on the schedule, Work being performed and the phase of the Project. The Owner or Operator may request additional meetings if deemed necessary. Such meetings shall be attended by the Contractor, all active subcontractors, and Owner representative(s). The purpose of the meetings will be to discuss current Work activity progress, schedule and potential changes to the schedule, invoicing and Project financials, requests for information, submittals, design or construction issues, interface issues, and potential changes to the Contract scope or amount. An “Issues List” will be provided at each meeting, the list shall contain a list of issues on the Project. The list shall have the person and company from which the issue originated, a description of the issues, person responsible for resolution, anticipated and actual resolution dates, actions, resolution, and an active or closed status of each issue on the Project.

The Contractor shall lead all progress meetings. The Contractor shall provide the meeting agenda, including but not limited to the topics mentioned above, at least one (1) day in advance of the meeting. The Contractor shall provide meeting minutes within three (3) days after the meeting which cover topics discussed during the meeting to solidify topics discussed.

Included in the Contractor’s Proposal price shall be four (4) on site progress meetings between the Contractor and Owner’s representative(s). The Owner will exercise the option to hold these on-site progress meetings at its discretion. The location of these meetings will be determined by the Owner as appropriate for the phase of the Project. During the design and fabrication phase of the Project, the Owner may choose to have the progress meetings held at the Contractor’s manufacturing facility. All expenses of these meeting shall be borne by the Contractor.

2.3 Project Schedule

Within 14 calendar days of Contract award, the Contractor shall revise the proposed schedule to reflect the Contract award date and submit it to the Owner as a baseline Project schedule for review and acceptance. The schedule shall be prepared in a Gantt chart format using Primavera P6 or approved equal. The schedule shall show the Work broken down into major phases and key items with the dates Work is expected to begin and be completed. The detailed Project schedule shall include the design submittals, procurement, fabrication, factory testing, transportation, Equipment setting on foundations, impact recorder data/charts and evaluation, on-site commissioning, on-site system testing, training, and final closeout documentation. The schedule shall show the amount of float in days. The schedule shall be updated and submitted to the Owner as an attachment to the monthly progress report as described in section 2.5. The schedule in the monthly progress report shall show scheduled and actual progress in addition to any proposed changes in the schedule of remaining Work. The Contractor shall not change the accepted baseline Project schedule without prior concurrence of the Owner.

2.4 Monthly Progress Reports

Monthly reports shall be submitted to the Project Manager. The reports should include an updated Project schedule; a financial statement including the amount invoiced to date, current invoice amount and the amount anticipated to be invoiced the coming month; a narrative should also be included in the monthly progress report. The narrative shall contain a description of Work completed during the last reporting period, current and anticipated Work for the next reporting period, delaying factors, if any, impact of possible delaying factors, and proposed corrective actions. More frequent reports may be required for critical phases of the Work.

2.5 Submittal Procedure and Requirements

Each submittal shall be accompanied by a letter of transmittal.

Consecutive transmittal numbers shall be used. All prints, reproducibles, and material submitted shall be stamped with the transmittal number.

Submittals shall include, but are not limited to, documents furnished for approval, final documents and As Built Drawings, and additional information to be supplied by Contractor as specified in this Specification. Documents shall be transmitted electronically through the Owner's cloud storage site or an approved Contractor document management system unless otherwise specified.

All electronic drawings shall be prepared using the most recent version of AutoCAD, unless otherwise specified at the kickoff meeting. Electronic copies of drawings shall be provided as .dwg files per Owner standards.

All electronic copies of photos shall be provided as .jpeg files.

Electronic copies of all information other than drawings and photos shall be provided in Microsoft Word with .docx file extension or Acrobat with .pdf file extension.

Hard copies of drawings shall be paper and full size.

Hard copies of photos shall be 8"x10" photographic prints.

Hard copies of Equipment manuals and instruction books shall be original. Xerox photocopies are not acceptable. General instruction manuals consisting of more than one Equipment manual or instruction book bound together shall be indexed and tabbed for easy location of information. Irrelevant sections of manuals shall be clearly crossed out or deleted.

All drawings or publications must be completely identified as to the item being furnished. Each must indicate in the title block, or in the body of the document, the Project title.

All drawings and/or publications covering Equipment must be identified with the terminology used in this Specification for the equipment name.

Each submittal shall contain all related information necessary to properly evaluate the material and services offered.

Drawings and lists of material and equipment, where applicable, for all Work related to a system, shall be submitted complete and concurrently. No approval will be given of partial submittals unless such partial approval is required to maintain the Project schedules, in which case it shall be so stated. Submittals which, in the Owner's opinion, cover features which are contingent upon approval of other features not yet submitted will not be reviewed until receipt of contingent items.

Contractor shall state explicit reasons, justifications, and benefits to the Owner for deviations from this Specification. Cost adjustments, if any, for deviations shall be identified.

Contractor shall indicate by signed stamps or other obvious means on all drawings or publications submitted, that Contractor has checked them and that the Work shown is submitted in accordance with the requirements of the Contract Documents. Submittals that are not in accordance with these requirements will not be reviewed by the Owner but will be returned to Contractor for proper submittal as outlined above.

All approvals of drawings or other materials to be submitted shall be in writing. Agreement or clarification obtained through consultation by telephone with the Owner shall not be binding unless confirmed in writing. If necessary, coordination meetings will be arranged to resolve outstanding issues. Such meetings will be at the location and convenience of the Owner. Contractor shall pay for its cost to attend coordination meetings.

2.6 Owner Review of Submittals

After review by the Owner, one set of documents will be returned to Contractor. The documents will be marked to show the status after review. The follow-up action required of Contractor shall be based on the review status as follows:

- No comments
    - Contractor may proceed with the Work covered by the documents
- Furnish as corrected – resubmit the corrected documents
    - Contractor may proceed with the Work covered by the document and the corrections shown; however, the Contractor shall promptly revise the document in accordance with the requirements of the Work and submit the revised document
- Correction required
    - On notice of such disapproval, Contractor shall revise the document to comply with the requirements of the Work and resubmit before proceeding with fabrication
- Received for information
    - Indicates items submitted for information only

No fabrication shall start until the applicable documents have been returned either "no comments" or "furnish as corrected – resubmit corrected documents" and Contractor accepts such notation without additional cost to the Owner.

If it is impossible to review documents submitted because all information required has not been included, Contractor will be notified in writing of the information required. The documents will not be returned until all information has been received and action taken as stated above.

The Owner will generally process all submittals within ten (10) working days of their receipt.

2.7 Resubmittals

Resubmittals shall be made in accordance with the initial submittal procedure and requirements, except that they must refer to the prior submittal number and must be accompanied by their own individual transmittal form. Resubmittals from more than one initial transmittal shall not be grouped in a common resubmittal, and not included in new transmittals.

2.8 Contractor Drawings

Contractor shall prepare all required drawings giving full and complete information and shall start this Work after the design kickoff meeting.

Contractor shall review, stamp with its approval, and submit, with reasonable promptness, and in orderly sequence as to cause no delay in its Work or the Work of any other contractor, all such drawings and samples required by modifications. Drawings and samples shall be properly identified as specified, or as the Owner may require. At the time of submission, Contractor shall inform the Owner in writing of any deviation in drawings or samples from the requirements of Contract Documents.

By approving and submitting drawings and samples, Contractor thereby warrants and represents that it has determined and verified all measurements, construction criteria, materials, catalog numbers, and similar data, and that it has checked and coordinated each drawing and sample with requirements of the Work and Contract Documents.

The Owner will review and approve Contractor's drawing and samples for conformance with the design concept of the Work and for the limited purposes and extent specified in the Contract Documents only.

The Owner's approval of any part, component, or subassembly shall not indicate or be construed as approval or acceptance of an assembly in which that item functions.

Contractor shall make any corrections required by the Owner and shall resubmit the required number of copies of drawings or new samples until approved. Contractor shall direct specific attention, in writing, or on resubmitted drawings, to revisions other than the corrections requested by the Owner or previous submissions.

Contractor shall be responsible for the design of all items within the scope of its Work and obligations as defined and specified in the Contract Documents. Any drawing submitted by Contractor which reflects inattention to, or noncompliance with, Specification requirements or which lacks certification for this specific Contract, or which is clearly an unchecked drawing, will be returned without comments by the Owner for proper compliance, completion, and/or checking by Contractor.

After the third instance of submission of noncompliant drawings that require further correction and review of Contractor's drawings by the Owner, Contractor will be responsible for reimbursing the Owner for all costs incurred by the Owner in connection with any noncompliant drawings. Should the progress of Work be in jeopardy due to Contractor's deficiencies, and the Owner is required to correct Contractor's drawings, Contractor will be considered liable and responsible for and shall pay all costs and damages incurred by the Owner as the result of Contractor's errors, omissions, or deficiencies. Any delay occasioned by such Contractor deficiencies shall not be a cause for an extension of time.

The Owner's review of Contractor's drawings or samples shall not relieve Contractor for responsibility for any deviation from requirements of the Contract Documents, unless Contractor has informed the Owner in writing of such deviation at the time of submission, and the Owner has given written approval to the specific deviation. Nor shall the Owner's review relieve Contractor from responsibility for errors or omissions in any drawings or samples.

No portion of Work for which Contractor is required to submit drawings or samples shall be commenced until the Owner has reviewed the submission. All such portions of Work shall be in accordance with reviewed drawings and samples.

Contractor shall submit drawings and samples as required by the Technical Specifications or as otherwise requested by the Owner. Submittal shall be in accordance with the requirements and procedures set forth herein. Submittals shall be made in accordance with a Schedule of Submissions to be provided by Contractor and approved by the Owner.

All drawings, samples, materials, files, documents, manuals, data and other items required by Contract Documents and supplied by Contractor shall become the property of the Owner. Drawings and instruction books will be retained by the Owner and will be the only means of identifying the Equipment after field installation. Therefore, general-purpose drawings and instruction books are acceptable only if the Equipment to be supplied is clearly identified and described.

All electronic drawings that depict physical aspects of Equipment furnished by the Contractor shall be drawn to scale. Such drawings include but are not limited to outline drawings, plan drawings, elevation drawings or section drawings.

The Owner CAD Drawing Standard is provided in Appendix F.

All schematic and wiring diagrams shall utilize IEEE Std 315-1975 (ANSI Y32.2-1975) standard drafting symbols and the ANSI device designations.

In order to coordinate the progress of the Project design and to verify that the design complies with the Statement of Work, the Contractor shall submit to the Owner design review drawings, calculations, associated documentation, and a schedule. The review documents shall include, but not be limited to the following design activities: Equipment drawings, design calculations and drawings for the enclosure containing the batteries and/or the inverters, and indoor and outdoor wiring and schematics. These drawings shall be marked “for review” and shall be submitted in the sequence of preparation of 30%, 60%, and 90%.

Intermediate partial review data may be submitted at any time in the Project when the Contractor needs clarification of design requirements.

The preliminary drawings submitted for review shall be accompanied by design memoranda which shall provide, when applicable, all data, calculations, and information necessary for an engineering review and understanding of the proposed design. Examples of documents to be submitted include but are not limited to:

- AC Single-line Drawing(s)
- DC Single–line Drawing(s)d
- Power Conversion System (PCS) Layout and Details
- Energy Storage Layout and Details
- Container Anchorage Plan (including PCS)
- Heating, Ventilation, and Air Conditioning (HVAC) Drawings and Details
- Fire System Drawings and Details

- Communication System Block Diagrams
- Control Narratives and Function Block Diagrams (suitable for use in PSS/E)
- Equipment Cut Sheets
- Nameplate Drawings and Details

2.9 Other Contractor Submittals

Other Vendor Submittals for review shall include, but is not limited to, the following documents:

- Railbelt BESS PSS/E Model and Summary Report
- Product datasheets on all individual BESS components
- Operations and Maintenance Manual
- Factory Testing Procedures
- Testing and Commissioning Plan and Procedures
- System Overload Capability Time-Current Curves
- Graphs or data points that show relationship between different use parameters and corresponding capacity degradation of BESS.
- Operator SCADA/AGC points list (to be developed with Owner and Operator)

2.10 Railbelt BESS PSS/E Model and Summary Report

Contractor shall develop and supply a PSS/E model to simulate the proposed BESS for inclusion in the Operator's model of the Alaska Railbelt. All BESS operational modes relevant to steady state and dynamic simulation must be modeled. The AGC regulation mode may be excepted from the PSSE modeling requirement. The model must be supplied with detailed documentation, including a model block diagram, model parameters, and a model description report that describes both the design and operation of the model. Each operational mode of the BESS model should be described in the model report. The supplied model must be interconnectable with the Operator's Railbelt PSS/E database and should be compatible with PSS/E V36. A steady state and dynamic model shall be provided in a Python format that can be imported directly into the provided Railbelt PSS/E database. If the dynamic model is a user-written model, then the FORTRAN FLEX code and a compiled DLL are required as deliverables. The Owner shall possess the ownership rights to, at its sole discretion, distribute the user-written model and related documentation to other entities for Railbelt purposes. Upon completion of modeling, the provided Railbelt PSS/E database should be delivered back to the Owner with the BESS model included, along with any other PSS/E cases used during the Project.

The Project must comply with AKMOD-025-2, AKMOD-027-2, AKMOD-032-2, and AKMOD-033-2, and any other applicable Alaska Railbelt Reliability Standards, attached as Appendix H.

Contractor shall provide a separate Proposal cost associated with the PSS/E model development and studies.

2.11 Operations and Maintenance Manual – Project Specific

Contractor shall supply a maintenance manual that includes detailed maintenance schedule including detailed instructions, manpower requirements, frequency, duration, and required specialized tools and materials.

No later than four weeks from the BESS shipment date, the Contractor shall furnish three (3) complete identical sets of detailed Operation and Maintenance Manuals in both print and digital (PDF) formats for the Project. These Manuals shall be accompanied by a letter of transmittal and shall have a table of contents, contain all illustrations, assembly drawings, outline drawings, wiring diagrams, replacement parts list that includes part number identification, a list of recommended spare parts, all test reports, cut sheets and instructions necessary for storing, installing, operating and maintaining the Project. The illustrated parts shall be numbered for identification. Additionally, these Manuals shall contain instructions and test procedures for integrating the Project into Owner control and monitoring computer networks. All information contained therein shall apply specifically to the Equipment and materials furnished and shall not include instructions that are not applicable. All illustrations shall be incorporated within the print of the page to form a durable and permanent reference book. Binding holes of all Table of Contents pages, illustrations and drawings bound into the Manual shall be reinforced with nylon circlets to prevent this information from being torn out of the Manual.

The Owner will inform the Contractor six weeks after receipt of the Operation and Maintenance Manuals either that there are “No Comments”, “Furnish as Corrected” or “Correction Required”. If there are “No Comments”, the Contractor shall promptly furnish two additional sets identical to the submitted copy. If there are corrections needed, one set will be returned to the Contractor by the Owner. The corrections shall be promptly incorporated in the Operation and Maintenance Manuals and a total of four complete, identical sets of such revised Operation and Maintenance Manuals shall be furnished to the Owner in both print and digital formats.

2.12 Workmanship

All Work must be done and completed in a thorough, workmanlike manner by personnel skilled in their various trades, notwithstanding any omission from drawings or this Specification. All parts of the Work shall be constructed accurately to standard gauge so that renewals and repairs may be made, when necessary, with the least possible expense.

2.13 Design and Material

All materials used in the Project shall be new and of the specified quality. All components and workmanship must be free from physical and electrical flaws and imperfections. The design shall not only be effective in engineering characteristics, it must comply with the finish requirements stated herein.

2.14 Spare Parts

The Project specific Operations and Maintenance Manual provided by Contractor will list the required spare parts to be furnished with the Project by Contractor. Each spare part shall be interchangeable with and shall be made of the same material and same part number and workmanship as the corresponding part included with the product furnished under these Specifications.

2.15 Special Tools

The Contractor shall furnish a complete set of any special tools, lifting devices, templates and jigs, which are specifically necessary for installation and/or maintenance of the Project. Any accessories normally furnished with this system required for satisfactory operation of the Project, and not specified herein, shall also be furnished by the Contractor. All tools furnished shall be new and plainly marked for identification. One complete set of tools shall be furnished for the Project Site.

2.16 Cleaning and Painting

All enclosures shall be waterproof and shall be thoroughly cleaned of rust, welding scale, and grease, and shall be treated to affect a bond between the metal and paint which shall prevent the formation of rust under the paint. A priming coat shall be applied immediately after the bonding treatment. The final finish shall consist of two coats of paint of ANSI 70 Gray. Contractor shall submit painting specifications and procedures for Owner approval.

Waterproofing is the combination of materials or systems that prevent water intrusion into structural elements of the buildings or its finished spaces.

2.17 Factory Acceptance Testing

2.17.1 General Requirements

The Contractor shall develop and submit a factory test plan as part of the design submittals. The Owner reserves the right to witness or have designated representative witness any or all tests at no additional cost. The Contractor shall provide a minimum of 21 days written notice to the Owner prior to each test for North American locations and a minimum of 30 days of notice for other locations. All travel and lodging expenses for Owner representative(s) associated with testing shall be borne by the Contractor including airfare, rental car, hotel accommodations and meals. The Contractor shall anticipate five (5) Owner representatives present at factory testing. The Contractor shall make all attempts to reduce the number of trips required to the minimum necessary. As a minimum, sufficient tests shall be conducted to demonstrate that all BESS controls, protective functions, and instrumentation perform as designed and are in compliance with this Specification. Successful tests performed using actual controls with a digital simulator to represent the Operator’s AC system will be deemed to meet the intent of this paragraph.

All Equipment to be supplied by the Contractor shall be subjected to routine and design tests in the factory as required under this Specification and applicable international standards for each piece of Equipment. Equipment with complex interfaces with other equipment, such as the SEC, shall be connected and tested as a system in the factory. The tests shall demonstrate full implementation and compatibility with the Operator’s RTUs. Control function tests are to include the following at a minimum:

A. Verification of each control function
B. Verification of each control linearity

C. Verification of each control redundancy
D. Verification of the monitoring system
E. Verification of the protection system
F. Verification of the overall system performance for minor and major system disturbances
G. Verification of BESS parallel operation with other controls in the system and control stability
H. Verification of control equipment performance for auxiliary power supply voltage (AC and DC)
I. Climate tests
J. Interference tests
K. SCADA I/O to Operator's RTU tests

Contractor shall indicate all factory design and production tests which will be performed on all major components and parts. Standard type tests previously performed on certain Equipment may be acceptable for new type testing if less than 5 years old and if approved by the Owner.

The test data shall be complete, including drawings, and shall clearly state the quantitative and qualitative performance of the Equipment subjected to the test.

The Contractor shall be responsible for compliance with all standard factory test procedures that check the quality and performance of the BESS. A detailed list of test and procedures shall be submitted in advance of fabrication.

The Contractor shall perform the tests specified in Section 2.17.2 and in other sections of this Specification. The Contractor shall propose additional tests to be conducted if required. Where appropriate, tests should conform to those contained in ANSI, NEMA, ASME, NEC, ASTM, NETA and IEEE standards and guidelines. Where standards are not suitable or applicable, other common industry procedures and mutually acceptable methods shall be used, as approved in advance by Owner.

If certain tests are performed by firms other than the Contractor, the Contractor shall furnish the test reports and certify that the necessary testing has been performed.

All Pre-Factory Acceptance Testing on individual components and Equipment shall be complete before commencement of Factory Acceptance Testing. This includes setup of testing and simulation equipment.

A complete factory test report shall be submitted to the Owner and Operator prior to shipment.

2.17.2 Factory Acceptance Testing of the Battery/Cells

The Contractor shall test and submit test data for the cells designated for use on this Project. At a minimum, the following tests shall be performed:

- Amp hour capacity
- UL 1642 Certificates (if applicable)
- As applicable, maximum noxious and toxic material release rates
- The Contractor shall make audible noise measurements during the FAT for the purpose of verifying adherence and compliance with the local ministerial ordinance and

requirements. The measurements shall be made using a Type 1 sound level meter that complies with the requirements of ANSI S1.4-1983 “American National Standard Specification for Sound Level Meters”

The Contractor shall propose a test plan for all required cell tests. Required tests may be proposed as a percentage of the cells in production lots. Test data for production lots other than those being supplied for this Project are not acceptable.

2.17.3 Factory Acceptance Testing of the SEC

Contractor shall propose a test plan for all functions of the SEC to be tested at the factory. Contractor shall provide for an Owner identified representative(s) and an Operator’s representative to be present at all SEC testing. Real-Time Digital Simulator (RTDS™) shall be used.

2.18 Onsite Acceptance Testing

2.18.1 General Requirements

The Contractor shall be responsible for developing and submitting to the Owner, a project test and commissioning plan with the 30% design submittals for the Operator’s review and comment. The plan will outline all tests that are required to ensure the new control system operates within its design parameters. The testing plan will ensure that all functions, alarms, controls, displays etc. are checked, exercised, and accepted by the Owner during onsite testing and commissioning. A final project test and commissioning plan shall be submitted with the issued for construction drawings for the Operator’s review and approval.

If certain design, production, or commissioning tests are performed by manufacturers other than the Contractor’s, the Contractor has the responsibility to furnish the test reports and certify that the necessary testing has been performed.

The testing shall confirm the PSS/E model for the BESS control system. The testing shall show comparison between predicted and actual control between the simulations and testing for a variety of conditions and disturbances approved by the Owner.

Onsite acceptance testing will be split into two phases. The first phase can be called pre-commissioning field testing. The purpose of this first phase is to test the installed Equipment before energization or interconnection to the bulk energy system. The second phase is the commissioning step of testing the system once it’s interconnected, which has been split into functional and performance acceptance testing. The individual phases are described below.

2.18.2 Pre-Commissioning Field Testing

The Contractor shall perform pre-commissioning field tests on the fully assembled BESS facility with the BESS disconnected from the high voltage source. The tests shall be performed on all Equipment to ensure that no damage occurred in transit and that all Equipment has been properly installed, is correctly set, and is functioning correctly.

Pre-commissioning tests shall include, but not be limited to, the following:

A. Functional tests on auxiliaries
B. Functional tests on control, protection, and alarm circuits, including relay and control settings
C. Functional testing of controller and redundancy
D. Functional tests of all interlock systems
E. Wiring continuity and insulation resistance tests
F. Fiber optic cables and attenuation
G. Test on signal path for firing signals
H. Diagnostic software functional demonstration
I. Verification and adjustment of cooling system
J. Calibration and adjustment of all gauges, meters, and instruments
K. Functional indication and control via the Operator’s SCADA system

In addition to the above tests, the Contractor shall energize or start up all independent subsystems. These tests shall demonstrate the electrical and mechanical integrity of these subsystems. During these tests, the Contractor shall make the initial adjustments to the Equipment required for satisfactory operation.

Following the successful completion of the above tests, the Contractor shall perform system tests as required to demonstrate the proper functioning of the associated controls and protection. Such tests may include trial operation during which the Contractor shall make final adjustments to the Equipment to meet the specifications.

2.18.3 Commissioning Field Tests

After successful completion of the pre-commissioning tests, the Contractor shall perform commissioning tests, subdivided here into functional and performance acceptance tests, to demonstrate that the BESS operates as specified. All modes of operation as described in this Specification shall be tested. Prior to proceeding with commissioning field testing, the Contractor shall determine that the BESS is fully operational and suitable for commissioning tests witnessed by the Owner. Commissioning tests shall include tests demonstrating that the BESS can meet the performance criteria put forth in this Specification. Engineered or calculated values, such as the PSS/E models provided, shall be verified during the commissioning field testing per the requirements of the Alaska Reliability Standards and the PSS/E modeling section of this Specification. If calculated design values do not closely match actual performance the Contractor shall correct this before the system is accepted. If design values are changed to meet actual performance the Contractor shall notify the Owner. In these cases, the Owner retains the option to require a review and/or corrective actions if the actual performance is deemed unacceptable. The Contractor shall coordinate with the Owner for all tests where the BESS is to be connected to the Operator’s power system. No such tests shall be performed unless permission by the Owner has been granted. The tests must be performed in a fashion to minimize unanticipated disturbances on the power system. These tests may have to be performed during the night or low load periods for certain types of tests. The Contractor shall document all acceptance tests performed. The Contractor shall submit documentation, analyses, and a summary in a test report for the Owner’s records.

Functional Acceptance Tests: The Contractor will perform comprehensive testing on the entire system to verify compliance with all requirements of this specification. The Owner’s representative(s) will witness these tests. Testing shall include, at a minimum, the following tests.

A. Verify change of reference point and slope both locally and remotely
B. Verify the automatic start-up and shutdown sequences, including restart following under voltage trip. This includes both those that are initiated automatically by the BESS controller, and manually by a system Operator from both local and remote locations
C. Demonstrate the repeatability of control system functions such as voltage setpoint changes
D. Operation of all control, protective relaying, and instrumentation circuits shall be demonstrated by direct test if feasible or by simulating operating states for all parameters that cannot be directly tested. Automatic, local, and remote operation will be demonstrated
E. Demonstrate correct fire alarm system actions initiated and/or responded to by the BESS

A plan for performing the functional acceptance tests shall be submitted to the Owner and Operator for review and approval at least 60 days prior to the start of the tests.

Performance Acceptance Tests: After the BESS functional acceptance testing is complete, the final performance acceptance testing can be performed. The performance acceptance testing shall include tests as determined by the Contractor to verify that the performance criteria specified in this Specification are met or exceeded. Accordingly, the Contractor shall provide a total system performance verification plan to ensure correct BESS response to system disturbances and operating scenarios described in this Specification. The total system performance verification plan shall be submitted to the Owner for review and approval as a part of the final test and commissioning plan. Testing shall include, at a minimum, the following tests.

A. Operating mode transfers
B. Performance under system disturbances and faults. This test should be simulated by the Operator prior to the test
C. Performance of the POD control
D. SEC DC auxiliary supply changeover or failure
E. Demonstrate and measure the BESS system operation and performance under prevailing system condition for a continuous 30-day period

The Owner and Operator will not accept completion of the Project until all commissioning tests have been successfully completed.

If failures occur during testing, the Contractor shall, at no cost to the Owner, make the necessary repairs, replacements, modifications, or adjustments to prevent the same failure or malfunction from occurring again. The replacement of certain BESS components in response to a system failure may necessitate, at the discretion of the Owner, the duplication of certain performance verification tests and restarting the 30-day demonstration period which shall be performed at the Contractor's expense.

2.19 Training

2.19.1 General

The Contractor shall provide training for the BESS facilities as specified below. The Contractor shall determine the content for each training session. The Contractor shall provide all material and equipment, as well as qualified fluent English-speaking instructors, to conduct the training program. If necessary, classroom sessions may be held in a convenient location close to the site with site visits to supplement the training.

Training manuals shall be provided to each trainee attending each course in accordance with the requirements of the documentation section of these specifications. At the completion of each course, the training manuals and any other training aids shall become the property of the Owner. One full set of training manuals will also be provided to the Operator.

The suggested class durations in this Specification are meant to illustrate the level of training expected. In preparation of the course material, the Contractor shall consider that the Operator's personnel are familiar with station equipment, including control, protection, and communications. The Operator's personnel are not familiar with power electronics and associated systems.

Training outlines shall be submitted to the Owner and Operator 90 days prior to the actual date of training. Approval of this outline shall be obtained from the Owner and Operator. The Owner will provide comments and/or approval within two weeks of the submittal. Each final training session must be approved 30 days before the scheduled training date.

2.19.2 Operator Training

The Contractor shall provide the necessary detailed training in orientation, theory, settings, user interface and proper operation of the BESS and related equipment to an intended audience of managers, engineers, dispatchers and other required personnel. The training shall thoroughly familiarize the personnel with the various aspects of the BESS including local and remote operations. At completion of the training, those trained shall be able to completely and properly operate the BESS Equipment without the Contractor assistance. Emphasis shall be placed on hands-on operating experience interspersed with the critical background as necessary, including switching procedures and emergency procedures to allow the Operator's personnel to respond to emergencies at the BESS. Such training shall include emergency shutdown procedures, switching to isolate the BESS, fire procedures, and any other procedures deemed necessary by the Owner and Operator.

The Contractor shall provide a total of four Operator training sessions, they will be held in Anchorage to accommodate a rotating shift schedule. It is anticipated that each session will last one (1) day. Each session will be limited to a maximum of 12 people. The training schedule shall be coordinated with the Owner.

The Operator training shall be recorded by the Contractor and provided to the Owner for use in training new personnel and as a refresher course.

2.19.3 Maintenance Training

The Contractor shall provide detailed training in maintenance of the BESS controls and related Equipment. The training shall thoroughly familiarize the maintenance personnel with the various aspects of the BESS. Maintenance training shall include preventative maintenance as well as troubleshooting. Maintenance of solid-state controls and microprocessor control systems used in the BESS shall be emphasized. The Contractor will supply training on all safety and grounding procedures necessary for safe maintenance of the BESS. At the completion of training, the maintenance personnel should be able to completely and properly maintain the BESS facility without Contractor assistance. The maintenance training shall include, but not be limited to:

A. Normal maintenance requirements and procedures
B. Repairs and replacement of parts to the component level

C. Diagnostic procedures
D. Equipment calibration
E. Re-energization
F. Special tests
G. Special tools including software maintenance PC with all required licenses and accessories
H. Safety and Grounding Procedures
I. Contacting the manufacturer for technical assistance
J. Ordering Parts
K. Network Troubleshooting

The Contractor shall provide two maintenance training sessions in Anchorage or onsite as required. Training shall be completed prior to commissioning the BESS. It is anticipated that maintenance training will last one (1) day and will be held on site. Each session will be limited to a maximum of 18 people. The maintenance training shall be recorded by the Contractor and provided to the Owner for use in training new personnel and as a refresher course.

In addition to maintenance training, SCADA and network training shall be provided. Among Owner's representatives, relay engineers and technicians will attend with the goal to be trained on troubleshooting network connection issues, I/O point mapping and assignments, relay and communication hardware, and network topology.

2.20 Shipping and Receiving of Material

Shipment is to be FOB foundation onto the appropriate foundation for each piece of Equipment at the Project Site. Contractor shall notify the Owner at least five (5) working days in advance of the date Equipment is ready for shipment.

The Contractor shall prepare Equipment and materials for shipment in such a manner as to protect from damage in transit. The Contractor shall pay particular attention to the proper packaging and bracing of the Equipment and materials to assure its safe arrival. Contractor shall provide all labor and equipment and dunnage material necessary to off-load any material or Equipment and place on foundation furnished by the Owner.

All shipments shall be clearly marked with the Contract number, the item number or numbers, and work order number. Bills of material shall be identified with corresponding numbers. Gross, tare and net weight in pounds shall be indicated on each shipping container.

A complete itemized bill of lading, which clearly identifies and inventories each assembly, subassembly, carton, package, envelop, etc., shall be furnished and enclosed with each item or items at the time of shipment.

All Equipment furnished under the Contract is to be shipped simultaneously. Each container or loose item is to be clearly marked with Owner name, address, and purchase order identification.

One impact recorder furnished by the Contractor shall be properly packaged, oriented, and attached to each container and/or transformer/inverter. The recorders shall indicate impacts separately on two axes, and the data/charts shall be stamped adequately to determine the date, time and place of severe impacts. Impact recorders furnished by the transportation company are not acceptable. The recorders shall be placed in operation before the Equipment begins shipment and shall remain attached and in operation until the Equipment has been offloaded at Owner's site. On-line access to continuous GPS stamped location of Equipment with impact data shall be provided to the Owner as a feature of the impact recorders used. This feature shall be available to the Owner as soon as the Equipment is shipped from the factory.

One reproduced copy of each of the recorders' data/charts and a written evaluation by the Contractor shall be sent to the Owner. The written evaluation shall include the field report of the Contractor's internal and external inspection of the Equipment after arrival and unloading.

If the impact recorder records an impact greater than 3g or if either impact recorder ceases to work before the Equipment is offloaded at Owner's site, the Contractor shall, at its expense, perform additional tests as required to ensure that the Equipment has not been damaged.

The Equipment and appurtenances shall be packed and protected against rough handling and corrosion due to exposure to marine atmosphere, exposure to dust or to open storage.

Contractor shall be solely responsible for the adequacy of the packaging of Equipment and for the furnishing and delivering of undamaged Equipment to the delivery site.

Packages shall have international markings indicating "This Side Up", "Fragile", "Use No Hooks", etc., as necessary or required. The center of gravity shall be plainly marked on all sides of each package when applicable.

The Equipment shall be shipped fully assembled to the greatest extent possible. The Contractor shall clearly list all loose items to be supplied with the Equipment.

Systems, Equipment, materials and components shall be transportable from the designated port at normal speeds over North American highways and railways and meet all United States Department of Transportation hazardous materials and other requirements. System components may be shipped separately as needed and assembled on-site. Battery shipments shall adhere to the requirements of Title 49 Code of Federal Regulations (CFR) Part 173.185.

2.21 Field Engineering Service

In addition to the Contractor providing the appropriate labor and construction equipment to off-load and set the Equipment on the foundation, including any Equipment specific assembly, the Contractor shall also provide a field service engineer(s) as required to be perform the field testing of the Equipment furnished under this Contract. The purpose of the field engineer is to satisfy the conditions of the warranty, to ascertain the extent of in-transit damages, if any, make necessary minor repairs, and advise the Owner's and Operator's representatives of proper installation and/or storage procedures.

Contractor shall notify the Owner three (3) weeks in advance of the Equipment arrival and assembly so the Owner can make arrangements for its construction inspector(s) to be on site.

2.22 Field Assembly

The Contractor shall furnish the appropriate labor and construction equipment to off-load the Equipment from the transport to the foundations. The Owner will chalk line the foundations for proper alignment and perform the anchoring, conduit attachments, and grounding attachments. The Owner shall perform all external cable connections.

2.23 Final Acceptance

When the required training, all tests and documentation have been completed and results delivered, the Contractor shall assist the BESS Operators in putting the BESS into service. Once the system is successfully in operation and the BESS Operator is satisfied with training, documentation, testing results and performance during the commissioning the site, the BESS system shall start a thirty (30) day trial period. During the trial period the BESS will be monitored by the Owner for performance. If anomalies are found in the performance the Contractor shall remedy the issue at no cost to the Owner. Failure to complete the trial period will result in restarting the trial period once anomalies have been corrected. A successful trial period will result in acceptance of the BESS and the start of the warranty period retroactively back to the beginning of the trial period. The Contractor's personnel will be required to stay in the vicinity and available should any issues arise with the BESS during the first week of the trial period.

3.0 FUNCTIONAL REQUIREMENTS

3.1 General

The Project will serve multiple purposes, each represented by a control mode. These modes will all be supported within the system capabilities and self-protection requirements. The Project shall be able to

1) Move freely between each mode of operation at any time

2) Turn on/off each mode independently

3) Operate one or more modes simultaneously without conflicting with each other

The Contractor shall specify the method used to determine the point where further discharge is no longer practical or safe and the storage media must be recharged before further use. All modes will be limited by the Contractor specified discharge limit to avoid damage to the Project. Termination of any operating scenario by the discharge limit, without reaching rated capacity discharge, will be included in the availability calculation unless the discharge was initiated with the energy storage partially discharged.

The Project shall be capable of functioning in the modes currently available within the Contractor's software.

For all modes, except modes that respond to abnormal system conditions, the Project shall ramp to the required output at an Operator selectable rate. Following a rated discharge or termination of the mode command, the Project shall ramp to zero at an Operator selectable rate suitable to allow other generation to follow. The total energy delivered shall be inclusive of the energy required to ramp the system to zero. Termination of operating modes due to reaching the discharge limit shall consider the ramp down energy required.

Not including errors from instrument transformers the controls accuracy shall have an error no greater than 0.1% of the calculated theoretical value.

3.2 Control Modes

The following sections describe the control/operational modes and sources of commands for the Project. Contractor shall work with the Operator to ensure that the appropriate commands, control functions, and source hierarchy are enforced by the Project.

The Project is expected to serve four primary functions as outlined in this section. The modes detailed below are intended to meet these requirements, and the Owner and Operator are expecting to work with the Project Contractor to refine the mode descriptions in this section to correctly serve these functions. All modes should be capable of functioning simultaneously and without conflict. Furthermore, all modes should be demonstrated successfully at both the FAT and during field commissioning.

Project Modes:

1) Microgrid. The Project operating in grid forming should provide the following functionalities: voltage and frequency mode, voltage and reactive power support, system strength, negative sequence support, and black start.

2) Frequency Response. The Project should provide over and under frequency response and should be high-speed with a speed droop characteristic like a rotating machine.

3) Active Power Regulation. The Project is expected to perform regulation as commanded with setpoints from AGC.

4) Renewables Following. The final service that the Project is expected to provide is ramp-rate control of variable renewable generation.

The table below shows the number of expected operations for each mode along with a power and energy estimate.

Mode	Minimum # Yearly Activations	Power/Energy Use Per Activation
Microgrid	1 activation per year	Up to full rating of Project
Frequency Response	100 activations per year	Up to full rating of Project
Active Power Regulation	550 activations per year	Up to full rating; average of 1 MWH per activation
Renewables Following	200 activations per year	Up to +/- 4.5 MW

3.2.1 Offline

The Project should be able to open the storage media breaker/contactor(s), inverter AC output breaker/contactor(s), and de-energize non-critical power supplies. It should physically isolate the inverter output from the grid, not just provide a zero output, to prevent interaction with the grid (nominal auxiliary load contactors may continue to serve these loads). This mode includes both normal shutdown and system trips requiring reset.

The SEC shall initiate the offline mode under the following conditions and remain in the offline state until a reset signal, either local or remote, is initiated.

- Emergency trip operation
- AC circuit breaker trips that isolates the Project from the grid
- Smoke/fire alarm and suppression operation
- Control logic trouble

3.2.2 Standby

The SEC should close the inverter AC output contactor after synching, but neither charge nor discharge, and only draw necessary auxiliary load.

When the SEC is in Frequency Response/Contingency Reserve Control modes, it may spend long amounts of time in standby mode. The Project is expected to maintain a state of charge of 100% (or other SOC setpoint as provided from the Operator's SCADA/AGC) and be prepared to respond to a signal for discharge within the specified time. The SEC will maintain a requested SOC within +/-1%.

3.2.3 Microgrid

The Project inverter shall have the following basic functionalities. Inverter shall be able to provide concurrent functionalities and control modes including maintaining a set state of charge.

The BESS operating in grid following should provide the following functionalities regardless of the control mode it is operating in: Steady state voltage, dynamic reactive power support, active power frequency control, disturbance ride through, fault current and negative sequence during faults, fast voltage support based on droops and dead band, and fast frequency support based on droops and dead band.

The BESS operating in grid forming should provide the following functionalities: voltage and frequency mode, voltage and reactive power support, system strength, negative sequence support, and black start.

1) Steady State Voltage. Capability to control steady-state voltage at the point of interconnection to a specific voltage schedule within an operating bandwidth.

2) Dynamic Reactive Power Support. Ability to provide dynamic reactive power support in response to normal and emergency grid conditions within the expected ride- though performance range.

3) Active Power Frequency Control. Capability to respond to changes in system frequency by changing active power output when the resource has available headroom/tail room.

4) Disturbance Ride Through. Capability to ride through normal grid disturbances within a defined set of parameters or expectations, including but not limited to faults and phase jumps.

5) Fault Current and Negative Sequence During Faults. Capability of the facility to provide fault current, including negative sequence current to mitigate unbalanced voltage conditions and facilitate relay operation.

6) Fast Voltage Support During Droops and Deadband. Fast voltage support during droops and deadbands is achieved through voltage droop control with deadband. This technology helps in load leveling, peak shaving, and black start support. In industry, units typically have deadbands and real sloped responses.

7) Fast Frequency Support During Droops and Deadband. Fast Frequency Response (FFR) is a rapid active power increase or decrease by generation or load in a timeframe of 2 seconds or less. It is used to correct a supply-demand imbalance and assist in managing power system frequency. FFR is also referred to as faster active power injection. It is considered an essential reliability service for the reliability of the bulk power system. FFR is a response from a resource that is automatically self-deployed and provides a full response within 30 cycles after frequency meets or drops below a preset threshold.

8) Voltage and Frequency Mode. Grid forming shall provide autonomous, near-instantaneous frequency and voltage support by maintaining a nearly constant internal voltage phasor in the sub-transient time frame.

9) Voltage and Reactive Power Support. Grid forming shall provide autonomous, near-instantaneous frequency and voltage support by maintaining a nearly constant internal voltage phasor in the sub-transient time frame.

10) System Strength. Grid forming shall help reduce the sensitivity of voltage change for a given change in current in the sub-transient time scale.

11) Negative Sequence Support. Grid forming shall provide negative sequence current as the Grid forming inverter-based resources should not oppose or prevent the flow of negative sequence current for small levels of voltage unbalance.

12) Black Start. During Blackout of the grid, based on operator command through control system, the BESS shall carry out a black start and energize the load. In Black Start mode, the BESS system shall be able to form grid without presence of utility voltage or any external generation sources. It shall control voltage and frequency of system.

3.2.4 Under Frequency Response

The Project will be used similar to that of rotating machinery such that the Project shall provide contingency reserve during underfrequency deviations beyond the deadband frequency without any intentional time delay. The deadband frequency shall be Owner selectable from 0 mHz to -1Hz. The total contingency reserve output during underfrequency events will be based on the owner-selectable droop setting (from 1% to 5%) without exceeding the maximum allowable reserve MW value selected by the owner (from 1MW to full MW output). The system shall be capable of transitioning from full rated charge current to full rated discharge current in 50 milliseconds or less, and the ramp rate shall be Owner settable. The maximum latency to activate the contingency reserve response from an idle state or any other operational mode shall be less than 50 milliseconds and should have no intentional delay.

When ramp-down and stop is received, within two seconds the Project will ramp down at an Operator’s selectable rate (100kw per second to 1000kW per second) until the MW output is less than or equal to 500 kW. Once the output is less than or equal to 500 kW, the Project will be capable of recharging at 500 kW until a user-defined SOC setpoint is achieved. The control for this service will reside in the SEC.

3.2.5 Over Frequency Response

The Project shall be capable of absorbing MW during over frequency deviations beyond the deadband frequency without any intentional time delay. The deadband frequency can be selectable from 0 mHz to 1Hz. The total MW absorbed during over frequency events will be based on the Owner-selectable droop setting (from 1% to 5%). If the battery SOC is at a level that the required negative MWs (absorbing) cannot be met, the Site Energy Controller shall only absorb the MW for the polarity it can achieve.

3.2.6 Active Power Regulation

The Project must be capable of performing regulation according to the MW set points received from the Operator's SCADA/AGC. The Project must be able to respond to these MW signals within two seconds or less with no intentional delay. Response is defined as the time from the SEC receiving a MW setpoint until that steady-state MW output is achieved.

The Project shall be capable of both positive (supplying) and negative (absorbing) MW setpoints, which may be of any magnitude up to 100% of the system's real power rating. Over time, these MW setpoints are intended to be energy neutral (no net gain or loss in energy). Under active power regulation, the allowable SOC range shall be kept between a minimum of 50% and a maximum determined by the Project's rated SOC limit. In the event battery SOC is at a level where the requested setpoint (either positive or negative MWs) cannot be met, the Site Energy Controller shall respond only to MW setpoints for the polarity it can achieve. The Project will resume responding to MW setpoints of both polarities once the battery SOC has returned to an acceptable range. The ramp rates for the setpoints in this mode should be Owner-settable.

Contractor must stipulate clearly how the thermal limitations of their system would impact this service.

3.2.7 Renewables Following

The Project must be capable of controlling the ramp rate of intermittent renewable generation to an Operator-settable rate, for example +/- 2.5 MW/minute. The positive and negative ramp rates should be separate settings as they may be different. The AGC signal of the combined renewable generation resource outputs will be provided to the Project, and the Project shall act to counteract the rate of change and smooth net output to the desired ramp rate.

3.2.8 Target SOC

The Project should charge according to its own optimum method considering available power limits to reach a defined SOC value. If the system SOC falls below the stated SOC dead band, the system shall charge to reach the desired set point.

The Contractor shall design the charging system to ramp up from zero to the maximum demand at an Operator selectable ramp rate to avoid shocking the system and allow generation to easily follow load. The Contractor shall provide a curve showing how demand from the Operator system varies with time throughout the charging cycle. The Project SEC shall allow the Operator's dispatcher to remotely initiate this mode. The maximum demand required by the charging cycle shall be Operator selectable but shall not exceed the Contractor specified charge rate. The Contractor shall provide data showing how the recharge period varies as maximum demand decreases.

The Contractor shall also specify restrictions, if any, on operation of the Project during any portion of the charge cycle. The Contractor shall provide a curve or table and data showing the SOC as a function of time.

3.2.9 Manual

The Project shall be capable of being operated manually from an Operator HMI. All energy storage system functionality shall be available via this HMI including all control modes, operating parameters or setpoints and monitored information/status.

This Operator HMI shall be capable of locking out other control modes and signals being received from the Operator's other integrated systems. Control setpoints and parameters shall be maintained during control mode changes to ensure smooth transition.

3.2.10 Integration to Other Owner Control Systems

The Project shall be capable of being integrated with other Owner and Operator control systems. See Appendix B for information on the SCADA interface.

3.2.11 Shut Down

The BESS shall be allowed to automatically disconnect from the utility system only due to system faults within the BESS and operating conditions which exceed the specifications and may be harmful to the BESS or its components. Once disconnected, the BESS shall remain in a fully energized and ready state, ready for connection to the utility system following a connection command either locally or through the SCADA system. The BESS control system shall disconnect for the following conditions:

A. Failure to synchronize with utility grid
B. Transient conditions on the utility grid outside of the BESS design parameters
C. Utility line voltage and/or frequency out of operating range for a specified length of time
D. Overheating of BESS and/or associated Equipment

BESS controls shall initiate a ramped shutdown of the BESS, the output of the BESS shall be driven to 0 kVA and the breaker shall open, all non-critical power supplies shall be de-energized, and critical BESS control power will remain energized. This state will be initiated under the following conditions and remain in the shutdown state until either a local or remote reset signal is initiated:

A. Operator emergency shutdown command
B. Loss of station service
C. Critical problem with the cooling system
D. BESS breaker trips/BESS protection trip signal
E. Doors open and interlock switches in discordance (a defeat feature shall allow for maintenance and be self-resetting)
F. Fire/Smoke alarm
G. Major alarm of the control system or current and voltage measurement subsystems
H. Failures to restart automatically

Where possible, all shutdowns shall be ramped shutdowns. Hard shutdowns shall not be used unless required for Equipment and/or personnel safety.

3.3 Control System General Requirements

The control system shall be capable of fully automatic unattended operation or manual operation from an Operator's workstation. The Operator's SCADA system shall have full read/write capability on any of the controller's interface memory map through the required protocol. Internal logic shall prevent external read/write signals from entering critical internal BESS controller memory and causing unsafe or damaging operation of the BESS system. Non-essential resets shall not require the presence of an Operator.

The control system shall be self-diagnosing for any control circuit failures. The control system shall have built-in test points and indicating lights to facilitate testing and maintenance. Where the control system is entirely digital, indications of intermediate points or diagnostic values to facilitate testing and troubleshooting and accessible to BESS Operators shall satisfy this requirement.

3.4 Status Monitoring and Alarming Requirements

3.4.1 Alarm Handling

The Operator console shall be designed so that alarms shall not be able to be acknowledged while they are active. The audible alarm signal shall be able to be silenced with a single keystroke or mouse click but shall reset itself with the addition of a new alarm. The audible alarm shall have the capability of being defeated from the local control, as the site will be primarily unmanned. The Operator shall be able to call up an alarm summary display with a single keystroke. The display shall enter the newest alarms at the top a minimum of one year of alarm history shall be available at the Operator console. The system shall log all alarms, control actions, and system abnormalities.

Alarm signals shall be separated into two types: warning and shutdown. Warning alarms indicate that a problem exists, but that the Equipment or its proper operation is not in immediate danger. Shutdown alarms initiate a partial or full shutdown of the BESS due to Equipment problems that may cause damage if left uncorrected. There shall be no grouped or summed alarms.

Alarm priority levels and corresponding filtering shall be provided to ensure the Operator is notified of primary events and is not inundated with lower-level events. A tabular screen shall be provided that lists a summary of all alarms.

The alarms and events shall be presented in chronological order with the status of the alarm shown in different color or text. The alarms shall be connected and synchronized to a GPS clock. If the existing GPS clock at the stations are not adequate an independent new GPS clock, antenna and time distribution unit and its interface shall be supplied by the Contractor.

3.4.2 Alarm Distribution

Each alarm shall be annunciated visually or audibly as appropriate, logged in an alarm history and be available to the Operator's SCADA via the SCADA interface. The alarm, both as recorded by the controls system and as passed to the SCADA system, must include the time the alarm was received to the resolution of the SOE capabilities of the local system. The controller must record all priority alarm and control functions in SOE format. The SOE must be retained within the controller and certain points designated by the Operator, passed through the SCADA system with time stamping.

3.4.3 Required Alarms

The control Equipment shall contain monitoring functions needed for safe and reliable operation of the BESS. All protective functions and diagnostic monitoring shall be included.

The Contractor shall develop a list of hardwired and/or software alarms for the Operator's review and approval based on available points.

RTU points will include the following as a minimum:

A. BESS Control System Failure (failsafe contact changes position upon failure)
B. Station AC Power Failure
C. Cooling system points required
D. Other points required for safety or critical control in the event of communications failure between the BESS system and the RTU

4.0 TECHNICAL REQUIREMENTS

4.1 General

The Project shall include the energy storage system, power conversion systems (inverter), pad-mount transformers, and control and communication interface systems.

All loads necessary to operate and protect the Project, such as controls, cooling systems, fans, pumps, and heaters, are included in scope of the Specification.

4.2 Storage Capacity

The Project shall be rated in terms of net delivered power and energy to the Point of Interconnection. All system loads and losses, including wiring losses, losses through the contactor/static switch, power conversion losses, auxiliary loads, and chemical/ionic losses are considered internal to the Project and ratings are net of these loads and losses as measured (or calculated if not measured) to the Point of Interconnection.

In such cases where auxiliary loads (such as heating and cooling systems) are periodic in nature, ratings may be described for conditions in which these loads are active in the worst-case conditions (or alternatively provide sufficient supplementary information such that ratings under these worst-case conditions may be easily determined).

Project ratings and capacity required shall be delivered to the POI. All auxiliary loads are powered by the BESS. Project design shall include the worst-case auxiliary loads built into delivering full project ratings and capacity to the POI.

The Contractor shall scale the reported SOC of the energy storage system so that 0-100% represents the maximum range of energy storage capacity available to the Operator regardless of the actual state of charge of the system. A reported 0% state of charge shall indicate that no further discharge of the system is permitted, and a reported 100% state of charge shall indicate that no further charging of the system is permitted. This range shall permit the Operator to fully realize the rated energy storage capacity of the system (i.e., for a 1.0 megawatt hour [MWh] system, the Operator shall be able to discharge 1.0 MWh of energy when discharging from a reported 100% to a reported 0% state of charge). Conversely, when charging a fully discharged BESS from 0% to 100%, the Operator shall have a BESS with a capacity of 1.0 MWh).

The BESS charging duration from 0% to 100% shall be equivalent to the discharge duration from 100% to 0%. It is recognized by the Operator that the charging duration can be altered to a longer duration but the standard BESS rating should be a 2hr charge duration.

The Project shall have a total minimum capacity as follows:

- 4.5 MW
- 9 MWh
- 0.8 leading or 0.8 lagging

4.3 Ratings

Following are fundamental Project unit ratings. Note that power, energy, and ampacity ratings apply through the full operating temperature range, as defined for the Project Site unless otherwise noted.

4.3.1 Medium Voltage Transformers

Pad mount Medium Voltage Transformers shall be supplied to connect to the AC output of the PCS to step-up the voltage to 34.5 kV.

Transformers shall be supplied with 600A loop feed bushings and a gang-operated coil disconnect switch with drawout bayonet dual sensing fuses in series with the switch. Transformers shall be protected by internally mounted ELSP current limiting fuse.

Transformers shall have BIL rating of 200kV for the 34.5kV bushings.

Insulating fluid shall be Natural Ester Fluid (FR3).

Transformer accessories shall include but not be limited to:

- Welded main tank cover with bolted handhole
- 1.0” upper fill plug
- 1.0” drain valve w/ sampling device outside LV compartment in a locking box
- Automatic pressure relief valve
- Dial-type liquid level gauge with alarm contact
- Dial-type liquid thermometer gauge with alarm contacts
- Dial-type Pressure-Vacuum gauge with alarm contacts
- External Mounted NEMA 4X terminal box for monitoring device alarms

Transformer must comply with latest published versions of IEEE C57.12.00, C57.12.28, C57.12.34, C57.12.90

Transformers shall meet the minimum US Department of Energy requirements for efficiency as required by the Distribution Transformer Energy Conservation Standard at the time of purchase.

Each transformer shall have 1" - 2" high yellow numbers/letters stenciled to the outside of the transformer door indicating the kVA rating and secondary voltage, located at the upper right-hand corner of the LV access door.

Safety decals shall be attached. No warning decals are to be placed on the outside of the transformer. "Mr. Ouch" danger decals (10" x 7" maximum size) shall be centered on the inside of each door, on the face of the HV and LV compartments, and on the face of the 5kV deadfront barrier. The safety decals shall meet Z535.1, NEMA 260 and 9.15.

A blue and white “PCBs less than 1 PPM” decal shall be attached (3" x 3" maximum) to the lower left-hand corner of the door.

4.3.2 Round-Trip Efficiency

The roundtrip AC-AC energy efficiency, measured at the Point of Interconnection, shall be provided and include parasitic and auxiliary losses under worst case conditions prescribed in the FAT Plan.

The calculation is as follows:

$$\boldsymbol{\eta} = \frac{\boldsymbol{kWh_{out}}}{\boldsymbol{kWh_{in}}} \times \mathbf{100}\% = \frac{(\boldsymbol{rated\ discharge\ power}) \times (\boldsymbol{discharge\ time})}{(\boldsymbol{rated\ charge\ power}) \times (\boldsymbol{charge\ time}) + \boldsymbol{losses}} \times \mathbf{100}\%$$

In which the discharge time is from a fully charged to fully discharged energy storage, and charge time is from a fully discharged to fully charged energy storage. If the auxiliary power is provided by a separate connection from the energy storage, these measured values should be reflected in the losses term in the equation.

4.3.3 Parasitic Losses

The total BESS unit losses shall be determined for standby operation, including power electronics and any environmental controls such as HVACs.

4.3.4 Self-Charge/Discharge

Contractor shall provide self-charge/discharge characteristics.

4.3.5 Basic Insulation Level

The Energy Storage System AC system Equipment shall have a Basic Insulation Level in accordance with IEEE standard for each piece of Equipment.

4.3.6 Inrush Capability

It may be advantageous to the Owner for the Project to have short time overload capabilities. This may occur for power system disturbances in which both real and reactive power are required for a short period of time to control both frequency and voltage excursions.

The Contractor shall provide a curve showing the inherent overload capability (if any) of the Project as a function of time. It is not a requirement of the Specification to design specific overload capability into the Project.

4.3.7 Power and Energy

System ratings are defined in kVA (AC) or MVA (AC) and kWh (AC) or MWh (AC) as measured at the Point of Interconnection.

4.3.8 Design Ambient Temperature Range

- Minimum -40˚C

- Maximum 40˚C

4.3.9 Audible Noise

The maximum sound level generated from the Project and any associated Equipment supplied by the Contractor under any output level within the Project operating range, shall be limited to levels specified by MOA. The Contractor shall comply with all Applicable Laws that may apply to the Project installation as determined by the jurisdiction applicable to the site.

The audible noise level in the Project control room if separate from areas housing inverters, cooling Equipment, etc. shall meet OSHA requirements for normally occupied areas.

The Contractor shall make audible noise measurements during the FAT and again before and after commissioning of the Project onsite for the purpose of verifying adherence and compliance with the local ministerial ordinance and requirements. The measurements shall be made at various locations using a Type 1 sound level meter that complies with the requirements of ANSI S1.4-1983 “American National Standard Specification for Sound Level Meters.”

4.3.10 Broadband Interference

The Contractor shall take necessary precautionary measures to ensure that there will be no mis-operation, damage or danger to the Project due to broadband interference and effects. The Contractor shall ensure that there are no discharge sources from the Project and related Equipment that could cause interference with radio and television reception, wireless communication systems, or microwave communication systems per the 47 CFR Part 15. The Contractor shall propose any necessary mitigation to ensure that communication is not adversely affected.

The Contractor shall make measurements before (or with all Equipment de-energized) and after commissioning of the Project for the purpose of verifying compliance with the broadband interference requirements.

All broadcast signals, radio noise, television interference and broadband interference measurements shall be made with instruments that comply with the latest revision of ANSI C63.2, “American National Standard for Electromagnetic Noise and Field Strength Instrumentation, 10 Hz to 40 GHz - Specification.” IEEE Standard 430, “IEEE Standard Procedures for the Measurement of Radio Noise from Overhead Power Lines and Substations” defines the measurement procedures that shall be used.

4.3.11 Interference and Harmonic Suppression

The PCS shall not produce Electromagnetic Interference (EMI) that will cause mis-operation of instrumentation, communication, or similar electronic equipment within the Project or any other system. The PCS shall be designed in accordance with the applicable IEEE standards to suppress EMI effects.

The Project must meet the harmonic specifications of IEEE 1547 and IEEE 519. Harmonic suppression may be included with the PCS or at the Project AC system level. However, the Contractor shall design the Project electrical system to preclude unacceptable harmonic levels in the Project auxiliary power system.

4.4 External AC Power Interface(s)

4.4.1 Termination

All terminations and locations of terminations shall be pre-approved by the Owner and specified in the appropriate submitted drawings.

4.4.2 Isolation/Disconnect

The Project shall be equipped with a means to isolate the power conditioning system from the substation. This may be accomplished through a lockable breaker.

A LV source side isolation contactor shall be provided. The disconnect breaker shall be lockable and have a visible break. It shall be capable of breaking the full rated power of the system. The contactor will be operated by the BESS control and will also have provisions to be operated manually. The Operator will have full access and control over this device.

4.4.3 Auxiliary Power

A complete auxiliary power system for the BESS is included in the Project scope. The auxiliary power for the BESS system including HVAC and control power shall be powered directly from the DC bus such that no separate auxiliary power supply is required to the individual battery containers. The Contractor shall note this technical exception in the exception list contained in their Proposal if they are unable to meet this requirement and Contractor shall be responsible for providing step down transformers, if necessary, and any low voltage power components necessary for BESS HVAC and control power.

4.4.4 Power Quality Metering and Telemetry

Contractor shall provide its own Current Transformers (CT) for protection and internal metering, and controls for Project operation. Contractor to provide Owner compliant metering and telemetry. Contractor to provide Potential Transformer (PT) connection points for synching and telemetry. Contractor to provide one revenue grade power quality meter installed on the line side of the main breaker(s) to validate system performance.

4.5 Instrument and Control Wiring

Control and instrumentation wiring shall be separated from power and high voltage wiring by use of separate compartments or enclosures or by use of separate wireways and appropriate barrier strips within a common enclosure as required by the NEC.

PCS control and instrumentation system wiring shall be bundled, laced and otherwise laid in an orderly manner. Where cable is in wire trays, waterfalls shall be used, as necessary. Wires shall be of sufficient length to preclude mechanical stress on terminals. Wiring around hinged panels or doors shall be extra flexible (Class K stranding or equivalent) and shall include loops to prevent mechanical stress or fatigue on the wires.

Cable insulation material shall be thermoset composition rated for 90˚C during normal operation. Insulation and jackets shall be flame retardant and self-extinguishing and shall be capable of passing the flame test of IEEE Standard 383 or IEEE 1202. Raceway and cable systems shall not block access to Equipment by personnel.

4.6 Modular Replacement

The Project PCS, control, batteries and current sensors shall be connected in a manner that enables field replacement. It is expected that most maintenance will be accomplished while maintaining partial service. The physical and electrical arrangement shall permit module replacement with the isolation breaker/contactor closed and the PCS disconnected.

Owner shall not be required to provide additional space or resources to accommodate the battery module replacement or supplementation. Contractor shall reserve the appropriate spacing and clearance per NESC into the design of the Project to accommodate battery module replacement and supplementation.

4.7 Physical Characteristics

The Project shall meet all applicable local codes and standards, OSHA, NEC, IEEE, ANSI, and NFPA requirements for electrical and fire safety.

The Project shall be designed to minimize footprint and volume. The allowable Project Site area is contained in Appendix C. The Contractor shall note this technical exception in the exception list contained in their Proposal if they are unable to locate all their Equipment in the allowable area described in Appendix C. The Owner will assign a Proposal penalty to accommodate additional costs associated with the extra space required due the additional soil preparation costs which will be required.

Project Modules PCS, and SEC shall be accessible and removable for replacement. The Project shall be designed to operate with minimal maintenance for at least ten years.

A nameplate shall be provided including:

- Manufacturer Name
- Connection diagram
- BESS ratings; Power, energy, voltage, BIL
- Specimen data; serial number, date of manufacture
- The nameplate shall meet the requirements of IEEE C57.12.00

A drawing containing this information shall be submitted for review and approval.

All necessary safety signs and warnings as described in ANSI Z535-2002 (entire series from Z535.1 through Z535.6) shall be included on each enclosure. All necessary signs and warnings for identification of hazardous materials as described in NFPA 704 shall be included on each enclosure.

Signage on the exterior of the BESS identifying the BESS fire suppression system, in accordance with NFPA 855 Article 4.3.5.2(4).

Signage on the exterior of the BESS and on the fence gate providing emergency contact information, as required by NFPA 855 Article 4.3.5.2(5).

Permanent plaque in the premises of the ESS pointing out the location of all electric power source disconnecting means as required by NEC 690.56(B), NEC 705.10 and NEC 706.11(A), and in accordance with NFPA 855 Article 4.3.5.3.

4.8 Cycle Life

The BESS must be designed to achieve a minimum lifetime of 15 years. If the BESS is subject to capacity degradation, degradation curves showing year 1 through year 15 following the Project commissioning date shall be provided in the Proposal as requested in this Specification.

The Contractor shall provide a graph or set of graphs that displays the relationship between depth of discharge, discharge energy throughput, operating temperature, C-rate, resting state-of-charge, and other relevant parameters and the corresponding capacity degradation experienced by the BESS.

Cycle counting shall be accomplished by applying a filter for each of the specified depth of discharge levels or based on other methodology proposed by the Contractor and agreed to by Owner. Contractor shall propose a methodology for tracking all other parameters that effect BESS capacity.

A separate capacity management plan option shall be provided for augmentation and replacements units according to the BESS cycle life over the life of the BESS.

4.9 Battery Management System

As a subcomponent of the Project, a Battery Management System shall be included to manage the operational health of the Project, provide cell-by-cell diagnostics information and assure safe and optimal performance of the BESS as an interconnected asset to the Operator’s electrical system. Primary functions include but are not limited to:

- Monitoring:
  - State of Charge
  - State of Health
  - Voltage/Current
    - String
  - Temperature
    - Module Internal
    - Various Ambient
  - Status

- Energy Throughput
- Maximum charge/discharge current or power
- Balancing
  - Cell voltage
- Warning and alarms
- Internal protective measures
- Logs of operations
- Management of any software versions
- Cyber Security management of the device itself
- Provide data exchange to the Site Energy Controller
- Contribute to functional safety of overall Project

4.10 Power Conversion System

The PCS shall be listed to UL 1741 Supplement A. The PCS shall be capable of operating in all four power quadrants at rated power.

Any combination of kW/MW and kVAR/MVAR output that results in the following equation being true:

$$〚kVA〛 \text{ rated} = \sqrt{(〚kW〛 \hat{}2 + 〚kVAR〛 \hat{}2)}$$

and as defined by the inverter P-Q capability curve, provided that at the system level there may be restrictions on reactive power output if the setpoint is chosen to boost system voltage that is already higher than nominal or reduce system voltage that is already lower than nominal.

The PCS shall be a static device (non-rotational) using solid-state electronic switch arrays in a self-commutated circuit topology. Line-commutated systems or systems that require the presence of utility voltage or current to develop an AC output are not acceptable. Only commercially proven switch technology and circuit designs are acceptable.

The PCS, in conjunction with the SEC, shall be capable of completely automatic unattended operation, including self-protection, synchronizing and paralleling with the Owner, and disconnect functions.

The control of the PCS shall be integrated with the SEC. However, the PCS also shall include all necessary self-protective features and self-diagnostic features to protect itself from damage in the event of component failure or from parameters beyond safe range due to internal or external causes. The self-protective features shall not allow the PCS to be operated in a manner that may be unsafe or damaging. Faults due to malfunctions within the PCS, including commutation failures, shall be cleared by the PCS protection device(s) or external protection devices.

All PCS components shall be designed to withstand the stresses associated with steady state operation, transient operation and overload conditions as implied by this Specification. The

Contractor shall be responsible to demonstrate that all relevant aspects of overvoltage stresses have been considered.

The PCS system shall include provisions for disconnection on both the AC and DC terminal(s) for maintenance work. These disconnects shall be capable of being locked open for maintenance work. Any PCS capacitors shall be provided with bleeder resistors or other such means of discharging capacitors to less than 50 volts within five minutes of de-energization per UL1741 requirements.

The PCS or battery system must have DC bus pre-charging functionality or other means of arc mitigation during switching of the DC disconnect devices.

The PCS shall be contained within the same enclosure as the batteries. The Contractor shall note this technical exception in the exception list contained in their Proposal if they are unable to meet this requirement.

Outdoor located PCS electronic compartments shall be NEMA 4 and the overall enclosure rating shall be NEMA 3R. PCS shall meet IEEE 519 for harmonic content. Total harmonic distortion shall not exceed IEEE 519 requirements.

PCS cooling system shall not be susceptible to particle contamination and require minimal maintenance. The PCS shall be furnished with nameplates or stickers that are suitable for the environment. Nameplates shall be located to be visible with Equipment installed and operating. Each nameplate shall indicate the following information:

- Nameplate ratings
- Component name
- Manufacturer's name
- Serial number
- Year built (or may be found in a reference document based on serial number)

Inverter shall have the capability to seamlessly transition from grid forming mode to grid following mode and vice-versa. In grid following mode (on grid) inverter shall have the capability to perform fast voltage and frequency support based on droops and dead band and can provide virtual inertia.

In grid forming mode (off grid) the inverter shall have the capability to operate as Virtual Generator providing voltage and frequency reference to an islanded grid.

The PCS shall have the ability of four quadrant (P,Q) operation ensuring bi-directional power flows.

No.	Details	Technical Requirements
1.	Inverter Rating	5000 kVA
2.	Nominal AC Voltage	480 VAC

No.	Details	Technical Requirements
3.	DC voltage range at nominal AC voltage	1000 – 1500 VDC
4.	Design Power Factor	0.95 pf
5.	Operating power factor range	0.8 Lag to 0.8 Lead
6.	Operating Voltage range	+10% to -10%
7.	Inverter response time	<20 msec
8.	Ambient Temperature	-40 deg. C to 40 deg. C
9.	Protection degree	NEMA 3R / IP-55
10.	Cooling and Heating	Provided
11.	Protection	Fuse on AC and DC side
12.	Safety Features	Overvoltage, Overcurrent, Overtemperature
13.	Ground fault detection	Yes
14.	Grid Connected / Off grid transition	Seamless transition in both directions available for PQ control
15.	Black Start Capable	Yes, shall include DC pre-charge
16.	Noise Level	<75 dBA at 3 m
17.	Control Interface	CAN, Modbus RS 485, or Modbus TCP, DNP3

Inverter shall meet the following minimum requirements:

- Inverter shall have UL1741 Certification, CE Compliance certificate and other global standards and grid codes certifications
- Operate in an environment of up to 100% humidity
- In case of outdoor installation in a high saline environment, the offered inverter shall have a stainless-steel enclosure with a minimum corrosion protection classification of C5M
- Be rated for use up to 1500V-DC application
- Peak efficiency greater than or equal to 98.6%
- Full load efficiency greater than or equal to 98% across the DC operating voltages at 100% load
- Harmonic Distortion shall be less than or equal to 2% TDDi per IEEE519
- Inverter shall have black start capability with inbuilt pre charge resistors
- Fully parameterizable for grid support

A drawing containing this information shall be submitted for approval.

4.11 Site Energy Controller (SEC)

The Project shall include all necessary software applications and supporting hardware required to meet the specified functional requirements. Software algorithms, external data input capabilities, and user interfaces shall provide for user specified variable input or set point values, as well as external data value streams required by programs directing the Project operations.

The Project shall include the necessary communication and telemetry hardware, and support communications protocols, to effectively provide the required services. No single mode of failure shall result in loss of power to the control and data acquisition module. The control shall include provisions for an orderly and safe shutdown in the absence of Owner power.

The SEC shall be a fully redundant control system with primary and backup hot swappable controllers. Upon loss of primary functioning controller capabilities the SEC shall perform an immediate and uninterrupted transfer of control to backup controller. Backup controller shall have preloaded backup configuration files and shall operate BESS identical to primary controller. Manual reset required from local HMI is required. Alarming shall be added to indicate a transfer event has taken place.

Testing of automatic transfer shall be performed during FAT by shutting off power to primary controller and witnessing a successful fail over to backup controller.

SEC shall have a digital input reserved for a remote mounted emergency stop push button dry contact. Input shall serve same function as HMI screen emergency stop push button.

4.11.1 Operations and Control Functions

The SEC shall be the primary dispatching location for local monitoring and control command functions, and is responsible to perform the following by priority in this order:

- Protect itself (isolate for any internal fault)
- Remain within power constraints (transformer and Project ratings)
- Remain within frequency constraints
- Remain within voltage constraints
- Remain within operating temperature constraints
- Charge/discharge Real Power and Reactive Power in response to SEC programs or external commands
- Communicate status and diagnostic data

The SEC shall respond to commands issued remotely or locally, including but not limited to:

- Change Modes (charge, discharge, etc.)
- Startup/Shutdown
- Change Status (enable/disable)
- Reset Alarms
- System Reset/Restart

The SEC shall respond to the following modes of operation:

- SEC must be able to transition from one mode to any other mode without ceasing operation (current source to voltage source mode changes, excluded). Changing of output from an existing inverter setpoint to any other setpoint as a transition step (example, returning inverter to zero output) before executing next command will be considered unacceptable
- The SEC must have the capability to limit system output based on an external signal. This will allow the unit to output to the limit of the circuit at any time. (e.g., if a circuit is rated for 10 MW and the current load is 5.5 MW unit should limit its maximum charge rate to 4.5 MW
- SEC must be able to transition from one setpoint within a given mode of operation to another setpoint within the same mode without ceasing operation. Changing of output from an existing inverter setpoint to any other setpoint as a transition step (e.g., returning inverter to 0 output) before executing next command will be considered unacceptable
- SEC must be able to accept and validate a given setpoint command prior to executing a given operation mode. For example, if the Owner sends a command for the BESS to discharge at 1.0 MW in constant real power output mode, the controller must be able to validate and accept the 1.0 MW setpoint prior to it initiating constant real power output mode. Setpoint validation will vary depending on the control mode command but may include limits associated with state of charge, facility ratings, ramp rates, system operating conditions, etc.
- SEC must be able to switch from current source mode to voltage source mode and back via a single remote-control point (“VSI Mode”), as well as a local point on the Human Machine Interface (HMI)
- SEC must be able to operate inverter breakers/contactors via remote control points (“Start” equals one is close command for breakers/contactors and “Start” equals zero is open command for breakers/contactors), as well as a local point on the HMI
- SEC must be able to reset all applicable system alarms via a remote-control point
- SEC must be able to conduct real and reactive power operations completely independently of one another until the apparent power limit of the asset is reached
- SEC shall allow for the prioritization of either real power setpoints over reactive power setpoints or reactive power setpoints over real power setpoints once the apparent power limit of the asset is reached. Prioritization shall be indicated via remote commands from the Owner
- SEC shall allow the Operator to “Idle” or “Standby” real or reactive power from the system while still operating the other
- SEC shall NOT have a real power mode command which ceases any reactive power mode operation or vice-versa
- SEC shall consider assign a positive sign convention to system real power output information when the system is discharging (real power)
- SEC shall assign negative sign convention to system real power output information when the system is charging (real power)

- SEC shall assign a positive sign convention to system information when the system is injecting reactive power (acting like a capacitor).
- SEC shall assign a negative sign convention to system information when the system is absorbing reactive power (acting like an inductor).
- SEC sign convention for real and reactive power commands shall match the desired convention assigned to system information reporting. In other words, positive real power commands refer to discharging, negative real power commands refer to charging, positive reactive power commands refer to injecting vars, and negative reactive power commands refer to absorbing vars
- Specific to the Target State of Charge or Energy (SOC) operational mode, the Controller shall ensure the system reaches the commanded SOC setpoint and then not dispatch the system until after the SOC falls outside the commanded SOC deadband

4.11.2 Permissive Operational States

As stated in the functional requirements, the Operator will permit the use of the Project in specific operational states remote signals. The Project must be able to integrate with the dispatch center to allow for and acknowledge each operational state. A command table must be submitted by the Contractor and approved by the Operator prior to the acceptance of the SEC and FAT.

4.11.3 User Settable Limits

User settable limits shall be provided for the parameters listed below. These limits should have the capability to be changed either through the HMI and/or a remote setpoint. If a limit is reached an alarm or warning should alert the Operator to the condition:

- Global Real Power Limit
- Global Reactive Power Limit
- Global Apparent Power Limit
- Mode-Specific Real Power Limit (unique limit for each mode)
- Mode-Specific Reactive Power Limit (unique limit for each mode)
- Mode-Specific Real Power Rate Limit (unique limit for each mode)
- Mode-Specific Reactive Power Rate Limit (unique limit for each mode)

The Site Energy Controller shall enforce whichever limit is most restrictive for the current mode of operation, either the mode-specific limit or the global limit.

4.11.4 Human Machine Interface

The Contractor shall supply an HMI which shall enable complete control and status monitoring of the BESS system both from the BESS control room and remotely from a remote console and/or the Operator's SCADA systems. The Contractor shall put emphasis on simplicity and usability. All information shall be accessible to the user. The Contractor shall submit HMI screens for review and approval with the 60% design submittal.

The HMI shall be a 19-inch rack mounted flat panel commercial quality color display with the provision for connection of portable USB data drives. Any PCs provided within the HMI subsystem or the main control systems shall be of the highest quality server grade quality and shall be equipped with redundant power supplies and solid-state hard drives.

The Contractor shall include one complete additional HMI for a spare.

The HMI system shall allow secure remote access for troubleshooting. The security for this connection shall be coordinated with the Operator.

All control commands shall be an SBO format. First, the component to be operated is selected, and then a clear selection of the control function to be performed is chosen (i.e. close or open) with “operate” and “cancel” commands. The state indication shall be shown with logical signs. The color of each equipment or function shall show the state of the equipment or function. Colors shall be designed to comply with the Operator’s standard color schemes. Information on the standard color schemes will be provided to the successful Contractor. The intermediate position or missing position of equipment such as motor-operated switches shall also be presented clearly. Switch numbers and representations shall conform to the Operator’s nameplate numbers. The Operator’s standard numbering system will be provided to the successful Contractor.

All settings must be viewable and settable, statuses viewable, operating parameters viewable, and logs configurable and viewable. Local password protection is required. Different login accounts shall be set up to allow for a hierarchy of operators: (i.e., observer: read, operator: read/write, admin).

A data entry screen shall be provided in the HMI to allow input of all user settable parameters, such as ramp rates, real and reactive power limits, power factor limits, etc. This data entry screen shall require admin login rights. Display screens shall be developed for each of the control modes. Each screen shall display the mode, setpoint(s), actual value(s), deviation(s) from setpoint, and any applicable limits or configuration parameters.

The HMI shall include alarm screens, including alarm summaries, alarm details, and alarm logging. Alarms screens shall be provided for balance of plant type information (HVAC, fire alarms, UPS, etc.) in addition to energy storage system information.

An Emergency Stop (E-Stop) button shall be located on the main overview graphic to allow the Operator to quickly shut down the BESS. The E-Stop button shall have the ability to open contactors/breakers to the inverter and batteries isolating the DC and AC potential.

4.11.5 Remote Operations

The Project shall provide a single interface with which the Owner can communicate. All commands, feedbacks, information, statuses, and alarms from all system components or subsystems (fire suppression and/or HVAC included) should be conveyed via said interface. Single interface must have a minimum of four fiber ports and four copper ports or a network switch which provides the specified number of ports.

The SEC shall be able to respond to manual commands that are issued remotely by Operator’s SCADA/AGC using a secure internet-based protocol.

The Project shall remain functional in the absence or loss of communication from the Operator’s SCADA/AGC. The Project shall continue its current mode of operation.

During an interruption to communications, the Operator’s SCADA/AGC will make repeated attempts to re-establish communications at a set time interval (variable setting). When communications have been re-established, the Operator’s SCADA/AGC shall make any necessary updates to resume performance.

A “Local/Remote” control function shall be provided in the HMI so that the Operator may allow or inhibit remote commands. The SEC shall log the source of each command (i.e., HMI/Operator Name, Remote). The source of the current active command shall also be displayed in the HMI.

4.11.6 Monitoring, Data Logging, Alarms, and Status

This information shall be developed with the Owner and Operator.

Alarms

- Alarms shall be provided for all critical energy storage system parameters
- Alarms shall be provided for all critical balance of plant system parameters
- The Operator shall be able to assign criticality or importance to alarms and filter the alarms so that only the most critical are displayed on the HMI
- Operator shall have the ability to acknowledge alarms
- An alarm log with time stamps shall be provided
- Details or help screens shall be provided for each alarm
- An alarm matrix shall be provided to show the relationship and hierarchy of all alarms

The SEC shall provide relevant status information, for feedback to the Operator’s SCADA/AGC. The telemetry points should include:

- Operation Control
- Operation Status
- System Information
- AC/DC Status
- Counters
- Status
- Device Status and Error Codes (Alarms)
- Historian Data Logging:
    - Log of Operations for one year on-site. Life-of-Project duration for off-site log
    - Historical data and trending for one year on-site for a limited set of parameters as-agreed with the Owner. Life-of-Project duration for off-site data

4.12 Network Communications

The Project and all its subcomponents required for operation shall be configured to be on its own sub-network, separate from any Operator communications network and must be in compliance with Operator's security requirements. Refer to preferred network topology in Appendix D for details.

Communication between the BESS and any Operator IP network shall be accomplished using a managed point of interconnection between the Contractor provided energy storage system and any Operator IP-based network. The Contractor connectivity solution shall use a barrier technical control, such as a firewall. The Contractor shall configure the Contractor barrier technical control to deny IP traffic by default and allow authorized IP traffic by exception. The Operator shall configure its own barrier technical control between Operator networks and the Contractor configured barrier technical control and shall configure the Operator barrier technical control to deny IP traffic by default and to allow authorized IP traffic only by exception.

A modern IP-based protocol shall be used for external communications between Operator networks and the Contractor's energy storage systems. Other protocol options shall be implemented only by mutual agreement between the Operator and the Contractor and are subject to Operator's security procedures and best practices.

The Project's SCADA and historian information shall be able to be accessed by the Operator's authorized personnel using a TCP/IP routable protocol specified by the Operator.

Contractor provided communications Equipment shall be suitable for the intended purpose and the environment where it is installed. Contractor shall use hardened devices that support extended temperature and humidity where required. For key system communications, the Equipment should have built in high availability or redundancy capabilities, or separate redundant devices should be used.

The solution shall be capable of communicating with the Operator-selected control monitoring, control, and maintenance systems via currently supported protocols and cabling types, as assisted by an Operator Interface. The energy storage site metering system shall be implemented to support polling via Operator's specified protocols.

4.13 Alaska Critical Infrastructure Protection (AKCIP)

The Owner has adopted a collection Cybersecurity Standards based on the NERC CIP standards. These standards are collectively known as the Alaska Critical Infrastructure Protection Standards (AKCIP). All the applicable standards are included in Appendix G. A glossary of terms from the AKCIP standards are included in Appendix G.

4.13.1 Electronic Security Perimeter – AKCIP-05

All applicable Cyber Assets connected to a network via a routable protocol shall reside within a defined Electronic Security Perimeter (ESP). The Contractor shall provide a list of all Cyber Assets delivered in the Project, and network diagram(s) that displays all Cyber Assets within an ESP.

All Cyber Assets with external routable connectivity must connected through an identified Electronic Access Point. The Contractor shall include in network diagrams all EAPs.

All Electronic Access Points require inbound and outbound access permissions. Contractor shall configure all EAP devices with inbound and outbound access permissions and deny all other access by default. Contractor shall provide a list of all configured access permission, and the reason for each permission.

4.13.2 Remote Access Management – AKCIP-05

The Contractor's solution for remote access shall meet the following requirements and deliverables:

- For all Interactive Remote Access, utilize an Intermediate System such that the system initiating Interactive Remote Access does not directly access an applicable Cyber Asset
- Contractor shall include intermediate systems on all network diagrams to demonstrate that this requirement will be met
- For all Interactive Remote Access sessions, utilize encryption that terminates at an Intermediate System
- Contractor shall provide a list of all encryption certificates used in the proposed solution, and their respective expiration dates
- For all Interactive Remote Access sessions, require multifactor authentication using Duo by Cisco
- Contractor shall transfer management and configuration of the multifactor authentication solution to Owner at Project completion
- Contractor shall include 1 or more methods for determining active remote access sessions
- Contractor shall provide documentation on how to determine active remote access sessions
- Contractor shall include 1 or more methods to disable active vendor remote access. Contractor shall provide documentation on how remote access is disabled

4.13.3 Physical Security of Cyber Systems – AKCIP-06

Contractor shall design the Project to support the following Physical Security of Cyber System requirements, with the understanding that these requirements are generally outside the scope of the Contractor:

- Utilize at least one Physical Access control to allow unescorted physical access to only those individuals who have authorized physical access
- Owner preference is that Physical Access for the Project is managed with Operator's existing Physical Access Control System, S2. Information on this will be provided to the successful Contractor
- If possible, preference is to centralize location of Cyber Assets to a locking, enclosed location
- Provide a method to monitor for unauthorized physical access
- Provide a method to issue an alarm in response to detected unauthorized physical access

4.13.4 Ports and Services – AKCIP-07 R1

Contractor shall design the Project to support the following requirements:

- For all Cyber Systems with External Routable connectivity, enable only open logical listening network ports (or ranges of ports) that have been determined to be needed for the Cyber System to function
- Provide a method to protect against unnecessary use of physical input/output ports

4.13.5 Security Patch Management – AKCIP-07 R2

Contractor shall design the Project to support the following requirements:

- Provide a listing of Cyber Assets that should be reviewed for Cyber Security updates, and include the source site for which updates should be obtained
- Contractor shall develop a cybersecurity plan that addresses and mitigates the critical vulnerabilities inherent in both the hardware and software that comprise the Cyber Systems. The cybersecurity plan will include regular qualified software patches and service packs for operating systems, and the underlying software and device firmware. The patches will be applied at least every 90 days with an expedited method for highly critical vulnerabilities (Common Vulnerability Scoring System Score of 10)

4.13.6 Malicious Code Protection – AKCIP-07 R3

The Contractor shall provide malicious code Endpoint protection software on all assets that support it in the Project and provide a method for updating the software. The Contractor shall configure the Endpoint protection software to perform periodic scans of the information systems and real-time scans of files that are downloaded, opened or executed. The malicious code protection software will block malicious code, quarantine malicious code and send alerts to administrators of the system. Enforced Whitelisting of system software and operation may be considered an alternative to Endpoint protection. For methods of malicious code prevention that rely upon signature or pattern file update, Contractor will provide documentation on how files are to be updated.

4.13.7 Security Event Monitoring – AKCIP-07 R4

Contractor shall design the system such that the following requirements are met:

- Log Events at the Cyber System or Cyber Asset level that includes:
    - Detected successful login attempts
    - Detected failed access attempts and login attempts
    - Detected malicious code
- Support the use of a log forwarder or logging agent to send log files to Operator’s SIEM
- Generate alerts for security events including:
    - Detected malicious code

  - Detected failure of event monitoring
- Retain event log for at least 90 days
- Configure logs to be sent to Owner central log repository (Splunk)

4.13.8 System Access Control – AKCIP-07 R5

Contractor shall design the system such that the following requirements are met:

- Have a method to require authentication prior to interactive user access (unless Cyber Asset does not support this functionality)
- Contractor shall provide a listing of all default or other type of generic account by Cyber System
- Provide a method to change default passwords for all active accounts
- Shared user accounts shall not be permitted
- For any system that uses password authentication and the cyber system supports the requirement:
  - Enforce passwords to have a minimum length of 8 characters, or the maximum length supported by the asset
  - Require password complexity including 3 of more of: uppercase alphabetic, lowercase alphabetic, numeric, special characters/non-numeric) or the maximum complexity supported by the Cyber Asset
  - Prohibits password reuse for 10 generations
- Where the capability exists, have a method to limit the number of unsuccessful login attempts
- Where the capability exists, have a method for passwords to expire at a configurable length of time
- Where the capability exists, have a method for alerting users and/or administrators of upcoming passwords expiration
- Generate alerts after a threshold has been met on unsuccessful login attempts
- Passwords are stored and transmitted in encrypted format

4.13.9 Backup and Recovery Plan – AKCIP-09

The Contractor shall provide the Project with a solution that is scheduled to conduct periodic backups of user and system-level information and protect the confidentiality, integrity, and availability of the backups. All backups must be encrypted and be disconnected from the network. The backup system must provide a method to verify the successful completion of a backup and provide alerts upon any backup failure. The Contractor shall provide documentation on backup software used, backup location, configuration, and frequency.

4.13.10 Configuration Change Management– AKCIP-10

The Contractor shall design the system such that the following requirements are met:

- Contractor shall provide a listing of all installed software, firmware, operating systems, installed security patches, and open logical ports by Cyber Asset
- Contractor shall include the following for any Transient Cyber Assets (TCA) (Laptops, Removable Media, etc) included in the Project:
  - Methods to mitigate introduction of malicious code to the TCA
  - Methods to mitigate malicious code
  - Method to restrict unauthorized use of TCA
  - Full disk encryption
  - Multi-factor authentication
  - Methods and documentation on the process to mitigate the risk of software vulnerabilities
- Any TCA such as process control service laptops will be configured to be regularly managed by policy to ensure it is inspected and found to be free from malicious code. Using latest version Endpoint protection with regular updates no older than 30 days. Portable devices will be restricted from connecting to a secondary network while connected to the Process Control network. The Owner or Operator may request logs and audit access to review system scans, patching and management tools to ensure compliance

4.13.11 Information Protection– AKCIP-11

As part of the Project, the Contractor shall implement Cyber Systems that:

- The Contractor will perform a review with Owner and Operator representatives of all Project data stored in Cyber Systems to identify locations of critical information.
- Provide methods to protects the confidentiality and integrity of information at rest.
- Implements encryption to prevent unauthorized disclosure and modification of information on Cyber Assets.

4.14 Information Security

4.14.1 Contractor

Contractor shall design the Project to be hardened against willful attack or human negligence using Cybersecurity industry best practices and incorporating technical controls as applicable to the Project as outlined in the AKCIP.

4.14.2 Application Partitioning

The Contractor shall design the Project to support integration with Role-based Access Controls, as assisted by an Owner interface. For example, functions necessary to administer databases, network components, workstations, or servers, and typically requires privileged user access. The separation of user functionality from information system management functionality is either physical or logical.

4.14.3 Authentication and Authorization Controls

The Contractor shall design the Project to provide the following authorization controls:

- Display an approved system use notification message or banner before granting access to the system that provides privacy and security notices consistent with all Applicable Laws, Executive Orders, directives, policies, regulations, standards, and guidance
- Prevent non-privileged users from executing privileged functions to include disabling, circumventing, or altering implemented security safeguards/countermeasures

4.14.4 Authenticator Feedback

The Contractor shall design the Project to obscure feedback of authentication information during the authentication process to protect the information from possible exploitation/use by unauthorized individuals. For example, do not display a separate error message for an invalid username versus an invalid password.

4.14.5 Baseline Configuration and Configuration Settings

The Contractor shall provide a checklist of security configuration requirements / system hardening requirements for all IT assets deployed as part of the Project, as assisted by the Operator's SCADA.

4.14.6 Boundary Protection System

The Contractor shall segment trust zones using a barrier technical control such as a firewall. The barrier technical control shall be configured to deny network communications traffic by default and allow network communications traffic by exception.

4.14.7 Device Identification and Authentication

The Contractor shall provide an asset inventory containing all IP addressable devices in the Project. The asset inventory will include the following fields: Device Name, Network Name, IP Address, MAC Address, Building Location, Rack Location, Firmware version / software version, Device Description.

4.14.8 Information Input Validation

The Contractor shall provide a solution that validates user input and network input for malicious content and unstructured data within the Project. For example, user interfaces should not be susceptible to untrusted user inputs.

4.14.9 Network Monitoring

The Contractor shall allow the Operator to monitor network traffic leveraging SPAN ports on switches and routers provided as part of the Project.

4.14.10 Session Authenticity

As part of the Project, the Contractor shall implement Information Systems that:

- Invalidates session identifiers upon user logout or other session termination
- Generates a unique session identifier for each session with randomness and recognizes only session identifiers that are system-generated
- Only allows the use of certificate authorities for verification of the establishment of protected sessions

4.14.11 3rd Party Assessment

Contractor shall contract information/cyber security scans and penetration tests by an Operator-approved third-party security company, prior to Substantial Completion.

The Contractor will provide the Operator with a copy of the original report from the third-party security company. The Operator, on behalf of the Owner, reserves the right to perform its own internal security testing in addition to the Contractor's testing.

4.15 Battery Container

4.15.1 HVAC Systems

The Project Site temperatures and the effect of temperature on component life shall be considered in developing the thermal design for all components, including the batteries and PCS. There may be several separate heat removal systems to accommodate the particular needs of Project components and subsystems (e.g., PCS, etc.). The heat removal and/or cooling system shall be liquid based. Final rejection of all waste heat from the Project shall be to the ambient air.

Sizing of the cooling system shall be sized for end-of-life battery heat loss information. Total battery heat dissipation shall account for all installed batteries including any provisions for battery augmentation throughout the Project life.

HVAC and ventilation systems shall be seismic braced/anchored. All design shall be in accordance with local and national seismic design requirements.

4.15.2 Fire Protection

The Contractor shall provide fire protection system for the complete BESS system in accordance with NFPA 855 “Standard for the Installation of Stationary Energy Storage Systems” and the latest approved revision of the applicable local fire protection codes.

The Contractor shall comply with NFPA coordination, design, installation, commissioning, testing, training and startup requirements. This shall include all other requirements as outlined in this specification. Fire Protection system design shall include, but not be limited to, the following:

- If UL 9540A and NFPA 855 codes have been revised as expected by the time of manufacture, the Contractor shall have completed the Large Scale Fire Testing of the proposed BESS in accordance with UL 9540A as required by the NFPA 855 Code. The Contractor shall provide the approved test results along with the required separation distances per the testing completed
- The Contractor shall provide the competed Hazard Mitigation Analysis for the proposed BESS as required by Section 4.14 of the NFPA 855 Code
- The battery container design shall be in accordance with NFPA requirements for location, separation, materials of construction, ventilation, smoke or flammable conditions detection, fire suppression, communications/alarms, training, commissioning, permitting, and documentation

Contractor will provide the potential combustion products and quantities for the batteries selected to be used with the BESS system.

The Contractor shall provide an optional price for a lithium-ion battery fault detector utilizing an off-gas sensing system that will detect off-gassing at the cell level. This system shall be integrated into the SEC.

4.16 Energy Storage System Design

The Contractor shall design and furnish a BESS that meets all the requirements of the Agreement, including this Specification.

4.16.1 Cells and Modules

The energy storage shall consist of cells of proven technology designed for the type of service described herein. For the purposes of this Specification, proven technology shall be defined as cells that have been in successful commercial service in similar type applications for a period of time sufficient to establish a service life and maintenance history. Only cells that are commercially available or for which suitable (not necessarily identical) replacement cells (or modules or strings) can be supplied on short notice throughout the Project life will be allowed. Cells shall be listed to UL 1642 and manufacturer must provide UL certificate prior to shipment to Project Site.

The cells shall be supplied as a group of cells combined into modules. Modules shall be listed to UL 1973 and UL 9540A and manufacturer must provide UL certificate prior to shipment to Project Site.

Cell construction and accessories (as applicable) shall be sealed to prevent electrolyte seepage. Post seals shall not transmit stresses between the cover or container and the posts. Cell terminals and interconnects shall have adequate current carrying capacity and shall be designed to withstand short circuit forces and current generated by the energy storage. Safety features shall be designed into each cell in accordance with UL 1642, UL 1973, and UL 9540A.

DC Contactors will disconnect the string from the circuit during high temperature conditions but will reconnect once the cell temperatures reach an acceptable range and other conditions are met allowing reconnection. Labeling of the cell (or modules) shall include manufacturer's name, cell type, nameplate rating and date of manufacture, in fully legible characters or QR code. Contractor shall provide a list showing all the modules by their unique identification number along with their corresponding physical location within the Project Site. The unique identification numbers shall correspond to their identification within the Project so to provide easy location of all cells or modules.

The energy storage subsystem as a whole and as individual cells shall be designed to withstand seismic events as described herein. The batteries may consist of one or more parallel strings of cells.

DC wiring shall be sized per NEC Article 310 or based on UL standards and be appropriately braced for available fault currents. Protection shall include a DC breaker, fuse or other current-limiting device on the energy storage bus. This protection shall be coordinated with the PCS capabilities and energy storage string protection and shall consider transients and the Inductance/Resistance (L/R) ratio at the relevant areas of the DC system. The Project shall operate no higher than 1,500 volts DC.

The Contractor shall provide information on the impact that weak or failed cells have on the life and performance of the entire string. The Contractor shall specify critical parameters, such as temperature variation limits between cells of a string. The Contractor shall provide a means of monitoring critical parameters to ensure the limits are being met.

Cells, wiring, switchgear and all DC electrical components shall be insulated for 2,000 volts DC. The Contractor shall have overall responsibility for the safety of the electrical design and installation of the Project. The Project shall include a monitoring/alarm system and/or prescribed maintenance procedures to detect abnormal cell conditions and other conditions that may impair the ability of the Project to meet performance criteria.

The energy storage monitoring system shall be capable of balancing the voltages across cells automatically and independently without any input from the Operator or the SEC. Cell monitoring system shall be specified to alert the proper personnel in a timely manner that an abnormal cell condition exists or may exist. Abnormal cell conditions shall include over- and under-cell voltage. Temperature is not expected to be monitored at the individual cell level.

The monitoring/alarm system will record data on the number and general location of failed modules, to expedite maintenance and cell replacement. This data shall be stored in non-volatile memory. Such monitoring/alarm systems shall be integrated into the overall control system.

The Project shall include racks or shall consist of stackable modules of batteries. Aisle spaces shall be set to permit access for equipment needed for easy removal and replacement of failed modules. The lengths and widths of aisles shall conform to all applicable codes and facilitate access by maintenance personnel. As applicable, the racks shall provide sufficient clearance between tiers to facilitate required modules maintenance, including modules testing and inspection, and replacement.

Rack-mounted modules shall have all connections located on the front of the enclosure or module. Modules shall not be required to be removed from the racks during regular maintenance. All racks and metallic conductive members of stackable modules shall be solidly grounded. Racks shall be seismically designed based on the requirements of Section 1.4 and shall include means to restrain cell movement during seismic events. All design shall be in accordance with seismic design requirements as specified in Section 1.4 of this Specification.

4.16.2 Arc Flash Analysis

The Contractor shall perform an arc flash analysis on provided Equipment. Arc flash labels shall be placed where visible on all access doors and panels. Labels shall contain all applicable information such as system voltage, PPE category, arc flash boundary, minimum rating of clothing (cal/cm2), equipment ID, and date.

To assist the Contractor in developing the arc flash analysis, the Owner's representative will provide the utility contributions at the inverter terminals and auxiliary power terminals, if required.

5.0 RELIABILITY REQUIREMENTS

5.1 Definitions

The following definitions apply to the BESS Equipment supplied for this Project.

Annual Availability:	A percentage defined by: [1 - ∑ (equivalent outage duration (hours)/8760)] x 100
Forced Outages:	Unscheduled outages caused by faults in the BESS that result in loss of part or all of the essential functions of the BESS.
Scheduled outages:	Outages which are necessary for preventive maintenance to assure continued and reliable operation of the BESS. They may result in the temporary loss of part or all of the essential functions of the BESS.
Outage duration:	Outage duration is the elapsed time in hours from the instant the BESS is out of service to the instant it is ready to be returned to service.
Burn in period:	The first sixty (60) days of Commercial Operation

The following will be included in outage duration:

A. The down time required to determine the cause of an outage or to determine which Equipment or units of Equipment to repair or replace.

B. The time required by system Operators to disconnect and ground equipment in preparation for repair work and to remove grounds and reconnect Equipment after repairs are complete. Delays caused by unavailability of qualified Operator personnel are not accumulated in the outage duration.

5.2 Reliability and Availability Requirements

Beginning at the end of the Burn-in Period, the Contractor shall guarantee the average Annual Availability of the BESS system shall be greater than 99.5% and the average number of forced outages shall not exceed two (2) per year.

The Contractor shall guarantee the quoted availability performance for fifteen (15) years from the date the Owner accepts the BESS. This period shall be known as the “Availability Guarantee Period”. The Contractor shall be notified of major outages. During the guarantee period, the Owner should maintain records of the number and duration of forced and scheduled outages, hours of operation, and any other relevant data and should make those records available to the Contractor upon request.

If the actual performance is below the values stated in this section at any time during the Availability Guarantee Period, the Contractor shall promptly provide corrections and modifications to meet the availability guarantees at no extra cost to the Owner. In this case the Availability Guarantee Period and Warranty Period shall be extended one (1) year for (i) each 1% below 99.5% Annual Availability or (ii) the number of forced outages exceeding two (2), whichever is greater, up to a maximum of five (5) years. This shall constitute the Owner’s sole and exclusive remedy for failure to meet the Availability Guarantee.

The following outages and delays shall not be included in Availability calculations: outages due to failure of Operator to follow the Contractor’s prescribed maintenance shall not be included in the availability calculations; outages caused by incorrect behavior of Operators taking actions which are not in accordance to the Contractor’s manuals or training; delays caused by the unavailability of tools or repair equipment which the Contractor provided or specified of use; delays caused by the unavailability of spare parts due to Owner’s failure to notify the Contractor of depleted spare parts; or delays caused by extreme weather related delays (flight operations and/or road passage abnormalities).

APPENDIX A APPLICABLE STANDARDS AND CODES

NO.	STANDARDS	CODE
1	**ANSI/IEEE C2**	National Electrical Safety Code
2	**IEEE 519**	IEEE Recommended Practices and Requirements for harmonic Control in Electrical Power Systems
3	**IEEE 1547**	IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems
4	**IEEE 1547.1**	Standard Conformance Test Procedure for Equipment Interconnecting Distributed Resources with Electric Power Systems
5	**IEEE 1547.2**	Interconnecting Distributed Resources with Electric Power Systems
6	**IEEE 1547.3**	Guide for Monitoring, Information Exchange, and Control of Distributed Resources Interconnected with Electric Power Systems
7	**ANSI Z535**	Product Safety Signs and Labels
8	**ANSI C57/IEEE**	Transformer Standards, whenever applicable
9	**ANSI C37/IEEE**	Surge withstand capabilities, whenever applicable
10	**UL 1642/IEC 62133**	Applicable sections related to battery cell safety, where applicable
11	**UL 1741**	Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use with Distributed Energy Resources
12	**NFPA 704**	Standard System for the Identification of the Hazards of Materials for Emergency Response
13	**UL 1778**	Underwriters Laboratory's Standard for Uninterruptible Power Systems (UPS) for up to 600 Volts AC
14	**UL 1973**	Standards for Batteries for Use in Light Electric Rail Applications and Stationary Applications
15	**UL 9540/9540A**	Standard for Energy Storage Systems and Equipment
16	**Electric Tariff Rule 21**	Generating Facility Interconnections
18	**NEC**	National Electrical Code
19	**NESC**	National Electrical Safety Code
20	**ASHRAE**	American Society of Heating, Refrigerating and Air-Conditioning Engineers
21	**CAA**	Clean Air Act and Amendments
22	**CERCLA**	Comprehensive Environmental Response, Compensation, and Liability Act of 1980
23	**EPA**	Environmental Protection Agency regulations
24	**FAA**	Federal Aviation Administration regulations
25	**FERC**	Federal Energy Regulatory Commission regulations
26	**FPA**	Federal Power Act
27	**RCRA**	Resource Conservation and Recovery Act
28	**SDWA**	Safe Drinking Water Act
29	**SWDA**	Solid Waste Disposal Act
30	**TSCA**	Toxic Substances Control Act
31	**ADA**	Americans with Disabilities Act
32	**MBTA**	Migratory Bird Treaty Act
33	**CWA**	Clean Water Act
34	**ANSI**	American National Standards Institute
35	**IEEE**	Institute of Electrical and Electronics Engineers
36	**NEMA**	National Electrical Manufacturers Association
37	**ASTM**	American Society for Testing and Materials
38	**ASME**	American Society of Mechanical Engineers
39	**IEEE 1881**	Standard Glossary of Stationary Battery Terminology
40	**IEEE 519**	Recommended Practice and Requirements for Harmonic Control in Electric Power Systems

NO.	STANDARDS	CODE
41	**IEEE 142**	Recommended Practice for Grounding of Industrial and Commercial Power Systems
42	**IEEE 242**	Recommended Practice for Protection and Coordination of Industrial and Commercial Power Systems
43	**IEEE 2030.3**	Standard Test Procedures for Electric Energy Storage Equipment and Systems for Electric Power Systems Applications
44	**EPRI 3002009313**	Energy Storage Integration Council Energy Storage Test Manual 2016
45	**IEEE 1881**	Standard Glossary of Stationary Battery Terminology
47	**MESA**	Open Standards for Energy Storage
48	**NFPA 855**	Standard for the Installation of Stationary Energy Storage Systems
49	**OSSC**	2014 Oregon Structural Specialty Code
50	**International Building Code**	2012 International Building Code
51	**ACI-318**	American Concrete Institute 318-11
52	**AWS**	American Welding Society D1.1 Structural Welding Code – Steel

APPENDIX B SCADA INTERFACE

Overview

The following is information of the data points being used by the Owner for the purpose of controlling and monitoring storage systems via a communications gateway. Contractor will appropriately deploy or provide an interface which implements utility standard protocols such as DNP 3.0 and Modbus encapsulated within TCP. DNP 3.0 is preferred. Contractor shall provide Device Profile for all applicable DNP 3.0 devices selected.

Note the alarms list for each system has not been listed, as systems provide a multitude of alarms. In all cases, the complete set of all possible alarms must be conveyed via digital input points at each level, System and Subsystems (Inverters and Energy Storage Banks). Failure and communication alarm points for each Subsystem must be propagated to higher interfacing System for overall inclusion to Operator's gateway.

It should be also noted that any other device capable of generating alarms within the BESS should have its alarms passed to the Operator's gateway via the same, single interface described in this section. Reference Appendix D for Network Topology. Any resettable alarms, for any device capable of generating alarms, must be able to be reset via the same, single interface, as well.

I/O List

Contractor will provide list of available data inputs and outputs for Owner review and approval in an editable format. List(s) shall be organized by data type, and must include attributes such as point name, description, and device source/destination.

Points of different types are expected to follow standard units, data type, and scale factor. Table C.1 shown below provides a minimum set of data values required to the Owner interface. Notice units are generally specified within point names. If there are questions around the configuration of a given data point, consult the table below and then reach out to the Owner for further clarification.

Points with the suffix "_OUT" are control/command points being issued from the Owner to the head-end controller

Points with the suffix "_FB" are confirmations of all control/command points being sent from the Owner to the head-end controller. The Contractor must echo received control/command points from the Owner back to the Owner, so it is understood whether the head-end controller has received them.

Points are split up into Analog Inputs (AI), Binary Inputs (BI), Analog Outputs (AO), and Binary Outputs (BO). All specified points take the perspective of the Owner. For example, Analog Inputs are Inputs to the Owner.

TABLE B.1 EXPECTED UNITS, TYPE AND SCALING

POINT TYPE	UNITS	DATA TYPE	SCALE FACTOR
Real Power	kW	INT	10
Reactive Power	kVar	INT	10

POINT TYPE	UNITS	DATA TYPE	SCALE FACTOR
Amperes	A	UINT	1
Frequency	Hz	UINT	100
AC Voltage	kV	UINT	10
DC Voltage	V	UINT	10
Real Power Ramp Rate	kW/s	INT	10
Reactive Power Ramp Rate	kVar/s	INT	10
SOC	Percentage	UINT	1
Energy	kWh	UINT32	1
Power Factor	Decimal	INT	100
Temperatures	Celsius	INT	1
Cell Voltage	V	UINT	10

Port of Alaska BESS Minimum Input Output Data Map

Convention	RO / RW			DNP Object	DNP Quality
SYSTEM DATA					
System Active Power Output Actual		RO	kW	5 - w/ time	6 - w/ quality
System Reactive Power Output Actual		RO	kVAr	5 - w/ time	6 - w/ quality
Total Battery Active Power Output Actual		RO	kW	5 - w/ time	6 - w/ quality
Total Battery Active Power Maximum Limit Actual		RO	kW	5 - w/ time	6 - w/ quality
Total Battery Active Power Minimum Limit Actual		RO	kW	5 - w/ time	6 - w/ quality
Total Battery Nominal Active Power Maximum Actual		RO	kW	5 - w/ time	6 - w/ quality
Total Battery Nominal Active Power Minimum Actual		RO	kW	5 - w/ time	6 - w/ quality
Total Battery Reactive Power Output Actual		RO	kVAr	5 - w/ time	6 - w/ quality
Total Battery Reactive Power Maximum Limit Actual		RO	kVAr	5 - w/ time	6 - w/ quality
Total Battery Reactive Power Minimum Limit Actual		RO	kVAr	5 - w/ time	6 - w/ quality
Total Battery Stored Energy Actual		RO	kWh	5 - w/ time	6 - w/ quality
Total Battery Nominal Energy Capacity Actual		RO	kWh	5 - w/ time	6 - w/ quality
Total Number of Online Battery Units		RO		5 - w/ time	6 - w/ quality
Total Renewable Active Power		RO	kW	5 - w/ time	6 - w/ quality
Total Renewable Reactive Power		RO	kVAr	5 - w/ time	6 - w/ quality
Total Renewable Actual Ramp Rate, kW per second		RO	kW/sec	5 - w/ time	6 - w/ quality
Total Renewable Actual Ramp Rate, MW per min		RO	MW/min	5 - w/ time	6 - w/ quality
Solar + BESS Output		RO	kW	5 - w/ time	6 - w/ quality
Total BESS Smoothing Dispatch		RO	kW	5 - w/ time	6 - w/ quality
ALGORITHM PARAMETERS					
BESS System, Enable PV Smoothing	0= Disabled, 1= Enabled	RW	bool		
Target Ramp Rate, Increase		RW	kW/sec		
Target Ramp Rate, Decrease		RW	kW/sec		
BESS SOC Max State of Charge		RW	%		
BESS SOC Min State of Charge		RW	%		
BESS System, Enable Voltage Support	0= Disabled, 1= Enabled	RW	bool		
Voltage Support Deadband Parameter		RW	V		
Voltage Support Gain Parameter		RW	kVAR/V		
Voltage Support Setpoint Time Constant		RW	sec		
BESS Battery, Enable Recharge Algorithm	0= Disabled, 1= Enabled	RW	bool		
BESS Battery, Recharge Gain		RW	kW/%		
BESS Battery, Recharge Power Loss		RW	kW		
BESS Battery, Ideal State of Charge		RW	%		
BESS Battery, Maximum Recharge Power		RW	kW		
BESS Battery, Minimum Recharge Power		RW	kW		
VOLTAGE SUPPORT					
Voltage Support Active Status		RO	bool	5 - w/ time	
Voltage Support Reactive Power Setpoint		RO	kVAr	5 - w/ time	

Notes:

1. w/ time means data is date time stamped
2. w/quality means any bad data is flagged due to internal communication failure of the BMS.
3. All mode controls such as on/off, enable/disable should use status point for readback and Object 12 Var 1 for control
4. All setpoint controls associated with watts, vars, and volts (points that may require re-scaling on customer side) will utilize integer setpoint controls Obj 41 Var 1 or 2. All other setpoint controls can be either integer, single precision, or double precision Obj 41.
5. All analogs shall be floating point or integer 16 or 32 bit with quality (Obj 30 with flag). Use floating pt where needed to provide precision desired w/o scaling
6. All status, analog, and control points shall be tested to verify point mapping and scaling between the BESS control system and the customers SCADA system
7. Provide SCADA point list for all controls, analogs, and status points, identify DNP Obj/Var, point name, point description units, scaling factor (if needed), max/min value, sample time (how often controller samples and updates the SCADA interface value)
Description on what action should be taken when status or analog alarms come in (and the associated analog alarm limits that should be set)
8. Provide SCADA pt scan time (between controller and downstream device) of 2-4 seconds.
9. Provide heartbeat setpoint and analog readback used to monitor if the controller is responding to controls.
10. Provide Continuous Counter analog value which updates every second to monitor if the controller is alive.

APPENDIX C ALLOWABLE LIMITS OF BESS SITE PLAN

RECORD DRAWING

DATA PROVIDED BY: ______

TITLE: ______

CONTRACTOR: ______

DATE: ______

THIS SHALL SERVE TO CERTIFY THAT THESE RECORD DRAWINGS ARE A TRUE AND ACCURATE REPRESENTATION OF THE PROJECT AS CONSTRUCTED.

GRAPHIC 40 20 0 20 40 SCALE

FIELD BOOKS	BM NO.	LOCATION	ELEV.
DESIGN:			
STAKING:			
ASBUILT:			
CONTRACTOR:	BASIS OF DATUM:		
INSPECTOR:			
CONSTRUCTION RECORD	VERTICAL DATUM		

DATA	DRAWN BY	CHECKED BY	DATA	DRAWN BY	CHECKED BY
BASE			TELEPHONE		
TOPOGRAPHY			ELECTRIC		
PROFILE			CABLE TV		
SANITARY SEWER			TRAFFIC SIGNAL		
STORM SEWER			DESIGN		
WATER			QUANTITIES		
GAS			MUN. FINAL CHECK		
PLAN CHECK					

REV	DATE	DESCRIPTION	BY
REVISIONS			

SEAL

2000 ANCHORAGE PORT ROAD
ANCHORAGE, ALASKA 99501

MUNICIPALITY OF ANCHORAGE
PORT OF ALASKA

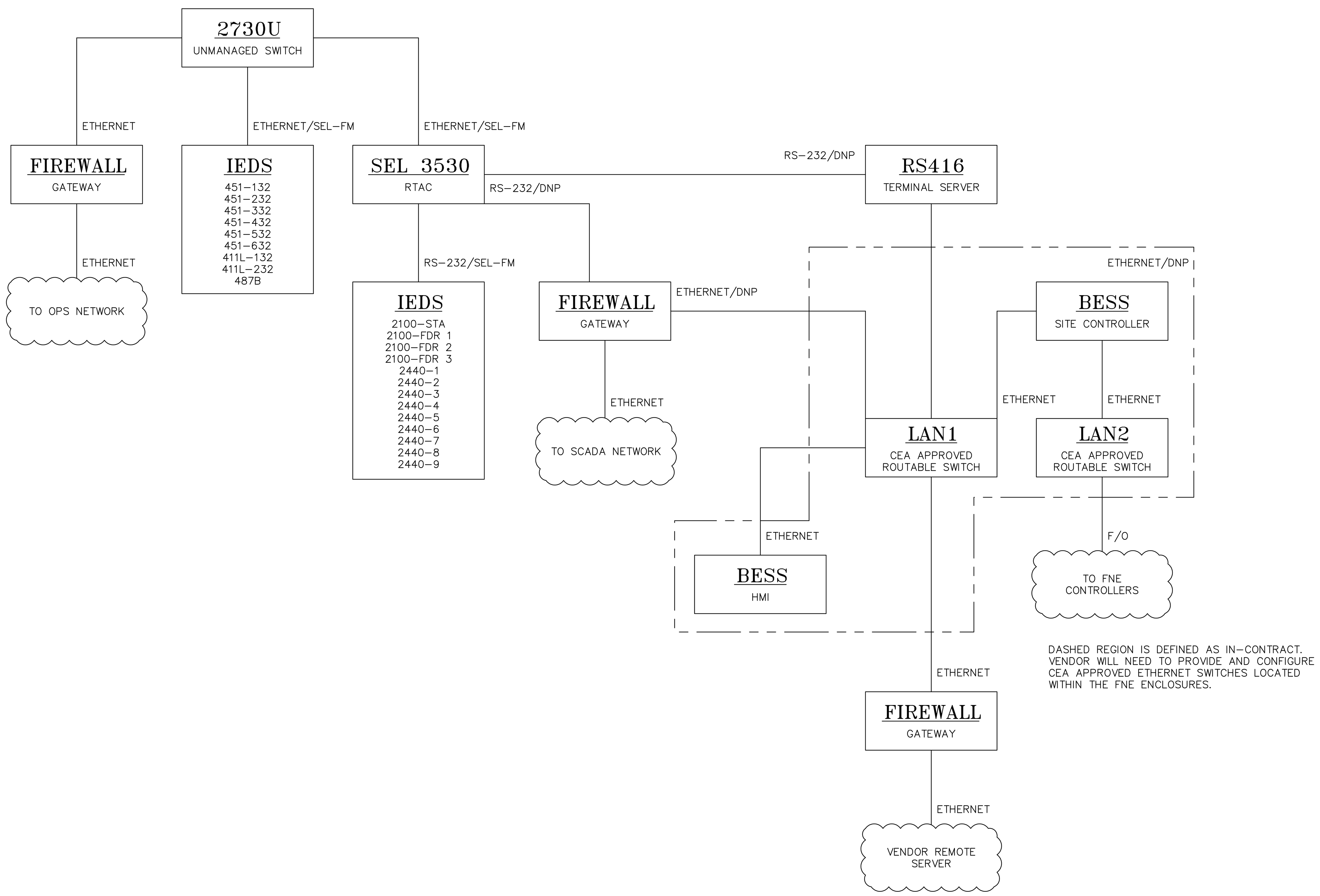
22-02 TRACK J SUBSTATION

PORT OF ALASKA (POA) 4.5 MW/9 MWh
BATTERY ENERGY STORAGE SYSTEM (BESS)
SITE PLAN FOOTPRINT AVAILABLE AREA

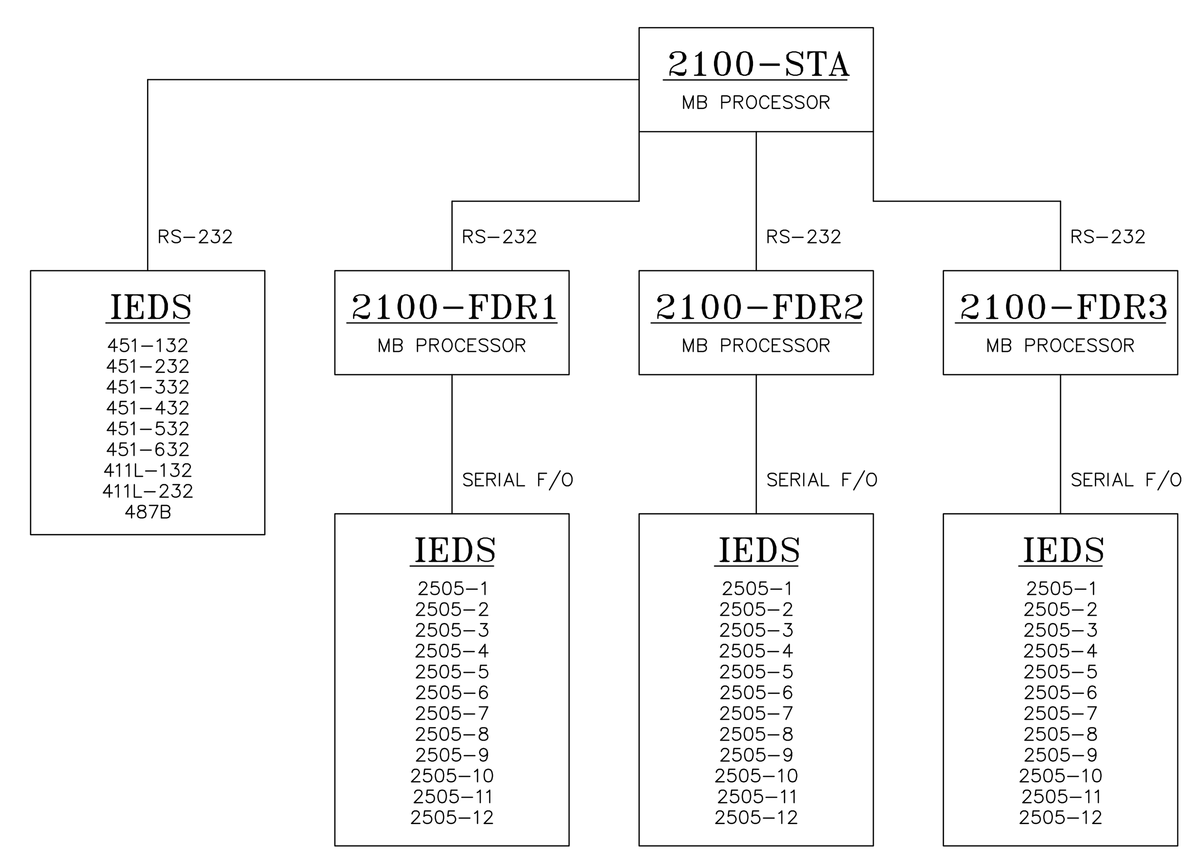
SCALE 1" = 20' | DATE: 02/20/2025 | GRID: – | ACCT. NO. | SHEET 1 of 1

APPENDIX D NETWORK TOPOLOGY

RELAY NETWORK
SEL–FM/DNP



MIRROR BIT NETWORK
MB



PROJECT: ______
ENG./DESIGN.: ______ W.O. #

NO.	DESIGN/CONSTRUCTION/ASBUILT REVISION	DWN. BY/DATE	REVIEWED MGR./SUPV./DATE	APPROVED DIRECTOR/DATE	ENG. STAMP

NO.	RECORD REVISION	CAD DRAWN BY	W.P.#	W.O. NUMBER	RECORD APPROVED	DATE

POWERING ALASKA'S FUTURE

Chugach Electric Association, Inc.
5601 Electron Drive - P.O. Box 196300
Anchorage, Alaska 99519-6300

DRAWING NAME:
BESS
NETWORK TOPOLOGY

CONFIDENTIAL

BESS–EL–OL–0001_0001_0–1

DRAWING NO. – PREVIOUS/REFERENCE

DRAWING NO.: BESS–EL–OL–0001

SHEET 0001 OF 1
PAGE ___ / ___

APPENDIX E OWNER DRAWING STANDARDS

(TO BE SUPPLIED UPON REQUEST BY OWNER)

APPENDIX F AKCIP STANDARDS

Glossary of AKCIP Terms

AKCIP-002-1 Cyber Security — AKBES Cyber System Categorization

AKCIP-005-1 Cyber Security — Electronic Security Perimeter(s)

AKCIP-006-1 Cyber Security — Physical Security of AKBES Cyber Systems

AKCIP-007-1 Cyber Security — System Security Management

AKCIP-008-1 Cyber Security — Incident Reporting and Response Planning

AKCIP-009-1 Cyber Security — Recovery Plans for AKBES Cyber Systems

AKCIP-010-1 Cyber Security — Configuration Change Management and Vulnerability Assessments

AKCIP-011-1 Cyber Security — Information Protection

AKCIP STANDARDS ARE PROPRIETARY AND CONFIDENTIAL

THESE WILL BE PROVIDED TO CONTRACTORS UPON COMPLETION OF A NON-DISCLOSURE AGREEMENT WITH THE OPERATOR, CHUGACH ELECTRIC ASSOCIATION, INC.

Glossary of AKCIP Terms

Term	Acronym	Definition
BES Cyber Asset	BCA	A Cyber Asset that if rendered unavailable, degraded, or misused would, within 15 minutes of its required operation, misoperation, or non-operation, adversely impact one or more Facilities, systems, or equipment, which, if destroyed, degraded, or otherwise rendered unavailable when needed, would affect the reliable operation of the Bulk Electric System. Redundancy of affected Facilities, systems, and equipment shall not be considered when determining adverse impact. Each BES Cyber Asset is included in one or more BES Cyber Systems.
Cyber Asset		Programmable electronic devices, including the hardware, software, and data in those devices.
Cyber System		One or more Cyber Assets logically grouped by a responsible entity to perform one or more reliability tasks for a functional entity
Electronic Access Point	EAP	A Cyber Asset interface on an Electronic Security Perimeter that allows routable communication between Cyber Assets outside an Electronic Security Perimeter and Cyber Assets inside an Electronic Security Perimeter.
Electronic Security Perimeter	ESP	The logical border surrounding a network to which BES Cyber Systems are connected using a routable protocol.
Interactive Remote Access		User-initiated access by a person employing a remote access client or other remote access technology using a routable protocol. Remote access originates from a Cyber Asset that is not an Intermediate System and not located within any of the Responsible Entity's Electronic Security Perimeter(s) or at a defined Electronic Access Point (EAP). Remote access may be initiated from: 1) Cyber Assets used or owned by the Responsible Entity, 2) Cyber Assets used or owned by employees, and 3) Cyber Assets used or owned by vendors, contractors, or consultants. Interactive remote access does not include system-to-system process communications
Intermediate System		A Cyber Asset or collection of Cyber Assets performing access control to restrict Interactive Remote Access to only authorized users. The Intermediate System must not be located inside the Electronic Security Perimeter.
Physical Security Perimeter	PSP	The physical border surrounding locations in which Cyber Assets, Cyber Systems, or

		Electronic Access Control or Monitoring Systems reside, and for which access is controlled.
Transient Cyber Asset	TCA	A Cyber Asset that is: 1. capable of transmitting or transferring executable code, 2. not included in a Cyber System, 3. not a Protected Cyber Asset (PCA) associated with high or medium impact BES Cyber Systems, and 4. directly connected (e.g., using Ethernet, serial, Universal Serial Bus, or wireless including near field or Bluetooth communication) for 30 consecutive calendar days or less to a: • BES Cyber Asset, • network within an Electronic Security Perimeter (ESP) containing high or medium impact BES Cyber Systems, or • PCA associated with high or medium impact BES Cyber Systems. Examples of Transient Cyber Assets include, but are not limited to, Cyber Assets used for data transfer, vulnerability assessment, maintenance, or troubleshooting purposes.

APPENDIX G ALASKA RAILBELT RELIABILITY STANDARDS

AKBAL-001-2 Real Power Balancing Control Performance

AKBAL-002-2 Disturbance Control Performance

AKBAL-003-2 Frequency Response and Bias

AKBAL-004-2 Time Error Correction

AKBAL-005-2 Automatic Generation Control

AKBAL-006-2 Inadvertent Interchange

AKBAL-502-2 Planning Resource Adequacy Analysis

AKFAC-001-2 Facility Connection Requirements

AKFAC-002-2 Coordination of Plans for New Facilities

AKINT-001-2 Interchange Information

AKMOD-025-2 Verification and Data Reporting of Generator Capabilities

AKMOD-026-2 Verification of Models and Data for Generators

AKMOD-027-2 Verification of Models and Data for Turbine Controls

AKMOD-028-2 Total Transfer Capability

AKMOD-032-2 Data for Power System Modeling and Analysis

AKMOD-033-2 Steady State and Dynamic Model Validation

AKPRC-006-2 Automatic Underfrequency Load Shedding

AKRES-001-2 Reserve Obligation and Allocation

AKTPL-001-2 Transmission Planning Performance

AKVAR-001-2 Voltage and Reactive Control

AKVAR-002-2 Generation Operation - Voltage Schedules

Exhibit A 2 – Functional Assignments

Exhibit B 2 - Glossary of Terms

Exhibit C 2 - Sanctions Matrix

Exhibit D 2 - Reliability Planning Guidelines

Alaska Railbelt Standard AKBAL-001-2 – Real Power Balancing Control Performance

A. Introduction

1. **Title:** **Real Power Balancing Control Performance**

2. **Number:** **AKBAL-001-2**

3. **Purpose:**

   3.1 To maintain Interconnection steady-state frequency within defined limits by balancing real power demand and supply in real-time.

4. **Applicability:**

   4.1 Balancing Authorities (BA)

5. **Effective Date:** 12 months from adoption by the Reliability Organization.

B. Requirements

R1. Each Balancing Authority shall operate such that, on a rolling 12-month basis, the average of the clock-minute averages of the Balancing Authority's Area Control Error (ACE) divided by 10B (B is the clock-minute average of the Balancing Authority Area's Frequency Bias) times the corresponding clock-minute averages of the Interconnection's Frequency Error is less than a specific limit, ε_1. This limit is a constant derived from a targeted frequency bound (separately calculated for each Interconnection) that is reviewed and set as necessary by the Regional Reliability Organization.

$$\mathrm{AVG}_{\mathrm{Period}}\left[\left(\frac{\mathrm{ACE_i}}{-10\mathrm{B_i}}\right)_1 * \Delta \mathrm{F}_1\right] \leq \epsilon_1{}^2 \quad \text{or} \quad \frac{\mathrm{AVG}_{\mathrm{Period}}\left[\left(\frac{\mathrm{ACE_i}}{-10\mathrm{B_i}}\right)_1 * \Delta \mathrm{F}_1\right]}{\epsilon_1{}^2} \leq 1$$

The equation for ACE is:

$ACE = (NI_A – NI_S) – 10B(F_A - F_S) - I_{ME}$

Where:

- NI_A is the algebraic sum of actual flows on all tie lines.
- NI_S is the algebraic sum of scheduled flows on all tie lines.
- B is the Frequency Bias Setting (MW/0.1 Hz) for the Balancing Authority. The constant factor 10 converts the frequency setting to MW/Hz.
- F_A is the actual frequency.
- F_S is the scheduled frequency. F_S is normally 60 Hz but may be offset to affect manual time error corrections.
- I_{ME} is the meter error correction factor typically estimated from the difference between the integrated hourly average of the net tie line flows (NI_A) and the hourly net interchange demand measurement (megawatt-hour). This term should normally be very small or zero.

R2. Each Balancing Authority shall operate such that its average ACE for at least 90% of clock-ten-minute periods (6 non-overlapping periods per hour) during a calendar month is within a specific limit, referred to as L_{10}.

$$AVG_{10-minute}(ACE_i) \leq L_{10}$$

Where:

$$L_{10} = 1.65\ \epsilon_{10}\ \sqrt{(-10B_i)(-10B_s)}$$

ε_{10} is a constant derived from the targeted frequency bound. It is the targeted root-mean-square (RMS) value of ten-minute average Frequency Error based on frequency performance over a given year. The bound, ε_{10}, is the same for every Balancing Authority Area within an Interconnection, and B_s is the sum of the Frequency Bias Settings of the Balancing Authority Areas in the respective Interconnection.

R3. Each Balancing Authority providing Overlap Regulation Service shall evaluate Requirement R1 (i.e., Control Performance Standard 1 or CPS1) and Requirement R2 (i.e., Control Performance Standard 2 or CPS2) using the characteristics of the combined ACE and combined Frequency Bias Settings.

R3.1. Any Balancing Authority receiving Overlap Regulation Service shall not have its control performance evaluated (i.e. from a control performance perspective, the Balancing Authority has shifted all control requirements to the Balancing Authority providing Overlap Regulation Service).

C. Measures

M1. Each Balancing Authority shall achieve, as a minimum, Requirement R1 (CPS1) compliance of 100%.

CPS1 is calculated by converting a compliance ratio to a compliance percentage as follows:

CPS1 = (2 – CF) * 100%

The frequency related compliance factor, CF, is a ratio of all one-minute compliance parameters accumulated over 12 months divided by the target frequency bound:

$$CF = \frac{CF_{12-month}}{\epsilon_1{}^2}$$

Where:

ε_1 is defined in Requirement R1.

The rating index $CF_{12\text{-month}}$ is derived from 12 months of data. The basic unit of data comes from one-minute averages of ACE, Frequency Error and Frequency Bias Settings.

A clock-minute average is the average of the reporting Balancing Authority's valid measured variable (i.e., for ACE and for Frequency Error) for each sampling cycle during a given clock-minute.

$$\left(\frac{\text{ACE}}{-10\text{B}}\right)_{\text{clock-minute}} = \frac{\left(\frac{\sum \text{ACE}_{\text{sampling cycles in clock-minute}}}{\text{n}_{\text{sampling cycles in clock-minute}}}\right)}{-10\text{B}}$$

$$\Delta\text{F}_{\text{clock-minute}} = \frac{\sum \Delta\,\text{F}_{\text{sampling cycles in clock-minute}}}{\text{n}_{\text{sampling cycles in clock-minute}}}$$

The Balancing Authority's clock-minute compliance factor (CF) becomes:

$$\text{CF}_{\text{clock-minute}} = \left[\left(\frac{\text{ACE}}{-10\text{B}}\right)_{\text{clock-minute}} * \Delta\text{F}_{\text{clock-minute}}\right]$$

Normally, sixty (60) clock-minute averages of the reporting Balancing Authority's ACE and of the respective Interconnection's Frequency Error will be used to compute the respective hourly average compliance parameter.

$$\text{CF}_{\text{clock-hour}} = \frac{\sum \text{CF}_{\text{clock-minute}}}{\text{n}_{\text{clock-minute samples in hour}}}$$

The reporting Balancing Authority shall be able to recalculate and store each of the respective clock-hour averages (CF clock-hour average-month) as well as the respective number of samples for each of the twenty-four (24) hours (one for each clock-hour, i.e., hour-ending (HE) 0100, HE 0200, ..., HE 2400).

$$\text{CF}_{\text{clock-hr average-month}} = \frac{\sum_{\text{days-in-month}}\left[(\text{CF}_{\text{clock-hour}})(\text{n}_{\text{one-minute samples in clock-hour}})\right]}{\sum_{\text{days-in-month}}\left[\text{n}_{\text{one-minute samples in clock-hour}}\right]}$$

$$\text{CF}_{\text{month}} = \frac{\sum_{\text{hours-in-day}}\left[(\text{CF}_{\text{clock-hour average month}})(\text{n}_{\text{one-minute samples in clock-hour averages}})\right]}{\sum_{\text{hours-in-day}}\left[\text{n}_{\text{one-minute samples in clock-hour averages}}\right]}$$

The 12-month compliance factor becomes:

$$\text{CF}_{\text{12-month}} = \frac{\sum_{\text{i}=1}^{12}\left[(\text{CF}_{\text{month-i}})(\text{n}_{(\text{one-minute samples in month})-\text{i}})\right]}{\sum_{\text{i}=1}^{12}\left[\text{n}_{(\text{one-minute samples in month})-\text{i}}\right]}$$

In order to ensure that the average ACE and Frequency Deviation calculated for any one-minute interval is representative of that one-minute interval, it is necessary that at least 50% of both ACE and Frequency Deviation samples during that one-minute interval be present. Should a sustained interruption in the recording of ACE or Frequency Deviation due to loss of telemetering or computer unavailability result in a one-minute interval not containing at least 50% of samples of both ACE and Frequency Deviation, that one-minute interval shall be excluded from the calculation of CPS1.

M2. Each Balancing Authority shall achieve, as a minimum, Requirement R2 (CPS2) compliance of 90%. CPS2 relates to a bound on the ten-minute average of ACE. A compliance percentage is calculated as follows:

$$\text{CPS2} = \left[1 - \frac{\text{Violations}_{\text{month}}}{(\text{Total Periods}_{\text{month}} - \text{Unvailable Periods}_{\text{month}})}\right] * 100$$

The violations per month are a count of the number of periods that ACE clock-ten minutes exceeded L_{10}. ACE clock-ten-minutes is the sum of valid ACE samples within a clock-ten-minute period divided by the number of valid samples.

Violation clock-ten-minutes

$$= 0 \text{ if}$$

$$\left|\frac{\sum \text{ACE}}{n_{\text{samples in 10-minutes}}}\right| \leq L_{10}$$

$$= 1 \text{ if}$$

$$\left|\frac{\sum \text{ACE}}{n_{\text{samples in 10-minutes}}}\right| > L_{10}$$

Each Balancing Authority shall report the total number of violations and unavailable periods for the month. L_{10} is defined in Requirement R2.

Since CPS2 requires that ACE be averaged over a discrete time period, the same factors that limit total periods per month will limit violations per month. The calculation of total periods per month and violations per month, therefore, must be discussed jointly.

A condition may arise which may impact the normal calculation of total periods per month and violations per month. This condition is a sustained interruption in the recording of ACE.

In order to ensure that the average ACE calculated for any ten-minute interval is representative of that ten-minute interval, it is necessary that at least half the ACE data samples are present for that interval. Should half or more of the ACE data be unavailable due to loss of telemetering or computer unavailability, that ten-minute interval shall be omitted from the calculation of CPS2.

M3. A Balancing Authority providing Overlap Regulation Service shall retain documentation that it evaluated Requirement R1 (i.e., Control Performance Standard 1 or CPS1) and Requirement R2 (i.e., Control Performance Standard 2 or CPS2) using the characteristics of the combined ACE and combined Frequency Bias Settings.

D. Compliance

C1. Compliance Monitoring Process

C1.1. Compliance Monitoring Responsibility

Reliability Organization.

C1.2. Compliance Monitoring Period and Reset Time Frame

One calendar month.

C1.3. Data Retention

The data that supports the calculation of CPS1 and CPS2 (Attachment 1-AKBAL 001-2) are to be retained in electronic form for at least a one-year period. If the CPS1 and CPS2 data for a Balancing Authority Area are undergoing a review to address a question that has been raised regarding the data, the data are to be saved beyond the normal retention period until the question is formally resolved. Each Balancing Authority shall retain for a rolling 12-month period the values of: one-minute average ACE (ACE_i), one-minute average Frequency Error, and, ten-minute value of Frequency Bias for the Balancing Authority and Interconnection.

C1.4. Additional Compliance Information

None

C2. Levels of Non-Compliance – CPS1

C2.1. Levels of Non-Compliance for Requirement R1, Measure M1

C2.1.1. Level 1 – The Balancing Authority Area's value of CPS1 is less than 100% but greater than or equal to 95%.

C2.1.2. Level 2 – The Balancing Authority Area's value of CPS1 is less than 95% but greater than or equal to 90%.

C2.1.3. Level 3 – The Balancing Authority Area's value of CPS1 is less than 90% but greater than or equal to 85%.

C.2.1.4 Level 4 – The Balancing Authority Area's value of CPS1 is less than 85%.

C2.2. Levels of Non-Compliance for Requirement R2, Measure M2

C2.2.1. Level 1 – The Balancing Authority Area's value of CPS2 is less than 90% but greater than or equal to 85%.

C2.2.2. Level 2 – The Balancing Authority Area's value of CPS2 is less than 85% but greater than or equal to 80%.

C2.2.3. Level 3 – The Balancing Authority Area's value of CPS2 is less than 80% but greater than or equal to 75%.

C2.2.4. Level 4 – The Balancing Authority Area's value of CPS2 is less than 75%.

C2.3. Levels of Non-Compliance for Requirement R3, Measure M3

C2.3.1. Level 1 – The Balancing Authority providing Overlap Regulation Service failed to retain evidence that it uses the characteristics of the combined ACE and combined Frequency Bias Settings when evaluating Requirement R1 (i.e., Control Performance Standard 1 or CPS1) and Requirement R2 (i.e., Control Performance Standard 2 or CPS2).

E. Regional Differences

None identified.

Version History

Version	**Date**	**Action**	**Change Tracking**
001A	11-1-2013	Approved –IMC	
001B	3-8-2016	EPS initial edits	Yes
001C	3-16-2016	IMC Revision	No
001D	2-2-2018	IMC Revision	Yes
002	3-30-2018	RRO Review	Yes

Attachment 1-AKBAL-001-2
CPS1 and CPS2 Data

CPS1 DATA	Description	Retention Requirements
ε_1	A constant derived from the targeted frequency bound. This number is the same for each Balancing Authority Area in the Interconnection.	Retain the value of ε_1 used in CPS1 calculation.
ACE_i	The clock-minute average of ACE.	Retain the 1-minute average values of ACE (525,600 values).
B_i	The Frequency Bias of the Balancing Authority Area.	Retain the value(s) of B_i used in the CPS1 calculation.
F_A	The actual measured frequency.	Retain the 1-minute average frequency values (525,600 values).
F_S	Scheduled frequency for the Interconnection.	Retain the 1-minute average frequency values (525,600 values).

CPS2 DATA	Description	Retention Requirements
V	Number of incidents per hour in which the absolute value of ACE clock-ten-minutes is greater than L_{10}.	Retain the values of V used in CPS2 calculation.
ε_{10}	A constant derived from the frequency bound. It is the same for each Balancing Authority Area within an Interconnection.	Retain the value of ε_{10} used in CPS2 calculation.
B_i	The Frequency Bias of the Balancing Authority Area.	Retain the value of B_i used in the CPS2 calculation.
B_s	The sum of Frequency Bias of the Balancing Authority Areas in the respective Interconnection. For systems with variable bias, this is equal to the sum of the minimum Frequency Bias Setting.	Retain the value of B_s used in the CPS2 calculation. Retain the 1-minute minimum bias value (525,600 values).
U	Number of unavailable ten-minute periods per hour used in calculating CPS2.	Retain the number of 10-minute unavailable periods used in calculating CPS2 for the reporting period.

Alaska Railbelt Standard AKBAL-002-2 – Disturbance Control Performance

A. Introduction

1. **Title:** **Disturbance Control Performance**

2. **Number:** **AKBAL-002-2**

3. **Purpose:**

   3.1 The purpose of the Disturbance Control Standard (DCS) is to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance.

4. **Applicability:**

   4.1 Balancing Authorities

   4.2. Reserve Sharing Groups (Balancing Authorities may meet the requirements of Standard AKBAL-002 through participation in a Reserve Sharing Group.)

   4.3. Reliability Organization

5. **Effective Date:** 12 months from adoption by the Reliability Organization.

B. Requirements

R1. Each Balancing Authority shall have access to and/or operate Contingency Reserves to respond to Disturbances. Contingency Reserves may be supplied from generation, energy storage systems, load-shed, controllable load resources, other devices, or coordinated adjustments to Interchange Schedules.

R1.1. A Balancing Authority may elect to fulfill its Contingency Reserve obligations by participating as a member of a Reserve Sharing Group. In such cases, the Reserve Sharing Group shall have the same responsibilities and obligations as each Balancing Authority with respect to monitoring and meeting the requirements of Standard AKBAL-002.

R2. Each Reliability Organization or Sharing Group shall specify its Contingency Reserve policies, including:

R2.1. The minimum reserve requirement for the group, as determined by a coordinated Railbelt UF load-shed/spinning reserve/droop coordination study approved by the Reliability Organization.

R2.2. Its allocation among members, as defined in the Reserve Policy of the Reliability Organization, and as modified by coordinated Railbelt UF load-shed/spinning reserve/droop coordination studies approved by the Reliability Organization.

R2.3. The permissible mix of Operating Reserve – Spinning and Operating Reserve – Supplemental that may be included in Contingency Reserve.

R2.4. The procedure for applying Contingency Reserve in practice including recommendations on geographic dispersion.

R2.5. The limitations, if any, upon the amount of SILOS that may be included as contingency reserve and its operation requirements.

R2.6. The same portion of resource capacity (e.g. reserves from jointly owned generation) shall not be counted more than once as Contingency Reserve by multiple Balancing Authorities.

R3. Each Balancing Authority or Reserve Sharing Group shall activate sufficient Contingency Reserve to comply with the DCS.

R3.1. At a minimum, the Balancing Authority or Reserve Sharing Group shall carry sufficient Contingency Reserves to comply with Requirement R2. All Balancing Authorities and Reserve Sharing Groups shall review, no less frequently than annually, their probable contingencies to determine their prospective most severe single contingencies.

R3.2. Each Balancing Authority within a Reserve Sharing Group shall coordinate its Contingency Reserve and Protection Reserve resources such that Contingency Reserve resources for all Reserve Sharing Group members are activated before any Reserve Sharing Group member must activate Protection Reserves for contingency events that are less than or equal to the largest single contingency event planned for in Requirement R2. The contingency reserve shall not be provided after the Protection Reserves have been provided.

R3.3. The activation of Contingency Reserves shall not cause the frequency to exceed 60.5 Hz for contingency events that are less than or equal to the largest single contingency event planned for in Requirement R2.

R4. A Balancing Authority or Reserve Sharing Group shall meet the Disturbance Recovery Criterion within the Disturbance Recovery Period for 100% of Reportable Disturbances. The Disturbance Recovery Criterion is:

R4.1. All Balancing Authorities shall change AGC operation from tie-line bias to flat frequency control in response to a Reportable Disturbance in a coordinated fashion. The frequency trigger for switching from tie-line bias to flat frequency control will be determined by the Reliability Organization.

R4.2. A Balancing Authority shall remain in flat frequency control until tie-line bias is activated by the Railbelt Interconnected system.

R4.2.1. The system will not return to coordinated tie-line bias control until all firm load is restored.

R4.2.2. A Balancing Authority may restore interrupted load before the return to tie-line bias control if sufficient generation reserves are available.

R4.3. The Balancing Authority shall activate sufficient controls or actions to return frequency between the acceptable frequency conditions of 60.2 and 59.8 Hz following a Reportable Disturbance.

R4.4. The default Disturbance Recovery Period is 10 minutes after the start of a Reportable Disturbance. This period may be adjusted to better suit the needs of the Interconnected System based on analysis approved by the Reliability Organization.

R4.5. Each Balancing Authority shall return AGC to tie-line bias control within the Disturbance Recovery Period accounting for schedule change(s) related to shared reserves. The trigger for returning to tie-line bias control will be determined by the Reliability Organization.

R4.6. The load restoration process shall be coordinated between Balancing Authorities and Reserve Sharing Groups.

R4.7. The load restoration process shall not result in a reportable disturbance.

R5. A Balancing Authority or Reserve Sharing Group shall meet the Disturbance Recovery Criterion for Multiple Contingencies within the Disturbance Recovery Period where the sum of all individual Contingencies are less than or equal to the largest single contingency event planned for in Requirement R2.

R5.1. The requirements for multiple contingencies within the initial Disturbance Recovery Period are the same as those for a single Reportable Disturbance except:

R5.1.1. The Disturbance Recovery Period is 10 minutes after the start of the last of the multiple contingencies.

R6. A Balancing Authority or Reserve Sharing Group shall fully restore its Contingency Reserves within the Contingency Reserve Restoration Period.

R6.1. The Contingency Reserve Restoration Period begins at the end of the Disturbance Recovery Period which is limited to a maximum of 10 minutes following a Reportable Disturbance.

R6.2. The default Contingency Reserve Restoration Period is 50 minutes. This period may be adjusted to better suit the reliability targets of the Interconnected System based on analysis approved by the Reliability Organization.

R7. Following a Reportable Excess Contingency Disturbance, the Balancing Authority shall activate sufficient controls or actions to return frequency between the acceptable frequency conditions of 60.7 and 59.3 Hz, within the Disturbance Recovery Period for 100% of Reportable Excess Contingency Disturbances within 10 minutes.

R7.1. In general, the frequency recovery period shall be less than the damage, trip points and control instability regions for all generation resources within the Balancing Authority area such that no generation resource is damaged or lost due to the lack of frequency recovery. The Actual

Disturbance Recovery Period is defined as the actual time required to restore the frequency from the time of the initiating multi-contingency event or the last in a series of contingency events to the time the frequency is within the frequency limits of 60.7 to 59.3 Hz.

R7.2. For a Reportable Excess Contingency Disturbance event a Balancing Authority must not be required to fully restore its Contingency Reserves until such a time that the Balancing Authority determines that additional reserves are available and under the control of the Balancing Authority to initiate the restoration of Contingency Reserves. There will be no maximum required Contingency Reserve Restoration Period.

C. Measures

M1. A Balancing Authority or Reserve Sharing Group must have documentation that it had access to and/or operated the Contingency Reserve levels specified in R2. The documentation must list the actual Contingency Reserve levels based upon data integrated over each clock hour except within the period of time determined by the sum of the Disturbance Recovery Period, plus the Contingency Reserve Restoration Period following the start of a Reportable Disturbance or Reportable Excess Contingency Disturbance.

M2. Each Balancing Authority must have documentation showing the Contingency Reserve policies. The Balancing Authority shall provide documentation showing the required Contingency Reserve requirement as well as how the Contingency Reserve requirement was allocated for each Reportable Disturbance.

M3. Each Balancing Authority must have documentation that it activated its Contingency Reserve resources before any Reserve Sharing Group member activated its Protection Reserves.

M4. A Balancing Authority or Reserve Sharing Group shall calculate and report compliance with the Disturbance Control Standard for all Disturbances involving all generating unit trips, transmission line trips, and distribution level disturbances that result in frequency deviation > 0.2 Hz. Regions may, at their discretion, require a lower reporting threshold. Disturbance Control Standard is measured as the monthly average Actual Disturbance Recovery Time in percent of the Disturbance Recovery Period.

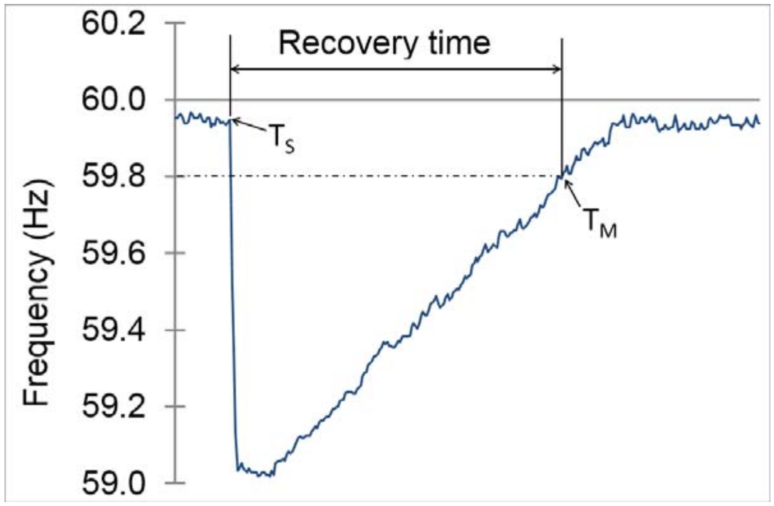
The equation for Actual Disturbance Recovery Period (ΔT_{f1}) is:

$$\Delta T_{f1} = T_M - T_S$$

Where:

T_M is the time when system frequency returned to the respective limit, 60.2 or 59.8 Hz following the initial reportable disturbance.

T_S is the time at the start of the reportable disturbance.



The monthly average Actual Disturbance Recovery Time ($Rf1_{avg}$) in percent of the Disturbance Recovery Period is:

$$Rf1_{avg} = \frac{100 * \sum_{number\ of\ events} \Delta T_{f1}}{R_{SDRP1} * n_{total\ events}}$$

Where:

- ΔT_{f1} is the Actual Disturbance Recovery Period in minutes for each disturbance.
- R_{SDRP1} is the Disturbance Recovery Period in minutes.
- "n" is the total number of reportable events per month.

The Balancing Authority shall have records that indicate the number of Reportable contingency events and the number of events whose individual Actual Disturbance Recovery Period was greater than the Disturbance Recovery Period in each reporting interval (months).

For events where the frequency returns to 59.8, and the system returns to tie-line bias control each Balancing Authority shall provide 100% of its declared contingency reserve obligation within the first 10 minutes after returning to tie-line bias control for any Reportable Disturbance. The updated schedules utilized in tie-line bias control will account for the Balancing Authority's contingency reserve obligation and schedule changes between the utilities. Utilities that cannot provide their declared reserves within 10 minutes of returning to tie-line bias shall be deemed deficient in providing the required contingency reserves.

Each Balancing Authority shall return its ACE to 0 within 10 minutes of returning to tie-line bias control. A Balancing Authority that does not return its ACE to zero within 10 minutes will be deficient by the magnitude of ACE 10 minutes after the restoration to tie-line bias control.

For disturbances where the system does not return to the target frequency within 10 minutes, each utility's reserve contribution shall be measured at 10 minutes, the Disturbance Recovery Period. Those utilities not providing their required reserves at that time will be deemed deficient in providing their declared reserves.

The deficiency shall be measured by the following formula for Balancing Authority that experienced the contingency (if contingency was a generator contingency and there are no dynamic power flows through the load balancing area):

$$Def_e = Net\_Int_e - (Net\_Int_{PreDisturbance\_e} + CRO_e - Contingency)$$

The deficiency shall be measured by the following formula for all other Balancing Authorities in the Reserve Sharing Group, if there are no dynamic power flows through the load balancing area:

$$Def_e = Net\_Int_e - (Net\_Int_{PreDisturbance\_e} + CRO_e)$$

Where:

$_e$ = Obligated Entity

Def = Deficiency (MW)

Net_Int = Net Interchange 10 minutes after the Reportable Disturbance (MW)

$Net\_Int_{PreDisturbance}$ = Net Interchange prior to the Reportable Disturbance (MW)

CRO = Contingency Reserve Obligation for Reportable Disturbance (MW)

Contingency = Contingency magnitude (MW)

M1.1.1 The Balancing Authority or Reserve Sharing Group shall have documentation that the Contingency Reserves were fully restored within the Contingency Reserve Restoration Period.

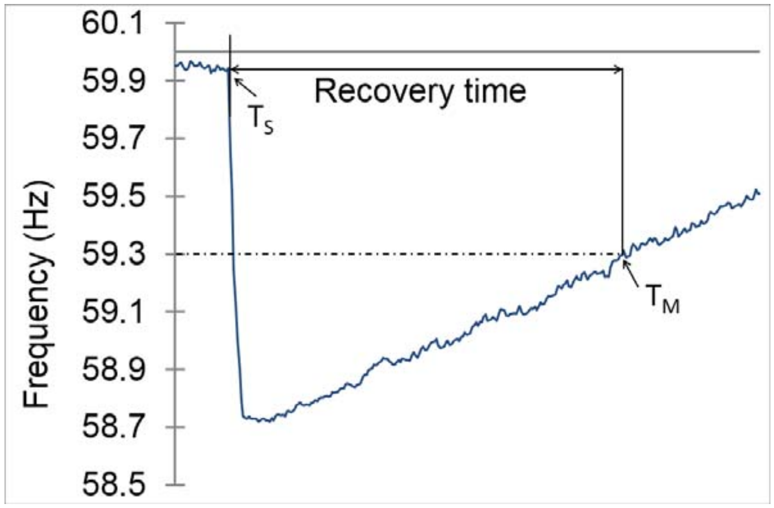
M2.1.1 The Balancing Authority or Reserve Sharing Group shall have documentation that the system frequency was restored between the acceptable frequency conditions of 60.7 and 59.3 Hz for Reportable Excess Contingency Disturbances within the Disturbance Recovery Period.

The equation for Actual Excess Contingency Disturbance Recovery Period (ΔT_{f2}) is:

$$\Delta T_{f2} = T_M - T_S$$

Where:

- T_M is the time when system frequency returned to the respective limit, 60.7 to 59.3 Hz following the initial Reportable Excess Contingency Disturbance.
- T_S is the time at the start of the Reportable Excess Contingency Disturbance.



The monthly average Actual Excess Contingency Disturbance Recovery Time in ($Rf2_{avg}$) in percent is:

$$Rf2_{avg} = \frac{100 * \sum_{number\ of\ events} \Delta T_{f2}}{R_{SDRP2} * n_{total\ events}}$$

Where:

- ΔT_{f2} is the Actual Excess Contingency Disturbance Recovery Period in minutes for each disturbance.
- R_{SDRP2} is the Disturbance Recovery Period in minutes for an Reportable Excess Contingency Disturbance.
- "n" is the total number of reportable events per month.

The Balancing Authority shall have records that indicate the number of Reportable Excess Contingency Disturbance events and the number of events whose individual Actual Excess Contingency Disturbance Recovery Period was greater than the Disturbance Recovery Period in each reporting interval (months).

D. Compliance

C1. Compliance Monitoring Process

Compliance with the DCS shall be measured on a percentage basis as set forth in the measures above.

Each Balancing Authority or Reserve Sharing Group shall submit one completed copy of DCS Form, "Alaskan Railbelt Control Performance Standard Survey – All Interconnections" or equivalent form to its Reliability Organization no later than the 10th day following the end of the calendar quarter (i.e. April 10th, July 10th, October 10th, January 10th).

C1.1. Compliance Enforcement Authority

Reliability Organization

C1.2. Compliance Monitoring Period and Reset Time Frame

Compliance for DCS will be evaluated for each reporting period. Reset is one calendar quarter without a violation.

C1.3. Data Retention

The data that support the calculation of DCS are to be retained in electronic form for at least a one-year period. If the DCS data for a Reserve Sharing Group and Balancing Area are undergoing a review to address a question that has been raised the question is formally resolved.

C1.4. Additional Compliance Information

Each Reliability Organization or Reserve Sharing Group may optionally reduce the frequency deviation required for a Reportable Disturbance, provided that normal operating characteristics are not being considered or misrepresented as contingencies. Normal operating characteristics are excluded because DCS only measures the recovery from sudden, unanticipated losses of supply-side resources.

If a multiple contingency event occurs within a time span greater than one minute the Reliability Organization will have at its discretion the option to consider the multiple Contingencies as a single Contingency event.

C2. Levels of Interconnection Non-Compliance

C2.1. Levels of BA Non-Compliance for Requirement R1, Measure M1

C2.1.1. Level 1 – A Balancing Authority or Reserve Sharing Group did not have documentation showing it had access to the Contingency Reserve resources specified in R2.

C2.1.2. Level 2 – A Balancing Authority or Reserve Sharing Group did not have documentation showing it had operated the Contingency Reserve resources specified in R2.

C2.2. Levels of Interconnection Non-Compliance for Requirement R2, Measure M2

C2.2.1. Level 1 –Reliability Organization or Sharing Group failed to retain dated evidence showing its Contingency Reserve policies.

C2.2.2. Level 2 –Reliability Organization or Sharing Group did not specify its Contingency Reserve policies.

C3. Levels of BA Non-Compliance for Requirement R3, Measure M3

C3.1. Level 1 – A Balancing Authority failed to retain dated evidence showing the amount of activated Contingency Reserves and activated Protection Reserves.

- **C3.2. Level 1 –** A Balancing Authority failed to coordinate its Contingency Reserve and Protection Reserve resources with other Reserve Sharing Group members.
- **C3.3. Level 2** – A Balancing Authority activated Contingency Reserves that caused frequency to exceed 60.2 Hz for an event that was less than or equal to the largest single contingency.
- **C3.4. Level 2** – A Balancing Authority failed to carry sufficient Contingency Reserves.

C4. Levels of Interconnection Non-Compliance for Requirement R4-R5, Measure M4

- **C4.1. Level 1 -** The Interconnection achieved a monthly average Actual Disturbance Recovery Time ($Rf1_{avg}$) greater than or equal to 100% but was less than 105%. (to be evaluated following monitoring period).
- **C4.2. Level 1 -** The Balancing Authority achieved a monthly average Actual Disturbance Recovery Time ($Rf1_{avg}$) greater than or equal to 100% but was less than 105%. (to be evaluated following monitoring period)
- **C4.3. Level 2 -** The Interconnection failed to meet all the requirements of Level 1 for Requirement R4, Requirement R5, and Measurement M4.

C5. Levels of BA Non-Compliance for Requirement R4-R5, Measure M4

- **C5.1. Level 2 -** The Balancing Authority failed to provide 100% of the declared contingency reserve obligation within the 10 minutes immediately following restoration of tie-line bias control for any Reportable Disturbance.
- **C5.2. Level 2 -** The Balancing Authority failed to provide 100% of the declared contingency reserve obligation for Reportable Disturbances that do not return system frequency to 59.8 Hz within the Disturbance Recovery Period.

Each Balancing Authority or Reserve Sharing Group not meeting the DCS during a given calendar quarter shall increase its Contingency Reserve obligation for the calendar quarter (offset by one month) following the evaluation by the Reliability Organization Reliability Coordinator or Compliance Monitor [e.g. for the first calendar quarter of the year, the penalty is applied for May, June, and July.] The increase shall be directly proportional to the non-compliance with the DCS in the preceding quarter. This adjustment is not compounded across quarters, and is an additional percentage of reserve needed beyond the most severe single Contingency. A Reserve Sharing Group may choose an allocation method for increasing its Contingency Reserve for the Reserve Sharing Group provided that this increase is fully allocated.

A representative from each Balancing Authority or Reserve Sharing Group that was non-compliant in the calendar quarter most recently completed shall provide written documentation verifying that the Balancing Authority or Reserve Sharing

Group will apply the appropriate DCS performance adjustment beginning the first day of the succeeding month, and will continue to apply it for three months. The written documentation shall accompany the quarterly Disturbance Control Standard Report when a Balancing Authority or Reserve Sharing Group is non-compliant.

C6. Levels of BA Non-Compliance for Requirement R6, Measure M5

C6.1. Level 1 - A Balancing Authority or Reserve Sharing Group failed to retain dated evidence demonstrating that Contingency Reserves were restored within the Contingency Restoration Period.

C6.2. Level 2 – A Balancing Authority or Reserve Sharing Group failed to restore Contingency Reserves within the Contingency Restoration Period.

C7. Levels of Interconnection Non-Compliance for Requirement R7, Measure M6

C7.1. Level 1 - The Balancing Authority achieved a monthly average Actual Excess Contingency Disturbance Recovery Time ($Rf2_{avg}$) greater than or equal to 100% but was less than 105%. (to be evaluated following monitoring period).

C7.2. Level 2 - The Balancing Authority failed to meet all the requirements of Level 1 for Requirement R7 and Measurement M6.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
000	11-1-2013	Approved – IMC	
001A	10-9-2015	EPS initial edits	Yes
001B	12-21-2015	EPS – Revision Edits	Yes
001C	12-31-2015	EPS – Revisions following IMC meeting	Yes
001D	1-19-2016	EPS – Revisions following IMC meeting	Yes
001E	1-22-2016	EPS – Revisions for review	Yes
001F	2-2-2016	EPS – Revisions following IMC meeting	Yes
001G	3-16-2016	IMC Revision	No
001H	2-2-2018	IMC Revision	Yes
002	3-30-2018	RRO Revision	Yes

Alaska Railbelt Standard AKBAL-003-2 – Frequency Response and Bias

A. Introduction

1. **Title:** **Frequency Response and Bias**
2. **Number:** **AKBAL-003-2**
3. **Purpose:**
   3.1 This standard provides a consistent method for calculating the Frequency Bias component of ACE.
4. **Applicability:**
   4.1. Balancing Authorities
5. **Effective Date:** 12 months from adoption by the Reliability Organization.

B. Requirements

R1. Each Balancing Authority shall review its unit droop settings by January 1 of each year to reflect any change in the Frequency Response of the Balancing Authority Area.

R1.1. The Balancing Authority may change its Frequency Bias Setting, and the method used to determine the setting, whenever any of the factors used to determine the current bias value change.

R1.2. Each Balancing Authority shall report its Frequency Bias Setting, and method for determining that setting, to the Reliability Organization.

R1.3. Each Balancing Authority shall establish and maintain a Frequency Bias Setting that is as close as practical to, or greater than, the Balancing Authority's Frequency Response.

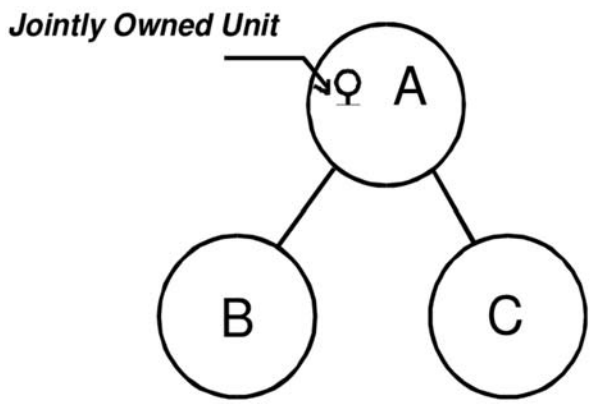
R2. Each Balancing Authority shall operate its Automatic Generation Control (AGC) on Tie Line Bias, unless such operation is adverse to system or Interconnection reliability.

R2.1. A Balancing Authority shall automatically change AGC operation from tie-line bias to flat frequency control in response to a measured system frequency trigger as specified in AKBAL-002. The frequency trigger for switching from tie-line bias and the allowable switching time to flat frequency control will be determined by the Reliability Organization.

R3. Balancing Authorities that use Dynamic Scheduling or Pseudo-ties for jointly owned units shall reflect their respective share of the unit governor droop response in their respective Frequency Bias Setting.

R3.1. Fixed schedules for Jointly Owned Units mandate that Balancing Authority (A) that contains the Jointly Owned Unit must incorporate the respective share of the unit governor droop response for any Balancing Authorities that have fixed schedules (B and C). See the diagram below.

R3.2. The Balancing Authorities that have a fixed schedule (B and C) but do not contain the Jointly Owned Unit shall not include their share of the governor droop response in their Frequency Bias Setting.



R4. A Balancing Authority that is performing Overlap Regulation Service shall increase its Frequency Bias Setting to match the frequency response of the entire area being controlled. A Balancing Authority shall not change its Frequency Bias Setting when performing Supplemental Regulation Service.

C. Measures

M1. Each Balancing Authority shall utilize the Frequency Response calculations to update the Frequency Bias Setting at the beginning of each hour. The Frequency Bias Setting shall be between 105% and 125% of the Calculated Frequency Response. Each Balancing Authority shall have documentation that includes the Frequency Bias Setting and all data used in its calculation. The Frequency Bias Setting shall be calculated as follows:

$$B = \sum_{i=1}^{N} \frac{MW_i}{10*60\ Hz*R_i} *X\%$$

Where:

B = Frequency Bias Setting (MW / 0.1 Hz)

MW_i = Unit capacity in MW for units with scheduled headroom

R_i = Unit droop in per-unit

X% = 105% to 125%

N = number of units

The Frequency Bias Settings shall be greater than or equal to 1% of the Balancing Authority's estimated maximum yearly peak demand or 1% of the estimated maximum generation level per 0.1 Hz change, whichever is greater when the calculation results in a Frequency Bias Setting that is less than 1% of the yearly peak demand or 1% of the estimated generation level per 0.1 Hz change.

M2. Each Balancing Authority shall have documentation that its Automatic Generation Control (AGC) was operated using Tie Line Frequency Bias control and shall include exceptions due to system or Interconnection reliability. Documentation shall also demonstrate the AGC automatically switching from tie-line bias to flat frequency control at the frequency and within the timeframe required by the Reliability Organization.

M3. Balancing Authorities that use Dynamic Scheduling or Pseudo-ties for jointly owned units shall have documentation showing their respective share of the unit governor droop response in their respective Frequency Bias Setting.

M4. A Balancing Authority that is performing Overlap Regulation Service shall have documentation showing its increase in Frequency Bias Setting to match the frequency response of the entire area being controlled.

D. Compliance

C1. Compliance Monitoring Process

C1.1. Compliance Monitoring Responsibility

Reliability Organization

C1.2. Compliance Monitoring Period and Reset Time Frame

Yearly

C1.3. Data Retention

The documentation required in M1 through M4 shall be retained for at least one calendar year. The calculated Frequency Bias Setting and data used to calculate the Frequency Bias Setting shall be retained in digital format for at least one calendar year.

C1.4. Additional Compliance Information

None

C2. Levels of Non-Compliance

C2.1. Levels of Non-Compliance for Requirement R1, Measure M1

C2.1.1. **Level 1 –** A Balancing Authority failed to retain dated evidence showing its review of its unit droop settings by January 1 or within 1 quarter of the request by the Reliability Organization.

C2.2. Levels of Non-Compliance for Requirement R2, Measure M2

C2.2.1. **Level 1 –** A Balancing Authority failed to maintain evidence that its Automatic Generation Control (AGC) was operated using Tie Line Frequency Bias control with documented exceptions due to system or Interconnection reliability.

C.3. Levels of Non-Compliance for Requirement R3, Measure M3

C3.1. Level 1 – Balancing Authorities that use Dynamic Scheduling or Pseudo-ties for jointly owned units failed to maintain dated evidence showing their respective share of the unit governor droop response in their respective Frequency Bias Setting.

C.4. Levels of Non-Compliance for Requirement R4, Measure M4

C.4.1. Level 1 – A Balancing Authority that is performing Overlap Regulation Service failed to retain dated evidence showing it increased its Frequency Bias Setting to match the frequency response of the entire area being controlled.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
000	11-1-2013	Approved – IMC	
001A	3-7-2016	EPS Edits	Yes
001B	3-16-2016	IMC Revision	No
001C	2-2-2018	IMC Revision	Yes
002	3-30-2018	RRO Revision	Yes

Alaska Railbelt Standard AKBAL-004-2 – Time Error Correction

A. Introduction

1. **Title:** **Time Error Correction**

2. **Number:** AKBAL-004-2

3. **Purpose:**

   3.1 The purpose of this standard is to ensure that Time Error Corrections are conducted in a manner that does not adversely affect the reliability of the Interconnection. Although encouraged, there is no obligation for an electrical island to obtain the same time error as a neighboring island prior to synchronization.

4. **Applicability:**

   4.1. Reliability Coordinators

   4.2. Balancing Authorities

5. **Effective Date:** 12 months from adoption by the Reliability Organization.

B. Requirements

R1. Only a Reliability Coordinator shall be eligible to act as Interconnection Time Monitor. A single Reliability Coordinator in each Interconnection shall be designated by the Reliability Organization to serve as Interconnection Time Monitor.

R2. The Interconnection Time Monitor shall monitor Time Error and shall initiate or terminate corrective action orders in accordance with the Time Error Correction Procedure.

R3. Each Balancing Authority, when requested, shall participate in a Time Error Correction by one of the following methods:

R3.1. The Balancing Authority shall offset its frequency schedule by 0.02 Hertz, leaving the Frequency Bias Setting normal; or

R3.2. The Balancing Authority shall offset its Net Interchange Schedule (MW) by an amount equal to the computed bias contribution during a 0.02 Hertz Frequency Deviation (i.e. 20% of the Frequency Bias Setting).

R4. Any Reliability Coordinator in an Interconnection shall have the authority to request the Interconnection Time Monitor to terminate a Time Error Correction in progress, or a scheduled Time Error Correction that has not begun, for reliability considerations.

R4.1. Balancing Authorities that have reliability concerns with the execution of a Time Error Correction shall notify their Reliability Coordinator and request the termination of a Time Error Correction in progress.

C. Measures

Not specified.

D. Non-Compliance

Level 1

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
000	June 7, 2013	Original	New
001	May 2, 2016	No time zero prior to sync	Modify
002	Mar 30, 2018	RRO Revision	Yes

Alaska Railbelt Standard AKBAL-005-2 – Automatic Generation Control

A. Introduction

1. **Title:** **Automatic Generation Control**
2. **Number:** **AKBAL-005-2**
3. **Purpose:**
   3.1 This standard establishes requirements for Balancing Authority Automatic Generation Control (AGC) necessary to calculate Area Control Error (ACE) and to routinely deploy the Regulating Reserve. The standard also ensures that all facilities and load electrically synchronized to the Interconnection are included within the metered boundary of a Balancing Area so that balancing of resources and demand can be achieved.
4. **Applicability:**
   4.1. Balancing Authorities
   4.2. Generator Operators
   4.3. Transmission Operators
   4.4. Load Serving Entities
5. **Effective Date:** 12 months from adoption by the Reliability Organization.

B. Requirements

R1. All generation, transmission, and load operating within an Interconnection must be included within the metered boundaries of a Balancing Authority Area.

R1.1. Each Generator Operator with generation facilities operating in an Interconnection shall ensure that those generation facilities are included within the metered boundaries of a Balancing Authority Area.

R1.2. Each Transmission Operator with transmission facilities operating in an Interconnection shall ensure that those transmission facilities are included within the metered boundaries of a Balancing Authority Area.

R1.3. Each Load-Serving Entity with load operating in an Interconnection shall ensure that those loads are included within the metered boundaries of a Balancing Authority Area.

R2. Each Balancing Authority shall maintain Regulating Reserve that can be controlled by AGC to meet the Control Performance Standard in AKBAL-001.

R3. A Balancing Authority providing Regulation Service shall ensure that adequate metering, communications, and control equipment are employed to prevent such service from becoming a Burden on the Interconnection or other Balancing Authority Areas.

R4. A Balancing Authority providing Regulation Service shall notify the Host Balancing Authority for whom it is controlling if it is unable to provide the service, as well as any Intermediate Balancing Authorities.

R5. A Balancing Authority receiving Regulation Service shall ensure that backup plans are in place to provide replacement Regulation Service should the supplying Balancing Authority no longer be able to provide this service.

R6. The Balancing Authority's AGC shall compare Net Actual Interchange to Net Scheduled Interchange plus Frequency Bias obligation to determine the Balancing Authority's ACE. Single Balancing Authorities operating asynchronously may employ alternative ACE calculations such as (but not limited to) flat frequency control. If a Balancing Authority is unable to calculate ACE for more than 10 minutes it shall notify all other interconnected Balancing Authorities.

- **R6.1.** The Balancing Authority shall automatically change from tie-line bias control to flat frequency control as specified in AKBAL-002.
- **R6.2.** The Balancing Authority shall automatically change AGC to a flat frequency control mode within one AGC cycle after the trigger has been detected.

R7. The Balancing Authority shall operate AGC continuously unless such operation adversely impacts the reliability of the Interconnection. If AGC has become inoperative, the Balancing Authority shall use manual control to adjust generation to maintain Net Scheduled Interchange or LBA load obligations when there are dynamic power flows through the LBA.

R8. The Balancing Authority shall ensure that data acquisition for and calculation of ACE occur at least every eight seconds.

- **R8.1.** Each Balancing Authority shall provide redundant and independent frequency metering equipment that shall automatically activate upon detection of failure of the primary source. This overall installation shall provide a minimum availability of 99.95%.

R9. The Balancing Authority shall include all Interchange Schedules with Adjacent Balancing Authorities in the calculation of Net Scheduled Interchange for the ACE equation.

- **R9.1.** Balancing Authorities with a high voltage direct current (HVDC) link to another Balancing Authority connected asynchronously to their Interconnection may choose to omit the Interchange Schedule related to the HVDC link from the ACE equation if it is modeled as internal generation or load.

R10. The Balancing Authority shall include all Dynamic Schedules in the calculation of Net Scheduled Interchange for the ACE equation.

R11. Balancing Authorities shall include the effect of ramp rates, which shall be identical and agreed to between affected Balancing Authorities, in the Scheduled Interchange values to calculate ACE.

R12. Each Balancing Authority shall include all Tie Line flows with Adjacent Balancing Authority Areas in the ACE calculation.

R12.1. Balancing Authorities that share a tie shall ensure Tie Line MW metering is telemetered to both control centers, and emanates from a common, agreed-upon source using common primary metering equipment. Balancing Authorities shall ensure that megawatt-hour data is telemetered or reported at the end of each hour.

R12.2. Balancing Authorities shall ensure the power flow and ACE signals that are utilized for calculating Balancing Authority performance or that are transmitted for Regulation Service are not filtered prior to transmission, except for the Anti-Aliasing Filters of Tie Lines.

R12.3. Balancing Authorities shall install common metering equipment where Dynamic Schedules or Pseudo-Ties are implemented between two or more Balancing Authorities to deliver the output of Jointly Owned Units or to serve remote load.

R13. Each Balancing Authority shall perform hourly error checks using Tie Line megawatt hour meters with common time synchronization to determine the accuracy of its control equipment. The Balancing Authority shall adjust the component (e.g., Tie Line meter) of ACE that is in error (if known) or use the interchange meter error (I_{ME}) term of the ACE equation to compensate for any equipment error until repairs can be made.

R14. The Balancing Authority shall provide its operating personnel with sufficient instrumentation and data recording equipment to facilitate monitoring of control performance, generation response, and after-the-fact analysis of area performance. As a minimum, the Balancing Authority shall provide its operating personnel with real-time values for ACE, Interconnection frequency and Net Actual Interchange with each Adjacent Balancing Authority Area.

R15. The Balancing Authority shall provide adequate and reliable backup power supplies and shall periodically test these supplies at the Balancing Authority's control center and other critical locations to ensure continuous operation of AGC and vital data recording equipment during loss of the normal power supply.

R16. The Balancing Authority shall sample data at least at the same periodicity with which ACE is calculated. The Balancing Authority shall flag missing or bad data for operator display and archival purposes. The Balancing Authority shall collect coincident data to the greatest practical extent, i.e., ACE, Interconnection frequency, Net Actual Interchange, and other data shall all be sampled at the same time.

R17. Each Balancing Authority shall at least annually check and calibrate its time error and frequency devices against a common reference. The Balancing Authority shall adhere to the minimum values for measuring devices as listed below:

Device	Accuracy
Digital frequency transducer	≤ 0.001 Hz
MW, MVAR, and voltage transducer	≤ 0.25% of full scale

Remote terminal unit	≤ 0.25% of full scale
Potential transformer	≤ 0.30% of full scale
Current transformer	≤ 0.50% of full scale

C. Measures

Not specified.

D. Compliance

C1. Compliance Monitoring Process

C1.1. Compliance Monitoring Responsibility

Balancing Authorities shall be prepared to supply data to the Reliability Organization in the format defined below:

C1.1.1. Within one week upon request, Balancing Authorities shall provide the Reliability Organization AGC source data in daily CSV files with time stamped averages of: 1) ACE and 2) Frequency Error for the requested period. The averages shall be as defined by the Reliability Organization.

C1.1.2. Within one week upon request, Balancing Authorities shall provide the Reliability Organization Disturbance Control Standard source data in CSV files with time stamped scan rate values for: 1) ACE and 2) Frequency Error for a time period of two minutes prior to and 15 minutes after a Reportable Disturbance.

C1.2. Compliance Monitoring Period and Reset Timeframe

None specified.

C1.3. Data Retention

C1.3.1. Each Balancing Authority shall retain its ACE, actual frequency, Scheduled Frequency, Net Actual Interchange, Net Scheduled Interchange, Tie Line meter error correction, actual Regulating Reserve and Frequency Bias Setting data in digital format at the same scan rate at which the data is collected for at least one year or a digital compression algorithm that provides similar accuracy.

C1.3.2. Each Balancing Authority or Reserve Sharing Group shall retain documentation of the magnitude of each Reportable Disturbance as well as the ACE charts and/or samples used to calculate Balancing Authority or Reserve Sharing Group disturbance recovery values. The data shall be retained for one year following the reporting quarter for which the data was recorded.

C1.4. Additional Compliance Information

None specified.

C2. Levels of Non-Compliance

C2.1. Levels of Non-Compliance for Requirement R1

C2.1.1. Level 2 – A facility operating within an interconnection is not included in the metered boundaries of a Balancing Authority.

C2.2. Levels of Non-Compliance for Requirement R2

C2.2.1. Level 1 – A Balancing Authority failed to retain documentation showing it maintained Regulating Reserve to meet the Control Performance Standard (AKBAL-001).

C2.2.2. Level 2 – A Balancing Authority failed to maintain Regulating Reserve that can be controlled by AGC to meet the Control Performance Standard (AKBAL-001).

C3. Levels of Non-Compliance for Requirement R3

C3.1. Level 2 – A Balancing Authority providing Regulation Service failed to provide adequate metering, communications, and control equipment are employed to prevent such service from becoming a Burden on the Interconnection or other Balancing Authority Areas.

C4. Levels of Non-Compliance for Requirement R4

C4.1. Level 1 – A Balancing Authority providing Regulation Service failed to notify the Host Balancing Authority for whom it is controlling if it is unable to provide the service, as well as any Intermediate Balancing Authorities.

C5. Levels of Non-Compliance for Requirement R5

C5.1. Level 1 – A Balancing Authority receiving Regulation Service failed to ensure that backup plans were in place to provide replacement Regulation Service.

C6. Levels of Non-Compliance for Requirement R6

C6.1. Level 1 – A Balancing Authority failed to notify all other interconnected Balancing Authorities after being unable to calculate ACE for more than 10 minutes.

C7. Levels of Non-Compliance for Requirement R7

C7.1. Level 1 – A Balancing Authority failed to operate AGC continuously even though such operation did not adversely impact the reliability of the Interconnection.

C8. Levels of Non-Compliance for Requirement R8

C8.1. Level 1 – A Balancing Authority failed to ensure that data acquisition for and calculation of ACE occurred at least every eight seconds.

C9. Levels of Non-Compliance for Requirement R9

C9.1. Level 1 – A Balancing Authority failed to include all Interchange Schedules with Adjacent Balancing Authorities in the calculation of Net Scheduled Interchange for the ACE equation.

C10. Levels of Non-Compliance for Requirement R10

C10.1. Level 1 – A Balancing Authority failed to include all Dynamic Schedules in the calculation of Net Scheduled Interchange for the ACE equation.

C11. Levels of Non-Compliance for Requirement R11

C11.1. Level 1 – A Balancing Authority failed to include the effect of ramp rates in the Scheduled Interchange values to calculate ACE.

C12. Levels of Non-Compliance for Requirement R12

C12.1. Level 1 – A Balancing Authority failed to include all Tie Line flows with Adjacent Balancing Authority Areas in the ACE calculation.

C13. Levels of Non-Compliance for Requirement R13

C13.1. Level 1 – A Balancing Authority failed to perform hourly error checks using Tie Line megawatt hour meters with common time synchronization to determine the accuracy of its control equipment.

C13.2. Level 2 – The Balancing Authority failed to adjust the component (e.g., Tie Line meter) of ACE that is in error (if known) or use the interchange meter error (I_{ME}) term of the ACE equation to compensate for any equipment error until repairs can be made.

C14. Levels of Non-Compliance for Requirement R14

C14.1. Level 2 – A Balancing Authority failed to provide its operating personnel with real-time values for ACE, Interconnection frequency and Net Actual Interchange with each Adjacent Balancing Authority Area.

C15. Levels of Non-Compliance for Requirement R15

C15.1. Level 1 – A Balancing Authority failed to periodically test the backup power supplies at the Balancing Authority's control center and other critical locations.

C15.2. Level 2 – A Balancing Authority failed to provide adequate and reliable backup power supplies at the Balancing Authority's control center and other critical locations.

C16. Levels of Non-Compliance for Requirement R16

C16.1. Level 1 – A Balancing Authority failed to flag missing or bad data for operator display and archival purposes or failed to collect coincident data to the greatest practical extent, i.e., ACE, Interconnection frequency, Net Actual Interchange, and other data shall all be sampled at the same time.

C16.2. Level 2 – A Balancing Authority failed to sample data at least at the same periodicity with which ACE is calculated.

C17. Levels of Non-Compliance for Requirement R17

C17.1. Level 1 – A Balancing Authority failed to check and calibrate its time error and frequency devices against a common reference.

C17.2. Level 2 – A Balancing Authority failed to adhere to the minimum values for measuring devices as listed in Requirement R17.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
000	11-1-2013	Approved – IMC	
001A	2-10-2016	EPS initial edits	Yes
001B	3-22-2016	EPS revisions after 2-11-2016 meeting	Yes
001C	2-2-2018	IMC Revision	Yes
002	3-30-2018	RRO Revision	Yes

Alaska Railbelt Standard AKBAL-006-2 – Inadvertent Interchange

A. Introduction

1. **Title:** **Inadvertent Interchange**

2. **Number:** **AKBAL-006-2**

3. **Purpose:**

    3.1. This standard defines a process for monitoring Balancing Authorities to ensure that, over the long term, Balancing Authority Areas do not excessively depend on other Balancing Authority Areas in the Interconnection for meeting their demand or Interchange obligations.

4. **Applicability:**

    4.1. Balancing Authorities

5. **Effective Date:** 12 months from adoption by the Reliability Organization.

B. Requirements

R1. Each Balancing Authority shall calculate and record hourly Inadvertent Interchange.

R2. Each Balancing Authority shall include all tie lines that connect to its Adjacent Balancing Authority Areas in its Inadvertent Interchange account. The Balancing Authority shall take into account interchange served by jointly owned generators.

R3. Each Balancing Authority shall ensure all of its Balancing Authority Area interconnection points are equipped with common megawatt-hour meters, with readings provided hourly to the control centers of Adjacent Balancing Authorities.

R4. Adjacent Balancing Authority Areas shall operate to a common Net Interchange Schedule and Net Actual Interchange value and shall record these hourly quantities, with like values but opposite sign. Each Balancing Authority shall compute its Inadvertent Interchange based on the following:

R4.1. Each Balancing Authority, by the end of the next business day, shall agree with its Adjacent Balancing Authorities to:

R4.1.1. The hourly values of Net Interchange Schedule, or;

R4.1.2. The hourly integrated megawatt-hour values of Net Actual Interchange.

R4.2. Each Balancing Authority shall use the agreed-to daily and monthly accounting data to compile its monthly accumulated Inadvertent Interchange for the On-Peak and Off-Peak hours of the month.

R4.3. A Balancing Authority shall make after-the-fact corrections to the agreed-to daily and monthly accounting data only as needed to reflect actual operating conditions (e.g. a meter being used for control was sending bad data). Changes or corrections based on non-reliability considerations shall not be reflected in the Balancing Authority's Inadvertent Interchange. After-the-fact corrections to scheduled or actual values will not be accepted without agreement of the Adjacent Balancing Authorities.

Adjacent Balancing Authorities that cannot mutually agree upon their respective Net Actual Interchange or Net Scheduled Interchange quantities by the 15th calendar day of the following month shall, for the purposes of dispute resolution, submit a report to their respective Reliability Organization. The report shall describe the nature and the cause of the dispute as well as a process for correcting the discrepancy.

R5. Reserved for future use.

C. Measures

None specified.

D. Compliance

C1. Compliance Monitoring Process

C1.1. Each Balancing Authority shall maintain a monthly summary of Inadvertent Interchange available to the Reliability Organization. These summaries shall not include any after-the-fact changes that were not agreed to by the Source Balancing Authority, Sink Balancing Authority and all Intermediate Balancing Authorities.

C1.2. Inadvertent Interchange summaries shall include at least the previous accumulation, net accumulation for the month, and final net accumulation, for both the On-Peak and Off-Peak periods.

C1.3. Each Balancing Authority shall perform an Area Interchange Error (AIE) survey as requested by the Reliability Organization to determine the Balancing Authority's Interchange error(s) due to equipment failures or improper scheduling operations, or improper AGC performance. Data for such surveys shall be collected for the time period as specified by the Reliability Organization.

C2. Levels of Non-Compliance

A Balancing Authority that neither submits a report to the Reliability Organization, nor supplies a reason for not submitting the required data, when such report is requested shall be considered Level 1 non-compliant.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
000	June 6, 2013	Original	New
001	May 2, 2016	Remove special Bradley Loss language	Modify
002	March 30, 2018	RRO Revision	Yes

Alaska Standard AKBAL-502-2 – Planning Resource Adequacy Analysis, Assessment and Documentation

A. Introduction

1. **Title:** **Planning Resource Adequacy Analysis, Assessment and Documentation**

2. **Number:** **AKBAL-502-2**

3. **Purpose:**

   3.1 To establish common criteria for each BA for a planning methodology based on the single largest unit contingency and an appropriate reserve margin or reserve criteria. The analysis, assessment, and documentation of Resource Adequacy, shall include Planning Reserve Margins for meeting system load, both real and reactive.

4. **Applicability:**

   4.1. Balancing Authorities (BA)

   4.2. Planning Coordinators

5. **Effective Date:** 12 months from adoption by the Reliability Organization.

B. Requirements

R1. The goal of the Resource Adequacy analysis is to plan the system to meet the following requirements as determined by the Reliability Organization.

R1.1. The Balancing Authority shall perform and document a Resource Adequacy analysis using one of the following two methods.

Method 1: The total capability of each Balance Authority's system plus the total amount of interruptible loads must be equal to or greater than the summation of the following:

- The capacity needed to serve the Forecasted Peak Demand for each period.
- The capacity of the unit(s) scheduled for maintenance for each period; and
- The capacity that would be lost by the Forced Outage of the largest unit/resource in service.

$$\sum_{i=1}^{N} N_i + L_{DR} \geq (L_{Peak} * F_{RM} + \sum_{m=1}^{N} N_m + N_{FO})$$

Where:

- N_i is the Normal Net Capability of available units.

- L_{DR} is the amount of Interruptible Demand designated and measureable for the BA's interruption that can be interrupted for the entire period of the expected capacity shortfall.
- L_{Peak} is the estimated system peak load and losses served from the available generation.
- N_m is the Normal Net Capability of units on scheduled maintenance.
- N_{FO} is the Normal Net Capability of the largest available unit(s) lost by Forced Outage.
- F_{RM} is the Reserve Margin multiplier and the BA must give consideration to using X percent (1.X) based on the reserve net capability. The Planning Coordinator shall set the required Reserve Margin multiplier (F_{RM}) for use in the Resource Adequacy analysis using Method 1 with approval by the Reliability Organization.

However, in no case shall the selection of F_{RM} in relationship to Normal Net Capability of the largest available unit(s) cause a shortage to serve the estimated system peak load and losses.

Method 2: Calculate a Planning Reserve Margin that will result in the sum of the probabilities for the loss of load for the integrated peak hour for all days of each planning year analyzed being equal to 0.X. (This is comparable to a "one day in X year" criterion). The Planning Coordinator shall set the minimum loss of load expectation in days per year for use in the Resource Adequacy analysis using Method 2 with approval by the Reliability Organization.

R1.2. The Resource Adequacy analysis must document that the applicable Balancing Authority has developed a resource plan that meets the requirements of R1.1 Method 1 or R1.1 Method 2.

R1.2.1. The utilization of Interruptible Demand must not contribute to the loss of load probability.

R1.2.2. The Planning Reserve Margin developed from R1.1 must be expressed as a percentage of the median[1] forecast peak Net Internal Demand (Planning Reserve Margin).

R1.3. Be performed or verified separately for each of the following planning years:

R1.3.1. Perform an analysis for Year One.

R1.3.2. Perform an analysis or verification at a minimum for one year in the 2 through 5-year period and at a minimum one year in the 6 through 10-year period.

[1] The median forecast is expected to have a 50% probability of being too high and 50% probability of being too low (50:50).

R1.3.2.1. If the analysis is verified, the verification must be supported by current or past studies for the same planning year.

R1.4. Include the following subject matter and documentation of its use:

R1.4.1. Load forecast characteristics:

- Median forecast peak load.
- Load forecast uncertainty (reflects variability in the load forecast due to weather and regional economic forecasts).
- Load diversity.
- Seasonal load variations.
- Daily demand modeling assumptions (firm, interruptible).
- Contractual arrangements concerning curtailable/Interruptible Demand.
- Load response to frequency and short and long-term changes in voltage.

R1.4.2. Resource characteristics:

- Historic resource performance and any projected changes.
- Seasonal resource ratings.
- Resource planned outage schedules, deratings, and retirements.
- Modeling assumptions of intermittent and energy limited resource such as wind, PV, and cogeneration.
- Criteria for including planned resource additions in the analysis.
- Starting/loading time if resources are to be used as Contingency Reserves.
- Frequency response characteristics.
- Inertia response characteristics.
- Frequency ride-through characteristics.
- Voltage ride-through characteristics.
- Short circuit current characteristics.
- Dispatch characteristics (ramp rate, minimum values, regulation, etc.).
- Mitigation resources required due to generation capacity resource characteristics.

R1.4.3. Transmission limitations that prevent the delivery of generation resources.

R1.4.3.1. Criteria for including planned Transmission Facility additions in the analysis.

R1.4.3.2. Criteria for remedial action systems employed in lieu of Transmission improvements.

R1.4.3.3. Resource additions to eliminate or increase transfer capacity between areas or through a transmission path.

R1.5. Consider the following resource availability characteristics and document how and why they were included in the analysis or why they were not included:

- Availability and deliverability of fuel.
- Common mode outages that affect resource availability
- Environmental or regulatory restrictions of resource availability.
- Any other demand (load) response programs not included in R1.3.1.
- Sensitivity to resource outage rates.
- Impacts of extreme weather/drought conditions that affect unit availability.
- Modeling assumptions for emergency operation procedures used to make reserves available.
- Market resources not committed to serving load (uncommitted resources) within each Balance Authority's Control Area.

R1.6. Consider Transmission maintenance outage schedules and document how and why they were included in the Resource Adequacy analysis or why they were not included.

R1.7. Document that capacity resources are appropriately accounted for in its Resource Adequacy analysis

R1.8. Document that all load in the Balance Authority's Area is accounted for in its Resource Adequacy analysis

R1.9. Provide a Corrective Action Plan to meet the Planning Reserve Margin where Resource Adequacy Analysis shows a shortfall.

R1.9.1. Corrective Action Plan should consider transmission constraints when a generation asset is recommended.

R1.9.2. The Corrective Action Plan should consider Transmission improvements to remove generation constraints.

R1.9.2.1. If transmission improvements are part of the Resource Adequacy Corrective Action Plan, the Transmission improvements must be included in the appropriate Corrective Action Plan for the transmission system.

R2. Every five years or as determined by the Reliability Organization, the BA must document the projected load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis.

R2.1. This documentation must cover each of the years selected for analysis or verification in R1.3.1 and R1.3.2.

R2.2. This documentation must include the Planning Reserve Margin calculated per requirement R1.1 for each of the three years in the analysis.

R2.3. The documentation as specified per requirement R2.1 and R2.2 must be publicly posted no later than 30 calendar days prior to the beginning of Year One.

R2.4. The documentation must include sufficient studies to show that the characteristics of proposed capacity addition do not result in a degradation of system performance.

C. Measures

M1. The BA must possess the documentation that a valid Resource Adequacy analysis was performed or verified in accordance with R1 Method 1 or R1 Method 2.

M2. The BA must possess the documentation of its projected load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis on an annual basis in accordance with R2. The documentation must include sufficient studies to determine that the characteristics of the proposed resource additions do not degrade system performance or reliability.

D. Compliance

C1. Compliance Monitoring Process

C1.1. Compliance Enforcement Authority

C1.1.1. Reliability Organization

C2. Compliance Monitoring Period and Reset Timeframe

C2.1. One calendar year

C3. Data Retention

C3.1. The BA must retain information from the current analysis and the most recent analysis. The Reliability Organization (or designee) will retain any audit data for five years.

C2. Levels of Non-Compliance for Requirement R1, Measure M1

C2.1. **Level 1 –** The BA met one of the following conditions for Requirement R1 and Measurement M1.

C2.1.1. The BA Resource Adequacy analysis failed to consider 1 or 2 of the Resource availability characteristics subcomponents under R1.4 and documentation of how and why they were included in the analysis or why they were not included.

C2.1.2. The BA Resource Adequacy analysis failed to consider 1 or 2 of the Resource availability characteristics subcomponents under R1.5 and documentation of how and why they were included in the analysis or why they were not included.

C2.1.3. The BA Resource Adequacy analysis failed to consider Transmission maintenance outage schedules and document how and why they were included in the analysis or why they were not included per R1.6.

C2.1.4. The Planning Authority did not provide the minimum Reserve Margin multiplier or the minimum Loss of Load Expectation.

C2.2. **Level 2 -** The BA failed to meet all the requirements of Level 1 for Requirement R1 and Measurement M1.

C3. Levels of Non-Compliance for Requirement R2, Measure M2

C3.1. **Level 1 –** The BA failed to publicly post the documents as specified per requirement R2.1 and R2.2 no later than 30 calendar days prior to the beginning of Year One per R2.3 for Requirement R2 and Measurement M2.

C3.2. **Level 2 -** The BA failed to meet all the requirements of Level 1 for Requirement R2 and Measurement M2.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
000	11-1-2015	Adapted from Hawaii BAL-502 Standard	Yes
001A	12-29-2015	Internal EPS edits	Yes
001B	1-4-2016	Submitted for IMC review	Yes
001C	1-25-2016	Submitted for IMC review	Yes
001D	2-3-2016	Submitted for IMC review	Yes
001E	2-12-2016	IMC Final Revision	No
002	3-30-2018	RRO Revision	Yes

<u>Alaska Railbelt Standard AKFAC-001-2 – Facility Connection Requirements</u>

A. Introduction

1. **Title:** **Facility Connection Requirements**

2. **Number:** **AKFAC-001-2**

3. **Purpose:**

   3.1. To avoid adverse impacts on reliability, Transmission Owners must establish facility connection and performance requirements. All entities proposing to interconnect and operate equipment connected to the transmission owners' facilities within the Railbelt will be required to adhere to these standards.

4. **Applicability:**

   4.1. Transmission Owner

5. **Effective Date:** 12 months from adoption by the Reliability Organization.

B. Requirements

R1. The Transmission Owner shall document, maintain, and publish facility connection requirements that ensure compliance with the Reliability Organization Operating and Reliability Standards and applicable Regional Reliability Organization, sub-regional, power pool, and individual Transmission Owner planning criteria and facility connection requirements. The Transmission Owner's facility connection requirements shall address connection requirements for:

- **R1.1.** Generation facilities,
- **R1.2.** Transmission facilities, and
- **R1.3.** End-user facilities.

R2. The Transmission Owner's facility connection requirements shall address, but are not limited to, the following items:

- **R2.1.** Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:
  - **R2.1.1.** Procedures for coordinated joint studies of new facilities and their impacts on the interconnected transmission systems.
  - **R2.1.2.** Procedures for notification of new or modified facilities to others (those responsible for the reliability of the interconnected transmission systems) as soon as feasible.
  - **R2.1.3.** Voltage level and MW and MVAR capacity or demand at point of connection.
  - **R2.1.4.** Breaker duty and surge protection.
  - **R2.1.5.** System protection and coordination.

R2.1.6. Metering and telecommunications.

R2.1.7. Grounding and safety issues.

R2.1.8. Insulation and insulation coordination.

R2.1.9. Voltage, Reactive Power, and power factor control.

R2.1.10. Power quality impacts.

R2.1.11. Equipment Ratings.

R2.1.12. Synchronizing of facilities.

R2.1.13. Maintenance coordination.

R2.1.14. Operational issues (abnormal frequency and voltages).

R2.1.15. Inspection requirements for existing or new facilities.

R2.1.16. Communications and procedures during normal and Emergency operating conditions.

R3. The Transmission Owner shall maintain and update its facility connection requirements as required. The Transmission Owner shall make documentation of these requirements available to the users of the transmission system, the Regional Reliability Organization on request within five business days.

C. Measures

M1. The Transmission Owner shall make available to the Reliability Organization for inspection evidence that it met all the requirements stated in Reliability Standard AKFAC-001-1; R1.

M2. The Transmission Owner shall make available to the Reliability Organization for inspection evidence that it met all requirements stated in Reliability Standard AKFAC-001-1; R2.

M3. The Transmission Owner shall make available to the Reliability Organization for inspection evidence that it met all the requirements stated in Reliability Standard AKFAC-001-1; R3.

D. Compliance

C1. Compliance Monitoring Process

C1.1. Compliance Monitoring Responsibility

Reliability Organization

C1.2. Compliance Monitoring Period and Reset Timeframe

On request (five business days)

C1.3. Data Retention

None specified.

C1.4. Additional Compliance Information

None

C2. Levels of Non-Compliance

Level 3

E. Regional Difference

None identified.

Version History

Version	Date	Action	Change Tracking
000	June 7, 2013	Original	New
001	May 2, 2016	Remove IMC interconnect standards	Modify
002	Mar 30, 2018	RRO Revision	Yes

<u>Alaska Railbelt Standard AKFAC-002-2 – Coordination of Plans for New Facilities</u>

A. Introduction

1. **Title:** **Coordination of Plans for New Generation, Transmission, and End User Facilities**

2. **Number:** **AKFAC-002-2**

3. **Purpose:**

   3.1. To avoid adverse impacts on reliability, Generator Owners and Transmission Owners and electricity end-users must meet facility connection and performance requirements. All entities proposing to interconnect and operate within the Railbelt will be required to adhere to these standards.

4. **Applicability:**

   4.1. Generator Owner.

   4.2. Transmission Owner.

   4.3. Distribution Provider.

   4.4. Load-Serving Entity.

   4.5. Transmission Planner.

   4.6. Planning Authority.

5. **Effective Date:** 12 months from adoption by the Reliability Organization.

B. Requirements

R1. The Generator Owner, Transmission Owner, Distribution Provider, and Load-Serving Entity seeking to integrate generation facilities, transmission facilities, and electricity end-user facilities shall each coordinate and cooperate on its assessments with its Transmission Planner and Planning Authority. The assessment shall include:

R1.1. Evaluation of the reliability impact of the new facilities and their connections on the interconnected transmission systems.

R1.2. Verification of compliance with the Reliability Organization's reliability standards and applicable power pool, and individual system planning criteria and facility connection requirements.

R1.3. Evidence that the parties involved in the assessment have coordinated and cooperated on the assessment of the reliability impacts of new facilities on the interconnected transmission systems. While these studies may be performed independently, the results shall be jointly evaluated and coordinated by the entities involved.

R1.4. Evidence that the assessment included steady-state, short-circuit, and dynamics studies as necessary to evaluate system performance.

R1.5. Documentation that the assessment included study assumptions, system performance, alternatives considered, and jointly coordinated recommendations.

R2. The Planning Authority, Transmission Planner, Generator Owner, Transmission Owner, Load-Serving Entity, and Distribution Provider shall each retain its documentation (of its evaluation of the reliability impact of the new facilities and their connections on the interconnected transmission systems) for three years and shall provide the documentation to the Reliability Organization on request (within 30 calendar days).

C. Measures

M1. The Planning Authority, Transmission Planner, Generator Owner, Transmission Owner, Load-Serving Entity, and Distribution Provider's documentation of its assessment of the reliability impacts of new facilities shall address all items in Reliability Standard AKFAC-002-0; R1.

M2. The Planning Authority, Transmission Planner, Generator Owner, Transmission Owner, Load-Serving Entity, and Distribution Provider shall each have evidence of its assessment of the reliability impacts of new facilities and their connections on the interconnected transmission systems is retained and provided to other entities in accordance with Reliability Standard AKFAC-002-0; R2.

D. Compliance

C1. Compliance Monitoring Process

C1.1. Compliance Monitoring Responsibility

Reliability Organization

C1.2 Compliance Monitoring Period and Reset Timeframe

On request (within 30 calendar days)

C1.3. Data Retention

Evidence of the assessment of the reliability impacts of new facilities and their connections on the interconnected transmission systems: Three years.

C1.4. Additional Compliance Information

None

C2. Levels of Non-Compliance

C2.1. **Level 1:** Assessments of the impacts of new facilities were provided, but were incomplete in one or more requirements of Reliability Standard AKFAC-002; R1.

C2.2. **Level 2:** Not applicable.

C2.3. **Level 3:** Not applicable.

C2.4. **Level 4:** Assessments of the impacts of new facilities were not provided.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
001	May 2, 2016	Remove gen & xmsn proforma	Modify
002	Mar 30, 2018	RRO Revision	Yes

<u>Alaska Railbelt Standard AKINT-001-2 – Interchange Information</u>

A. Introduction

1. **Title:** **Interchange Information**

2. **Number:** **AKINT-001-2**

3. **Purpose:**

   3.1. Scheduled interchange must be coordinated between Balancing Authorities to prevent frequency deviations and accumulations of inadvertent interchange, and prevent exceeding mutually established transfer limits.

4. **Applicability:**

   4.1. Purchase-Selling Entities.

   4.2. Balancing Authorities.

5. **Effective Date:** 12 months from adoption by the Reliability Organization.

B. Requirements

R1. Interchange shall be scheduled only between Balancing Authorities having directly connecting facilities in service unless there is a contract or mutual agreement with another Balancing Authority to provide connecting facilities.

R2. Interchange schedules or schedule changes shall not cause any other system to violate established reliability criteria.

R2.1. When Balancing Authorities are connected so that parallel flows present reliability issues, the combinations of Balancing Authorities shall develop multi-control area interchange monitoring techniques and pre-determined corrective actions to mitigate or alleviate potential or actual transmission system overloads.

R2.2. Transfer limits shall be re-evaluated and interchange schedules adjusted as soon as practicable if transmission facilities become overloaded or are out of service, or when changes are made to the bulk system which can affect these limits.

R3. The maximum net scheduled interchange between two Balancing Authorities shall not exceed:

R3.1. The total capacity of the transmission facilities in service between the two Balancing Authorities owned by them or available to them under specific arrangements, contract, or mutual agreements.

R4. The sending, contract intermediary, and receiving Balancing Authorities that are parties to an interchange transaction shall agree on the following:

R4.1. The schedule’s magnitude, starting and ending times.

R4.2. The schedule’s magnitude and rate of change shall be equal and opposite and not exceed the ability of the systems to effect the change.

R4.3. The scheduled generation in one Balancing Authority that is delivered to another Balancing Authority must be scheduled with all intermediate Balancing Authorities unless there is a contract or mutual agreement among the sending, contract intermediary, and receiving Balancing Authorities to do otherwise.

R5. Balancing Authorities shall develop procedures to disseminate information on interchange schedules and facilities out of service which may have an adverse effect on other Balancing Authorities not involved in the scheduled interchange and the involved parties shall predetermine schedule priorities, which will be used if a schedule reduction becomes necessary.

C. Compliance

Level 1

D. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
000	May 2, 2016	Original	New
001	Mar 30,2018	Review	Yes
002	Mar 30, 2018	Review	Yes

Alaska Railbelt Standard AKMOD-025-2 – Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability

A. Introduction

1. **Title:** **Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability**

2. **Number:** **AKMOD-025-2**

3. **Purpose:**

   3.1 To ensure that accurate information on generator gross and net Real and Reactive Power capability and synchronous condenser Reactive Power capability is available for planning models used to assess Bulk Electric System (BES) reliability.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Generator Owner

   4.1.2. Transmission Planner

   4.1.3. Transmission Owner

   4.2. Facilities:

   For the purpose of the requirements contained herein, Facilities that are directly connected to the Bulk Electric System (BES) will be collectively referred as an "applicable unit" that meets the following:

   4.2.1. Generation in the Interconnection with the following characteristics:

   4.2.1.1. Individual generating unit greater than 5 MVA (gross nameplate rating).

   4.2.1.2. Individual generating plant consisting of multiple generating units that are directly connected at a common BES bus with total generation greater than 5 MVA (gross aggregate nameplate rating).

   4.2.2. Synchronous condenser greater than 5 MVA (gross nameplate rating) directly connected to the Bulk Electric System.

   4.2.3. Power Electronics Transmission Assets greater than 1 MVA directly connected to the Bulk Electric System.

5. **Effective Date:** 12 months from adoption by the Reliability Organization.

B. Requirements

Each Generator Owner or Transmission Owner shall provide any Transmission Planner with verification of the Real Power capability of its applicable Facilities as follows:

R1. Verify, in accordance with Attachment 1, (i) the Real Power capability of its generating units and (ii) the Real Power capability of its Power Electronics Transmission Assets.; and

R2. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to any Transmission Planner within 60 calendar days of either (i) the date the data is recorded for a staged test; or (ii) the date the data is selected for verification using historical operational data; or

R3. Submit a completed Attachment 3 (or a form containing the same information as identified in Attachment 3) to any Transmission Planner within 60 calendar days of either (i) the date the data is recorded for a staged test; or (ii) the date the data is selected for verification using historical operational data for Temperature Sensitive Units.

Each Generator Owner or Transmission Owner shall provide any Transmission Planner with verification of the Reactive Power capability of its applicable Facilities as follows:

R4. Verify, in accordance with Attachment 1, (i) the Reactive Power capability of its generating units, (ii) the Reactive Power capability of its synchronous condenser units, and (iii) the Reactive Power capability of its Power Electronics Transmission Assets.

R5. Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to any Transmission Planner within 60 calendar days of either (i) the date the data is recorded for a staged test; or (ii) the date the data is selected for verification using historical operational data.

C. Measures

M1. Each Generator Owner or Transmission Owner will have evidence that it performed the verification, such as a completed Attachment 2 or 3 or the Generator Owner or Transmission Owner form with the same information or dated information collected and used to complete attachments and will have evidence that it submitted the information within 60 days to any Transmission Planner; such as dated electronic mail messages or mail receipts in accordance with Requirement R1. Each Generator Owner or Transmission Owner will have evidence that the Real Power capability was verified within the periodicity specified in Attachment 1.

M2. Each Generator Owner or Transmission Owner will have evidence that it performed the verification, such as a completed Attachment 2 or the Generator Owner or Transmission Owner form with the same information, or dated information collected and used to complete attachments and will have evidence that it submitted the information within 60 days to any Transmission Planner; such as dated electronic mail messages or mail receipts in accordance with Requirement R2. Each Generator Owner or Transmission Owner will have evidence that the Reactive Power capability was verified within the periodicity specified in Attachment 1.

D. Compliance

C1. Compliance Monitoring Process

C1.1. Compliance Enforcement Authority

Reliability Organization

C1.2. Evidence Retention

The following evidence retention periods identify a period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention specified below is shorter than the time since the last compliance audit, the Reliability Organization Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The Generator Owner and Transmission Owner shall each keep the data or evidence to show compliance as identified below, unless directed by its Reliability Organization Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Generator Owner shall retain the latest AKMOD-025 Attachment 2 or 3 and the data behind Attachment 2 or 3 or Generator Owner form with equivalent information and submittal evidence for Requirements R1 through R5 and measures M1 and M2 for the time period since the last compliance audit.
- The Transmission Owner shall retain the latest AKMOD-025 Attachment 2 and the data behind Attachment 2 or Transmission Owner form with equivalent information and submittal evidence for Requirements R1 through R5for the time period since the last compliance audit.

If a Generator Owner or Transmission Owner is found noncompliant, it shall keep information related to the noncompliance until mitigation is complete or for the time specified above, whichever is longer.

The Reliability Organization Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

C1.3. Compliance Monitoring and Assessment Processes:

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting

- Complaint

C1.4. Additional Compliance Information

None

C2. Levels of Non-Compliance

C2.1. Levels of Non-Compliance for Requirement R1, Measure M1

C2.1.1. Level 1 – The Generator Owner or Transmission Owner failed to provide any Transmission Planner with verification of the Real Power capability verification of its applicable Facilities within 60 days.

C2.1.2. Level 1 – The Generator Owner or Transmission Owner failed to meet the periodicity requirements of Attachment 1 for verification of its applicable Facilities.

C2.1.3. Level 2 – The Generator Owner or Transmission Owner failed to retain evidence that it performed the Real Power capability verification of its applicable Facilities as required by Requirement R1.

C2.2. Levels of Non-Compliance for Requirement R2, Measure M2

C2.2.1. Level 1 – The Generator Owner or Transmission Owner failed to provide any Transmission Planner with verification of the Reactive Power capability of its applicable Facilities within 60 days.

C2.2.2. Level 1 – The Generator Owner or Transmission Owner failed to meet the periodicity requirements of Attachment 1 for verification of its applicable Facilities.

C2.2.3. Level 2 – The Generator Owner or Transmission Owner failed to retain evidence that it performed the Reactive Power capability verification of its applicable Facilities as required by Requirement R2.

Version History

Version	Date	Action	Change Tracking
000	-	NERC Version	-
001A	2-17-2016	EPS – Initial edits	Yes
001B	3-16-2016	EPS Revision following 3/11/2016 meeting	Yes
001C	9-16-2016	EPS Revision following 8/25/2016 meeting	Yes
001D	11-18-2016	EPS Revision, addition of RCC.	Yes
001E	12-6-2016	Final Version	No
002	3-30-2018	RRO Revision	Yes

AKMOD-025 Attachment 1

Verification of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability

Periodicity for conduction of a new verification:

The periodicity for performing Real and Reactive Power capability verification is as follows:

1. For staged verification; verify each applicable Facility at least every five years or as approved by the Reliability Organization (with no more than 66 calendar months between verifications), or within 6 calendar months of the discovery of a change that affects its Real Power or Reactive Power capability by more than 10 percent of the last reported verified capability and is expected to last more than six months. The first verification for each applicable Facility under this standard must be a staged test.
2. For verification using operational data; verify each applicable Facility at least every calendar year or as approved by the Reliability Organization (with no more than 18 calendar months between verifications), or within 3 calendar months following the discovery that its Real Power or Reactive Power capability has changed by more than 10 percent of the last reported verified capability and is expected to last more than six months. For temperature sensitive units, verification of Real Power capability using operational data may require data over the course of several months. Operational data should be obtained within a string of consecutive months if allowable by ambient temperatures. If data for different points is recorded on different months, designate the earliest of those dates as the verification date, and report that date as the verification date on AKMOD-025, Attachment 2 for periodicity purposes. Units whose real power is verified using operational data shall confirm its Reactive Power using staged verifications.

For either verification method, verify each new applicable Facility within 6 calendar months of its commercial operation date or within a timeline approved by the Reliability Organization. Existing units that have been in long term shut down and have not been tested for more than five years shall be verified within 6 calendar months or within a timeline approved by the Reliability Organization if the units are scheduled to return to regular service.

It is intended that Real Power testing be performed at the same time as full load Reactive Power testing, however separate testing is allowed for this standard. For synchronous condensers, perform only the Reactive Power capability verifications as specified below. For all Power Electronics Transmission Assets perform Reactive Power capability verifications and perform real power verifications for Power Electronics Transmission Assets with real power capability.

If the Reactive Power capability is verified through test, it is to be scheduled at a time advantageous for the unit being verified to demonstrate its Reactive Power capabilities while the Transmission Operator takes measures to maintain the plant's system bus voltage at the scheduled value or within acceptable tolerance of the scheduled value.

Generators that have a current average Net Capacity Factor over the most recent three calendar years, beginning on January 1 and ending on December 31, of 5% or less are exempt. The equations for calculating the Net Capacity Factor are listed in AKMOD-027 Attachment 1 Note

4. The Generator Owner shall verify the capability within one year of the date of the capacity factor exemption expiration. The verification can be done by either a staged test or using operational data following the expiration of the capacity factor exemption.

Verification specifications for applicable Facilities:

1. For generating units of 5 MVA or less that are part of a plant greater than 5 MVA in aggregate connected through a single contingency condition, record data either on an individual unit basis or as a group. Perform verification individually for every generating unit or synchronous condenser greater than 5 MVA (gross nameplate rating). Perform verification individually for every Power Electronics Transmission Asset greater than 1 MVA.

2. Verify all auxiliary equipment needed for expected normal operation is in service for both the Real Power and Reactive Power capability verification. Perform verification with the automatic voltage regulator in service for the Reactive Power capability verification. Operational data from within the 18 months prior to the verification date is acceptable for the verification of either the Real Power or the Reactive Power capability, as long as a) that operational data meets the criteria in 2.1 through 2.4 below and b) the operational data demonstrates at least 90 percent of a previously staged test that demonstrated at least 50 percent of the Reactive capability shown on the associated thermal capability curve (D-curve). If the previously staged test was unduly restricted (so that it did not demonstrate at least 50 percent of the associated thermal capability curve) by unusual generation or equipment limitations (e.g., capacitor or reactor banks out of service), then the next verification will be by another staged test, not operational data:

2.1. Verify Real Power capability and Reactive Power capability over-excited (lagging) of all applicable Facilities at the applicable Facilities' normal (not emergency) expected maximum Real Power output at the time of the verifications.

2.1.1. Verify synchronous generating unit's maximum Real Power for one hour and lagging Reactive Power for a minimum of fifteen minutes.

2.1.2. Verify Power Electronics Transmission Asset maximum Real Power. The verification should use greater than 20% of the rated energy at the rated Real Power output. The verification may use less than 20% of the rated energy with approval from the Reliability Organization.

2.1.2.1. Verify that Power Electronics Transmission Assets used for Contingency Reserve have the capability to provide Contingency Reserve at the Real Power level for the expected duration.

2.1.2.2. Verification of Power Electronics Transmission Assets used for Contingency Reserve may include staged tests or operational data.

2.1.3. Verify variable generating units, such as wind, solar, and run of river hydro, at the maximum Real Power output the variable resource can provide at the time of the verification. Perform verification of Reactive

Power capability of wind turbines and photovoltaic inverters with at least 90 percent of the wind turbines or photovoltaic inverters at a site on-line. If verification of wind turbines or photovoltaic inverter Facility cannot be accomplished meeting the 90 percent threshold, document the reasons the threshold was not met and test to the full capability at the time of the test. Reschedule the test of the facility within six months of being able to reach the 90 percent threshold. Maintain, as steady as practical, Real and Reactive Power output during verifications.

2.2. Verify Reactive Power capability of all applicable Facilities, other than wind and photovoltaic, for maximum overexcited (lagging) and under-excited (leading) reactive capability for the following conditions:

2.2.1. At the minimum Real Power output at which they are normally expected to operate collect maximum leading and lagging reactive values as soon as a limit is reached. The Reactive Power capability of Power Electronics Transmission Assets shall be verified at a Real Power output of zero if such devices are expected to provide reactive support.

2.2.2. At maximum Real Power output collect maximum expected leading and lagging Reactive Power for 15 minutes.

2.3. For hydrogen-cooled generators, perform the verification at normal operating hydrogen pressure.

2.4. Calculate the Generator Step-Up (GSU) transformer losses if the verification measurements are taken from the high side of the GSU transformer. GSU transformer real and reactive losses may be estimated, based on the GSU impedance, if necessary.

3. Record the following data for the verifications specified above:

3.1. The value of the gross Real and Reactive Power generating capabilities at the end of the verification period.

3.2. The voltage schedule provided by the Transmission Operator, if applicable.

3.3. The voltage at the high and low side of the GSU and/or system interconnection transformer(s) at the end of the verification period. If only one of these values is metered, the other may be calculated.

3.4. The ambient conditions, if applicable, at the end of the verification period that the Generator Owner requires to perform corrections to Real Power for different ambient conditions such as:

- Ambient air temperature
- Relative humidity
- Cooling water temperature
- Other data as determined to be applicable by the Generator Owner to perform corrections for ambient conditions.

3.5. The date and time of the verification period, including start and end time in hours and minutes.

3.6. The existing GSU and/or system interconnection transformer(s) voltage ratio and tap setting.

3.7. The GSU transformer losses (real or reactive) if the verification measurements were taken from the high side of the GSU transformer.

3.8. Whether the test data is a result of a staged test or if it is operational data.

4. Develop a simplified key one-line diagram (refer to AKMOD-025, Attachment 2) showing sources of auxiliary Real and Reactive Power and associated system connections for each unit verified. Include GSU and/or system Interconnection and auxiliary transformers. Show Reactive Power flows, with directional arrows.

4.1. If metering does not exist to measure specific Reactive auxiliary load(s), provide an engineering estimate and associated calculations. Transformer Real and Reactive Power losses will also be estimates or calculations. Only output data are required when using a computer program to calculate losses or loads.

5. If an adjustment is requested by the Transmission Planner, then develop the relationships between test conditions and generator output so that the amount of Real Power that can be expected to be delivered from a generator can be determined at different conditions, such as peak summer conditions. Adjust MW values tested to the ambient conditions specified by the Transmission Planner upon request and submit them to the Transmission Planner within 60 days of the request or the date the data was recorded/selected whichever is later.

N**ote 1:** Under some transmission system conditions, the data points obtained by the MVAr verification required by the standard will not duplicate the manufacturer supplied thermal capability curve (D-curve) or power electronics capability curves. However, the verification required by the standard, even when conducted under these transmission system conditions, may uncover applicable Facility limitations; such as rotor thermal instability, improper tap settings or voltage ratios, inaccurate AVR operation, etc., which could be further analyzed for resolution. The MVAr limit level(s) achieved during a staged test or from operational data may not be representative of the unit's reactive capability for extreme system conditions. See Note 2.

Note 2: While not required by the standard, it is desirable to perform engineering analyses to determine expected applicable Facility capabilities under less restrictive system voltages than those encountered during the verification. Even though this analysis will not verify the complete thermal capability curve (D-curve) or power electronics capability curves, it provides a reasonable estimate of applicable Facility capability that the Transmission Planner can use for modeling.

Note 3: The Reactive Power verification is intended to define the limits of the unit's Reactive Power capabilities. If a unit has no leading capability, then it should be reported with no leading capability; or the minimum lagging capability at which it can operate.

Note 4: Synchronous Condensers and Power Electronics Transmission Assets without Real Power capability only need to be tested at two points (one over-excited point and one under-excited point) since they have no Real Power output.

AKMOD-025 Attachment 2

One-line Diagram, Table, and Summary for Verification Information Reporting

Note: If the configuration of the applicable Facility does not lend itself to the use of the diagram, tables, or summaries for reporting the required information, changes may be made to this form, provided that all required information (identified in AKMOD-025, Attachment 1) is reported.

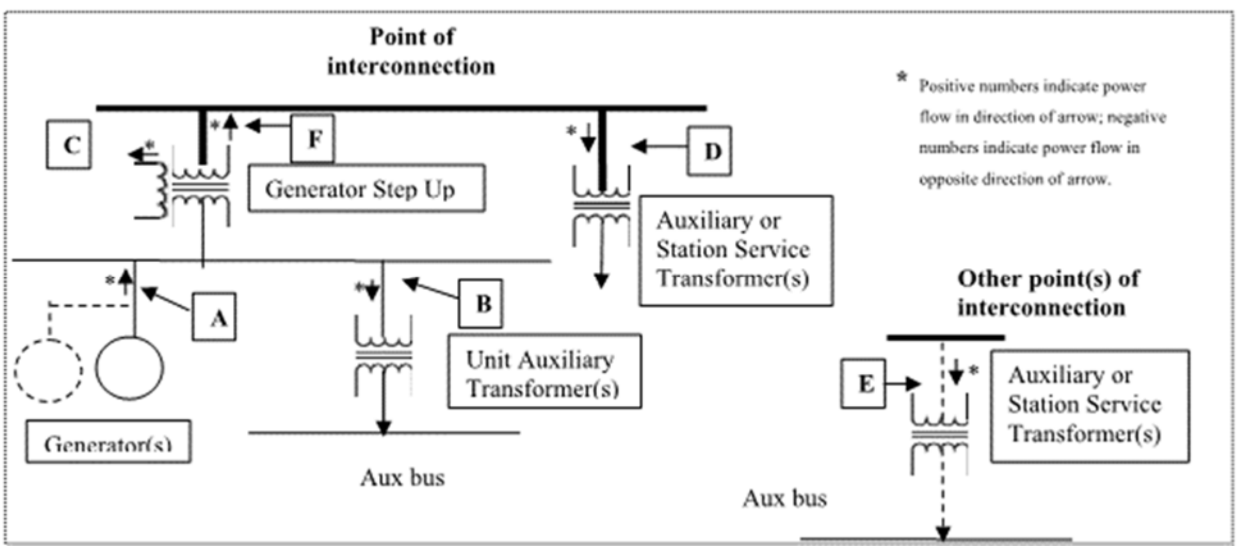
Company: **Reported By (name):**

Plant: **Unit No.:** **Date of Report:**

<u>Check all that apply:</u>

- ☐ Over-excited Full Load Reactive Power Verification
- ☐ Under-excited Full Load Reactive Power Verification
- ☐ Over-excited Minimum Load Reactive Power Verification
- ☐ Under-excited Minimum Load Reactive Power Verification
- ☐ Real Power Verification
- ☐ Staged Test Data
- ☐ Operational Data

Simplified one-line diagram showing plant auxiliary Load connections and verification data:



Point	Voltage	Real Power	Reactive Power	Comment
A	**kV**	**MW**	**Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 5 MVA or Power Electronics Transmission Assets > 1 MVA.
Identify calculated values if any:				
B	**kV**	**MW**	**Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values if any:				
C	**kV**	**MW**	**Mvar**	Sum multiple tertiary Loads, if any.
Identify calculated values if any:				
D	**kV**	**MW**	**Mvar**	Sum multiple auxiliary and station service transformers.
Identify calculated values if any:				
E	**kV**	**MW**	**Mvar**	If multiple points of Interconnection, describe these for accurate modeling; report points individually (sum multiple auxiliary transformers).
F	**kV**	**MW**	**Mvar**	Net unit capability
Identify calculated values if any:				

AKMOD-025 – Attachment 2 (continued)

Verification Data

Provide data by unit or Facility as appropriate

Data Type	Data Recorded	Last Verification (Previous Data; will be blank for the initial verification)
Gross Reactive Power Capability (*Mvar)		
Aux Reactive Power (*Mvar)		
Net Reactive Power Capability (*Mvar) equals Gross Reactive Power Capability (*Mvar) minus Aux Reactive Power connected at the same bus (*Mvar) minus tertiary Reactive Power connected at the same bus(*Mvar)		
Gross Real Powr Capability (*MW)		
Aux Real Power (*MW)		
Net Real Power Capability (*MW) equals Gross Real Power Capability (*MW) minus Aux Real Power connected at the same bus (*MW) minus tertiary Real Power connected at the same bus (*MW)		
* Note: Enter values at the end of the verification period.		
GSU losses (only required if verification measurements are taken on the high side of the GSU - Mvar)		

Summary of Verification

- Date of Verification _________, Verification Start Time _______, Verification End Time ______
- Scheduled Voltage _______________
- Transformer Voltage Ratio: GSU _______, Unit Aux ______, Station Aux _____, Other Aux _____
- Transformer Tap Setting: GSU ______, Unit Aux _____, Station Aux _____, Other Aux _____
- Ambient conditions at the end for the verification period:

  Air Temperature: _________

  Humidity: ________

  Cooling water temperature: ________

  Other data as applicable: ________
- Generator hydrogen pressure at time of test (if applicable) __________

Date that data shown in last verification column in table above was taken ____________

<u>Remarks :</u>

Note: If the verification value did not reach the thermal capability curve (D-curve), describe the reason.

AKMOD-025 – Attachment 3

The Real Power capability verification for Temperature Sensitive Units shall be performed as follows:

1. The Real Power capability verification for Temperature Sensitive Units shall occur annually or as approved by the Reliability Organization.

2. Real Power verification shall be performed for generating units 5 MVA or larger or generating units smaller than 5 MVA that are part of a plant greater than 5 MVA in aggregate connected through a single contingency condition.

3. Verify with all auxiliary equipment needed for expected normal operation in service for the Real Power capability verification.

3.1. Verify Real Power capability of all applicable Facilities at the applicable Facilities' maximum Real Power output for the ambient air temperature at the time of the verification.

3.1.1. Verify Temperature Sensitive Unit's maximum real power for a minimum of fifteen minutes.

3.1.2. Verification shall be performed at ambient air temperature increments of 10 degrees Fahrenheit from annual minimum temperature to the annual maximum temperature at the unit location.

3.1.3. Verification data shall include the Temperature Sensitive Unit's maximum real power, the temperature in Fahrenheit, and the time and date of test.

4. Record the following data for the verifications specified above:

4.1. The value of the gross Real Power generating capabilities at the end of the verification period.

4.2. The auxiliary power, temperature, date, and time of test for applicable Temperature Sensitive Unit.

Data Type	Data Recorded	Temperature	Date	Time
Gross Power Capability, Aux Power	_______ MW, _______ MW	_______°F	________	________
Gross Power Capability, Aux Power	_______ MW, _______ MW	_______°F	________	________
Gross Power Capability, Aux Power	_______ MW, _______ MW	_______°F	________	________
Gross Power Capability, Aux Power	_______ MW, _______ MW	_______°F	________	________
Gross Power Capability, Aux Power	_______ MW, _______ MW	_______°F	________	________
Gross Power Capability, Aux Power	_______ MW, _______ MW	_______°F	________	________
Gross Power Capability, Aux Power	_______ MW, _______ MW	_______°F	________	________
Gross Power Capability, Aux Power	_______ MW, _______ MW	_______°F	________	________
Gross Power Capability, Aux Power	_______ MW, _______ MW	_______°F	________	________
Gross Power Capability, Aux Power	_______ MW, _______ MW	_______°F	________	________

Alaska Railbelt Standard AKMOD-026-2 – Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions

A. Introduction

1. **Title:** **Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions**

2. **Number:** **AKMOD-026-2**

3. **Purpose:**

   3.1 To verify that the generator excitation control system or plant volt/var control function[1] model (including the power system stabilizer model and the impedance compensator model) and the model parameters used in dynamic simulations accurately represent the generator excitation control system or plant volt/var control function behavior when assessing Bulk Electric System (BES) reliability.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Generator Owner

   4.1.2. Transmission Planner

   4.1.3. Transmission Owner

   4.2. Facilities:

   For the purpose of the requirements contained herein, Facilities that are directly connected to the Bulk Electric System (BES) will be collectively referred as an "applicable unit" that meets the following:

   4.2.1. Generation in the Interconnection with the following characteristics:

   4.2.1.1. Individual generating unit greater than 5 MVA (gross nameplate rating).

   4.2.1.2. Individual generating plant consisting of multiple generating units that are directly connected at a common BES bus with total generation greater than 5 MVA (gross aggregate nameplate rating).

   4.2.2. Synchronous condenser greater than 5 MVA (gross nameplate rating) directly connected to the Bulk Electric System.

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[1] Excitation control system or plant volt/var control function:

a. For individual synchronous machines, the generator excitation control system includes the generator, exciter, voltage regulator, impedance compensation and power system stabilizer.
b. For an aggregate generating plant, the volt/var control system includes the voltage regulator & reactive power control system controlling and coordinating plant voltage and associated reactive capable resources.

4.2.3. Power Electronics Transmission Assets greater than 1 MVA directly connected to the Bulk Electric System.

5. Effective Date: 12 months from adoption by the Reliability Organization.

B. Requirements

R1. Each Transmission Planner shall provide the following information to the Generator Owner or Transmission Owner within 30 calendar days of receiving a written request:

- Instructions on how to obtain the list of excitation control system or plant volt/var control function models that are acceptable to the Transmission Planner for use in dynamic simulation,
- Instructions on how to obtain the dynamic excitation control system or plant volt/var control function model library block diagrams and/or data sheets for models that are acceptable to the Transmission Planner, or
- Model data for any of the Generator Owner's or Transmission Owner's existing applicable unit specific excitation control system or plant volt/var control function contained in the Transmission Planner's dynamic database from the current (in-use) models, including generator MVA base.

R2. Each Generator Owner shall provide for each applicable unit, a verified generator excitation control system or plant volt/var control function model, including documentation and data (as specified in R2.1) to any Transmission Planner in accordance with the periodicity specified in AKMOD-026 Attachment 1. Transmission Owners shall provide the same documentation and data for applicable Power Electronics Transmission Assets.

R2.1 Each applicable unit's model shall be verified by the Generator Owner or Transmission Owner using one or more models acceptable to the Transmission Planner. Verification for individual units less than 5 MVA (gross nameplate rating, 1 MVA for Power Electronics Transmission Assets) in a generating plant (per Section 4.2.1.2.) may be performed using either individual unit or aggregate unit model(s), or both. Each verification shall include the following:

R2.1.1. Documentation demonstrating the applicable unit's model response matches the recorded response for a voltage excursion from either a staged test or a measured system disturbance,

R2.1.2. Manufacturer, model number (if available), and type of the excitation control system including, but not limited to static, AC brushless, DC rotating, and/or the plant volt/var control function (if installed),

R2.1.3. Model structure and data including, but not limited to reactance, time constants, saturation factors, total rotational inertia, or equivalent data for the generator,

R2.1.4. Model structure and data for the excitation control system, including the closed loop voltage regulator if a closed loop voltage regulator is installed or the model structure and data for the plant volt/var control function system,

R2.1.5. Compensation settings (such as droop, line drop, differential compensation), if used, and

R2.1.6. Model structure and data for power system stabilizer, if so equipped,

R2.1.7. Model for plant control system, including control parameters used to control plant voltage/var output, including mode or control switching due to off-schedule voltage or var output.

R2.2 Each Generator Owner or Transmission Owner shall provide model structure, data, and source code (if available) for any excitation control system or plant volt/var control function that requires a custom model that is not in the model list provided by the Transmission Planner.

R2.2.1. The Generator Owner or Transmission Owner shall document the need for using a custom model and provide the documentation to the Transmission Planner.

R3. Each Generator Owner or Transmission Owner shall provide a written response to any Transmission Planner within 60 calendar days of receiving one of the following items for an applicable unit:

- Written notification from any Transmission Planner (in accordance with Requirement R6) that the excitation control system or plant volt/var control function model is not usable,
- Written comments from any Transmission Planner identifying technical concerns with the verification documentation related to the excitation control system or plant volt/var control function model, or
- Written comments and supporting evidence from any Transmission Planner indicating that the simulated excitation control system or plant volt/var control function model response did not match the recorded response to a transmission system event.

The written response shall contain either the technical basis for maintaining the current model, the model changes, or a plan to perform model verification[2] (in accordance with Requirement R2).

R4. Each Generator Owner or Transmission Owner shall provide revised model data or plans to perform model verification (in accordance with Requirement R2) for an applicable unit to any Transmission Planner within 60 calendar days of making

[2] If verification is performed, the 5-year period as outlined in AKMOD-026 Attachment 1 is reset.

changes to the excitation control system or plant volt/var control function that alter the equipment response characteristic[3].

R5. Each Generator Owner and Transmission Owner shall provide a written response to any Transmission Planner, within 60 calendar days following receipt of a technically justified[4] unit request from the Transmission Planner to perform a model review of a unit or plant that includes one of the following:

- Details of plans to verify the model (in accordance with Requirement R2), or
- Corrected model data including the source of revised model data such as discovery of manufacturer test values to replace generic model data or updating of data parameters based on an on-site review of the equipment.

R6. Each Transmission Planner shall provide a written response to the Generator Owner or Transmission Owner within 30 calendar days of receiving the verified excitation control system or plant volt/var control function model information in accordance with Requirement R2 that the model is usable (meets the criteria specified in R6.1 through R6.3) or is not usable.

R6.1. The excitation control system or plant volt/var control function model initializes to compute modeling data without error,

R6.2. A no-disturbance simulation results in negligible transients, and

R6.3. For an otherwise stable simulation, a disturbance simulation results in the excitation control and plant volt/var control function model exhibiting positive damping.

If the model is not usable, the Transmission Planner shall provide a technical description of why the model is not usable.

C. Measures

M1. The Transmission Planner must provide the dated request for instructions or data, the transmitted instructions or data, and dated evidence of a written transmittal (e.g., electronic mail message, postal receipt, or confirmation of facsimile) as evidence that it provided the request within 30 calendar days in accordance with Requirement R1.

M2. The Generator Owner or Transmission Owner must provide dated evidence it verified each generator excitation control system or plant volt/var control function

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[3] Exciter, voltage regulator, plant volt/var or power system stabilizer control replacement including software alterations that alter excitation control system equipment response, plant digital control system addition or replacement, plant digital control system software alterations that alter excitation control system equipment response, plant volt/var function equipment addition or replacement (such as static var systems, capacitor banks, individual unit excitation systems, etc.), a change in the voltage control mode (such as going from power factor control to automatic voltage control, etc.), exciter, voltage regulator, impedance compensator, or power system stabilizer settings change. Automatic changes in settings that occur due to changes in operating mode do not apply to Requirement R4.

[4] Technical justification is achieved by the Transmission Planner demonstrating that the simulated unit or plant response does not match the measured unit or plant response.

model according to Part 2.1 for each applicable unit and a dated transmittal (e.g., electronic mail message, postal receipt, or confirmation of facsimile) as evidence it provided the model, documentation, and data to any Transmission Planner, in accordance with Requirement R2.

M3. Evidence for Requirement R3 must include the Generator Owner's or Transmission Owner's dated written response containing the information identified in Requirement R3 and dated evidence of transmittal (e.g., electronic mail message, postal receipt, or confirmation of facsimile) of the response.

M4. Evidence for Requirement R4 must include, for each of the Generator Owner's or Transmission Owner's applicable units for which system changes specified in Requirement R4 were made, a dated revised model data or plans to perform a model verification and dated evidence (e.g., electronic mail message, postal receipt, or confirmation of facsimile) it provided the revised model and data or plans within 60 calendar days of making changes.

M5. Evidence for Requirement R5 must include the Generator Owner's or Transmission Owner's dated written response containing the information identified in Requirement R5 and dated evidence (e.g., electronic mail message, postal receipt, or confirmation of facsimile) it provided a written response within 30 calendar days following receipt of a technically justified request.

M6. Evidence of Requirement R6 must include, for each model received, the dated response indicating the model was usable or not usable according to the criteria specified in Parts 6.1 through 6.3 and for a model that is not usable, a technical description; and dated evidence of transmittal (e.g., electronic mail message, postal receipt, or confirmation of facsimile) that the Generator Owner or Transmission Owner was notified within 30 calendar days of receipt of model information.

D. Compliance

C1. Compliance Monitoring Process

C1.1. Compliance Enforcement Authority

Reliability Organization

C1.2. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner, Transmission Owner, and Transmission Planner shall each keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Planner shall retain the information/data request and provided response evidence of Requirements R1 and R6, Measures M1 and M6 for three calendar years from the date the document was provided.
- The Generator Owner or Transmission Owner shall retain the latest excitation control system or plant volt/var control function model verification evidence of Requirement R2, Measure M2.
- The Generator Owner or Transmission Owner shall retain the information/data request and provided response evidence of Requirements R3 through R5, and Measures M3 through M5 for three calendar years from the date the document was provided.

If a Generator Owner, Transmission Owner, or Transmission Planner is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete or approved or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

C2. Compliance Monitoring and Assessment Processes:

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting
- Complaints

C3. Additional Compliance Information

None

E. Regional Variances

None

F. Associated Documents

None

Version History

Version	Date	Action	Change Tracking
000	-	NERC Version	-
001A	2-23-2016	EPS edit from NERC Standard	Yes
001B	3-16-2016	EPS edit	Yes
001C	9-16-2016	EPS edit following 8/25/2016 meeting	Yes
001D	11-18-2016	EPS revision, addition of RCC	Yes
001E	12-06-2016	Final Version	No
002	3-30-2018	RRO Revision	Yes

AKMOD-26 Attachment 1 Excitation Control System or Plant Volt/Var Function Model Verification Periodicity		
Row Number	**Verification Condition**	**Required Action**
1	Establishing the initial verification date for an applicable unit. (Requirement R2)	Transmit the verified model, documentation and data to the Transmission Planner on or before the Effective Date. Row 4 applies when calculating generation fleet compliance during the 5-year implementation period See Section A5 for Effective Dates.
2	Subsequent verification for an applicable unit. (Requirement R2)	Transmit the verified model, documentation and data to the Transmission Planner on or before the 5-year anniversary of the last transmittal (per Note 1).
3	Initial verification for a new applicable unit or for an existing applicable unit with new excitation control system or plant volt/var control function equipment installed. (Requirment R2)	Transmit the verified model, documentation and data to the Transmission Planner within 90 calendar days after the commissioning date.

AKMOD-26 Attachment 1 Excitation Control System or Plant Volt/Var Function Model Verification Periodicity		
Row Number	**Verification Condition**	**Required Action**
4	Existing applicable unit that is equivalent to another unit(s) at the same physical location. AND Each applicable unit has the same MVA nameplate rating. AND The nameplate rating is ≤ 30 MVA or 2 MVA for Power Electronics Transmission Assets. AND Each applicable unit has the same components and settings. AND The model for one of these equivalent applicable units has been verified.	Document circumstance with a written statement and include with the verified model, documentation, and data provided to the Transmission Planner for the verified equivalent unit. Verify a different equivalent unit during each 5-year verification period. Applies to Row 1 when calculating generation fleet compliance during the 5-year implementation period.
5	The Generator Owner or Transmission Owner has submitted a verification plan. (Requirement R3, R4 or R5)	Transmit the verified model, documentation and data to the Transmission Planner within 60-calendar days after the model verification.

AKMOD-26 Attachment 1 Excitation Control System or Plant Volt/Var Function Model Verification Periodicity		
Row Number	**Verification Condition**	**Required Action**
6	New or existing applicable unit does not include an active closed loop voltage or reactive power control function. (Requirement R2)	Requirement 2 is met with a written statement to that effect transmitted to the Transmission Planner. Perform verification per the periodicity specified in Row 3 for a "New Generating Unit" (or new equipment) only if active closed loop function is established. See Footnote 1 (see Section A.3) for clarification of what constitutes an active closed loop function for both conventional synchronous machines (reference Footnote 1a) and aggregate generating plants (reference Footnote 1b).
7	Existing applicable unit has a current average net capacity factor over the most recent three calendar years, beginning on January 1 and ending on December 31 of 5% or less. Existing Power Electronics Transmission Assets was available for less than 10% of the most recent one year, beginning on January 1 and ending on December 31. (Requirement R2)	Requirement 2 is met with a written statement to that effect transmitted to the Transmission Planner. At the end of this 5-year timeframe, the current average three year net capacity factor (for years 3, 4, and 5) can be examined to determine if the capacity factor exemption can be declared for the next 5-year period. If not eligible for the capacity factor exemption, then model verification must be completed within 365 calendar days of the date the capacity factor exemption expired. For the definition of net capacity factor, refer to Note 3.

AKMOD-26 Attachment 1 Excitation Control System or Plant Volt/Var Function Model Verification Periodicity		
Row Number	**Verification Condition**	**Required Action**

NOTES:

NOTE 1: Establishing the recurring 5-year unit verification period start date:
The start date is the actual date of submittal of a verified model to the Transmission Planner for the most recently performed unit verification.

NOTE 2: Consideration for early compliance:
Existing generator excitation control system or plant volt/var control function model verification is sufficient for demonstrating compliance for a 5-year period from the actual transmittal date if either of the following applies:

- The Generator Owner or Transmission Owner has a verified model that is compliant with the applicable regional policies, guidelines or criteria existing at the time of model verification.
- The Generator Owner or Transmission Owner has an existing verified model that is compliant with the requirements of this standard.

NOTE 3: Net Capacity Factor Equations:

$$Equation\,1:\ NCF = \frac{Net\ Actual\ Generation}{PH * NMC} * 100\% \qquad Equation\,2:\ NCF = \frac{\sum(Net\ Actual\ Generation)}{\sum(PH * NMC)} * 100\%$$

Where:
- PH = Period Hours (Number of hours in the period being reported that the unit was in the active state)
- NMC = Net Maximum Capacity
- Equation 2 is an energy-weighted equation. Use Equation 2 when calculating for a group of units (or a unit that has a varying capacity value over time), do not simply average these factors. Follow Equation 2

Alaska Railbelt Standard AKMOD-027-2 – Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions

A. Introduction

1. **Title:** **Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions**

2. **Number:** **AKMOD-027-2**

3. **Purpose:**

   3.1. To verify that the turbine/governor and load control or active power/frequency control[1] model and the model parameters, used in dynamic simulations that assess Bulk Electric System (BES) reliability, accurately represent generator unit real power response to system frequency variations.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Generator Owner

   4.1.2. Transmission Planner

   4.1.3. Transmission Owner

   4.2. Facilities:

   For the purpose of the requirements contained herein, Facilities that are directly connected to the Bulk Electric System (BES) will be collectively referred to as an "applicable unit" that meets the following:

   4.2.1. Generation in the Interconnection with the following characteristics:

   4.2.1.1. Individual generating unit greater than 5 MVA (gross nameplate rating).

   4.2.1.2. Individual generating plant consisting of multiple generating units that are directly connected at a common BES bus with total generation greater than 5 MVA (gross aggregate nameplate rating).

   4.2.2. Power Electronics Transmission Assets with Real Power capabilities greater than 1 MVA directly connected to the Bulk Electric System.

5. **Effective Date:** 12 months from adoption by the Reliability Organization.

[1] Turbine/governor and load control or active power/frequency control:
a. Turbine/governor and load control applies to conventional synchronous generation.
b. Active power/frequency control applies to inverter connected generators (often found at variable energy plants).

B. Requirements

R1. Each Transmission Planner shall provide the following information to the Generator Owner or Transmission Owner within 30 calendar days of receiving a written request:

- Instructions on how to obtain the list of turbine/governor and load control or active power/frequency control system models that are acceptable to the Transmission Planner for use in dynamic simulation,
- Instructions on how to obtain the dynamic turbine/governor and load control or active power/frequency control function model library block diagrams and/or data sheets for models that are acceptable to the Transmission Planner, or
- Model data for any of the Generator Owner's or Transmission Owner's existing applicable unit specific turbine/governor and load control or active power/frequency control system contained in the Transmission Planner's dynamic database from the current (in-use) models.
- It is noted that digital governors with multiple modes of control and operation may require the Generation Owner or Transmission Owner to develop custom models to simulate the response of the unit. Such models will be based on standard models provided by the Transmission Planner to the extent possible.

R2. Each Generator Owner shall provide, for each applicable unit, a verified turbine/governor and load control or active power/frequency control model, including documentation and data (as specified in R2.1) to any Transmission Planner in accordance with the periodicity specified in MOD-027 Attachment 1. Transmission Owners shall provide the same documentation and data for applicable Power Electronics Transmission Assets.

R2.1. Each applicable unit's model shall be verified by the Generator Owner or Transmission Owner using one or more models acceptable to the Transmission Planner. Verification for individual units rated less than 5 MVA (gross nameplate rating, 1 MVA for Power Electronics Transmission Assets) in a generating plant (per 4.2.1.2.) may be performed using either individual unit or aggregate unit model(s) or both. Each verification shall include the following:

R2.1.1. Documentation comparing the applicable unit's MW model response to the recorded MW response for either:

- A frequency excursion from a system disturbance that meets MOD-027 Attachment 1 Note 1 with the applicable unit on-line,
- A speed governor reference change with the applicable unit online, or

- For staged tests, the governor reference change should occur at multiple operating points including minimum, peak load, and near peak load to show the impact that unit output has on the unit response to a reference change.
- Staged tests shall include verification of governor performance for each mode transition, including transitions back from transient mode if applicable for system modeling.

- A partial load rejection test,[2]

R2.1.2. Type of governor and load control or active power control/frequency control[3] equipment,

R2.1.3. A description of the turbine (e.g. for hydro turbine - Kaplan, Francis, or Pelton; for steam turbine - boiler type, normal fuel type, and turbine type; for gas turbine - the type and manufacturer; for variable energy plant - type and manufacturer; for Power Electronics Transmission Asset – type and manufacturer),

R2.1.4. Model structure and data for turbine/governor and load control or active power/frequency control,

R2.1.5. Description and recommended modeling method for any governor actions that would limit the active power or change governor control modes including, but not limited to:

- Temperature limiters
- Pressure limiters
- Rate limiters

R2.1.6. Description and recommended modeling method for any governor response resulting from a control mode change within the governor during on-line operations. All control mode changes must be included in the recommended modeling method.

R2.1.7. Representation of the real power response effects of outer loop controls (such as operator set point controls, and load

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[2] Differences between the control mode tested and the final simulation model must be identified, particularly when analyzing load rejection data. Most controls change gains or have a set point runback which takes effect when the breaker opens. Load or set point controls will also not be in effect once the breaker opens. Some method of accounting for these differences must be presented if the final model is not validated from on-line data under the normal operating conditions under which the model is expected to apply.

[3] Turbine/governor and load control or active power/frequency control:

a. Turbine/governor and load control applies to conventional synchronous generation.
b. Active power/frequency control applies to inverter connected generators (often found at variable energy plants).

control but excluding AGC control) that would override the governor response (including blocked or nonfunctioning governors or modes of operation that limit Frequency Response), if applicable.

R2.2. Each Generator Owner or Transmission Owner shall provide model structure, data, and source code (if available) for any turbine/governor and load control or active power/frequency control function model that requires a custom model that is not in the model list provided by the Transmission Planner.

R2.2.1. The Generator Owner or Transmission Owner shall document the need for using a custom model and provide the documentation to the Transmission Planner.

R3. Each Generator Owner or Transmission Owner shall provide a written response to any Transmission Planner within 60 calendar days of receiving one of the following items for an applicable unit.

- Written notification, from any Transmission Planner (in accordance with Requirement R5) that the turbine/governor and load control or active power/frequency control model is not "usable,"
- Written comments from any Transmission Planner identifying technical concerns with the verification documentation related to the turbine/governor and load control or active power/frequency control model, or
- Written comments and supporting evidence from any Transmission Planner indicating that the simulated turbine/governor and load control or active power/frequency control response did not approximate the recorded response for three or more transmission system events.

The written response shall contain either the technical basis for maintaining the current model, the model changes, or a plan to perform model verification[4] (in accordance with Requirement R2).

R4. Each Generator Owner or Transmission Owner shall provide revised model data or plans to perform model verification (in accordance with Requirement R2) for an applicable unit to any Transmission Planner within 60 calendar days of making changes to the turbine/governor and load control or active power/frequency control system that alter the equipment response characteristic[5].

R5. Each Transmission Planner shall provide a written response to the Generator Owner or Transmission Owner within 30 calendar days of receiving the turbine/governor and load control or active power/frequency control system

[4] If verification is performed, the 5 year period as outlined in MOD-027 Attachment 1 is reset.

[5] Control replacement or alteration including software alterations or plant digital control system addition or replacement, plant digital control system software alterations that alter droop, and/or dead band, and/or frequency response and/or a change in the frequency control mode (such as going from droop control to constant MW control, etc.).

verified model information in accordance with Requirement R2 that the model is usable (meets the criteria specified in R5.1 through R5.3) or is not usable.

R5.1. The turbine/governor and load control or active power/frequency control function model initializes to compute modeling data without error,

R5.2. A no-disturbance simulation results in negligible transients, and

R5.3. For an otherwise stable simulation, a disturbance simulation results in the turbine/governor and load control or active power/frequency control model exhibiting positive damping.

If the model is not usable, the Transmission Planner shall provide a technical description of why the model is not usable.

C. Measures

M1. The Transmission Planner must provide the dated request for instructions or data, the transmitted instruction or data, and dated evidence of a written transmittal (e.g., electronic mail message, postal receipt, or confirmation of facsimile) as evidence that it provided the request within 30 calendar days in accordance with Requirement R1.

M2. The Generator Owner or Transmission Owner must provide dated evidence it verified each generator turbine/governor and load control or active power/frequency control model according to Part 2.1 for each applicable unit and a dated transmittal (e.g., electronic mail message, postal receipt, or confirmation of facsimile) as evidence it provided the model, documentation, and data to any Transmission Planner, in accordance with Requirement R2.

M3. Evidence for Requirement R3 must include the Generator Owner's or Transmission Owner's dated written response containing the information identified in Requirement R3 and dated evidence of transmittal (e.g., electronic mail message, postal receipt, or confirmation of facsimile) of the response.

M4. Evidence for Requirement R4 must include, for each of the Generator Owner's or Transmission Owner's applicable units for which system changes specified in Requirement R4 were made, dated revised model data or dated plans to perform a model verification and dated evidence of transmittal (e.g., electronic mail message, postal receipt, or confirmation of facsimile) within 60 calendar days of making changes.

M5. Evidence of Requirement R5 must include, for each model received, the dated response indicating the model was usable or not usable according to the criteria specified in R5.1 through R5.3 and for a model that is not useable, a technical description that the model is not usable, and dated evidence of transmittal (e.g., electronic mail messages, postal receipts, or confirmation of facsimile) that the Generator Owner or Transmission Owner was notified within 30 calendar days of receipt of model information in accordance with Requirement R5.

D. Compliance

C1. Compliance Monitoring Process

C1.1. Compliance Enforcement Authority

Reliability Organization

C1.2. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Reliability Organization Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner, Transmission Owner, and Transmission Planner shall each keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Planner shall retain the information/data request and provided response evidence of Requirements R1 and R5, Measures M1 and M5 for 3 calendar years from the date the document was provided.
- The Generator Owner or Transmission Owner shall retain the latest turbine/governor and load control or active power/frequency control system model verification evidence of Requirement R2, Measure M2.
- The Generator Owner or Transmission Owner shall retain the information/data request and provided response evidence of Requirements R3, and R4 Measures M3 and M4 for 3 calendar years from the date the document was provided.

If a Generator Owner, Transmission Owner, or Transmission Planner is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

The Reliability Organization Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

C1.3. Compliance Monitoring and Assessment Processes:

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting
- Complaint

C1.4. Additional Compliance Information

None

C2. Levels of Non-Compliance

C2.1. Levels of Non-Compliance for Requirement R1, Measure M1

C2.1.1. Level 1 – The Transmission Planner failed to retain dated evidence that it provided the requested information within 30 calendar days in accordance with Requirement R1.

C2.1.2. Level 2 – The Transmission Planner failed to provide the Generator Owner or Transmission Owner with the requested information in accordance with Requirement R1.

C2.2. Levels of Non-Compliance for Requirement R2, Measure M2

C2.2.1. Level 1 – The Generator Owner or Transmission Owner failed to retain dated evidence it provided the model, documentation, and data to any Transmission Planner, in accordance with Requirement R2.

C2.2.2. Level 2 – The Generator Owner, or Transmission Owner failed to provide the model, documentation, and data to any Transmission Planner, in accordance with Requirement R2.

C2.3. Levels of Non-Compliance for Requirement R3, Measure M3

C2.3.1. Level 1 – The Generator Owner, or Transmission Owner failed to retain dated evidence showing it responded to the Transmission Planner and provided the information identified in Requirement R3.

C2.3.2. Level 2 – The Generator Owner, or Transmission Owner failed to respond to the Transmission Planner with the information identified in Requirement R3.

C2.4. Levels of Non-Compliance for Requirement R4, Measure M4

C2.4.1. Level 1 – The Generator Owner, or Transmission Owner failed to retain evidence which includes, for each of the Generator Owner's or Transmission Owner's applicable units for which system changes specified in Requirement R4 were made, dated revised model data or dated plans to perform a model verification.

C2.5. Levels of Non-Compliance for Requirement R5, Measure M5

C2.5.1. Level 1 – The Transmission Planner failed to retain dated response to the Generator Owner or Transmission Owner which must include, for each model received, an indication that the model was usable or not usable according to the criteria specified in R5.1 through R5.3.

E. Regional Variances

None

F. Associated Documents

None

Version History

Version	Date	Action	Change Tracking
000	-	NERC Version	-
001A	2-23-2016	EPS edit from NERC Standard	Yes
001B	3-16-2016	EPS edit	Yes
001C	9-16-2016	EPS edit following 8/25/2016 meeting	Yes
001D	11-18-2016	EPS revision, addition of RCC	Yes
001E	12-6-2016	Final Version	No
002	3-30-2018	RRO Revision	Yes

AKMOD-27 Attachment 1 Turbine/Governor and Load Control or Active Power/Frequency Control Model Periodicity		
Row Number	**Verification Condition**	**Required Action**
1	Establishing the initial verification date for an applicable unit. (Requirement R2)	Transmit the verified model, documentation and data to the Transmission Planner on or before the Effective Date. Row 5 applies when calculating generation fleet compliance during the 5 year implementation period. See Section A5 for Effective Dates.
2	Subsequent verification for an applicable unit. (Requirement R2)	Transmit the verified model, documentation and data to the Transmission Planner on or before the 5-year anniversary of the last transmittal (per Note 2).
3	Applicable unit was not subjected to a frequency excursion per Note 1 with available generating capacity available to show Governor or Load Control response by the date otherwise required to meet the dates per Rows 1, 2, 4, or 6. (This row is only applicable if a frequency excursion from a system disturbance that meets Note 1 is selected for the verification method and the ability to record the applicable unit's real power response to a frequency excursion is installed and expected to be available). (Requirement R2)	Requirement 2 is met with a written statement to that effect transmitted to the Transmission Planner. Transmit the verified model, documentation and data to the Transmission Planner on or before 60 calendar days after a frequency excursion per Note 1 occurs and the recording equipment captures the applicable unit's real power response as expected.
4	Initial verification for a new applicable unit or for an existing applicable unit with new turbine/governor and load control or active power/frequency control equipment installed. (Requirment R2)	Transmit the verified model, documentation and data to the Transmission Planner within 90 calendar days after the commissioning date.

AKMOD-27 Attachment 1 Turbine/Governor and Load Control or Active Power/Frequency Control Model Periodicity		
Row Number	**Verification Condition**	**Required Action**
5	Existing applicable unit that is equivalent to another applicable unit(s) at the same physical location. AND Each applicable unit has the same MVA nameplate rating. AND The nameplate rating is ≤ 30 MVA or 2 MVA for Power Electronics Transmission Assets. AND Each applicable unit has the same components and settings; AND The model for one of these equivalent applicable units has been verified. (Requirement R2)	Document circumstance with a written statement and include with the verified model, documentation and data provided to the Transmission Planner for the verified equivalent unit. Verify a different equivalent unit during each 5-year verification period. Applies to Row 1 when calculating generation fleet compliance during the 5-year implementation period.
6	The Generator Owner or Transmission Owner has submitted a verification plan. (Requirement R3, R4 or R5)	Transmit the verified model, documentation and data to the Transmission Planner within 60 calendar days after the model verification.

AKMOD-27 Attachment 1 Turbine/Governor and Load Control or Active Power/Frequency Control Model Periodicity		
Row Number	**Verification Condition**	**Required Action**
7	Applicable unit is not responsive to both over and under frequency excursion events (The applicable unit does not operate in a frequency control mode, except during normal start up and shut down, that would result in a turbine/governor and load control or active power/frequency control mode response.); OR Applicable unit either does not have an installed frequency control system or has a disabled frequency control system. (Requirement R2)	Requirement 2 is met with a written statement to that effect transmitted to the Transmission Planner. Perform verification per the periodicity specified in Row 4 for a "New Generating Unit" (or new equipment) only if responsive control mode operation for connected operations is established.
8	Existing applicable unit has a current average net capacity factor over the most recent three calendar years, beginning on January 1 and ending on December 31 of 5% or less. Existing Power Electronics Transmission Assets was available for less than 10% of the most recent one year, beginning on January 1 and ending on December 31. (Requirement R2)	Requirement 2 is met with a written statement to that effect transmitted to the Transmission Planner. At the end of this 5 calendar year timeframe, the current average three year net capacity factor (for years 3, 4, and 5) can be examined to determine if the capacity factor exemption can be declared for the next 5 calendar year period. If not eligible for the capacity factor exemption, then model verification must be completed within 365 calendar days of the date the capacity factor exemption expired. For the definition of net capacity factor, refer to Note 4.

AKMOD-27 Attachment 1 Turbine/Governor and Load Control or Active Power/Frequency Control Model Periodicity		
Row Number	**Verification Condition**	**Required Action**

NOTES:

NOTE 1: Unit model verification frequency excursion criteria:

- ≥ 0.30 hertz deviation (nadir point) from scheduled frequency for the Interconnection with the applicable unit operating in a frequency responsive mode

NOTE 2: Establishing the recurring 5 year unit verification period start date:

- The start date is the actual date of submittal of a verified model to the Transmission Planner for the most recently performed unit verification.
- The Generator Owner or Transmission Owner has an existing verified model that is compliant with the requirements of this standard.

NOTE 3: Consideration for early compliance:

Existing turbine/governor and load control or active power/frequency control model verification is sufficient for demonstrating compliance for a 5 year period from the actual transmittal date if either of the following applies:

- The Generator Owner or Transmission Owner has a verified model that is compliant with the applicable regional policies, guidelines or criteria existing at the time of model verification
- The Generator Owner or Transmission Owner has an existing verified model that is compliant with the requirements of this standard

NOTE 4: Net Capacity Factor Equations:

$$Equation\,1:\; NCF = \frac{Net\ Actual\ Generation}{PH * NMC} * 100\% \qquad Equation\,2:\; NCF = \frac{\sum(Net\ Actual\ Generation)}{\sum(PH * NMC)} * 100\%$$

Where:

- PH = Period Hours (Number of hours in the period being reported that the unit was in the active state)
- NMC = Net Maximum Capacity
- Equation 2 is an energy-weighted equation. Use Equation 2 when calculating for a group of units (or a unit that has a varying capacity value over time), do not simply average these factors. Follow Equation 2

Alaska Railbelt Standard AKMOD-028-2 – Total Transfer Capability

A. Introduction

1. **Title:** **Total Transfer Capability**
2. **Number:** **AKMOD-028-2**
3. **Purpose:**
   - **3.1.** To ensure that determinations of transmission system capability are completed in a manner that supports the reliable operation of the Bulk-Power System (BPS) and that the methodology and data underlying those determinations are disclosed to those registered entities that need such information for reliability purposes.
4. **Applicability:**
   - **4.1.** Transmission Planner
   - **4.2.** Transmission Operator
   - **4.3.** Transmission Service Provider
5. **Effective Date:** 12 months from adoption by the Reliability Organization.

B. Requirements

R1. Each Transmission Planner shall develop a written methodology (or methodologies) for determining Total Transfer Capability (TTC) or Emergency Transfer Capability (ETC) values. The methodology (or methodologies) shall reflect the Transmission Operator's current practices.

R2. Each methodology shall describe the method used to account for the following limitations in both the pre- and post-contingency state:

- **R2.1.** Facility ratings;
- **R2.2.** System voltage limits;
- **R2.3.** Transient stability limits;
- **R2.4.** Path Thermal Limits; and
- **R2.5.** Voltage stability limits.

R3. Each methodology shall describe the method used to account for each of the following elements, provided such elements impact the determination of TTC or ETC:

- **R3.1.** The simulation of transfers performed through the adjustment of generation, load, or both;
- **R3.2.** Transmission topology, including, but not limited to, additions and retirements;
- **R3.3.** Planned outages;

R3.4. Generator commitment;

R3.5. Parallel path (loop flow) adjustments;

R3.6. Transmission Reliability Margin;

R3.7. Contingency Reserve obligations of source area;

R3.8. Load forecast; and

R3.9. Generator dispatch, including, but not limited to, additions and retirements.

R.4. When calculating TTCs and ETCs, the Transmission Planner shall use a Transmission model which satisfies the following requirements:

R4.1. The model utilizes data and assumptions consistent with the time period being studied and that meets the following criteria:

R4.1.1. Includes all transmission lines and facilities rated at 69 kV and higher.

R4.1.2. Models all system elements as in-service for the assumed initial conditions.

R4.1.3. Models all generation (may be either a single generator or multiple generators) that is greater than 5 MVA at the point of interconnection in the studied area.

R4.1.4. Models phase shifters in non-regulating mode, unless otherwise specified in the Total Transfer Capability Implementation Document (TTCID).

R4.1.5. Uses Load forecast by Balancing Authority.

R4.1.6. Uses Transmission Facility additions and retirements.

R4.1.7. Uses Generation Facility additions and retirements.

R4.1.8. Uses Special Protection System (SPS) models where currently existing or projected for implementation within the studied time horizon unless specified otherwise in the TTCID.

R4.1.9. Models series compensation for each line at the expected operating level unless specified otherwise in the TTCID.

R4.1.10. Includes any other modeling requirements or criteria specified in the TTCID.

R5. The model utilizes Facility Ratings as provided by the Transmission Owner and Generator Owner

R6. The Transmission Planner shall use the following process to determine TTC and ETC:

R6.1. Except where otherwise specified within AKMOD-028, adjust base case generation and load levels within the updated power flow model to determine the TTC (maximum flow or reliability limit) that can be simulated on the path while at the same time satisfying all planning criteria contingencies as follows:

R6.1.1. When modeling normal and contingency conditions, the projected generation commitment for the study time period shall be used.

R6.1.2. When modeling normal conditions, all transmission elements will be modeled at or below 100% of their continuous rating.

R6.1.3. When modeling contingencies, the system shall demonstrate transient, dynamic and voltage stability, with no transmission element modeled above its emergency rating following the contingency.

R6.1.3.1. The modeled contingencies shall include N-1 outages of generating units and transmission lines.

R6.1.3.2. The Steady-State Transfer Limit shall be identified.

R6.1.3.3. The Steady-State Transfer Capability shall be identified.

R6.1.3.4. The Transient Transfer Limit shall be identified.

R6.1.4. Uncontrolled separation shall not occur.

R6.1.4.1. Separation is allowed for outages of a tie to a radial system or a tie between areas connected by one transmission element.

R7. For a path whose capacity is limited by contract, set TTC on the path at the lesser of the maximum allowable contract capacity or the reliability limit as determined by R3.

R8. For a path whose TTC varies due to simultaneous interaction with one or more other paths, develop a nomogram or chart describing the interaction of the paths and the resulting TTC under specified conditions.

R9. The Transmission Planner shall identify when the TTC for the path being studied has an adverse impact on the TTC value of any existing path. Do this by modeling the flow on the path being studied at its proposed new TTC level simultaneous with the flow on the existing path at its TTC level while at the same time honoring the reliability criteria outlined in R3. The Transmission Planner shall include the resolution of this adverse impact in its study report.

R10. Create a study report that describes the steps above that were undertaken, including the contingencies and assumptions used, when determining the TTC and the results of the study.

R11. The Transmission Operator shall operate the system such that each path is at or below its respective TTC.

R11.1. In normal operating conditions all paths shall be operated below the minimum of:

R11.1.1. Facility ratings

R11.1.2. System voltage limit

R11.1.3. Transient stability limit

R11.1.4. Path thermal limit

R11.1.5. Voltage stability limit

R12. Paths that are stability limited may be operated above the TTC in an Emergency.

R12.1. The Emergency Transfer Capability is the minimum of:

R12.1.1. ETC limited by Facility ratings

R12.1.2. ETC limited by System voltage limit

R12.1.3. ETC limited by Path thermal limit

R12.2. The path must be restored below its TTC limit in accordance with the contingency reserve restoration period defined in AKBAL-002.

R13. Within seven calendar days of the finalization of the study report, the Transmission Planner shall make available to the Transmission Operator and Transmission Service Provider of the path, the most current value for TTC and the TTC study report documenting the assumptions used and steps taken in determining the current value for TTC for that path.

R14. Within 45 calendar days of receiving a written request that references this specific requirement from a Planning Coordinator, Reliability Coordinator, Transmission Operator, Transmission Planner, Transmission Service Provider, or any other registered entity that demonstrates a reliability need, each Transmission Planner shall provide:

R14.1. The TTC methodology

R14.2. A written response to any request for clarification of its TTC methodology. If the request for clarification is contrary to the Transmission Planner's confidentiality, regulatory, or security requirements then a written response shall be provided explaining the clarifications not provided, on what basis and whether there are any options for resolving any of the confidentiality, regulatory, or security concerns.

C. Measures

M1. Each Transmission Planner that determines TTC shall provide its current written methodology (or methodologies) or other evidence (such as written documentation) to show that its methodology (or methodologies) contains the following:

- A description of the method used to account for the limits specified in R1. Methods of accounting for these limits may include, but are not limited to, one or more of the following:
  - TTC being determined by one or more limits.

  - Simulation being used to find the maximum TTC that remains within the limit.
  - Monitoring a subset of limits and a statement that those limits are expected to produce the most severe results.
  - A statement that the monitoring of a select limit(s) results in the TTC not exceeding another set of limits.
  - A statement that one or more of those limits are not applicable to the TTC determination.
- A description of the method used to account for the elements specified in R2, provided such elements impact the determination of TTC. Methods of accounting for these elements may include, but are not limited to, one or more of the following:
  - A statement that the element is not accounted for since it does not affect the determination of TTC.
  - A description of how the element is used in the determination of TTC.
- Each Transmission Planner that determines TTC shall provide evidence that currently active TTC values were determined based on its current written methodology, as specified in Requirement R1.

M2. Each Transmission Planner shall produce any Transmission model it used to calculate TTC, as required in R4, for the time horizon(s) to be examined.

M2.1. The Transmission model produced must include all system elements rated 69 kV and higher.

M2.2. The Transmission model produced must show the use of the modeling parameters stated in R4.1; except that, no evidence shall be required to prove: 1) utilization of a Special Protection System where none was included in the model or 2) that no additions or retirements to the generation or Transmission system occurred.

M2.3. The Transmission Planner must provide evidence that the models used to determine TTC included Facility Ratings as provided by the Transmission Owner and Generator Owner.

M3. Each Transmission Planner shall produce the TTCID it uses to show where it has described and used additional modeling criteria in its TTCID that are not otherwise included in AKMOD-28.

M4. Each Transmission Planner shall produce as evidence the study reports, as required in R13, for each path for which it determined TTC for the period examined.

M5. Each Transmission Operator shall provide evidence that it operated the system within the TTC or ETC, when appropriate, provided by the Transmission Planner. The evidence shall include, at a minimum, any and all instances when a path exceeded its TTC during normal operations or any and all instances when a path exceeds its Emergency Transfer Capability.

M6. Each Transmission Planner shall provide evidence (such as logs or data) that it provided the TTC and its study report to the Transmission Service Provider within seven calendar days of the finalization of the study report.

M7. Examples of evidence required in R6 include, but are not limited to:

- Dated records of the request and the Transmission Planner's response to the request;
- A statement by the Transmission Planner that they have received no requests; or
- A statement by the Transmission Planner that they do not determine TTC.

D. Compliance

C1. Compliance Monitoring Process

C1.1. Compliance Enforcement Authority

Reliability Organization

C1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

C1.3. Data Retention

The following evidence retention periods identify the period of time a registered entity is required to retain specific evidence to demonstrate compliance. For instances in which the evidence retention period specified below is shorter than the time since the last audit, the Reliability Organization Compliance Enforcement Authority may ask the registered entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- Implementation and methodology documents shall be retained for five years.
- Components of the calculations and the results of such calculations for all values contained in the implementation and methodology documents.
- If a Transmission Planner is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved.
- The Reliability Organization Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.
    - The Transmission Planner shall keep data or evidence to show compliance as identified below unless directed by its

Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Planner shall have its latest models used to determine TTC for R2. (M2)
- The Transmission Operator shall retain documentation that it operated the system within the TTC and Emergency Transfer Capability. (M4)
- The Transmission Operator shall retain the latest version and prior version of the TTC study reports to show compliance with R3. (M5)
- The Transmission Operator shall retain evidence for the most recent three calendar years plus the current year to show compliance with R4. (M6)
- If a Transmission Planner or Transmission Operator is found noncompliant, it shall keep information related to the non-compliance until found compliant.

The Reliability Organization Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

C1.4. Compliance Monitoring and Enforcement Processes:

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

C1.5. Additional Compliance Information

None

C2. Levels of Non-Compliance

C2.1. Levels of Non-Compliance for Requirement R2&R3, Measure M1

C2.1.1. **Level 1 –** The methodology did not reflect the Transmission Operator's current practices.

C2.1.2. **Level 1 –** The methodology failed to describe the method used to account for an element in R2.

C2.1.3. **Level 2 –** The methodology failed to describe the method used to account for an element in R3.

C2.1.4. **Level 2 –** Transmission Operator failed to develop a written methodology for determining TTC values.

C2.2. Levels of Non-Compliance for Requirement R4, Measures M2, M3

C2.2.1. **Level 1 –** The model used for calculating TTCs failed to account for up to two of the criteria specified in R4.

C2.2.2. **Level 2 –** The model used for calculating TTCs failed to account for more than two of the criteria specified in R4.

C2.2.3. **Level 2 –** The TP failed to produce a TTCID.

C2.3. Levels of Non-Compliance for Requirement R6, Measure M4

C2.3.1. **Level 1 –** The study report did not account for one of the planning criterion listed in R6.

C2.3.2. **Level 1 –** Either the study report did not account for: contractual limitations, simultaneous interactions with one or more other paths, or the study report did not account for adverse impacts on the TTC of any existing path.

C2.3.3. **Level 2 –** A study report was not created to support TTC values.

C2.4. Levels of Non-Compliance for Requirement R11, Measure M5

C2.4.1. **Level 1 –** The TO failed to provide evidence that it operated the system within the TTC provided by the Transmission Planner.

C2.4.2. **Level 2 –** The TO failed to take corrective action to reduce path flow below its TTC or Emergency Transfer Capability.

C2.5. Levels of Non-Compliance for Requirement R13, Measure M6

C2.5.1. **Level 1 –** The TP failed to make the most current TTC and TTC study report available to the TO and TSP for the path within 7 days of the report finalization.

C2.6. Levels of Non-Compliance for Requirement R14, Measure M7

C2.6.1. **Level 1 –** The TP failed to provide an acceptable response to a written request from a registered entity within 45 days.

Version History

Version	Date	Action	Change Tracking
000	9-16-2016	EPS – Initial Release	-
001A	11-18-2016	EPS - Revisions following 10/20/2016 Meeting	Yes
001B	12-06-2016	EPS – Revisions following 12/05/2016 Meeting	Yes
001C	12-06-2016	Final Version	No
002	3-30-2018	RRO Revision	Yes

AKMOD-028 Attachment 1

Sample Total Transfer Capability Implementation Document (TTCID)

This document should serve as a guideline when the Alaska Railbelt transmission planners create a TTCID as required in AKMOD-028.

Transmission Planner's Total Transfer Capability Methodology and Implementation Document

Base Case Creation

The Transmission Planner will use regionally approved planning base cases as the starting point for the study. The base cases will include the winter peak, summer peak, and summer valley load conditions. Additional cases with different load levels are recommended to identify the full range of path transfer capabilities for a wide range of operating conditions.

It is assumed that the modeling requirements listed in AKMOD-028 R2.1.1 through R2.1.5, R2.1.8, R2.1.9, and R2.2 are confirmed as part of the base case approval process. Alaska does not have phase shifting transformers and is exempt from AKMOD R2.1.4. To comply with AKMOD-028 R1.2.2 and R1.2.9 for cases focused on future time frames, the TP should confirm transmission and generation additions and retirements are modeled in the database.

The transmission planner will verify that all transmission elements are modeled at or below 100% of their continuous rating.

For operational studies that are studying the impact of a planned outage, remove the element from service for all base cases. If the planned outage is a generator, update the case using a commitment order as provided by the applicable BA. If the planned outage is a transmission line, remove the line from service and confirm the power flow case solves and identify if the change in system losses or transfers requires re-dispatch or re-commitment.

Power Flow Analysis

Power flow analysis (contingency analysis) shall be performed on the base cases. The contingency list should include all N-1 line contingencies rated at 69 kV and higher plus the largest generation contingency for each BA at a minimum. Confirm that at the post-contingency condition all transmission elements remain below their emergency ratings, and all buses rated at 69 kV or higher shall have voltages that are between 0.95 and 1.05 per-unit voltage.

The generation dispatch and commitment will be adjusted to increase transfers across the path(s) that are the focus of the analysis. The following steps will be used to increase the transfers:

1. Increase source area generation and decrease sink area generation in 5 MW increments.
    - **a.** The next generating unit in the commitment order should be committed if the source area would have insufficient capacity to meet local demand, to source generation through the path, and to provide the required contingency reserves.
    - **b.** The lowest generating unit in the commitment order should be de-committed if the sink area has sufficient capacity to meet local demand and to provide the required contingency reserves.

c. The Transmission Planner shall use the commitment order provided by each BA

  i. Each BA shall provide a commitment and dispatch philosophy if a commitment order is not provided.

2. Run power flow analysis

  a. Confirm that at the post-contingency condition all transmission Elements remain below their emergency ratings, and all buses rated at 69 kV or higher shall have voltages that are between 0.95 and 1.05 per-unit voltage. If post-contingency conditions meet requirements in 2.a, return to step 1.

  b. If the flow on the transmission exceeds the emergency rating or a bus voltage is greater than 5% off its nominal voltage rating,

    i. Revert to the case with 5 MW less transfer and record the path's Steady-State Transfer Limit, record the generation commitment and dispatch of the source and sink areas, and save the pre-contingency case.

3. Repeat steps 1 and 2 for each of the following conditions to satisfy R.4

  a. Each generation commitment of interest

  b. If not already included in 3.a, the source area has its largest committed generation unit out of service for maintenance

    i. Recommit generation to replace the lost capacity

  c. If not already included in 3.a, the sink area has its largest committed generation unit out of service for maintenance

    i. Recommit generation to replace the lost capacity

The Emergency Transfer Capability shall be set equal to the Steady-State Transfer Limit identified above. The following process will be used to identify the Steady-State Transfer Capability.

1. Subtract the source areas Contingency Reserve obligation for the largest single contingency outside the source area per AKBAL-002 R3.
2. Subtract Transmission Reliability Margin from result of 1. TRM is set to 5 MW unless specified by RRO.
3. The resulting number is the Steady-State Transfer Capability.

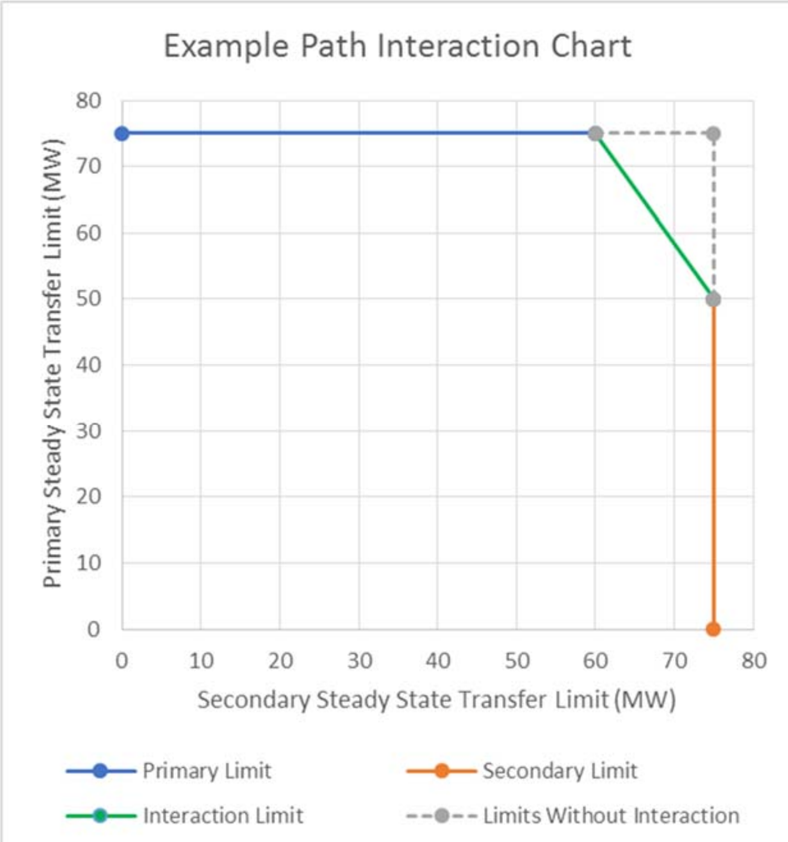
Additional sensitivity cases should be created to analyze if the Steady-State Transfer Limit for the path in question (primary) varies due to simultaneous interaction with one or more other paths (secondary). If feasible, the generation commitment and dispatch should be adjusted so that the flow on the primary path is near its Steady-State Transfer Limit and the secondary path is near its Steady-State Transfer Limit.

If it is not feasible to create a case with both primary and secondary paths near their Steady-State Transfer Limits, document why it is not feasible.

Run the power flow analysis described above to determine if the planning criteria is violated with both primary and secondary paths at their Steady-State Transfer Limits (or reduced limits if not feasible). If the cases satisfy the pre- and post-contingency planning criteria, no further analysis is needed because the path flows do not have simultaneous interaction. Neither nomogram nor chart is required. The sensitivity analysis will be performed as described below if the paths do have simultaneous interactions.

Path interactions and nomogram/chart data generation

1. Use the case with the primary path at its Steady-State Transfer Limit and the secondary path at its Steady-State Transfer Limit, if feasible.
2. Reduce flow on the secondary path until the case meets the pre- and post-contingency planning criteria.
    a. Record both primary and secondary path limits.
    b. Save power flow case
3. Starting with the case used in step 1, reduce flow on the primary path until the case meets the pre- and post-contingency planning criteria.
    a. Record both primary and secondary path limits.
    b. Save power flow case
4. Create nomogram or chart using data generated in steps 1 through 3.
    a. An example is shown below with primary and secondary Steady-State Transfer Limits of 75 MW
    b. The secondary path can be loaded to 50 MW with the primary path at its Steady-State Transfer Limit
    c. The primary path can be loaded to 60 MW with the secondary path at its Steady-State Transfer Limit



Dynamic Stability Analysis

The initial transient stability simulations should include an exhaustive list of N-1 contingencies. Future studies can use a subset of the most severe contingencies to reduce analysis burden. The analysis should progress in the following order.

1. Start with the power flow cases saved in the power flow analysis study including:
    a. Cases with primary path at its Steady-State Transfer Capability with secondary paths at nominal flows,
    b. Cases with largest generator in source and sink areas out of service.
    c. Sensitivity cases saved as part of the path interaction and nomogram/chart data generation.
2. Simulate all contingencies in the contingency list.
3. Confirm that the case is stable, well-damped, does not suffer uncontrolled separation, and that the voltages recover to near nominal.
    a. If all contingencies meet the requirements in step 3, the Transient Transfer Limit is larger than the Steady-State Transfer Capability and no more work is necessary.
    b. If one or more contingencies does not meet the requirements in step 3, reduce the transfers in the same manner as was used to increase the transfers in the power flow analysis.

- **i.** Repeat step 2 until all contingencies result in a stable condition.
- **ii.** Record the Stability Limit at which all simulations were stable.
- **iii.** Set the Transient Transfer Limit equal to the Stability Limit minus the Transmission Reliability Margin.

The TTC will be recorded as follows:

1. For paths that have simultaneous interactions with other paths,
   - **a.** A nomogram or chart will describe the TTC of both the primary path and the secondary path.
   - **b.** Set the TTC nomogram/chart equal to the minimum of the Transient Transfer Limit and Steady-State Transfer Capability.
   - **c.** Set the ETC nomogram/chart equal to the Steady-State Transfer Limits.
2. For paths that do not have simultaneous interactions with other plants,
   - **a.** The TTC will be the minimum of the Steady-State Transfer Capability and the Transient Transfer Limit.
   - **b.** Set the ETC equal to the Steady-State Transfer Limit.

Study Report

Create a TTC study report documenting the assumptions used and steps taken in determining the current value for TTC and ETC for that path. Within one week of finalization, the report should be provided to the Transmission Operator.

Alaska Railbelt Standard AKMOD-032-2 – Data for Power System Modeling and Analysis

A. Introduction

1. **Title:** **Data for Power System Modeling and Analysis**

2. **Number:** **AKMOD-032-2**

3. **Purpose:**

   3.1. To establish consistent modeling data requirements and reporting procedures for development of planning horizon cases necessary to support analysis of the reliability of the interconnected transmission system.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Balancing Authority

   4.1.2. Generator Owner

   4.1.3. Load Serving Entity

   4.1.4. Planning Coordinator

   4.1.5. Resource Planner

   4.1.6. Transmission Owner

   4.1.7. Transmission Planner

   4.1.8. Transmission Service Provider

5. **Effective Date:** 12 months from adoption by the Reliability Organization.

B. Requirements

R1. The Reliability Organization, in conjunction with each areas' Transmission Planner, shall develop steady-state, dynamics, and short circuit modeling data requirements and reporting procedures for the Planning Coordinator's planning area that include:

R1.1. The data listed in Attachment 1.

R1.2. Specifications of the following items consistent with procedures for building the Interconnection-wide case(s):

Data format;

R1.2.1 Level of detail to which equipment shall be modeled;

R1.2.2 Case types or scenarios to be modeled; and

R1.2.3. A schedule for submission of data at least once every 13 calendar months.

R1.3. Specifications for distribution or posting of the data requirements and reporting procedures so that they are available to those entities responsible for providing the data.

R2. Each Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, and Transmission Service Provider shall provide steady-state, dynamics, and short circuit modeling data to any Transmission Planner(s) and Planning Coordinator(s) according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1. For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient.

R3. Upon receipt of written notification from the Reliability Organization regarding technical concerns with the data submitted under Requirement R2, including the technical basis or reason for the technical concerns, each notified Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider shall respond to the Reliability Organization as follows:

R3.1. Provide either updated data or an explanation with a technical basis for maintaining the current data;

R3.2. Provide the response within 90 calendar days of receipt unless a longer time period is agreed upon by the notifying the Reliability Organization.

R4. Each Planning Coordinator shall make available models for its planning area reflecting data provided to it under Requirement R2 to the Reliability Organization or its designee to support creation of the Interconnection-wide case(s) that includes the Planning Coordinator's planning area.

C. Measures

M1. The Reliability Organization shall provide evidence that it has jointly developed the required modeling data requirements and reporting procedures specified in Requirement R1.

M2. Each registered entity identified in Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted the required modeling data to the Reliability Organization; or written confirmation that the data has not changed.

M3. Each registered entity identified in Requirement R3 that has received written notification from the Reliability Organization regarding technical concerns with the data submitted under Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has provided either updated data or an explanation with a technical basis for maintaining the current data to the Reliability Organization within 90 calendar days of receipt (or within the longer time period agreed upon by the notifying the Reliability Organization).

M4. Each Planning Coordinator shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted models for its planning area reflecting data provided to it under Requirement R2 when requested by the Reliability Organization or its designee.

D. Compliance

C1. Compliance Monitoring Process

C1.1. Compliance Enforcement Authority

Reliability Organization

C1.2. Data Retention

The following data retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Reliability Organization Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The applicable entity shall keep data or evidence to show compliance with Requirements R1 through R4, and Measures M1 through M4, since the last audit, unless directed by its Reliability Organization Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If an applicable entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The Reliability Organization Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

C1.3. Compliance Monitoring and Assessment Processes:

Refer to the NERC Rules of Procedure for a list of compliance monitoring and assessment processes.

C1.4. Additional Compliance Information

None

Version History

Version	Date	Action	Change Tracking
000	-	NERC Version	-
001A	8-24-2016	EPS – Initial Edits	Yes
001B	9-16-2016	EPS – Revisions following 8/25/2016 Meeting	Yes
001C	11-18-2016	EPS – Revisions following 10/20/2016 Meeting	Yes
001D	12-06-2016	EPS – Revisions following 12/05/2016 Meeting	Yes
001E	12-06-2016	Final Version	No
002	3-30-2018	RRO Revision	Yes

MOD-032-01 – ATTACHMENT 1:

Data Reporting Requirements

The table, below, indicates the information that is required to effectively model the interconnected transmission system for the Near-Term Transmission Planning Horizon and Long-Term Transmission Planning Horizon. Data must be shareable on an interconnection-wide basis to support use in the Interconnection-wide cases. A Planning Coordinator may specify additional information that includes specific information required for each item in the table below. Each functional entity1 responsible for reporting the respective data in the table is identified by brackets "[functional entity]" adjacent to and following each data item. The data reported shall be as identified by the bus number, name, and/or identifier that is assigned in conjunction with the PC, TO, or TP.

		steady-state (Items marked with an * indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)			**dynamics** (If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, a list of all state variables, and source code of the model, if available)			**short circuit**
1		Each bus [TO]	1		Generator [GO, RP (for future planned resources only)]	1		Provide for all applicable elements in column "steady-state" [GO, RP, TO]
	a.	nominal voltage						
	b.	area, zone and owner	2		Excitation System [GO, RP(for future planned resources only)]		a.	Positive Sequence Data
2		Aggregate Demand[2] [LSE]					b.	Negative Sequence Data
	a.	real and reactive power*	3		Governor [GO, RP(for future planned resources only)]		c.	Zero Sequence Data
	b.	in-service status*				2		Mutual Line Impedance Data [TO]
3		Generating Units[3] [GO, RP (for future planned resources only)]		a.	real power capabilities - seasonal (summer valley, summer peak, and winter peak) maximum and minimum values	3		Fault current contribution from non-synchronous(inverter, power electronics, etc) generation sources
	a.	real power capabilities - seasonal (summer valley, summer peak, and winter peak)maximum and minimum values						
	b.	reactive power capabilities - maximum and minimum values at real power capabilities in 3a above	4		Power System Stabilizer [GO, RP(for future planned resources only)]	4		Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling
	c.	station service auxiliary load for normal plant configuration (provide data in the same manner as that required for aggregate Demand under item 2, above).	5		Demand [LSE]			
	d.	regulated bus* and voltage set point* (as typically provided by the TOP)		a.	Frequency dependence settings and documentation supporting the use of frequency dependent demand			
	e.	machine MVA base	7		Photovoltaic systems [GO]			
	f.	generator step up transformer data (provide same data as that required for transformer under item 6, below)	6		Wind Turbine Data [GO]			
	g.	generator type (hydro, wind, fossil, solar, nuclear, etc)	7		Photovoltaic systems [GO]			
	h.	in-service status*						

steady-state (Items marked with an * indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)		dynamics (If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, a list of all state variables, and source code of the model, if available)		short circuit
4	AC Transmission Line or Circuit [TO]	8	Energy Storage Systems [GO]	
a.	impedance parameters (positive sequence)	a.	Frequency response characteristics	
b.	susceptance (line charging)	b.	Contingency response characteristics	
c.	seasonal ratings (summer valley, summer peak, winter peak)*	c.	Ability to simulate all modes of actual ESS operation	
d.	in-service status*	9	Static Var Systems and FACTS [GO, TO, LSE]	
5	DC Transmission systems [TO]	10	DC system models [TO]	
6	Transformer (voltage and phase-shifting) [TO]	11	Unit Protection Settings	
a.	nominal voltages of windings	a.	Voltage Ride Through Settings	
b.	impedance(s)	b.	Frequency Ride Through Settings, as determined by PRC-006	
c.	tap ratios (voltage or phase angle)*			
d.	minimum and maximum tap position limits	12	Special Protection Systems	
e.	number of tap positions (for both the ULTC and NLTC)	13	Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, LSE, TO, TSP]	
f.	regulated bus (for voltage regulating transformers)*			
g.	maximum seasonal (summer valley, summer peak, and winter peak) rating*			
h.	in-service status*			
7	Reactive compensation (shunt capacitors and reactors) [TO]			
a.	admittances (MVars) of each capacitor and reactor step			
b.	regulated voltage band limits* (if mode of operation not fixed)			
c.	mode of operation (fixed, discrete, continuous, etc.)			
d.	regulated bus* (if mode of operation not fixed)			
e.	in-service status*			
8	Static Var Systems [TO]			
a.	reactive limits			
b.	voltage set point*			
c.	fixed/switched shunt, if applicable			
d.	in-service status*			
9	Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, LSE, TO, TSP]			

[1] For purposes of this attachment, the functional entity references are represented by abbreviations as follows: Balancing Authority (BA), Generator Owner (GO), Load Serving Entity (LSE), Planning Coordinator (PC), Resource Planner (RP), Transmission Owner (TO), Transmission Planner (TP), and Transmission Service Provider (TSP).

[2] For purposes of this item, aggregate Demand is the Demand aggregated at each bus under item 1 that is identified by a Transmission Owner as a load serving bus. A Load Serving Entity is responsible for providing this information, generally through coordination with the Transmission Owner.

[3] Including synchronous condensers, ~~and~~ pumped storage, and energy storage systems.

Alaska Railbelt Standard AKMOD-33-2 – Steady State and Dynamic System Model Validation

A. Introduction

1. **Title:** **Steady-State and Dynamic System Model Validation**
2. **Number:** **AKMOD-033-2**
3. **Purpose:**

   3.1. To establish consistent validation requirements to facilitate the collection of accurate data and building of planning models to analyze the reliability of the interconnected transmission system.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Planning Coordinator

   4.1.2. Reliability Coordinator

   4.1.3. Transmission Operator

5. **Effective Date:** 12 months from the adoption by the Reliability Organization.

B. Requirements

The Reliability Organization shall implement a documented data validation process that includes the following attributes:

R1. Comparison of the performance of the existing system in a planning power flow model simulation compared to actual system behavior, represented by a state estimator case or other real-time data sources, for at least the summer minimum, summer and winter maximum peak conditions, at least once every 24 calendar months;

R2. Comparison of the performance of the existing system in a planning dynamic model to actual system response, through simulation of a dynamic event, at least once every 24 calendar months (use a dynamic event that occurs within 24 calendar months of the last dynamic event used in comparison and complete each comparison within 24 calendar months of the dynamic event). If no dynamic event occurs within the 24 calendar months, use the next dynamic event that occurs;

R2.1. Performance comparison simulations should include a generation trip and a transmission line fault, at a minimum.

R2.1.1. By specifying these duties of the Reliability Organization, it is the intent of the standard that until such a time that the Railbelt becomes more closely interconnected, that such verifications will be completed using a generation trip and a transmission line fault in each of the three major load/generation areas.

R2.1.2. The dynamic event chosen must be able to be simulated with reasonable accuracy. Recordings and accurate description of the sequence of the event (power output of a unit that is tripped, or line from unit / plant, line flow of the line that was tripped, etc.) must be available to accurately complete the comparison. Dynamic events that are a result of discreet action (unit breaker, line breaker) should be given priority over other events. Events such as unbalanced faults, unexplained unit / plant output reductions, and other obscure events should not be used for purposes of this comparison.

R3. Guidelines the Reliability Organization will use to determine unacceptable differences in performance under R1 and R2, and at a minimum will include the following;

R3.1. Bus frequency differences should not exceed 0.05 Hz at minimum frequency and 0.2 Hz at maximum frequency

R3.2. Machine electrical power differences should not exceed 2 MW during the transient and 1 MW after the transient has occurred (5 seconds after event), and 0.5 MW during steady state conditions (power flow).

R3.3. Tie line flow differences should not exceed 5 MW after the transient event has occurred (5 seconds after event), and 0.5 MW during steady state conditions (power flow).

R3.4. Voltage differences should not exceed +/- 5% after the transient event has occurred (5 seconds after event), and +/- 1% during steady state conditions (power flow).

R4. Guidelines to resolve the unacceptable differences in performance identified under R3 and at a minimum will include the following;

R4.1 Identification of equipment in an area for the source of a difference. If a machine, synchronous condenser, or Power Electronic Transmission Asset, response is found to be the source of the difference, the applicable owning body (Generator Owner or Transmission Owner) shall be required to verify the modeling data as required in the applicable modeling standard (AKMOD-025, AKMOD-026, or AKMOD-027). Otherwise facility inspections shall be completed to verify the accuracy of the equipment modeling (conductor or transformer impedances, etc.). The validation shall be completed no later than 6 months after notification of the modeling deficiency is made to the applicable Owner or Reliability Organization.

R4.2 Identification of area(s)/equipment where additional recording devices are required to determine source of difference. A plan must be developed to increase visibility/recordings for the area/equipment and be completed 12 months after identification from the comparison is made.

Each Reliability Coordinator and Transmission Operator shall provide actual system behavior data (or a written response that it does not have the requested data) to the

Reliability Organization performing validation under Requirement R1 within 30 calendar days of a written request, such as, but not limited to, state estimator case or other Real-time data (including disturbance data recordings) necessary for actual system response validation.

C. Measures

M1. The Reliability Organization shall provide evidence that it has a documented validation process according to Requirement R1 as well as evidence that demonstrates the implementation of the required components of the process. Attachment 1 is provided as an example for the guidelines in Requirement R3.

M2. The Reliability Organization shall provide evidence, such as email notices or postal receipts showing recipient and date that it has distributed the requested data or written response that it does not have the data, to any Planning Coordinator performing validation under Requirement R1 within 30 days of a written request in accordance with Requirement R2; or a statement by the Reliability Organization that it has not received notification regarding data necessary for validation by any Planning Coordinator.

D. Compliance

C1. Compliance Monitoring Process

C1.1. Compliance Enforcement Authority

Reliability Organization

C1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Reliability Organization Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance with Requirements R1 through R2, and Measures M1 through M2, since the last audit, unless directed by its Reliability Organization Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If an applicable entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The Reliability Organization Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

C1.3. Compliance Monitoring and Assessment Processes:

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting
- Complaints

C1.4. Additional Compliance Information

None

C2. Levels of Non-Compliance

C2.1. Levels of Non-Compliance for Requirement R1, Measure M1

C2.1.1. Level 1 – The Reliability Organization documented and implemented a process to validate data but did not address one of the four required topics under Requirement R1; or the Reliability Organization did not perform simulation as required by part 1.1 within 24 calendar months but did perform the simulation within 30 calendar months; or the Reliability Organization did not perform simulation as required by part 1.2 within 24 calendar months (or the next dynamic event in cases where there is more than 24 months between events) but did perform the simulation within 30 calendar months.

C2.1.2. Level 2 – The Reliability Organization did not have a validation process at all or did not document or implement any of the four required topics under Requirement R1; or The Reliability Organization did not validate its portion of the system in the power flow model as required by R1 within 36 calendar months; or The Reliability Organization did not perform simulation as required R2 within 36 calendar months (or the next dynamic event in cases where there is more than 24 months between events).

C3. Levels of Non-Compliance for Requirement R2, Measure M2

C3.1. Level 1 – The Reliability Organization Reliability Coordinator or Transmission Operator did not provide requested actual system behavior data (or a written response that it does not have the requested data) to a requesting Reliability Organization within 30 calendar days of the written request, but did provide the data (or written response that it does not have the requested data) in less than or equal to 45 calendar days.

C3.2. Level 2 – The Reliability Organization Reliability Coordinator or Transmission Operator did not provide requested actual system behavior data (or a written response that it does not have the requested data) to a requesting Reliability Organization within 75 calendar days; or The Reliability Organization Reliability Coordinator or Transmission Operator provided a written response that it does not have the requested data, but actually had the data.

E. Regional Variances

None

F. Interpretations

None

G. Associated Documents

None

Guidelines and Technical Basis

Requirements:

The requirement focuses on the results-based outcome of developing a process for and performing a validation but does not prescribe a specific method or procedure for the validation outside of the attributes specified in the requirement. For further information on suggested validation procedures, see “Procedures for Validation of Powerflow and Dynamics Cases” produced by the NERC Model Working Group.

The specific process is left to the judgment of the Planning Coordinator, but the Planning Coordinator is required to develop and include in its process guidelines for evaluating discrepancies between actual system behavior or response and expected system performance for determining whether the discrepancies are unacceptable.

For the validation in part R1, the state estimator case or other real-time data should be taken as close to desired seasonal conditions as possible. While the requirement specifies “once every 24 calendar months,” entities are encouraged to perform the comparison on a more frequent basis. Until the model has been sufficiently verified to confirm its accuracy in varying load and generation conditions, each entity is encouraged to confirm the model following each major system disturbance.

In performing the comparison required in R1, the Planning Coordinator may consider, among other criteria:

1. System load;
2. Transmission topology and parameters;
3. Voltage at major buses; and
4. Flows on major transmission elements.

Validation would include consideration of the load distribution and load power factors (as applicable) used in the power flow models. The validation may be made using metered load data or state estimator cases. The comparison of system load distribution and load power factors shall be made on the substation level at a minimum but may also be made on a bus by bus basis within each substation, or smaller area basis as deemed appropriate by the Planning Coordinator.

The required validation required may include simulations that are to be compared with actual system data and may include comparisons of:

- Voltage oscillations at major buses
- System frequency (for events with frequency excursions)
- Real and reactive power oscillations on generating units and major inter-area ties

Determining when a dynamic event might occur may be unpredictable, and because of the analytic complexities involved in simulation, the time parameters in R2 specify that the comparison period of “at least once every 24 calendar months” is intended to both provide for at least 24 months between dynamic events used in the comparisons and that comparisons must be completed within 24 months of the date of the dynamic event used. This clarification ensures that PCs will not face a timing scenario that makes it impossible to comply. If the time referred to the completion time of the comparison, it would be possible for an event to occur in month 23 since the last comparison, leaving only one month to complete the comparison. With the 30-day timeframe in Requirement R4 for TOPs or RCs to provide actual system behavior data (if necessary in the comparison), it would potentially be impossible to complete the comparison within the 24 month timeframe.

In contrast, the requirement language clarifies that the time frame between dynamic events used in the comparisons should be within 24 months of each other (or, as specified at the end of R2 in the event more than 24 months passes before the next dynamic event, the comparison should use the next dynamic event that occurs). Each comparison must be completed within 24 months of the dynamic event used. In this manner, the potential problem with a "month 23" dynamic event described above is resolved. For example, if a PC uses for comparison a dynamic event occurring on day 1 of month 1, the PC has 24 calendar months from that dynamic local event's occurrence to complete the comparison. If the next dynamic event the PC chooses for comparison occurs in month 23, the PC has 24 months from that dynamic event's occurrence to complete the comparison.

R3 requires the PC to include guidelines in its documented validation process for determining when discrepancies in the comparison of simulation results with actual system results are unacceptable. The PC may develop the guidelines required by R3.1 through R3.4, reference other established guidelines, or both. For the power flow comparison, as an example, this could include a guideline the Planning Coordinator will use that flows on 138 kV lines should be within 10% or 5 MW, whichever is larger. It could be different percentages or MW amounts for different voltage levels. Or, as another example, the guideline for voltage comparisons could be that it must be within 1%. But the guidelines the PC includes within its documented validation process should be meaningful for the Planning Coordinator's system. Guidelines for the dynamic event comparison may be less precise. Regardless, the comparison should indicate that the conclusions drawn from the two results should be consistent. For example, the guideline could state that the simulation result will be plotted on the same graph as the actual system response. Then the two plots could be given a visual inspection to see if they look similar or not. Or a guideline could be defined such that the rise time of the transient response in the simulation should be within 20% of the rise time of the actual system response. As for the power flow guidelines, the dynamic comparison criteria should be meaningful for the Planning Coordinator's system.

The guidelines the PC includes in its documented validation process to resolve differences in R4 could include direct coordination with the data owner, and, if necessary, through the provisions of AKMOD-032-2, Requirement R3 (i.e., the validation performed under this requirement could identify technical concerns with the data). In other words, while this standard is focused on validation, results of the validation may identify data provided under the modeling data standard that needs to be corrected. If a model with estimated data or a generic model is used for a generator, and the model response does not match the actual response, then the estimated data should be corrected or a more detailed model should be requested from the data provider.

If the simulations can be made to match the actual system responses by reasonable changes to the data in the Planning Coordinator's area, then the Planning Coordinator should make those changes in coordination with the data provider. The guidelines the Planning Coordinator included under R4 could cover these situations.

Rationale for R1:

Requirement R1 requires the Planning Coordinator to implement a documented data validation process to validate data in the Planning Coordinator's portion of the existing system in the steady-state and dynamic models to compare performance against expected behavior or response. The following items were chosen for the validation requirement:

A. Comparison of performance of the existing system in a planning power flow model to actual system behavior; and

B. Comparison of the performance of the existing system in a planning dynamics model to actual system response.

Implementation of these validations will result in more accurate power flow and dynamic models. This, in turn, should result in better correlation between system flows and voltages seen in power flow studies and the actual values seen by system operators during outage conditions. Similar improvements should be expected for dynamics studies, such that the results will more closely match the actual responses of the power system to disturbances.

Validation of model data is a good utility practice, but it does not easily lend itself to Reliability Standards requirement language. Furthermore, it is challenging to determine specifications for thresholds of disturbances that should be validated and how they are determined. Therefore, this requirement focuses on the Planning Coordinator performing validation pursuant to its process, which must include the attributes listed in R3.1 through R3.4, without specifying the details of "how" it must validate, which is necessarily dependent upon facts and circumstances. Other validations are best left to guidance rather than standard requirements.

Rationale for R2:

The Planning Coordinator will need actual system behavior data in order to perform the required validations. The Reliability Coordinator or Transmission Operator may have this data. Requirement R2 requires the Reliability Coordinator and Transmission Operator to supply actual system data, if it has the data, to any requesting Planning Coordinator for purposes of model validation under Requirement R1.

This could also include information the Reliability Coordinator or Transmission Operator has at a field site. For example, if a phasor measurement unit (PMU) or dynamic fault recorder (DFR) is at a generator site and it is recording the disturbance, the Reliability Coordinator or Transmission Operator would typically have that data.

Version History

Version	Date	Action	Change Tracking
00	-	NERC Version	-
001A	3-21-2016	EPS edit from NERC Standard	Yes
001B	9-16-2016	EPS – Revisions following 8/25/2016 Meeting	Yes
001C	11-18-2016	EPS – Revisions following 10/20/2016 Meeting	Yes
001D	12-06-2016	Final Version	No
002	3-30-2018	RRO Revision	Yes

AKMOD-033 – Attachment 1

Example Interconnection Model Validation Process and Guidelines:

Alaska's primary concerns include loss of synchronism over the major tie lines, and the activation of UFLS in response to the loss of generation. The guidelines listed below were created for the Alaskan Railbelt. The validation sections below should serve as an example set of guidelines as required in Requirement 1.3.

Power Flow

Input Data

The following items from the recorded snapshot data are transferred directly into the steady-state power flow case (state estimators may be a suitable source for this data):

- Generators
    - Real power output
    - Reactive power output or voltage setting
    - Control mode (voltage control, power factor control)
    - Voltage regulation point (local or remote, if on voltage control)
    - Status
- Loads
    - Measured real power at available granularity
    - Measured reactive power
- Transmission Network
    - Network topology
        - Device statuses
            - Transmission lines
            - Breakers (may result in split buses)
            - Reactive shunt elements (Capacitor, Reactor)
            - Reactive series elements (Capacitor, Reactor)
        - Fixed-tap transformer tap positions
        - ULTC transformers – Fixed tap position and LTC voltage setting
        - Phase-shifting transformers – angle position or MW setting
    - Static VAR systems and fast-switched shunt devices – reactive output or voltage setting
    - DC lines – active power flow
    - Other devices present in system model

- Wide-Area Control
    - Area interchange totals

After data is inserted, a power flow solution is performed. After the initial power flow solution is performed, the following priority list should be used when comparing the power flow solution to the recorded values.

Validation

1. Minimize the tie flow error (recorded vs. simulation) between areas with a desired error of 0.5 MW or less.
    a. The tie flows should take top priority due to the transient stability concerns.
    b. May need to adjust recorded generation and/or area load.
2. Minimize generation error within +/- 0.5 MW.
    a. Use recorded values to the extent possible. May need adjustment based on tie flows.
    b. May need to adjust area load so slack generator matches the recorded MW while keeping tie flows close to recorded values.
3. Adjust voltage setpoints to match recorded voltages within +/- 1%. Minimize generation error within +/- 1.0 MVAR.
    a. Engineering judgement should be used when balancing the voltage errors and generation reactive power errors.
4. Use recorded load MW, MVAR.
    a. To match generation and tie flows the unobservable load should be adjusted
    b. If necessary, the recorded load may need to be adjusted to match line flows, tie flows, and generation outputs.

If using power flow case for transient stability analysis, the relative priority above may change based on the goals of the validation case. The generation output would take highest priority if a specific unit is going to be tripped as part of the transient stability validation. Whereas, the line flow would take priority when a transmission line fault and trip will be simulated as part of the transient stability validation process.

Transient Stability

Input Data

Comparisons between simulation results from the model and measured dynamic data provide an indication of the collective validity of a large set of component dynamics models. The following data must be entered in the transient stability database, at a minimum:

- Generator
    - Status of exciter
    - Status of power system stabilizer (PSS)
    - Status of governor (droop, temperature limits, etc.)

    - Control parameters (gains, feedback time constants, etc.)
    - Machine characteristics (inertia, time constants)
- Load model
    - Real and reactive power under dynamic conditions
- Transmission Network model
    - Reactive shunt dynamics models (automatic shunt switching)
    - Static VAR compensator (SVC) model characteristics
- Dynamic Load Characteristics
    - Dynamic load characteristic models have never been utilized with the Railbelt model. In other islanded systems, the dynamic load characteristics can have a noticeable impact on the ability of the model to replicate actual system disturbances. Transient recorders at stations that serve load should be utilized to ascertain the dynamic response of load to changes in voltage and frequency characteristics. Often times, this characteristic will vary depending upon the time of day/season of the event. Estimates of load characteristics at stations with recorders should be used as a proxy for similar loads in the system.

Validation

Non-3-phase faults are going to be more difficult to validate since industry tools are positive sequence programs.

1. Match interconnection frequency response within 0.05 Hz at minimum frequency and 0.2 Hz at maximum frequency.
    a. In order to ensure proper margin, it is preferable that the simulation response has an interconnection frequency that is slightly lower or equal to the recorded interconnection frequency response for under frequency events. Adjustments to the load characteristics may be made to get the load to match recorded load during the transient event after all other possible adjustments have been exhausted.
2. Match the recorded and simulated generation responses to within 2 MW during the transient and 1 MW after the transient has occurred (5 seconds after event).
    a. The primary goal of the validating is to match the interconnection frequency. The simulated generation response should match the recordings but preference should be given to the interconnection frequency. Multiple iterations alternating between matching the system load characteristics and generation output may be required to obtain close correlation between the simulation and recorded values.
3. Using engineering judgement, match the significant flows between areas within 5 MW after the transient has occurred (5 seconds after event).
    a. The stability limits along the tie from Kenai to Anchorage and from Anchorage to Fairbanks are a significant concern and dictate many operational limits. Ensuring simulations match the recorded tie-line flows will improve the confidence in the defined limits.

4. Using engineering judgement, match the recorded and simulated major bus voltages within +/-2% during pre and post-disturbance comparisons.

<u>**Alaska Railbelt Standard AKPRC-006-2 – Automatic Underfrequency Load Shedding**</u>

A. Introduction

1. **Title:** **Automatic Underfrequency Load Shedding**

2. **Number:** **AKPRC-006-2**

3. **Purpose:**

    3.1 To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.

4. **Applicability:**

    4.1. UFLS entities shall mean all entities that are responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program established by the Reliability Organization. Such entities may include one or more of the following:

    4.1.1. Planning Coordinators

    4.1.2. Transmission Owners

    4.1.3. Distribution Providers

5. **Effective Date:** 12 months from adoption by the Reliability Organization.

B. Requirements

R1. The Reliability Organization shall develop and document criteria within the Railbelt system, including consideration of historical events and system studies, to select load levels within the Distribution Provider's Area to form load shedding stages.

R1.1. The UFLS program shall be designed for the system to survive the following imbalance scenarios (at a minimum) for all system load conditions.

R1.1.1. Loss of generation or transfers as determined by the Maximum N-1 Contingency Criteria.

R1.1.2. Loss of generation or transfers as defined in AKBAL-002 as a Reportable Excess Contingency.

R1.1.3. Loss of largest plant.

R1.2. The UFLS program may be designed with a provision for a backup block of load (s) with an extended time delay to prevent extended low frequency operation.

R1.3. The UFLS program shall be designed such that the loss of a contingency less than 75% of the Maximum N-1 Contingency Criteria should not result in the activation of the UFLS program.

R1.4. The UFLS program shall consider severe scenarios of unit commitment and dispatch defined to limit reserve response and location.

R2. The Reliability Organization shall design the UFLS with the requirements of the interconnected system and subsequently identify one or more islands to serve as a basis for designing its UFLS program during islanding conditions including:

R2.1. Any portions of the BES designed to detach from the Interconnection (planned islands) as a result of the operation of a relay scheme or Special Protection System, and

R2.2. A single island that includes all portions of the BES in either the Regional Entity area or the Interconnection in which the Planning Coordinator's area resides.

R2.3. The load included in the UFLS for the protection of the interconnected system shall not be included in a SILOS program. Load included in an island's UFLS system designed to protect the area following islanding may be included in a SILOS program.

R3. The Reliability Organization shall develop a UFLS program within the Railbelt system, including notification of and a schedule for implementation by UFLS entities within the interconnected system, that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where imbalance = [(load — actual generation output) / (load)].

R3.1. Frequency shall remain within the bounds of the Underfrequency Performance Characteristic curve contained within Attachment 1, either for 60 seconds or until a steady-state condition between 59.5 Hz and 60.5 Hz is reached for any contingency less than or equal to the Maximum N-1 Contingency Criteria.

R3.2. Frequency shall remain within the bounds of the Underfrequency Performance Characteristic curve contained within Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached for any contingency larger than the Maximum N-1 Contingency Criteria.

R3.3. The UFLS program shall be designed such that no UFLS program action results in an interconnected system frequency that exceeds 61.8 Hz for any contingency.

R3.3.1. Portions of the BES designed to detach from the Interconnection as a result of the operation of a relay scheme or Special Protection System may exceed these frequency limits but should not exceed 63.0 Hz following a UFLS program activation.

R3.4. Simulated UFLS events shall not result in Volts per Hertz (V/Hz) exceeding the generator trip settings or equipment damage limits if no protection exists.

R3.5. Simulated UFLS events shall not result in an increase in transfers between areas that exceed the transfer limits of the transmission path.

R4. The Reliability Organization shall conduct and document a UFLS design assessment within the Railbelt system at least once every five years or upon any significant changes in Distribution Providers' resources or characteristics of the Bulk Electric Transmission System that may impact UFLS performance. The design assessment shall update the UFLS design as necessary to maintain the performance characteristics in Requirement R3 for each island identified in Requirement R2. The simulation shall model each of the following:

R4.1. Underfrequency trip settings of each generating unit / plant with a nameplate capability larger than or equal to 5 MVA directly connected to the BES through a single contingency interconnection that trips within the bounds of the Generator Underfrequency Trip Modeling curve in AKPRC-006 - Attachment 1.

R4.2. Overfrequency trip settings of each generating unit / plant greater than 5 MVA (gross nameplate rating) directly connected to the BES through a single contingency interconnection that trips below the Generator Overfrequency Trip Modeling curve in AKPRC-006 — Attachment 1

R4.3. Any system action that impacts Interconnection frequency response including:

R4.3.1. Any automatic load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.

R4.3.2. Any operation of a relay scheme or Special Protection System that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.

R4.3.3. Operation of plant controls that affect unit response and system frequency.

R4.3.4. The best estimate of each Distribution Provider load's response to changes in system frequency or voltage.

R5. Each Planning Coordinator, whose area or portions of whose area is part of an island designed to detach from the BES as a result of the operation of a relay scheme or Special Protection System shall coordinate its UFLS program with the Reliability Organization:

- Develop a common UFLS program design and schedule for implementation per Requirement R3 among the Planning Coordinators whose areas or portions of whose areas are part of the same identified island, or
- Conduct a joint UFLS design assessment per Requirement R4 among the Planning Coordinators whose areas or portions of whose areas are part of the same identified island, or

- Conduct an independent UFLS design assessment per Requirement R4 for the identified island, and in the event the UFLS design assessment fails to meet Requirement R3, identify modifications to the UFLS program(s) to meet Requirement R3 and report these modifications as recommendations to the other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island.

R6. Each Planning Coordinator shall maintain a UFLS database containing data necessary to model its UFLS program for use in event analyses and assessments of the UFLS program at least once each calendar year, with no more than 15 months between maintenance activities.

R7. Each Planning Coordinator shall provide its UFLS database containing data necessary to model its UFLS program to other Planning Coordinators within the Interconnection within 30 calendar days of a request.

R8. Each UFLS entity shall provide data to its Planning Coordinator(s) according to the format and schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.

R9. Each UFLS entity shall provide automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by its Planning Coordinator(s) in each Planning Coordinator area in which it owns assets.

R10. Each Transmission Owner shall provide automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage as a result of underfrequency load shedding if required by the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission.

R11. The Reliability Organization shall conduct and document an assessment for an event that results in system frequency excursions below the initializing set points of the UFLS program, within two (2) months of event to evaluate:

R11.1. The performance of the UFLS equipment,

R11.2. The effectiveness of the UFLS program.

R11.3. If further analysis is not required, all documentation should be completed within two (2) months from the initial event.

R12. The Reliability Organization shall conduct and document a UFLS design assessment as outlined in R4 to evaluate the event and UFLS response, when an UFLS initial event assessment (per R11) shows need for additional analysis, within six (6) months of the event. The analysis shall include, but not be limited to:

R12.1. A description of the event including initiating conditions.

R12.2. A review of the UFLS set points and tripping times.

R12.3. A simulation of the event.

R12.4. A summary of the findings.

R13. The Reliability Organization shall respond to written comments submitted by UFLS entities and Transmission Owners following a comment period and before finalizing its UFLS program, indicating in the written response to comments whether changes will be made or reasons why changes will not be made to the following:

R13.1. UFLS program, including a schedule for implementation

R13.2. UFLS design assessment

R13.3. Format and schedule of UFLS data submittal

C. Measures

M1. Each Planning Coordinator shall have evidence such as reports, or other documentation of its criteria to select portions of its system that may form load shedding blocks including how system studies and historical events were considered to develop the criteria per Requirement R1.

M2. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, or other documentation supporting its identification of potential islands to serve as a basis for designing a UFLS program that meet the criteria in Requirement R2.

M3. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, program plans, or other documentation of its UFLS program, including the notification of the UFLS entities of implementation schedule, that meet the criteria in Requirement R3.

M4. Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its UFLS design assessment that demonstrates it meets Requirement R4.

M5. Each Planning Coordinator, whose area or portions of whose area is part of an island identified by it or another Planning Coordinator shall have dated evidence such as joint UFLS program design documents, reports describing a joint UFLS design assessment, letters that include recommendations, or other dated documentation demonstrating that it coordinated its UFLS program design with all other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island per Requirement R5.

M6. Each Planning Coordinator shall have dated evidence such as a UFLS database, data requests, data input forms, or other dated documentation to show that it maintained a UFLS database for use in event analyses and assessments of the UFLS program per Requirement R6 at least once each calendar year, with no more than 15 months between maintenance activities.

M7. Each Planning Coordinator shall have dated evidence such as letters, memorandums, e-mails or other dated documentation that it provided their UFLS database to other Planning Coordinators within the Interconnection within 30 calendar days of a request per Requirement R7.

M8. Each UFLS Entity shall have dated evidence such as responses to data requests, spreadsheets, letters or other dated documentation that it provided data to its Planning Coordinator according to the format and schedule specified by the Planning Coordinator to support maintenance of the UFLS database per Requirement R8.

M9. Each UFLS Entity shall have dated evidence such as spreadsheets summarizing feeder load armed with UFLS relays, spreadsheets with UFLS relay settings, or other dated documentation that it provided automatic tripping of load in accordance with the UFLS program design and schedule for application per Requirement R9.

M10. Each Transmission Owner shall have dated evidence such as relay settings, tripping logic or other dated documentation that it provided automatic switching of its existing capacitor banks, Transmission Lines, and reactors in order to control over-voltage as a result of underfrequency load shedding if required by the UFLS program and schedule for application per Requirement R10.

M11. Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it conducted an event assessment of the performance of the UFLS equipment and the effectiveness of the UFLS program per Requirement R9.

M12. Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it conducted a UFLS design assessment per Requirements R12 and R4 if UFLS program deficiencies are identified in R11.

M13. Each Planning Coordinator shall have dated evidence of responses, such as e-mails and letters, to written comments submitted by UFLS entities and Transmission Owners within the Interconnection following a comment period and before finalizing its UFLS program per Requirement R13.

D. Compliance

C1. Compliance Monitoring Process

C1.1. Compliance Monitoring Responsibility

Reliability Organization

C1.2. Data Retention

Each Planning Coordinator and UFLS entity shall keep data or evidence to show compliance as identified below unless directed by its Reliability Organization Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Each Planning Coordinator shall retain the current evidence of Requirements R1, R2, R3, R4, R5, R12, and R13, Measures M1, M2, M3, M4, M5, M12, and M13 as well as any evidence necessary to show compliance since the last compliance audit.

- Each Planning Coordinator shall retain the current evidence of UFLS database update in accordance with Requirement R6, Measure M6, and evidence of the prior year's UFLS database update.
- Each Planning Coordinator shall retain evidence of any UFLS database transmittal to other Planning Coordinators in the Interconnection since the last compliance audit in accordance with Requirement R7, Measure M7.
- Each UFLS entity shall retain evidence of UFLS data transmittal to the Planning Coordinator(s) since the last compliance audit in accordance with Requirement R8, Measure M8.
- Each UFLS entity shall retain the current evidence of adherence with the UFLS program in accordance with Requirement R9, Measure M9, and evidence of adherence since the last compliance audit.
- Transmission Owner shall retain the current evidence of adherence with the UFLS program in accordance with Requirement R10, Measure M10, and evidence of adherence since the last compliance audit.
- Each Planning Coordinator shall retain evidence of Requirements R11, and R13, and Measures M11, and M13 for 6 calendar years.

If a Planning Coordinator or UFLS entity is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the retention period specified above, whichever is longer.

The Reliability Organization Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

C1.3. Compliance Monitoring and Assessment Process

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Violation Investigation
- Self-Reporting
- Complaint

C1.4. Additional Compliance Information

Not applicable.

C2. Levels of Non-Compliance

C2.1. Levels of Non-Compliance for Requirement R1, Measure M1

C2.1.1. Level 1 - The Reliability Organization developed and documented criteria but failed to include either the consideration of historical events or the consideration of system studies.

C2.1.2. Level 2 - The Reliability Organization failed to meet all the requirements of Level 1 for Requirement R1 and Measurement M1.

C2.2. Levels of Non-Compliance for Requirement R2, Measure M2

C2.2.1. Level 1 - NA

C2.2.2. Level 2 - The Reliability Organization failed to identify islands to serve as a basis for designing its UFLS program as specified in Requirement R2.

C2.3. Levels of Non-Compliance for Requirement R3, Measure M3

C2.3.1. Level 1 - The Reliability Organization developed a UFLS program, including a schedule for implementation within its area where imbalance = (load — actual generation output) / (load), but failed to meet one (1) of the performance characteristic in Requirement Part R3.1 through Part R3.3 in simulations of underfrequency conditions.

C.2.3.2. Level 2 – The Reliability Organization failed to meet all the requirements of Level 1 for Requirement R3 and Measurement M3.

C2.4. Levels of Non-Compliance for Requirement R4, Measure M4

C.2.4.1. Level 1 - The Reliability Organization conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include one (1) of the items as specified in Requirement Part R4.1 through Part R4.4.

C2.4.2. Level 2 – The Reliability Organization failed to meet all the requirements of Level 1 for Requirement R4 and Measurement M4.

C2.5. Levels of Non-Compliance for Requirement R5, Measure M5

C2.5.1. Level 1 – The Planning Coordinator failed to retain dated evidence of joint UFLS program design documents, reports describing a joint UFLS design assessment, letters that include recommendations, or other dated documentation demonstrating that it coordinated its UFLS program design with all other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island.

C2.5.2. **Level 2 -** The Planning Coordinator failed to coordinate its UFLS program design with all other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island.

C2.6. **Levels of Non-Compliance for Requirement R6, Measure M6**

C2.6.1. **Level 1 –** N/A

C2.6.1. **Level 2 -** The Planning Coordinator failed to perform maintenance on the UFLS database within 15 months of previous maintenance activity.

C2.7. **Levels of Non-Compliance for Requirement R7, Measure M7**

C2.7.1. **Level 1 –** The Planning Coordinator provided data more than 5 calendar days but less than or equal to 10 calendar days following the schedule specified by Requirement R7 to support maintenance of the UFLS database.

C2.7.2. **Level 2 -** The Planning Coordinator failed to meet all the requirements of Level 1 for Requirement R7 and Measurement M7.

C2.8. **Levels of Non-Compliance for Requirement R8, Measure M8**

C2.8.1. **Level 1 -** The UFLS entity provided data more than 5 calendar days but less than or equal to 10 calendar days following the schedule specified by Requirement R8 to support maintenance of the UFLS database.

C2.8.2. **Level 2 -** The UFLS entity failed to meet all the requirements of Level 1 for Requirement R8 and Measurement M8.

C2.9. **Levels of Non-Compliance for Requirement R9, Measure M9**

C2.9.1. **Level 1 -** The UFLS entity provided less than 100% but more than (and including) 90% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Requirement R9.

C2.9.2. **Level 2 -** The UFLS entity failed to meet all the requirements of Level 1 for Requirement R9 and Measurement M9.

C2.10. **Levels of Non-Compliance for Requirement R10, Measure M10**

C2.10.1. **Level 1 -** The Transmission Owner provided less than 100% but more than (and including) 90% automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for application determined by Requirement R10.

C2.10.2. Level 2 - The Transmission Owner failed to meet all the requirements of Level 1 for Requirement R10 and Measurement M10.

C2.11. Levels of Non-Compliance for Requirement R11, Measure M11

C2.11.1. Level 1 - The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R9, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than six months but less than or equal to 7 months of event actuation.

C2.11.2. Level 2 - The Planning Coordinator failed to meet all the requirements of Level 1 for Requirement R11 and Measurement M11.

C2.12. Levels of Non-Compliance for Requirement R12, Measure M12

C2.12.1. Level 1 – The Planning Coordinator, in whose area an event results in a system frequency excursion below the initializing set points of the UFLS program, conducted an assessment of the UFLS event more than one (1) month but less than two (2) months after the initiating event.

C2.12.2. Level 2 - The Planning Coordinator failed to meet all the requirements of Level 1 for Requirement R12 and Measurement M12.

C2.13. Levels of Non-Compliance for Requirement R13, Measure M13

C2.13.1. Level 1 – N/A

C2.13.2. Level 2 – The Planning Coordinator failed to retain dated evidence of responses submitted by UFLS entities and Transmission Owners within the Interconnection.

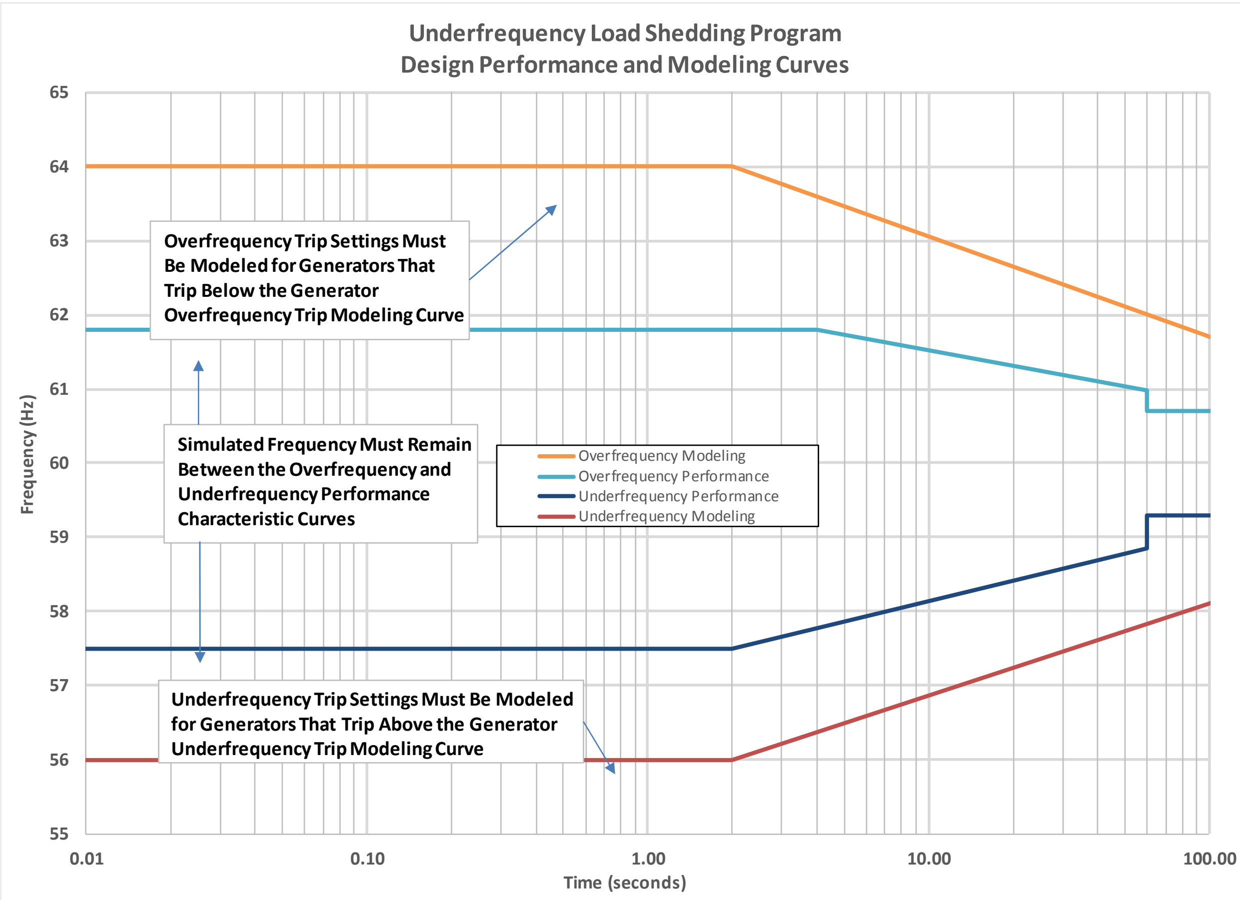
E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
000	-	Approved – IMC	-
001A	11-05-2015	EPS – Initial Edits	Yes
001B	12-21-2015	EPS – Revision Edits	Yes
001C	1-4-2016	EPS – Revision Edits	Yes
001D	1-22-2016	EPS – Revision following 1/19 Meeting	Yes
001E	2-9-2016	EPS – Revision following 1/28 Meeting	Yes
001F	2-12-2016	Final IMC Revision	No
001G	11-18-2016	EPS – Inclusion of RCC	Yes
001H	12-06-2016	Final	No
002	3-30-2018	RRO Revision	Yes

AKPRC-006 – Attachment 1



Generator Overfrequency Trip Modeling		Generator Overfrequency Performance Characteristic		
t < 2 s	t ≥ 2 s	t < 4 s	60 s > t ≥ 4 s	t ≥ 60 s
f = 64 Hz	f = -0.686*log(t)+62.41 Hz	f = 61.8 Hz	f = -0.686*log(t)+62.21 Hz	f = 60.7 Hz

Generator Underfrequency Trip Modeling		Generator Underfrequency Performance Characteristic		
t < 2 s	t ≥ 2 s	t < 2 s	60 s > t ≥ 2 s	t ≥ 60 s
f = 56 Hz	f = 0.575*log(t)+57.63 Hz	f = 57.5 Hz	f = 0.915*log(t)+57.23 Hz	f = 59.3 Hz

Alaska Railbelt Standard AKRES-001-2 – Reserve Obligation and Allocation

A. Introduction

1. **Title:** **Reserve Obligation and Allocation**

2. **Number:** **AKRES-001-2**

3. **Purpose:**

   3.1 This standard describes Reserve Obligations for all Obligated Entities interconnected to the Railbelt Grid.

4. **Applicability:**

   4.1. Balancing Authorities

   4.2. Load Serving Entities

   4.3. Generation Owners

5. **Effective Date:** 12 months from adoption by the Reliability Organization.

B. Requirements

R1. Reserve Capacity Obligation Requirement

R1.1. Each Load Serving Entity (LSE) is expected to have and maintain responsibility to provide capacity for its own firm load. As part of such responsibility, the LSE shall maintain or otherwise provide for annually, Accredited Capacity, in an amount equal to or greater than its maximum System Demand for such year plus the Load Serving Entities' Reserve Capacity Obligation, as set forth in Subsection R1.2.

R1.2. The Reserve Capacity Obligation of a LSE, for any year, shall be equal to thirty (30) percent of the Annual System Demand (described in R1.4) for that year for that LSE. The Reserve Capacity Obligation of the Load Serving Entity may be adjusted from time to time by the Reliability Organization.

R1.3. The Reliability Organization may determine the annual Accredited Capacity for each Load Serving Entity.

R1.4. Reserve Capacity Obligation shall be determined by the one-hour average of peak electrical demand of the LSE as determined for each the average of the previous three calendar years of load data of the LSE. The LSE may petition the Reliability Organization to use a different value if their studies indicate a different value is warranted than that calculated as described above.

R2. Responsibility for Operating Reserve

R2.1. Each LSE and/or Generation Owner shall provide, or contract for, Regulating Reserve, Spinning Reserve and Non-Spinning Reserve as required by Section R3 of this Standard equal to or greater than the Operating Reserve Obligation of the entity. As soon as practicable, but not to exceed four hours, after the occurrence of an incident which uses Operating Reserves, each entity shall restore its Operating Reserve Obligation.

R2.2. The System Reserve Basis (SRB) is equal to the declared Largest Single Generating Contingency of the system or other such value as determined by engineering studies and approved by the Reliability Organization. The SRB is determined on an hourly basis and may include critical infrastructure whose loss would deprive the majority of the system of multiple generating units as defined in the Reserves Policy.

R3. Total Operating Reserve Obligation

R3.1. The Total Operating Reserve Obligation at any time shall be an amount equal to 150 percent of the System Reserve Basis of the Railbelt Grid.

R3.2 The Spinning Reserve portion of the Total Operating Reserve Obligation shall not be less than an amount equivalent to 100 percent of the System Reserve Basis.

R3.3 The regulation amount of the Operating Reserve Obligation must be an amount of reserve responsive to Automatic Generation Control, which is sufficient to provide required regulating margin.

R3.4 The balance of the Total Operating Reserve Obligation shall be maintained with Non-Spinning Reserve.

R4. Generating Unit Capability

Declared generating unit capability for operating reserve shall be determined by the following criteria:

R4.1. It shall not be less than the load and reserves on the machine at any particular time nor greater than R4.2 below.

R4.2. It shall not exceed that maximum amount of load (MW) that the unit is capable of continuously supplying for a two-hour period through action of automatic governor controls. Alternatively, if the unit is not capable of continuously supplying for a two-hour period, it must be supplemented by other sources of reserves when it runs out. For example, a Battery Energy Storage System that is supplemented by a load shedding scheme.

R5. Operating Reserve

R5.1. An Obligated Entities' Spinning Reserve shall be calculated at any given instant as the difference between the sum of the net Declared Capability of all generating units on line in the respective entity and the integrated Systems Demand of the system involved and other sources (for example, SILOS and BESS) or declared restrictions on spinning reserve (for example, Bradley Lake or tie line restrictions) as accepted by the Reliability Organization. See the Reserve Policy of the Reliability Organization for spin performance criteria.

R5.2. An Obligated Entities' Spinning Reserve may be satisfied by an automatically controlled load shedding program (SILOS – Shed In Lieu of Spin). The load shedding program shall assure that controlled load can be dropped to meet the requirement of Spinning Reserve in such a manner as to maintain system stability and not cause degradation or cascading effects in the Railbelt system. The load included in the Underfrequency Load Shed system (UFLS) for the protection of the interconnected system shall not be included in a SILOS program. Load included in an island's UFLS system designed to protect the area following islanding may be included in a SILOS program.

R5.3. The Reliability Organization may establish procedures to assure that the Operating Reserve of an entity is available on the Railbelt System at all times.

R5.4. Prudent Utility Practices shall be followed in distributing Operating Reserve, taking into account effective utilization of capacity in an Emergency, time required to be effective, transmission limitations and local area requirements. Available Transfer Capability (ATC) shall include a component (Capacity Benefit Margin) recognizing the need to move reserves between areas. Geographical constraints and remedies are defined in the Reserve Policy.

R5.5. Subject to R5.4 above, an entity may arrange for one or more other entities to supply part of, or its entire, Operating Reserve requirement.

R5.6. In an Emergency, any Obligated Entity, upon request by its Balancing Authority shall supply such Balance Authority part or all of its Non-Spinning Reserve up to the full amount of its available total Operating Reserve Obligation as indicated in R3.

R5.7. In an Emergency, any Obligated Entity shall automatically supply to such Balancing Authority part or all of its Spinning Reserve obligation. An Obligated Entity experiencing an Emergency is not required to maintain its Operating Reserve Obligation. There shall be no obligation of an Obligated Entity to supply Operating Reserve if the requesting entity is not making full use of its own available Accredited Capacity.

R6. Responsibility for Regulating Reserve

R6.1. *Regulating Reserve*- each Balancing Authority shall provide, or contract for, Regulating Reserve equal to or greater than the Regulating Reserve Obligation of the party. Regulating Reserve may not overlap reserves dedicated for Spinning Reserve. Regulating Reserve (both up and down) is required to compensate for uncertainty in forecasting and is established during the unit commitment planning process, and as such the Balancing Authority may then utilize their reserve as required during the course of the day. If a Balancing Authority exhausts its Regulating Reserve, it is required to procure or commit additional reserves immediately. Available Transfer Capability (ATC) for interconnecting

Transmission lines shall recognize a component included in Transmission Reliability Margin (TRM) to allow for the delivery of Regulating Reserve between areas.

R6.2. On an annual basis, after the year end CPS statistics are compiled, Reliability Organization shall modify each Balancing Authorities' Regulating Reserve by increasing/decreasing its current Regulating Reserve by multiplying by 5 the % deviation in its CPS1. The Regulating Reserve obligations so calculated will be rounded up to the nearest integer MW. For example, if an Obligated Entity's CPS1 reaches 5% deviation (level 1 violation), the Obligated Entity will be required to increase its Regulating Reserve obligation by 25%.

R6.3. The Reliability Organization reserves the right to increase/decrease a Balancing Authorities' Regulating Reserve or require other measures at any time due to changes in the system or repeat infractions.

R7. Spinning Reserve Components

R7.1. The components determining the makeup of the spin obligation as well as the allocation is defined in the Reserve Policy of the Reliability Organization.

R7.2. The Spinning Reserve Obligation (SRO) shall be converted to energy and may be called upon for up to an hour when the system is experiencing a generating deficiency.

C. Measures

M1. Each Obligated Entity and Balancing Authority shall maintain:

M1.1. Records of their available Accredited Capacity at any point in time. These records will be updated as new Generating Assets are added and other Generating Assets are retired. These records will be available by for review by the Balancing Authority or Reliability Organization Compliance Monitor with 1 business week written notice.

M1.2. Hourly records of Operating Reserve and Regulating Reserve (scheduled and actual) will be maintained by all Obligated Entities'. These will be made available in real-time to the Balancing Authority for archival and storage.

M1.3. The Reliability Organization Compliance Monitor will review the performance of each Balancing Authority and Obligated Entity at least annually. More frequent reviews shall be performed if spin obligation compliance warrants such reviews.

D. Compliance

C1. Balancing Authorities

C2. Reliability Organization

E. Non-Compliance

Level 1

Version History

Version	Date	Action	Change Tracking
000	June 7, 2013	Original	New
001A	May 2, 2016	Per the IMC/RRO re-alignment	Change
001B	October 20, 2016	Put allocation in Reserve Policy	Move
001C	April 24, 2017	IOC Edits to Standard	On
001D	May 8, 2017	IOC Edits to Standard	On
001E	February 2, 2018	IMC Revision	On
002	March 30, 2018	RRO Revision	Yes

Alaska Railbelt Standard AKTPL-001-2 – Transmission Planning Performance Requirements

A. Introduction

1. **Title:** **Transmission System Planning Performance Requirements**

2. **Number:** **AKTPL-001-2**

3. **Purpose:**

   3.1 Establish Transmission system planning performance requirements within the planning horizon to develop a System that will operate reliably over a broad spectrum of conditions and following a wide range of probable Contingencies applicable to the portions of the Bulk Electrical System (BES) used to supply power to or from major load and generation centers.

4. **Applicability:**

   4.1. Planning Authority

   4.2. Transmission Planner

   4.3. Resource Planner

5. **Effective Date:** 12 months from the adoption by the Reliability Organization.

B. Requirements

R1. System Model

The Reliability Organization, in conjunction with each areas Transmission Planner, shall maintain System models for performing the studies needed to complete its Planning Assessment. The models shall use data consistent with that provided in accordance with the AKMOD-032 standard, supplemented by other sources as needed, including items represented in the CAP, and must represent projected System conditions. This establishes Category P0 as the normal System condition in Table 1.

R1.1. System models shall represent:

R1.1.1. Existing Facilities

R1.1.2. Known outage(s) of generation or transmission facility(ies) with a duration of at least six months.

R1.1.3. New planned facilities and changes to existing facilities

R1.1.4. Real and reactive Load forecasts

R1.1.5. Known commitments for Firm Transmission Service and Interchange

R1.1.6. Resources (supply or demand side) required for Load

R1.1.7. Resources required for Transmission stability or contingencies

R1.1.8. Future facilities identified in BAL-502 Resource Adequacy analysis

R2. Assessment

The Reliability Organization, in conjunction with and each Transmission Planner and Planning Coordinator shall prepare a Planning Assessment of its portion of the BES no longer than every five years or as determined by the Reliability Organization. This Planning Assessment shall use current or qualified past studies (as indicated in R2.6), document assumptions, and document summarized results of the steady state analyses, short circuit analyses, and Stability analyses.

R2.1. Near Term – Steady State

For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed no longer than every five years or as determined by the Reliability Organization, and be supported by current studies or qualified past studies as indicated in R2.6. Qualifying studies need to include the following conditions:

R2.1.1. System Summer and Winter Peak Load (with minimum and maximum Intermittent Generation) for Year One.

R2.1.2. System Summer and Winter Peak Load (with minimum and maximum Intermittent Generation) for year five.

R2.1.3. System Minimum Load (with minimum and maximum Intermittent Generation) for one of the five years.

R2.1.4. P1 events in Table 1, with known outages modeled as in Requirement 0, under those System Summer Peak, Winter Peak, or System Minimum conditions when known outages are scheduled.

R2.1.5. For each of the studies described in R2.1.1 through R2.1.5, sensitivity case(s) may be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment shall vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in System response: (as accepted by the Reliability Organization)

R2.1.5.1. Real and reactive forecasted Load.

R2.1.5.2. Expected transfers

R2.1.5.3. Expected in-service dates of new or modified Transmission Facilities.

R2.1.5.4. Reactive resource capability.

R2.1.5.5. Generation additions, retirements.

R2.1.5.6. Unit commitment and Dispatch scenarios to maximize transfers between each load and generation area.

R2.1.5.7. Controllable Loads and Demand Side Management.

R2.1.5.8. Duration or timing of known Transmission outages.

R2.1.6. When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2, categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.

R2.1.7. Determine the actual Transfer Limits in accordance with AKMOD-028-2 for each line between Balance Authorities during each load level.

R2.2. Long Term – Steady State

For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed no longer than every five years or as determined by the Reliability Organization, and be supported by the following current study, supplemented with qualified past studies as indicated in R2.6. Qualifying studies need to include the following conditions:

R2.2.1. For one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.

R2.2.2. System Summer and Winter Peak Load (with minimum and maximum Intermittent Generation) for year selected.

R2.2.3. System Minimum Load (with minimum and maximum Intermittent Generation) for year selected.

R2.2.4. Unit commitment and Dispatch scenarios to maximize transfers between each load and generation area.

R2.3. Near Term – Short Circuit

The short circuit analysis portion of the Planning Assessment shall be conducted no longer than every five years or as determined by the Reliability Organization, addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in R2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

R2.4. Near Term – Stability

For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed no longer than every five years or as determined by the Reliability Organization, and be supported by current or past studies as qualified in R2.6. The following studies are required:

R.2.4.1. Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

R2.4.2. System Summer and Winter Peak Load (with minimum and maximum Intermittent Generation) for one of the five years.

R2.4.3. System Minimum Load (with minimum and maximum Intermittent Generation) for one of the five years.

R2.4.4. For each of the studies described in R2.4.2 and R2.4.3, sensitivity case(s) may be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment shall vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance: (as accepted by the Reliability Organization)

R2.4.4.1. Load level, Load forecast, or dynamic Load model assumptions.

R2.4.4.2. Expected transfers.

R2.4.4.3. Expected in service dates of new or modified Transmission Facilities.

R2.4.4.4. Reactive resource capability.

R2.4.4.5. Generation additions, retirements.

R2.4.4.6. Unit commitment and Dispatch scenarios to maximize transfers between each load and generation area.

R2.4.5. Determine the actual Transfer Limits in accordance with AKMOD-028 for each line between Balance Authorities during each load level.

R2.5. Long Term – Stability

For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed no longer than every five years or as determined by the Reliability Organization, to address the impact of proposed material generation additions or changes in that time frame and be supported by current or past studies as qualified in R2.6 and shall include documentation to support the technical rationale for determining material changes. Qualifying studies need to include the following conditions:

- **R2.5.1.** For one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.
- **R2.5.2.** System Summer and Winter Peak Load (with minimum and maximum Intermittent Generation) for year selected.
- **R2.5.3.** System Minimum Load (with minimum and maximum Intermittent Generation) for year selected.
- **R2.5.4.** Unit commitment and Dispatch scenarios to maximize transfers between each load and generation area.

R2.6. Past Studies

Past studies may be used to support the Planning Assessment if they meet the following requirements:

- **R2.6.1.** For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.
- **R2.6.2.** For steady state, short circuit, or Stability analysis: no material changes have occurred to the System represented in the study. Documentation to support the technical rationale for determining material changes shall be included.

R2.7. Planning Analysis – CAP(s)

For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include CAP(s) detailing the plans to meet the performance requirements. The CAP(s) must:

- **R2.7.1.** Include both operational measures, such as reduced or revised transfer limits, system operating constraints, loss of firm load or suspension of firm transmission service, as well as long-term capital improvement plans.
- **R2.7.2.** Include in the presentation of operational measures and/or capital projects that are capable of eliminating the deficiencies identified in the system studies:

1. Complete description of the proposed project
2. Complete cost estimate of the proposed project
3. Complete time frame of the project from project approval to project completion, including major milestones
4. Complete Cost/Benefit analysis using the costs above and the reduced operating costs and reliability improvements achieved over the life of the project

R2.7.3. Be reviewed in subsequent annual Planning Assessments for continued validity and status of items in the CAP(s).

R2.7.4. If resource additions or changes are part of a CAP, the resources required in the CAP must be included as a proposed resource in AKBAL-502 for the corresponding time period.

R2.7.5. Provide the System operator any written summary of the recommended operating guidelines to mitigate the cause and/or effect of any deficiencies.

R2.8. Short Circuit – CAP

For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in R2.3 exceeds their Equipment Rating, the Planning Assessment shall include a CAP to address the Equipment Rating violations. The CAP must:

R2.8.1. List System deficiencies and the associated CAP needed to meet required System performance.

R2.8.2. Be reviewed in subsequent annual Planning Assessments for continued validity and status of items in the CAP.

R2.8.3. Steady State – Performance

For the steady state portion of the Planning Assessment, the Reliability Organization, the Planning Authority, and Transmission Planner shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in R2.1, and R2.2. The studies shall be based on computer simulation models using data provided in R1.

R2.9. For the steady state, studies shall be performed for planning events to determine whether the System meets the performance requirements in Table 1 based on the Contingency list created in R2.12.

R2.10. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in R2.13.

R2.11. Contingency analyses for R2.9 and R2.10 must:

R2.11.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention.

R2.11.2. Simulate the expected automatic operation of existing and planned devices designed to provide steady state control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.

R2.12. Those planning events in Table 1, that are expected to produce more severe System impacts shall be identified and a list of those Contingencies to be evaluated for System performance in R2.9 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

R2.12.1. The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

R2.13. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in R2.10. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

R2.13.1. Stability – Performance
For the Stability portion of the Planning Assessment, as described in Requirement R2, Parts R2.4 and R2.5, the Reliability Organization, Planning Authority, and Transmission Planner shall perform the Contingency analyses listed in Table 1. The studies shall be based on computer simulation models using data provided in Requirement R1.

R2.14. For the stability portion, studies shall be performed for planning events to determine whether the System meets the performance requirements in Table 1 based on the Contingency list created in R2.16.

R2.14.1. For planning event P1: No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Special Protection System is not considered pulling out of synchronism.

R2.14.2. For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities.

R2.14.3. For planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Balancing Authority.

R2.15. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in R2.17.

R2.16. Contingency analyses for R2.14 and R2.15 must:

R2.16.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

R2.16.1.1. Successful high speed (less than one second) reclosing and unsuccessful high-speed reclosing into a Fault where high speed reclosing is utilized.

R2.16.2. Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static var compensators and power flow controllers.

R2.17. Those planning events in Table 1 that are expected to produce more severe System impacts shall be identified, and a list created of those Contingencies to be evaluated in R2.14 The rationale for those Contingencies selected for evaluation shall be available as supporting information.

R2.17.1. The Planning Coordinator and Transmission Planner shall coordinate with their own Resource Planner and adjacent Planning Coordinators and Transmission Planners and Resource Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

R2.18. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in R2.15. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.

R3. The Reliability Organization, Planning Authority, and Transmission Planner shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level.

R4. The Reliability Organization, Planning Authority, and Transmission Planner shall define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding.

R5. The Reliability Organization, in conjunction with the Planning Coordinators and Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment.

R6. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to the Reliability Organization within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request.

R6.1. If a recipient of the Planning Assessment results provides documented comments on the results, the respective party shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

Table 1 – Steady State & Stability Performance Planning Events
Steady State & Stability:
a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur.
b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.
c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.
d. Simulate Normal Clearing unless otherwise specified.
e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.
Steady State Only:
f. Applicable Facility Ratings shall not be exceeded.
g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Authority and Transmission Planner.
h. Planning event P0 is applicable to steady state only.
i. The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.
Stability Only:
j. Transient voltage response shall be within acceptable limits established by the Planning Authority and Transmission Planner.

Category	Initial Condition	Event	Fault(s) Type[1]	Interruption of Firm Transmission Service Allowed	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	NA	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator, no fault 2. Generator 3. Transmission Circuits 4. Transformer[2] 5. Shunt Device-Ancillary Service Device[3] 6. Single Pole of a DC line	 N/A (1) 3Ø (2–5) SLG (6)	No	No
P2 Single Contingency	Normal System	1. Opening a line section w/o fault[4] 2. Bus Section fault 3. Internal Breaker Fault[5] (non-Bus-tie Breaker) 4. Internal Breaker Fault (Bus-tie Breaker)[5]	N/A (1) SLG (2–4)	No	No

Category	Initial Condition	Event	Fault(s) Type[1]	Interruption of Firm Transmission Service Allowed	Non-Consequential Load Loss Allowed
P3a Multiple Contingency	Loss of generator unit followed by System adjustments[6] Unit Commitment Changes Allowed for All Events	Loss of one of the following: 1. Generator 2. Transmission Circuits 3. Transformer[2] 4. Shunt Device/ Ancillary Service Device[3]	3Ø	No	No
		5. Single pole of a DC line	SLG		
P3b Multiple Contingency	Loss of generator unit followed by System adjustments[6]	Loss of one of the following: 1. Generator 2. Transmission Circuits 3. Transformer[2] 4. Shunt Device/ Ancillary Service Device[3]	3Ø	No	Yes, 10% of System Load No
		5. Single pole of a DC line	SLG		
P4 Multiple Contingency (Fault plus stuck breaker[7])	Normal System	Loss of multiple elements caused by a stuck breaker[7] (non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuits 3. Transformer[2] 4. Shunt Device[3] 5. Bus Section 6. Loss of multiple elements caused by a stuck breaker[7] (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	Yes	Yes, 25% for Islanded Area Load, 10% of System Load
P5 Multiple Contingency (Fault plus relay failure to operate)	Normal System	Delayed Fault Clearing due to the failure of a non-redundant relay[9] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuits 3. Transformer[2] 4. Shunt Device[3] 5. Bus Section	SLG	Yes	Yes, 25% for Islanded Area Load, 10% of System Load
P6 Multiple Contingency (Two overlapping singles)	Loss of one of the followed by System adjustments[6] 1. Transmission Circuits 2. Transformer[2] 3. Shunt Device[3]	Loss of one of the following: 1. Transmission Circuits 2. Transformer[2] 3. Shunt Device[3]	3Ø	Yes	Yes, 25% for Islanded Area Load, 10% of System Load
	4. Single Pole of a DC Line	4. Single pole of a DC line	SLG		
P7 Multiple Contingency (Common Structure)	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure.[8] 2. Loss of a bipolar DC line	SLG	Yes	Yes, 25% for Islanded Area Load, 10% of System Load

Table 1 – Steady State & Stability Performance Extreme Events			
Steady State & Stability			
For all extreme events evaluated:			
1.	Simulate the removal of all elements that Protection systems and automatic controls are expected to disconnect for each Contingency.		
2.	Simulate Normal Clearing unless otherwise specified.		
Steady State		**Stability**	
1.	Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service prior to System adjustments.	**1.**	Loss of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer force out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments.
2.	Local area events affecting the Transmission System such as:	**2.**	Local or wide area events affecting the Transmission System such as:
a.	Loss of a tower line with three or more circuits[9].	**a.**	3Ø fault on generator with stuck breaker[8] or a relay failure[10] resulting in Delayed Fault Clearing.
b.	Loss of all Transmission lines on a common Right-of-Way[9].	**b.**	3Ø fault on Transmission circuit with stuck breaker[8] or a relay failure[10] resulting in Delayed Fault Clearing.
c.	Loss of a switching station or substation (loss of one voltage level plus transformers).	**c.**	3Ø fault on transformer with stuck breaker[8] or a relay failure[10] resulting in Delayed Fault Clearing.
d.	Loss of all generating units at a generating station.	**d.**	3Ø fault on bus section with stuck breaker[8] or a relay failure[10] resulting in Delayed Fault Clearing.
e.	Loss of a large Load or major Load center.	**e.**	3Ø internal breaker fault.
3.	Wide area events affecting the Transmission System based on System topology such as:	**f.**	Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances.
a.	Loss of two generating stations resulting from conditions such as:		
i.	Loss of a large fuel line into an area.		
ii.	Loss of the use of a large body of water as the cooling source for generation.		
iii.	Wildfires		
iv.	Severe weather, e.g., hurricanes		
v.	A successful cyber attack		
vi.	Large earthquake, tsunami or volcanic eruption		
b.	Other events based upon operating experience that may result in wide area disturbances.		

Table 1 – Steady State & Stability Performance Footnotes (Planning Event and Extreme Events)	
1.	Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that shall be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.
2.	For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the System connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.
3.	Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.
4.	Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point.
5.	An internal breaker fault means a breaker failing internally, thus creating a System fault which shall be cleared by protection on both sides of the breaker.
6.	An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed both as a System adjustment (as identified in the column entitled 'Initial Condition') and a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non-Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered. System adjustments assume the system has been brought back to 60 Hz and transfers are adjusted based on the constraints of the reduced system.
7.	A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing.
8.	Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less.
9.	Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94).

C. Measures

M1. The Reliability Organization, Transmission Planner, and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models within their respective area, using data consistent with AKMOD-032, including items represented in the CAP, representing projected System conditions, and that the models represent the required information in accordance with R1.

M2. The Reliability Organization, Transmission Planner, and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of its annual Planning Assessment, that it has prepared an annual Planning Assessment of its portion of the System in accordance with Requirement R2 through R2.8.

M3. The Reliability Organization, Transmission Planner, and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment, in accordance with Requirement R2.9.

M4. The Reliability Organization, Transmission Planner, and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment in accordance with Requirement R2.14.

M5. The Reliability Organization, Transmission Planner, and Planning Coordinator shall provide dated evidence such as electronic or hard copies of the documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System in accordance with Requirement R3.

M6. The Reliability Organization, Transmission Planner, and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of documentation specifying the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding that was utilized in preparing the Planning Assessment in accordance with Requirement R4.

M7. Each Transmission Planner and Planning Coordinator shall provide evidence, such as email notices, postal receipts showing recipient and date that it has distributed its Planning Assessment results to the Reliability Organization within 30 calendar days upon a written request for the information in accordance with Requirement R5.

M8. Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient and date; or a demonstration of a public posting, that it has distributed its Planning Assessment results to the Reliability Organization within 90 days of having completed its Planning Assessment, and to any functional entity who has indicated a reliability need within 30 days of a written request and that the Reliability Organization has provided a documented response to comments received on Planning Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R6.

D. Compliance

C1. Compliance Monitoring Process

C1.1. Compliance Enforcement Authority

Reliability Organization

C1.2. Compliance Monitoring Period and Reset Timeframe

Not Applicable

C1.3. Compliance Monitoring and Enforcement Processes:

C1.3.1 Compliance Audits

C1.3.2. Self-Certifications

C1.3.3. Spot Checking

C1.3.4. Compliance Violation Investigations

C1.3.5. Self-Reporting

C1.3.6. Complaints

C1.4. Data Retention

The Reliability Organization, Transmission Planner, and Planning Coordinator shall each retain data or evidence to show compliance as identified unless directed by the Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

C1.4.1. The models utilized in the current in-force Planning Assessment and one previous Planning Assessment in accordance with Requirement R1 and Measure M1.

C1.4.2. The Planning Assessments performed since the last compliance audit in accordance with Requirement R2 and Measure M2.

C1.4.3. The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R2.9 and Measure M3.

C.1.4.4. The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R2.14 and Measure M4.

C1.4.5. The documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and transient voltage response since the last compliance audit in accordance with Requirement R3 and Measure M5.

C1.4.6. The documentation specifying the criteria or methodology utilized in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding in support of its Planning Assessments since the last compliance audit in accordance with Requirement R4 and Measure M6.

C1.4.7. The current, in force documentation for the agreements(s) on roles and responsibilities, as well as documentation for the agreements in force since the last compliance audit, in accordance with Requirement R5, and Measure M7.

The Planning Coordinator shall retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

C1.4.8. Three calendar years of the notifications employed in accordance with Requirement R6 and Measure M8

If the Transmission Planner and Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time periods specified above, whichever is longer.

C2. Levels of Non-Compliance for Requirement R1, Measure M1

C2.1. **Level 1 -** The Reliability Organization, Planning Authority's and Transmission Planner's System model failed to represent one of the Requirement R1, Parts R1.1.1 through R1.1.5 for Requirement R1 and Measurement M1.

C2.2. **Level 2 -** The Reliability Organization, Transmission Planner and Planning Coordinator failed to meet all the requirements of Level 1 for Requirement R1 and Measurement M1.

C3. Levels of Non-Compliance for Requirement R2, Measure M2

C3.1. **Level 1 -** The Reliability Organization, Transmission Planner, and Planning Coordinator failed to comply with Requirement R2 through R2.8 and Measurement M2.

C3.2. **Level 2 -** The Reliability Organization, Transmission Planner, and Planning Coordinator failed to meet all the requirements of Level 1 for Requirement R2 through R2.8 and Measurement M2.

C4. Levels of Non-Compliance for Requirement R3, Measure M3

C4.1. **Level 1 -** The Reliability Organization, Transmission Planner, and Planning Coordinator did not identify planning events as described in Requirement R2.9 through R2.13 or extreme events as described in Requirement R2.13 for Measurement M3.

C4.2. **Level 2 -** The Reliability Organization, Transmission Planner, and Planning Coordinator failed to meet all the requirements of Level 1 for Requirements R2.9 through R2.13 Measurement M3.

C5. Levels of Non-Compliance for Requirement R4, Measure M4

C5.1. **Level 1 -** The Reliability Organization, Transmission Planner, and Planning Coordinator did not identify planning events as described in Requirement R2.17, extreme events as described in Requirement R2.17 for Measurement M4.

C5.2. **Level 2 -** The Reliability Organization, Transmission Planner, and Planning Coordinator failed to meet all the requirements of Level 1 for Requirements R2.14 through 2.18 and Measurement M4.

C6. Levels of Non-Compliance for Requirement R5, Measure M5

C6.1. **Level 1 –** N/A

C6.2. **Level 2 -** The Reliability Organization, Transmission Planner, and Planning Coordinator does not have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, or the transient voltage response for its System for Requirement R3 and Measurement M5.

C7. Levels of Non-Compliance for Requirement R4, Measure M6

C7.1. **Level 1 –** N/A

C7.2. **Level 2 -** The Transmission Planner and Planning Coordinator failed to define and document the criteria or methodology for System instability used within its analysis as described in Requirement R4 for Requirement R4 and Measurement M6.

C8. Levels of Non-Compliance for Requirement R5, Measure M7

C8.1. The Transmission Planner and Planning Coordinator distributed its Planning Assessment results to Reliability Organization but it was more than 30 days but less than or equal to 40 days following the request as described in Requirement R5 for Requirement R5 and Measurement M7.

C8.2. The Transmission Planner and Planning Coordinator failed to meet all the requirements of Level 1 for Requirement R5 and Measurement M7.

Version History

Version	Date	Action	Change Tracking
000	-	Approved IMC	-
001A	11/5/2015	EPS - Initial Edits	Yes
001B	12/21/2015	EPS - Revision Edits	Yes
001C	12/30/2015	EPS - Revision Edits	Yes
001D	1/5/2016	EPS - Revision Edits	Yes
001E	1/18/2016	EPS - Revision Edits	Yes
001F	1/22/2016	EPS - Revision Edits	Yes
001G	2/9/2016	EPS - Revision Edits	Yes
001H	2/11/2016	Final Version	No
001I	11/18/2016	EPS - Inclusion RRC	Yes
001J	12/6/2016	Final	No
001K	4/20/2016	IOC - Revision Edits	No
002	3/30/2018	RRO Revision	Yes

Alaska Railbelt Standard AKVAR-001-2 – Voltage and Reactive Control

A. Introduction

1. **Title:** **Voltage and Reactive Control**

2. **Number:** **AKVAR-001-2**

3. **Purpose:**

   3.1 To ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in real time to protect equipment and the reliable operation of the Interconnection.

4. **Applicability:**

   4.1. Transmission Operators.

   4.2. Purchasing-Selling Entities.

5. **Effective Date:** 12 months from the adoption by the Reliability Organization.

B. Requirements

R1. Each Transmission Operator, individually and jointly with other Transmission Operators, shall ensure that formal policies and procedures are developed, maintained, and implemented for monitoring and controlling voltage levels and MVAR flows within their individual areas and with the areas of neighboring Transmission Operators.

R2. Each Transmission Operator shall acquire sufficient reactive resources within its area to protect the voltage levels under normal and Contingency conditions. This includes the Transmission Operator's share of the reactive requirements of interconnecting transmission circuits.

R3. The Transmission Operator shall specify criteria that exempt generators from compliance with the requirements defined in Requirement 4, and Requirement R6.1.

R3.1. Each Transmission Operator shall maintain a list of generators in its area that are exempt from following a voltage or Reactive Power schedule.

R3.2. For each generator that is on this exemption list, the Transmission Operator shall notify associated Generator Owner.

R4. Each Transmission Operator shall specify a voltage or Reactive Power schedule [1] at the interconnection between the generator facility and the Transmission Owner's facilities to be maintained by each generator. The Transmission Operator shall provide the voltage or Reactive Power schedule to the associated Generator Operator and direct the Generator Operator to comply with the schedule in automatic voltage control mode (AVR in service and controlling voltage).

[1] The voltage schedule is a target voltage to be maintained within a tolerance band during a specified period. The Reliability Organization will allow this up to the safe voltage/VAR limits of the equipment.

R5. Each Purchasing-Selling Entity shall arrange for (self-provide or purchase) reactive resources to satisfy its reactive requirements identified by its Transmission Service Provider.

R6. The Transmission Operator shall know the status of all transmission Reactive Power resources, including the status of voltage regulators and power system stabilizers.

R6.1. When notified of the loss of an automatic voltage regulator control, the Transmission Operator shall direct the Generator Operator to maintain or change either its voltage schedule or its Reactive Power schedule.

R7. The Transmission Operator shall be able to operate or direct the operation of devices necessary to regulate transmission voltage and reactive flow.

R8. Each Transmission Operator shall operate or direct the operation of capacitive and inductive reactive resources within its area – including reactive generation scheduling; transmission line and reactive resource switching; and, if necessary, load shedding – to maintain system and Interconnection voltages within established limits.

R9. Each Transmission Operator shall maintain reactive resources to support its voltage under first Contingency conditions.

R9.1. Each Transmission Operator shall disperse and locate the reactive resources so that the resources can be applied effectively and quickly when Contingencies occur.

R10. Each Transmission Operator shall correct Interconnection Reliability Operating Limit (IROL) or System Operating Limit (SOL) violations resulting from reactive resource deficiencies (IROL violations must be corrected within 30 minutes) and complete the required IROL or SOL violation reporting.

R11. After consultation with the Generator Owner regarding necessary step-up transformer tap changes, the Transmission Operator shall provide documentation to the Generator Owner specifying the required tap changes, a timeframe for making the changes, and technical justification for these changes.

R12. The Transmission Operator shall direct corrective action, including load reduction, necessary to prevent voltage collapse when reactive resources are insufficient.

C. Measures

M1. The Transmission Operator shall have evidence it provided a voltage or Reactive Power schedule as specified in Requirement 4 to each Generator Operator it requires following such a schedule.

M2. The Transmission Operator shall have evidence to show that, for each generating unit in its area that is exempt from following a voltage or Reactive Power schedule, the associated Generator Owner was notified of this exemption in accordance with Requirement 3.2.

M3. The Transmission Operator shall have evidence to show that it issued directives as specified in Requirement 6.1 when notified by a Generator Operator of the loss of an automatic voltage regulator control.

M4. The Transmission Operator shall have evidence that it provided documentation to the Generator Owner when a change was needed to a generating unit's step-up transformer tap in accordance with Requirement 11 of AKVAR-001-2.

D. Compliance

C1. Compliance Monitoring Process

C1.1. Compliance Monitoring Responsibility

Reliability Organization

C1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

C1.3. Data Retention

The Transmission Operator shall retain evidence for Measures 1 through 4 for 12 months.

The Reliability Organization Compliance Monitor shall retain any audit data for three years.

C1.4. Additional Compliance Information

The Transmission Operator shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Reliability Organization Compliance Monitor.

C2. Levels of Non-Compliance

C2.1. Level 1: No evidence that exempt Generator Owners were notified of their exemption as specified under R3.2.

C2.2. Level 2: There shall be a level two non-compliance if either of the following conditions exists:

- No evidence to show that directives were issued in accordance with R6.1.
- No evidence that documentation was provided to Generator Owner when a change was needed to a generating unit's step-up transformer tap in accordance with R11.

C2.3. Level 3: There shall be a level three non-compliance if either of the following conditions exists:

- Voltage or Reactive Power schedules were provided for some but not all generating units as required in R4.

C2.4. Level 4: No evidence voltage or Reactive Power schedules were provided to Generator Operators as required in R4.

E. Regional Difference

None identified.

Version History

Version	Date	Action	Change Tracking
000	June 7, 2013	Original	New
001	May 2, 2016	Voltage schedule range	Modify
002	March 30, 2018	RRO Revision	Yes

Alaska Railbelt Standard AKVAR-002-2 – Generator Operation for Maintaining Network Voltage Schedules

A. Introduction

1. **Title:** **Generator Operation for Maintaining Network Voltage Schedules**

2. **Number:** **AKVAR-002-2**

3. **Purpose:**

   3.1. To ensure generators provide reactive and voltage control necessary to ensure voltage levels, reactive flows, and reactive resources are maintained within applicable Facility Ratings to protect equipment and the reliable operation of the Interconnection.

4. **Applicability**

   4.1. Generator Operator

   4.2. Generator Owner

5. **Effective Date:** 12 months from the adoption by the Reliability Organization.

B. Requirements

R1. The Generator Operator shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (automatic voltage regulator in service and controlling voltage) unless the Generator Operator has notified the Transmission Operator.

R2. Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power output (within applicable Facility Ratings[1]) as directed by the Transmission Operator.

R2.1. **W**hen a generator's automatic voltage regulator is out of service, the Generator Operator shall use an alternative method to control the generator voltage and reactive output to meet the voltage or Reactive Power schedule directed by the Transmission Operator.

R2.2. When directed to modify voltage, the Generator Operator shall comply or provide an explanation of why the schedule cannot be met.

R3. Each Generator Operator shall notify its associated Transmission Operator as soon as practical, but within 30 minutes of any of the following:

R3.1. A status or capability change on any generator Reactive Power resource, including the status of each automatic voltage regulator and power system stabilizer and the expected duration of the change in status or capability.

[1] When a Generator is operating in manual control, reactive power capability may change based on stability considerations and this will lead to a change in the associated Facility Ratings.

R3.2. A status or capability change on any other Reactive Power resources under the Generator Operator's control and the expected duration of the change in status or capability.

R4. The Generator Owner shall provide the following to its associated Transmission Operator and Transmission Planner within 30 calendar days of a request.

R4.1. For generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage:

R4.1.1. Tap settings.

R4.1.2. Available fixed tap ranges.

R4.1.3. Impedance data.

R4.1.4. The +/- voltage range with step-change in % for load-tap changing transformers.

R5. After consultation with the Transmission Operator regarding necessary step-up transformer tap changes, the Generator Owner shall ensure that transformer tap positions are changed according to the specifications provided by the Transmission Operator, unless such action would violate safety, an equipment rating, a regulatory requirement, or a statutory requirement.

R5.1. If the Generator Operator can't comply with the Transmission Operator's specifications, the Generator Operator shall notify the Transmission Operator and shall provide the technical justification.

C. Measures

M1. The Generator Operator shall have evidence to show that it notified its associated Transmission Operator any time it failed to operate a generator in the automatic voltage control mode as specified in Requirement R1.

M2. The Generator Operator shall have evidence to show that it controlled its generator voltage and reactive output to meet the voltage or Reactive Power schedule provided by its associated Transmission Operator as specified in Requirement R2.

M3. The Generator Operator shall have evidence to show that it responded to the Transmission Operator's directives as identified in Requirement R2.1 and Requirement R2.2.

M4. The Generator Operator shall have evidence it notified its associated Transmission Operator within 30 minutes of any of the changes identified in Requirement R3.

M5. The Generator Owner shall have evidence it provided its associated Transmission Operator and Transmission Planner with information on its step-up transformers and auxiliary transformers as required in Requirements R4.1.1 through R4.1.4

M6. The Generator Owner shall have evidence that its step-up transformer taps were modified per the Transmission Operator's documentation as identified in Requirement R5.

M7. The Generator Operator shall have evidence that it notified its associated Transmission Operator when it couldn't comply with the Transmission Operator's step-up transformer tap specifications as identified in Requirement R5.1.

D. Compliance

C1. Compliance Monitoring Process

C1.1. Compliance Monitoring Responsibility

Reliability Organization

C1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

C1.3. Data Retention

The Generator Operator shall maintain evidence needed for Measure M1 through Measure M5 and Measure M7 for the current and previous calendar years.

The Generator Owner shall keep its latest version of documentation on its step-up and auxiliary transformers. (Measure M6)

The Reliability Organization Compliance Monitor shall retain any audit data for three years.

C1.4. Additional Compliance Information

The Generator Owner and Generator Operator shall each demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Reliability Organization Compliance Monitor.

C2. Levels of Non-Compliance for Generator Operator

C2.1. Level 1: There shall be a Level 1 non-compliance if any of the following conditions exist:

C2.1.1. One incident of failing to notify the Transmission Operator as identified in R3.1, R3.2 or R5.1.

C2.1.2. One incident of failing to maintain a voltage or reactive power schedule (R2).

C2.2. Level 2: There shall be a Level 2 non-compliance if any of the following conditions exist:

C2.2.1. More than one but less than five incidents of failing to notify the Transmission Operator as identified in R1, R3.1, R3.2 or R5.1.

C2.2.2. More than one but less than five incidents of failing to maintain a voltage or reactive power schedule (R2).

C2.3. Level 3: There shall be a Level 3 non-compliance if any of the following conditions exist:

C2.3.1. More than five but less than ten incidents of failing to notify the Transmission Operator as identified in R1, R3.1, R3.2 or R5.1.

C2.3.2. More than five but less than ten incidents of failing to maintain a voltage or reactive power schedule (R2).

C2.4. Level 4: There shall be a Level 4 non-compliance if any of the following conditions exist:

C2.4.1. Failed to comply with the Transmission Operator's directives as identified in R2.

C2.4.2. Ten or more incidents of failing to notify the Transmission Operator as identified in R1, R3.1, R3.2 or R5.1.

C2.4.3. Ten or more incidents of failing to maintain a voltage or reactive power schedule (R2).

C3. Levels of Non-Compliance for Generator Owner:

C3.1. Level One: Not applicable.

C3.2. Level Two: Documentation of generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage was missing two of the data types identified in R4.1.1 through R4.1.4.

C3.3. Level Three: No documentation of generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage.

C3.4. Level Four: Did not ensure generating unit step-up transformer settings were changed in compliance with the specifications provided by the Transmission Operator as identified in R5.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
001	January 15, 2016	Effective Date	New
002	March 30, 2018	RRO Revision	Yes

Exhibit A

Functional Assignments

The following table lays out the functional assignments of Railbelt organizations. To the extent practical these assignments have been aligned with the NERC definitions, based on recent Railbelt history and the currently accepted operating plans of the Railbelt Utilities.

The terms and entity functional assignments found in the left column entitled "Entity Function" are found throughout the Railbelt Reliability Standards and are defined in the Railbelt Regional Reliability Standards Glossary.

Entity Function	AEA	AMLP	CEA	GVEA	MEA	RO	HEA	SES
Balancing Authority		X	X	X	X		X	
Compliance Enforcement Authority						X		
Compliance Monitor						X		
Distribution Provider		X	X	X	X		X	X
Generator Operator		X	X	X	X		X	X
Generator Owner	X	X	X	X	X		X	X
Generation Planner		X	X	X	X		X	X
Interchange Authority		X	X	X	X		X	
Load-Serving Entity		X	X	X	X		X	X
Market Operator (Resource Integrator)								
Obligated Entity		X	X	X	X		X	X
Reliability Coordinator		X				X	X	
Planning Authority	X	X	X	X	X	X	X	X
Purchasing-Selling Entity		X	X	X	X		X	X
Regional Reliability Organization						X		
Reliability Assurer						X		
Resource Planner		X	X	X	X		X	X
Standards Developer						X		
Transmission Operator		X	X	X	X	X	X	X
Transmission Owner	X	X	X	X	X		X	X
Transmission Planner	X	X	X	X	X	X	X	X
Transmission Service Provider		X	X	X	X	X	X	X

Exhibit B

Glossary of Terms Used in Railbelt Reliability Standards

Updated February 28, 2018

Introduction:

This Glossary lists each term that was defined for use in one or more of Railbelt Reliability Standards.

Railbelt-Wide Term	Acronym	Approved Date	Definition
Accredited Capacity		5/2/16	The total amount of generator nameplate capacity and firm energy contracts under contract to a Load Serving Entity.
Actual Disturbance Recovery Period		2/2/18	The actual duration of time for the period, in minutes from the time of the initiating event to the time the frequency is restored to within acceptable frequency limits of 60.2 to 59.8 Hz for Reportable Disturbance events. Source: AK proposed definition
Actual Excess Contingency Disturbance Recovery Period		2/2/18	The actual duration of time for the period, in minutes from the time of the initiating event to the time the frequency is restored to within acceptable frequency limits of 60.7 to 59.3 Hz for Reportable Excess Contingency Disturbance events. Source: AK proposed definition
Adjacent Balancing Authority		11/18/10	A Balancing Authority Area that is interconnected with another Balancing Authority Area either directly or via a multi-party agreement or transmission tariff.
Annual System Demand		10/13/11	The highest System Demand occurring during the 12-month period ending with the current month.
Anti-Aliasing Filter		12/9/10	A filter installed at a metering point to remove the high frequency components of the signal over the AGC sample period.
Area Control Error	ACE	5/2/16	The instantaneous difference between a Balancing Authority's net actual and scheduled interchange, taking into account the effects of Frequency Bias and correction for meter error,
Area Interchange Error	AIE	5/2/16	The Balancing Authority's Interchange error(s) due to equipment failures or improper scheduling operations, or improper AGC performance.
Automatic Generation Control	AGC	12/9/10	Equipment that automatically adjusts generation in a Balancing Authority Area from a central location to maintain the Balancing Authority's interchange schedule plus Frequency Bias. AGC may also accommodate automatic inadvertent payback and time error correction.

Railbelt-Wide Term	Acronym	Approved Date	Definition
Available Transfer Capability	ATC	5/2/16	A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as Total Transfer Capability less existing Transmission commitments (including retail customer service), less a Capacity Benefit Margin, less a Transmission Reliability Margin, plus Post backs, plus counter flows.
Balancing Authority (Load Balancing Authority)	BA/LBA	5/2/16	The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.
Balancing Authority Area (Load Balancing Area)		5/2/16	The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area.
Black start Capability Plan		5/2/16	A documented procedure for a generating unit or station to go from a shutdown condition to an operating condition delivering electric power without assistance from the electric system. This procedure is only a portion of an overall system restoration plan.
Bulk Electric System	BES	5/2/16	As defined by its associated Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 69 kV or higher.
Burden		12/9/10	Operation of the Bulk Electric System that violates or is expected to violate a System Operating Limit or Interconnection Reliability Operating Limit in the Interconnection, or that violates any other Railbelt, associated Reliability Organization, or local operating reliability standards or criteria.
Business Practices		5/2/16	Those business rules contained in the Transmission Service Provider’s applicable tariff, rules, or procedures; Reliability Organization or regional entity business practices.
Calculated Frequency Response		2/2/18	The result of a calculation that estimates a Balancing Authorities expected frequency response based on the droop settings and available headroom of online units. Source: AK proposed definition

Railbelt-Wide Term	Acronym	Approved Date	Definition
Capacity Benefit Margin	CBM	5/2/16	The amount of firm transmission transfer capability preserved by the transmission provider for Load-Serving Entities (LSEs), whose loads are located on that Transmission Service Provider's system, to enable access by the LSEs to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for an LSE allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission transfer capability preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies.
Compliance Monitor		5/2/16	The entity that monitors, reviews, and ensures compliance of responsible entities with reliability standards.
Contingency		12/16/10	The unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element.
Contingency Reserve		11/18/10	The provision of capacity deployed by the Balancing Authority to meet the Disturbance Control Standard (DCS) and other Railbelt and Reliability Organization contingency requirements.
Contingency Reserve Restoration Period		2/2/18	The time, in minutes set as the target goal in the standard to allow restoration of contingency reserves starting at the end of the Disturbance Recovery Period and ending when the contingency reserves have been restored. Source: AK proposed definition
Control Performance Standard	CPS	11/18/10	The reliability standard that sets the limits of a Balancing Authority's Area Control Error over a specified time period.

Railbelt-Wide Term	Acronym	Approved Date	Definition
Corrective Action Plan	CAP	3/30/18	The Corrective Action Plan (CAP) shall include Operational measures, such as reduced or revised transfer limits, system operating constraints, loss of firm load or suspension of firm transmission service, was well as long-term capital improvement plans. The CAP shall include recommendations on longer term projects that are capable of eliminating the deficiencies identified in the system studies. Included in the plan for each of the projects must be: 1) Complete description of the proposed project 2) Complete cost estimate of the proposed project 3) Complete time frame of the project from project approval to project completion, including major milestones 4) Complete Cost/Benefit analysis using the costs above and the reduced operating costs and reliability improvements achieved over the life of the project 5) Be accepted by the Reliability Organization.
Curtailment		5/2/16	A reduction in the scheduled capacity or energy delivery of an Interchange Transaction.
Declared Capability		5/2/16	Declared Capability- not less than the load (MW) on the unit at any point in time and not more than the temperature compensated maximum amount of load (MW) the unit is capable of supplying for a two-hour period or immediately supplying through the actions of AGC.
Demand		5/2/16	1. The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time. 2. The rate at which energy is being used by the customer.
Distribution Provider	DP	5/2/16	Provides and operates the “wires” between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the distribution function at any voltage.
Disturbance		11/18/10	1. An unplanned event that produces an abnormal system condition. 2. Any perturbation to the electric system. 3. The unexpected change in ACE that is caused by the sudden failure of generation or interruption of load.

Railbelt-Wide Term	Acronym	Approved Date	Definition
Disturbance Control Standard	DCS	11/18/10	The reliability standard that sets the time limit following a Disturbance within which a Balancing Authority must return its Area Control Error to within a specified range.
Disturbance Recovery Criterion		1/1/16	A Balancing Authority shall return its ACE to zero if its ACE just prior to the Reportable Disturbance was positive or equal to zero. For negative initial ACE values just prior to the Disturbance, the Balancing Authority shall return ACE to its pre-Disturbance value.
Disturbance Recovery Period		2/2/18	The time, in minutes set as the target goal in the standard to allow restoration of the frequency from the time of the initiating event to the time the frequency is restored to within acceptable frequency limits of 60.2 to 59.8 Hz for Reportable Disturbance events. Source: AK proposed definition
Dynamic Interchange Schedule or Dynamic Schedule		12/9/10	A telemetered reading or value that is updated in real time and used as a schedule in the AGC/ACE equation and the integrated value of which is treated as a schedule for interchange accounting purposes. Commonly used for scheduling jointly owned generation to or from another Balancing Authority Area.
Emergency or BES Emergency		5/2/16	Any abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Bulk Electric System.
Emergency Transfer Capability		TBD	The amount of electric power that can be moved or transferred from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under emergency conditions.
End User		10/6/11	Greater than 10 MW aggregate load that may be an independent entity or part of a utilities service area.
Facility Rating		5/2/16	The maximum or minimum voltage, current, frequency, or real or reactive power flow through a facility that does not violate the applicable equipment rating of any equipment comprising the facility.
Firm Demand		5/2/16	That portion of the Demand that a power supplier is obligated to provide except when system reliability is threatened or during emergency conditions.
Firm Generation or Firm Power		TBD	Power producing capacity intended to be available at all times during the period covered by a commitment even under adverse conditions.
Firm Transmission Service		5/2/16	The highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption.

Railbelt-Wide Term	Acronym	Approved Date	Definition
Forecasted Peak Demand		TBD	The highest peak demand of the BA's forecasted system load requirements for the specified portion of the planning year.
Forced Outage		1/13/11	1. The removal from service availability of a generating unit, transmission line, or other facility for emergency reasons. 2. The condition in which the equipment is unavailable due to unanticipated failure.
Frequency Bias		11/18/10	A value, usually expressed in megawatts per 0.1 Hertz (MW/0.1 Hz), associated with a Balancing Authority Area that approximates the Balancing Authority Area's response to Interconnection frequency error.
Frequency Bias Setting		11/18/10	A value, usually expressed in MW/0.1 Hz, set into a Balancing Authority ACE algorithm that allows the Balancing Authority to contribute its frequency response to the Interconnection.
Frequency Deviation		12/9/10	A change in Interconnection frequency.
Frequency Error		5/2/16	The difference between the actual and scheduled frequency. ($F_A – F_S$)
Frequency Regulation		12/9/10	The ability of a Balancing Authority to help the Interconnection maintain Scheduled Frequency. This assistance can include both turbine governor response and Automatic Generation Control.
Frequency Response		12/9/10	(Equipment) The ability of a system or elements of the system to react or respond to a change in system frequency. (System) The sum of the change in demand, plus the change in generation, divided by the change in frequency, expressed in megawatts per 0.1 Hertz (MW/0.1 Hz).
Generating Assets	GA	5/2/16	Primarily refers to machines synchronously connected to the Railbelt Grid providing real and reactive power. In some specialized instances, these may include assets that are asynchronously connected to the Railbelt, or devices that provide only reactive power (synchronous condensers, SVC's, cables, wind turbines, FACTS etc.).
Generator Operator	GOP	5/2/16	The entity that operates generating unit(s) and performs the functions of supplying energy and Interconnected Operations Services.
Generator Owner	GO	5/2/16	Entity that owns and maintains generating units.

Railbelt-Wide Term	Acronym	Approved Date	Definition
Host Balancing Authority		12/9/10	1. A Balancing Authority that confirms and implements Interchange Transactions for a Purchasing Selling Entity that operates generation or serves customers directly within the Balancing Authority's metered boundaries. 2. The Balancing Authority within whose metered boundaries a jointly owned unit is physically located.
Inadvertent Interchange		5/2/16	The difference between the Balancing Authority's Net Actual Interchange and Net Scheduled Interchange. (I_A – I_S)
Interchange		5/2/16	Energy transfers that cross Balancing Authority boundaries.
Interchange Authority	IA	5/2/16	The responsible entity that authorizes implementation of valid and balanced Interchange Schedules between Balancing Authority Areas, and ensures communication of Interchange information for reliability assessment purposes.
Interchange Schedule		11/18/10	An agreed-upon Interchange Transaction size (whole megawatts), start and end time, beginning and ending ramp times and rate, and type required for delivery and receipt of power and energy between the Source and Sink Balancing Authorities involved in the transaction, .
Interchange Transaction		11/18/10	An agreement to transfer energy from a seller to a buyer that crosses one or more Balancing Authority Area boundaries.
Interconnected Operations Service		5/2/16	A service (exclusive of basic energy and transmission services) that is required to support the reliable operation of interconnected Bulk Electric System.
Interconnected Value		5/2/16	The technical value of a generating asset to the Railbelt Grid and its subdivisions (LSE's, BAL's etc.) in terms of dispatch-ability, real and reactive power output and absorption, inertia, system response, operating and non-operating reserves, etc.
Interconnection		11/18/10	When capitalized, the Alaska Railbelt Interconnection.
Interconnection Reliability Operating Limit	IROL	5/2/16	The value (such as MW, MVAr, Amperes, frequency or Volts) derived from, or a subset of the System Operating Limits, which if exceeded, could expose a widespread area of the Bulk Electric System to instability, uncontrolled separation(s) or cascading outages.
Intermediate Balancing Authority		5/2/16	A Balancing Authority Area that has connecting facilities in the Scheduling Path between the Sending Balancing Authority Area and Receiving Balancing Authority Area and operating agreements that establish the conditions for the use of such facilities.

Railbelt-Wide Term	Acronym	Approved Date	Definition
Interruptible Demand		TBD	Demand not under direct control of the system operator that the end-use customer makes available to its BA via contract or agreement for curtailment. Interruptible Demand may include interruptible load that is not available for use in reducing the BA's forecast demand requirements due to contractual or implementation restrictions.
Largest Single Generation Contingency	LSGC	5/2/16	The declared Capability of the largest generating unit contingency (or combination of units with a single point of interconnection forming a single contingency regardless of RAS applications) interconnected to the Railbelt Grid.
Load Serving Entity	LSE	5/2/16	An entity that secures energy and transmission service (and related Interconnected Operations Services) to serve the electrical demand and energy requirements of its end-use customers.
Monthly Peak Hour Load	MPHL	5/2/16	The MPHL of an entity shall be defined as the monthly peak hour load from the month 1 year earlier. Adjustments for permanent loss, or expected increases due to large industrial loads may be made if agreed to by the Reliability Assurer. Economy sales are not counted as loads, but non-firm/interruptible loads are.
Multiple Contingencies within the Reportable Disturbance Period		2/2/18	Additional Contingencies that occur after one minute of the start of a Reportable Disturbance but before the end of the Disturbance Recovery Period. Source: AK proposed definition
Net Actual Interchange		5/2/16	The algebraic sum of all metered interchange over all interconnections between two physically Adjacent Balancing Authority Areas.
Net Interchange Schedule		5/2/16	The algebraic sum of all Interchange Schedules with each Adjacent Balancing Authority.
Net Internal Demand		TBD	Total of all end-use customer demand and electric system losses within specified metered boundaries and period, and less Direct Control Load Management and Interruptible Demand.
Net Scheduled Interchange		5/2/16	The algebraic sum of all Interchange Schedules across a given path or between Balancing Authorities for a given period or instant in time.
Non-Spinning Reserve		12/9/10	1. That generating reserve not connected to the system but capable of serving demand within a specified time. 2. Interruptible load that can be removed from the system in a specified time.

Railbelt-Wide Term	Acronym	Approved Date	Definition
Normal Net Capability		TBD	The maximum continuous rating of the resource minus the station service demand required to achieve the maximum continuous rating of the unit within the specified period. Station service or plant loads not attributable to the operation of the unit must not be included in the Normal Net Capability of the unit.
Obligated Entity		5/2/16	A Railbelt entity who is obligated to provide operating and or non-operating reserves or reserve capacity.
Off-Peak		12/9/10	Those hours between HE 2300 and HE 0600, weekdays and Saturdays and all hours Sunday. Also all hours on the following holidays; New Year's Day, Memorial Day, July 4th, Labor day, Thanksgiving and Christmas.
On-Peak		12/9/10	Those hours or other periods that are not Off-Peak
Operating Reserve		11/18/10	That capability above firm system demand required to provide for regulation; loading forecasting error, equipment forced and scheduled outages and local area protection. It consists of spinning and non-spinning reserve.
Operating Reserve - Spinning		11/18/10	The portion of Operating Reserve consisting of: • Generation synchronized to the system and fully available to serve load within the Disturbance Recovery Period following the contingency event within operational or procedural limitations; or • Load fully removable from the system within the Disturbance Recovery Period following the contingency event, for example SILOS. • Other approved sources.
Operating Reserve - Supplemental		11/18/10	The portion of Operating Reserve consisting of: • Generation (synchronized or capable of being synchronized to the system) that is fully available to serve load within the Disturbance Recovery Period following the contingency event; or • Load fully removable from the system within the Disturbance Recovery Period following the contingency event. • Other approved sources.
Overlap Regulation Service		5/2/16	A method of providing regulation service in which the Balancing Authority providing the regulation service incorporates another Balancing Authority's actual interchange, frequency response, and schedules into providing Balancing Authority's AGC/ACE equation.
Planning Authority	PA	5/2/16	The responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems.

Railbelt-Wide Term	Acronym	Approved Date	Definition
Planning Reserve Margin		TBD	The ratio of the total amount of planned available Firm Generation capacity divided by the Forecasted Peak Demand of the system minus 1.0, expressed in % for the specified period. The Planning Reserve Margin requirement must be calculated by each BA by system analysis.
Point of Delivery	POD	5/2/16	A location that the Transmission Service Provider specifies on its transmission system where an Interchange Transaction leaves or a Load-Serving Entity receives its energy.
Point of Receipt	POR	5/2/16	A location that the Transmission Service Provider specifies on its transmission system where an Interchange Transaction enters or a generator delivers its output.
Postback		5/2/16	Positive adjustments to ATC as defined in Business Practices. Such Business Practices may include processing of redirects and unscheduled service.
Power Electronics Transmission Asset		TBD	A device connected to the Bulk Electric system whose Real and Reactive Power outputs are controlled through the use of power electronics. Power Electronics Transmission Assets are not generation, but may produce Real and Reactive Power up to an energy limit. Power Electronics Transmission Assets include SVCs, STATCOMs, and Energy Storage Devices.
Protection Reserves		2/2/18	The resources under the control of the Under Frequency Load Shedding System designed to protect the interconnected system against single or multiple contingency events. Such reserves cannot be declared as contingency reserves. Source: AK proposed definition

Railbelt-Wide Term	Acronym	Approved Date	Definition
Prudent Utility Practice		5/2/16	Shall mean at a particular time any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, would have been expected to accomplish the desired result at the lowest reasonable cost consistent with reliability, safety and expedition, including but not limited to the regional practices, methods and acts engaged in or approved by a significant portion of the electrical utility industry prior thereto. In applying the standard of Prudent Utility Practices to any matter under these standards, equitable consideration should be given to the circumstances, requirements and obligations of each of the entities, and the fact that many of the entities are cooperatives, public corporations, or political subdivisions of the State of Alaska with prescribed statutory powers, duties and responsibilities. It is recognized that Prudent Utility Practice are not intended to be limited to the optimum practices, methods or acts to the exclusion of all others, but rather is a spectrum of possible practices, methods or acts which could have been expected to accomplish the desired result at the lowest reasonable cost consistent with reliability, safety and expedition. Prudent Utility Practices include due regard for manufacturers' warranties and the requirements of governmental authorities having jurisdiction.
Pseudo-Tie		12/9/10	A telemetered reading or value that is updated in real time and used as a “virtual” tie line flow in the AGC/ACE equation but for which no physical tie or energy metering actually exists. The integrated value is used as a metered MWh value for interchange accounting purposes.
Purchasing-Selling Entity	PSE	5/2/16	The entity that purchases or sells, and takes title to, energy, capacity, and Interconnected Operations Services. Purchasing-Selling Entities may be affiliated or unaffiliated merchants and may or may not own generating facilities.
Railbelt (Railbelt Grid, Railbelt Interconnection, Railbelt System)		5/2/16	The *interconnected* generation and transmission system of Central Alaska, currently The Railbelt region extending from North of the Fairbanks area to the Kachemak bay area in the South..
Reactive Power	VARS	5/2/16	The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive Power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive Power is provided by generators, synchronous condensers, or electrostatic equipment such as capacitors and directly influences electric system voltage. It is usually expressed in kilovars (kVAr) or megavars (MVAr).

Railbelt-Wide Term	Acronym	Approved Date	Definition
Receiving Balancing Authority		12/16/10	The Balancing Authority importing the Interchange.
Regional Coordinating Council		TBD	The responsible entity that enforces, coordinates, and integrates reliability standards used by the associated Reliability Organizations.
Regional Reliability Organization	RRO	11/18/10	An entity that ensures that a defined area of the Bulk Electric System is reliable, adequate and secure.
Regulating Reserve		12/9/10	An amount of reserve responsive to Automatic Generation Control, which is sufficient to provide normal regulating margin.
Regulating Reserve Obligation		5/2/16	The minimum amount of regulating reserve required during day ahead planning.
Regulation Service		12/9/10	The process whereby one Balancing Authority contracts to provide corrective response to all or a portion of the ACE of another Balancing Authority. The Balancing Authority providing the response assumes the obligation of meeting all applicable control criteria as specified by its associated Reliability Organization for itself and the Balancing Authority for which it is providing the Regulation Service.
Reliability Assurer		5/2/16	Monitors and evaluates the activities related to planning and operations, and coordinates activities of responsible entities to secure the reliability of the bulk power system.
Reliability Coordinator	RC	5/2/16	The entity that is the highest level of authority who is responsible for the reliable operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.
Reliability Coordinator Area		5/2/16	The collection of generation, transmission, and loads within the boundaries of the Reliability Coordinator. Its boundary coincides with one or more Balancing Authority Areas.
Reliability Organization	RO	3/30/18	The responsible entity that enforces, coordinates, and integrates reliability standards used by the Reliability Organizations.
Reliability Planner	RP	3/30/18	Group that plans for and determines future resource needs for the BES, including generation and transmission improvements.
Remedial Action Scheme	RAS	5/2/16	See "Special Protection System".

Railbelt-Wide Term	Acronym	Approved Date	Definition
Reportable Disturbance		2/2/18	Reportable Disturbances are contingencies involving any generating unit trips, transmission line trips, and distribution level disturbances that result in frequency deviation > 0.3 Hz. Source: AK proposed definition
Reportable Excess Contingency Disturbance		2/2/18	Any series of events, or multiple contingency events which exceed the maximum contingency event for which the Contingency Reserve Policy was designed. These series of events or multiple contingency events occur in a manner that causes System frequency to exceed the limits of +/- 0.3 Hz in the Balancing Authority's area. The excess contingency events occur prior to the contingency reserves being re-established following a single contingency disturbance or for multiple contingency events which exceed the reserve requirements of the maximum contingency event for which the Contingency Reserve Policy was designed. Source: AK proposed definition
Reserve Capacity Obligation		5/2/16	For any year, shall be equal to thirty (30) percent of the projected Annual System Demand for that year for that Load Serving Entity.
Reserve Margin		TBD	The ratio of the actual total amount of available Firm Generation capacity, expressed in %, between the total available Firm Generation capacity divided by the Peak Demand of the system minus 1.0, expressed in % for the specified period.
Reserve Sharing Group	RSG	11/18/10	A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each Balancing Authority's use in recovering from contingencies within the group. Scheduling energy from an Adjacent Balancing Authority to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (e.g., ten minutes). If the transaction is ramped in quicker (e.g., between zero and ten minutes) then, for the purposes of the Disturbance Control Standard, the areas become a Reserve Sharing Group.
Resource Adequacy		TBD	The ability of supply-side and demand-side resources to meet the aggregate electrical demand (including losses within a BA's area) at all times within the specified period taking into account scheduled and reasonably expected unscheduled outages of system elements.
Resource Planner	RP	5/2/16	The entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a Planning Authority area.

Railbelt-Wide Term	Acronym	Approved Date	Definition
Schedule		12/9/10	(Verb) To set up a plan or arrangement for an Interchange Transaction. (Noun) An Interchange Schedule.
Scheduled Frequency		12/9/10	60.0 Hertz, except during a time correction.
Scheduling Entity		12/9/10	An entity responsible for approving and implementing Interchange Schedules.
Scheduling Path		5/2/16	The Transmission Service arrangements reserved by the Purchasing-Selling Entity for a Transaction.
Sending Balancing Authority		12/16/10	The Balancing Authority exporting the Interchange.
Shed In Lieu Of Spin	SILOS	11/18/10	Computer or relay based load shedding scheme with timing and frequency parameters approved by its associated Reliability Organization. This is not to be confused with system coordinated under-frequency load shedding.
Simultaneous Contingencies		2/2/18	Multiple Contingencies occurring within one minute or less of each other shall be treated as a single Contingency. Source: AK proposed definition
Sink Balancing Authority		12/16/10	The Balancing Authority in which the load (sink) is located for an Interchange Transaction. (This will also be a Receiving Balancing Authority for the resulting Interchange Schedule.)
Source Balancing Authority		12/16/10	The Balancing Authority in which the generation (source) is located for an Interchange Transaction. (This will also be a Sending Balancing Authority for the resulting Interchange Schedule.)
Special Protection System (Remedial Action Scheme)	SPS	5/2/16	An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS). Also called Remedial Action Scheme.
Spin Balancing Account	SBA	5/2/16	Procedures to track small changes in spin obligations due to forecasting errors.
Spinning Reserve		12/9/10	See Operating Reserve - Spinning
Spinning Reserve Obligation	SRO	5/2/16	The amount of spinning reserve an Obligated Entity is required to maintain.

Railbelt-Wide Term	Acronym	Approved Date	Definition
Stability Limit		TBD	The maximum power flow possible through some particular point in the system while maintaining stability in the entire system or the part of the system to which the stability limit refers.
Steady-State Transfer Capability		TBD	The capability of a transmission system to reliably transfer electric power from one area to another by way of all transmission lines (or paths). The Steady-State Transfer Capability is equal to the Steady-State Transfer Limit minus Contingency Reserve obligations of source area and Transmission Reliability Margin.
Steady-State Transfer Limit		TBD	The amount of electric power that can be moved or transferred from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) before a contingency event would result in unacceptable system response.
Supplemental Regulation Service		12/9/10	A method of providing regulation service in which the Balancing Authority providing the regulation service receives a signal representing all or a portion of the other Balancing Authority's ACE.
System		5/2/16	A combination of generation, transmission, and distribution components.
System Demand		10/13/11	That number of kilowatts which is equal to the kilowatt-hours required in any clock hour, attributable to energy required during such hour for supply of energy to an entities' consumers, including system losses, and wheeling losses occurring on other systems. System Demand excludes generating station uses.
System Operating Limit	SOL	5/2/16	The value (such as MW, MVAr, Amperes, frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to: • Facility Ratings (Applicable pre- and post-Contingency equipment or facility ratings) • Transient Stability Ratings (Applicable pre- and post-Contingency Stability Limits) • Voltage Stability Ratings (Applicable pre- and post-Contingency Voltage Stability) • System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits).
System Operator		5/2/16	An individual at a control center (Balancing Authority, Transmission Operator, Generator Operator, Reliability Coordinator) whose responsibility it is to monitor and control that electric system in real time

Railbelt-Wide Term	Acronym	Approved Date	Definition
System Reserve Basis	SRB	5/2/16	The amount of Spinning Reserve required to prevent first stage load-shed. Generally determined by system studies of the frequency response of the system under various conditions for the loss of the Largest Single Generation Contingency.
Temperature Sensitive Units		TBD	A generating unit whose maximum real power capability changes by more than 10 percent due to change in ambient air temperature. The 10 percent change in real power capability is based on the local average annual maximum and annual minimum ambient air temperatures.
Tie Line		12/9/10	A circuit connecting two Balancing Authority Areas.
Tie Line Bias		12/9/10	A mode of Automatic Generation Control that allows the Balancing Authority to 1.) maintain its Interchange Schedule and 2.) respond to Interconnection frequency error.
Tie Line Deviation		8/11/11	See Inadvertent Interchange.
Time Error		12/9/10	The difference between the Interconnection time measured at the Balancing Authority(ies) and the time specified by the National Institute of Standards and Technology. Time error is caused by the accumulation of Frequency Error over a given period.
Time Error Correction		12/9/10	An offset to the Interconnection's scheduled frequency to return the Interconnection's Time Error to a predetermined value.
Time Monitor		5/2/16	The entity that monitors Time Error and initiates or terminates corrective action orders in accordance with the Time Error Correction procedure.
Total Operating Reserve Obligation		5/2/16	At any time shall be an amount equal to 150 percent of the System Reserve Basis of the Railbelt Grid and may be composed of both spinning and non-spinning reserve.
Total Transfer Capability	TTC	5/2/16	The amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions.
Transient Transfer Limit		TBD	Stability Limit minus the Transmission Reliability Margin.
Transaction		12/9/10	See Interchange Transaction.
Transmission		12/9/10	An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems. Generally operated at or above 69 kV.

Railbelt-Wide Term	Acronym	Approved Date	Definition
Transmission Constraint		12/9/10	A limitation on one or more transmission elements that may be reached during normal or contingency system operations.
Transmission Customer		12/9/10	1. Any eligible customer (or its designated agent) that can or does execute a transmission service agreement or can or does receive transmission service. 2. Any of the following responsible entities: Generator Owner, Load-Serving Entity, or Purchasing-Selling Entity.
Transmission Line		12/9/10	A system of structures, wires, insulators and associated hardware that carry electric energy from one point to another in an electric power system. Lines are operated at relatively high voltages varying from 69 kV up to 765 kV, and are capable of transmitting large quantities of electricity over long distances.
Transmission Operator	TOP	12/9/10	The entity responsible for the reliability of its “local” transmission system, and that operates or directs the operations of the transmission facilities.
Transmission Operator Area		12/9/10	The collection of Transmission assets over which the Transmission Operator is responsible for operating.
Transmission Owner	TO	5/2/16	The entity that owns and maintains transmission facilities.
Transmission Planner	TP	5/2/16	The entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority area.
Transmission Reliability Margin	TRM	5/2/16	The amount of transmission transfer capability necessary to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change.
Transmission Service		12/9/10	Services provided to the Transmission Customer by the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery.
Transmission Service Provider	TSP	5/2/16	The entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable transmission service agreements.
Wide Area		5/2/16	The entire Reliability Coordinator Area as well as the critical flow and status information from adjacent Reliability Coordinator Areas as determined by detailed system studies to allow the calculation of Interconnection Reliability Operating Limits.

Exhibit C
Sanctions Matrix
TBD by the Reliability Organization

Letter (A) is letter to management
Letter (B) is letter to Board
Specified Period is calendar year

Exhibit D

Railbelt Reliability Planning Guidelines

During all excursions subsequent to the occurrence as described in AKTPL-004 Table 1, the following parameters should be maintained within applicable Emergency limits without system separation or instability:

Quantity Level:	Minimum	Maximum
First Power Swing:	0.80 pu V	1.10 pu V (< 0.5 sec.)
Intermediate:	0.92 pu V	1.05 pu V
Steady State:	0.95 pu V	1.05 pu V
Frequency:	58.8 Hz	61.5 Hz