Document Title:	Facility Interconnection Requirements	Revision Date:	8/7/2023
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Document Owner (role):	Transmission Planning Engineer		

Purpose:

This document has been prepared to identify the technical requirements for connecting new facilities to the Gainesville Regional Utilities' (GRU) transmission system, or interconnecting a third party Facility to GRU's existing Facilities.

It applies to new connections or substantial modifications of existing generating units or transmission interconnections as well as existing and new end user delivery points. The requirements and guidelines found in this document are consistent with those used by GRU when installing new GRU facilities or modifying existing GRU facilities.

The standards in this document apply to new Facilities and to modification of existing Facilities. The standards in effect at the time a Facility was constructed or modified are to continue to apply to such Facility until it is subsequently modified, or until GRU determines the Facility must be upgraded to the current standard to avoid unacceptable risk to the reliability or operation of the Transmission System, or to the safety of workers or the public.

Detailed interconnection Facility-specific requirements will be developed as part of System Impact Studies and/or Interconnection Feasibility Studies. Rather than give detailed technical specifications, this document provides a general overview of the functional objectives and requirements written to establish a basis for maintaining reliability, power quality, and a safe environment for the general public, power consumers, maintenance personnel and the equipment and to meet NERC FAC001 compliance obligations.

Scope:

This Facility Interconnection Requirements document is revised from time to time to reflect changes or clarifications in planning, operating, or interconnection policies. The GRU Transmission Planning Engineer will maintain the most current version

That document is at http://gru.com/WorkWithGRU.aspx

This document defines responsibilities for persons assigned to the following roles:

- Transmission Planning Engineer
- Power Systems Operation Manager
- Project Manager (Energy Supply)
- Project Manager (Subs-Relay)

(Refer to https://gruadmin.sharepoint.com/sites/GRUProceduresManagement/Lists/Roles/AllItems.aspx for the current list of roles assignments)

Authorization:

This document is authorized and enforced by all the following:

Document factor	Name	Approval Details

Owner	Hidalgo, Milvia A	Approve - 08/01/2023 02:25 PM
Approver for role: Transmission Planning Engineer	Rahman, Ziaur	Approve - 08/01/2023 01:23 PM
Approver for role: Power Systems Operation Manager	Walters, Eric A	Approve - 08/07/2023 12:09 PM
Approver for role: Project Manager (Energy Supply)	Hollandsworth, David W	Approve - 08/07/2023 12:46 PM
Approver for role: Project Manager (Subs-Relay)	Garteiser, Jeff T	Approve - 08/07/2023 01:07 PM
Compliance	[ComplianceName]	Approve - 08/01/2023 01:43 PM

*Approvals are electronic. Reassignment of an approver role does not require re-approval of the document.

Contents

I. COMMON REQUIREMENTS

This section addresses the technical requirements that are common to the connection of generation, transmission and delivery point (end-users) facilities to the GRU transmission system. General overviews of functional requirements are given in this section. This document is not intended to be a design specification.

I. A. Responsibilities (Transmission Planning)

It is the responsibility of the facility owner to provide all devices necessary to protect the customer's equipment from damage by abnormal conditions and operations that might occur on the interconnected power system. The facility owner shall protect its generator and associated equipment from overvoltage, undervoltage, overload, short circuits (including ground fault conditions), open circuits, phase unbalance, phase reversal, surges from switching and lightning, over and under frequency conditions, and other injurious electrical conditions that may arise on the interconnected system.

It is the responsibility of the generation, transmission, and end-user facility owners to provide for the orderly re-energization and synchronizing of their high voltage equipment to other parts of the electric system. Appropriate operating procedures and equipment designs are needed to guard against out of synch closure or uncontrolled energization. Each owner is responsible to know and follow all applicable regulations, industry guidelines, safety requirements, and accepted practice for the design, operation and maintenance of the facility.

I. B. Site Access (Substation & Relay)

There are situations where some equipment that is owned by GRU is located within the Customer's facility. This is often required for data acquisition or metering. In these cases, installed equipment owned by GRU will be clearly identified as such on the appropriate station drawings, on the reference documents and at the site. Site access is to be always provided to GRU employees where GRU equipment is located within the Customer's facility.

I. C. Safety (Substation & Relay)

Safety is of utmost importance. Strict adherence to established switching, lockout, tagging and grounding procedures is required at all times for the safety of personnel. Any work carried out within a facility shall be performed in accordance with all applicable laws, rules, and regulations and in compliance with Occupational Safety and Health Administration (OSHA), National Electric Safety Code (NESC), National Electric Code (NEC) and good utility practice. Automatic and manual disconnect devices are to be provided as a means of removing all sources of current to any particular element of the power system. Only trained operators are to perform switching functions within a facility under the direction of the responsible dispatcher or designated person as outlined in the National Electric Safety Code.

I. D. Operations (Substation & Relay)

Operational procedures are to be established in accordance with NESC, OSHA, Florida Reliability Coordinating Council (FRCC) and NERC requirements. Each party shall designate operating representatives to address: communications, maintenance coordination, actions to be taken after de-energization of interconnected facilities, and other required operating policies. All parties are to be provided with current station operating diagrams. Common, agreed upon nomenclature is to be used for naming stations, lines and switches. Updated diagrams are to be provided when changes occur to interconnected facilities.

The operator of facilities interconnecting to the GRU transmission system must not perform any switching that energizes or de-energizes portions of the GRU transmission system or that may adversely affect the GRU transmission system without prior approval of the GRU System Operator. Operators of facilities interconnecting to the GRU transmission system must notify the GRU System Operator before performing any switching that would significantly affect voltages, power flows or reliability in the GRU transmission system.

I. E. Control Areas (Transmission Planning, Power Systems Operations)

All loads, generation, and transmission facilities must be part of a control area. At least six months before Trial Operation, the facility owner shall notify GRU in writing of the control area in which it will be located. If the Customer elects to be located in a control area other than the control area in which GRU is located or change control areas, all necessary agreements shall be executed and technical and equipment requirements implemented prior to the placement of the facility in the other control area.

Facilities owners shall follow good utility practice to avoid creating oversupply imbalances or undersupply imbalances. The facility owner shall contract for or have available to it resources within its control area that are capable of supplying in real time any deviations between power schedules and the actual power interchange with the GRU Transmission System by the facility.

I. F. Responsibilities during Emergency Conditions (Power Systems Operations)

All control areas within the FRCC region are responsible for maintaining voltage and frequencies within agreed upon limits. All operators of facilities (generation, transmission and end-users) interconnected to the GRU transmission systems in the FRCC Region are required to communicate and coordinate with their control area operator. During emergency conditions, the facility operator shall raise or lower generation, adjust reactive power, switch facilities in or out, or reduce end user load as directed by the control area operator.

Within the FRCC Region, the Reliability Coordinator has overall responsibility for the secure operation of the interconnected transmission systems. All control area operators must communicate and coordinate with and follow the directions of the Reliability Coordinator. All facility owners are expected to follow the procedures and guides contained in the FRCC Operating Handbook. The FRCC's Operating Committee Handbook and Reliability Coordinator documents are posted electronically at "www.frcc.com."

I. G. Maintenance of Facilities (Substation & Relay)

The maintenance of facilities is the responsibility of the owner of those facilities. This maintenance includes the periodical inspection of all existing facilities and the initial inspection of newly installed facilities. Adjoining facilities on the interconnected power system are to be maintained in accordance with accepted industry practices and procedures. Each party is to have a documented maintenance program ensuring the proper operation of equipment. GRU will have the right to review maintenance reports and calibration records of equipment that could impact the GRU system if not properly maintained. GRU is to be notified as soon as practicable about any out of service equipment that might affect the protection, monitoring, or operation of interconnected facilities.

Maintenance of facilities interconnected to the GRU transmission system shall be done in a manner that does not place the reliability and capability of the GRU transmission system at risk. Planned maintenance must be coordinated and scheduled with the GRU System Operator.

I. H. Point of Interconnection (Substation & Relay)

The point of interconnection is to be clearly described. GRU will demark the metering point for the new installation. Usually the change of facility ownership and the point of interconnection are the same point.
An interconnection junction box may be required to connect control circuits and signals between the parties at a point of demarcation. Fiber optics is the preferred means of interconnection of control circuits. Metallic control cables will present problems if the distances are great, ground potential rise during faults can cause failures when these signals are needed the most. Long cable voltage drops can make control systems unreliable or produce inaccurate signal levels and therefore are to be avoided. GRU reserves the right to specify the type of lines and cables to be used.

Metering equipment should be provided as close to the interconnection point as practicable. The interconnecting facility must be connected to the GRU system through a transmission voltage interrupting device. GRU Metering voltage and current transformers shall be located ahead of any non-GRU owned switches or disconnects.

Facilities interconnecting to the GRU transmission system that are not solely operated and controlled by the GRU System Operator must have an isolating device installed at the point of interconnection. This isolating device, typically a disconnect switch, must be capable of physically and visibly isolating the facilities from the GRU transmission system. This isolating device must be lockable in the open position by GRU and must be under the ultimate control of the GRU System Operator.

I. I. Transmission Line Configurations (Substation & Relay)

Three source terminal interconnection configurations are to be avoided within the GRU transmission system. This is due to problems associated with protective relay coverage from in-feed, sequential fault clearing, out-feed or weak source conditions, reduced load flow, and automatic reclosing complications. Extensive studies are necessary to evaluate all possible implications when considering three terminal line applications. These studies will be totally funded by the requesting party.
Some new connections to the GRU transmission system may require one or more GRU transmission circuits to be looped through the new facility. The design and ratings of the new facilities and the transmission loop into them shall not restrict the capability of the transmission circuits or impair GRU’s contractual transmission service obligations.

Long taps to feed connected load directly tied to a transmission line are to be avoided. This presents coverage problems to the protective relay system due to in-feed. Power line carrier signals will not be allowed.
Any interconnection configuration should not restrain GRU from taking a GRU transmission line out of service for just cause. GRU shall not be forced to open a transmission line for an adjacent interconnected generator or transmission line to obtain an outage. Manual switching or clearing electrical faults within the non-GRU facility shall not curtail the ability of GRU to transmit power or serve its customers.

Reliable station and breaker arrangements will be used when there are new or substantial modifications to existing GRU switching stations affecting transmission lines rated at or above 138kV. In general, GRU transmission switching stations are configured such that line and transformer, bus and circuit breaker maintenance can be performed without degrading transmission connectivity. This generally implies a breaker and a half or double breaker, double bus configuration. A ring bus may be used when a limited number of transmission lines are involved.

I. J. Grounding (Substation & Relay)

Each interconnection substation must have a ground grid that solidly grounds all metallic structures and other non-energized metallic equipment. This grid and grounding system shall be designed to meet the requirements of ANSI/IEEE 80, IEEE Guide for Safety in AC Substation Grounding and ANSI/IEEE C2, National Electrical Safety Code. The transmission line overhead ground wire (OHGW) shall be connected to the substation ground grid.

If the interconnection substation is close to another substation, the two grids shall be bonded/connected. The interconnecting cables must have sufficient capacity to handle the fault currents, duration, and duty. GRU must approve any connection to a GRU substation ground grid.

All transmission line structures must be adequately bonded and grounded to control step and touch potential in compliance with the NESC, and to provide adequate lightning performance. All transmission lines should have a continuous ground wire/counterpoise, not relying on earth as the primary conductor, to transfer fault current between structures and to substations and plant switchyards. Any exceptions to a continuous ground wire shall be verified with a system study. All ground wires and bond wires must be adequately sized to handle anticipated maximum fault currents and duty without damage.

Transmission interconnections may substantially increase fault current levels at nearby substations and transmission lines. Modifications to the ground grids of existing substations and OHGWs of existing lines may be necessary. The interconnection studies will determine if modifications are required and the scope and cost of the modifications. These studies will be fully funded by the requesting party.

I. K. Insulation Coordination (Substation & Relay)

Insulation coordination is the selection of insulation strength. Insulation coordination must be done properly to ensure electrical system reliability and personnel safety. Basic switching impulse level (BSLs), surge arrester, basic lightning impulse level (BIL), conductor spacing and gap application, substation and transmission line insulation strength, protection, and shielding shall be documented and submitted for evaluation as part of the interconnection plan. Shielding, and surge protective devices are to meet the requirements as determined by lightning and switching surge analysis, and the latest IEEE C62 standards.

GRU's standard is to shield generation, substations and transmission lines from direct lightning strokes and to provide line entrance arresters at transmission line terminals including delivery point for end-users. Surge arresters are also applied at major components and subsystems.
Interconnection facilities to be constructed in areas with salt spray contamination or other type of contamination shall be properly designed to meet or exceed the performance of facilities not in a contamination area with regard to contamination caused outages.

I. L. Structures (Substation & Relay)

Transmission and substation structures for facilities connected to the GRU transmission system shall be designed to meet the National Electrical Safety Code (NESC). Substation bus systems shall be designed to comply with ANSI/IEEE Standard 605, IEEE Guide for the Design of Substation Rigid-Bus Structures.

All GRU structures are currently designed to meet extreme wind loading requirements from American Society of Civil Engineers (ASCE) 7-93[1]. Structures connected to the GRU transmission system shall be designed to meet ASCE 7-93 when the outage of these structures would interrupt power flow through the GRU transmission system or interrupt service to GRU customers.

I. M. Ratings (Transmission Planning, Substation & Relay)

There may be cases where adding generation will increase the available fault current above the present interrupting ratings of the existing breakers at a substation or stations. When this occurs, breaker upgrades are to be considered as part of the interconnection project. For non-fault facility and equipment ratings, reference the latest revision of the GRU Facility Ratings, available upon request. Interconnection facility ratings shall be compatible with those of connected GRU facilities.

AC high voltage circuit breakers and their duty requirements are specified by operating voltage, continuous current, interrupting current, and operating time in accordance with ANSI/IEEE Standards C37 series, "Symmetrical Current Basis." These ratings are displayed on the individual Circuit Breaker nameplate. Breakers are scheduled for replacement when they exceed 100% of ANSI C37 Guidelines and/or when required to do so due to short circuit duty deficiencies, among other factors considered by the Substation & Relay Dept.

[1] ASCE 7-93, Category IV, I=1, Exposure C (D for coastal areas) with drag coefficients from adequately documented Industry Standard sources

All circuit breakers and other fault interrupting devices shall be capable of safely interrupting fault currents for any fault they may be required to interrupt. Ratings of facilities must conform to the requirements set by NERC Facility and Planning Standards.

I. N. Reliability and System Security (Transmission Planning)

GRU designs and operates its transmission system to meet FRCC and NERC Planning and Operating Standards. GRU's Bulk Electric System (BES) is planned and operated such that, with all transmission facilities in service (category P0) and with normal (pre-contingency) operating procedures in effect, the transmission system can be operated to supply projected customer demands and projected firm (non-recallable reserved) transmission services at all forecasted demand levels under the conditions defined in Category P0 of Table I of NERC Reliability Standard TPL-001-5. Single and multiple contingency (Categories P1-P7) planning events may require planned system adjustments in order to respond as prescribed in Table I of NERC Reliability Standards TPL-001-5.

The design of new transmission connections should take into account and minimize, to the extent practical, the adverse consequences of Table 1 Extreme Event contingencies.

System and generator stability is to be maintained for normal clearing of all three phase faults. A normally cleared fault is assumed to last five cycles (0.083 seconds) for circuit elements protected by three cycle breakers. This provides approximately one cycle margin for slower than expected fault clearing. For circuit elements protected by two cycle breakers, a normally cleared fault is assumed to last four cycles.

The power system must be stable for single line to ground faults with the failure of a protection system component to operate. This includes clearing of a system fault with the simultaneous failure of a current transformer, protective relay, breaker, or communication channel. Three phase faults with the failure of a protection system component to operate are to be considered in all design alternatives with adverse consequences to system stability minimized.

GRU transmission circuits are protected with primary system relays that provide no intentional time delay when clearing faults for 100% of a line. A second high-speed relay system with communications and no intentional time delay is required if a failure of the primary system can result in instability when a fault is cleared by time delay backup protection. This can be the case for an end of line fault on a short line combined with a failed relay. Likewise, two independent high-speed protection systems may be required for bus protection if backup clearing results in instability.

I. O. Protective Relaying (Substation & Relay)

Utility grade, transmission level protective relays and fault clearing systems are to be provided on the interconnected power system. All protective relays should meet or exceed ANSI/IEEE Standard C37.90. Adjoining power systems may share a common zone of protection between two parties. Compatible relaying equipment must be used on each side of the point of ownership within a given zone of protection. The design must provide coordination for speed and sensitivity in order to maintain power system security and reliability.

System protection design and coordination with GRU must be done to meet all applicable NERC Protection and Control (PRC) Standards and FRCC guidelines and procedures.

All bulk transmission power systems are to have primary protective relaying that operates with no intentional time delay for 100% of the specified zone of coverage. On transmission circuits, this is accomplished through the use of a communication channel. A second high-speed protection system is required on a line and may be required on a bus.

Backup protective systems should provide additional coverage for breaker and relay failure outside the primary zone. Specific breaker failure protection schemes must always be applied at the bulk transmission level. Specific relay failure backup must also be provided. Backup systems should operate for failures on either side of an interconnection point. Time and sensitivity coordination must be maintained to prevent misoperations.

A power source for tripping and control must be provided at substations by a DC storage battery system. The battery system is to be sized with enough capacity to operate all tripping devices after eight hours without a charger. The battery should be sized as per IEEE Standard 485-1997 "IEEE Recommended Practice for Sizing Lead-Acid Batteries for Stationary Applications." An undervoltage alarm must be provided for remote monitoring by the facilities owners who shall take immediate action to restore power to the protective equipment. The referenced battery charger shall be DC grounded providing filtered power to the DC storage battery system. A separate alarm shall monitor the proper operation of the battery charger.

Mechanical and electrical logic and interlocking mechanisms are required between interconnected facilities to ensure safe and reliable operation. These include, but are not limited to, breaker and switch auxiliary contacts, undervoltage and synch-check relays, and physical locking devices.

A transfer trip is required for many installations. It is used for backup protection and islanding schemes. Fiber optics communication is required. Entities connecting to the GRU transmission system shall investigate and keep a log of all protective relay actions and misoperations as required by the FRCC. The most current requirements for analysis and reporting of protection misoperations are available from FRCC staff.

Entities connecting to the GRU transmission system must have a maintenance program for their protection systems. Documentation of the protection maintenance program shall be supplied to GRU, the FRCC, and NERC on request. Test reports as outlined in the maintenance program are to be made available for review by GRU and the FRCC. At intervals described in the documented maintenance program and following any apparent malfunction of the protection equipment, the entity shall perform both calibration and functional trip tests of its protection equipment at its owner's expense.

Any protective relaying performance issues that occur over time must be corrected to the satisfaction of GRU's Relay Protection Department and at the expense of the interconnected party.

I. P. Transmission Reclosing (Substation & Relay)

It is GRU's practice to automatically and manually test its transmission lines following breaker operations for system faults. This is required to minimize customer outage time and maintain system stability. On 230 kV lines and below, automatic reclosing occurs at 10 seconds on the weak source end of the line. Interconnected facilities must not interfere with GRU's ability to quickly restore transmission lines following temporary or permanent system faults.

Automatic reclosing on lines originating at GRU generation sites is usually accomplished by hot line synch-check permissive. Any party wishing to interconnect with GRU must consider the implications of automatic reclosing in their design.

I. Q. Revenue Metering (Substation & Relay, Metering)

Each installation needs to be evaluated separately for metering requirements because of the many possible contractual agreements and interconnection configurations. In general, however, the following quantities are to be provided for each supply point:

- Megawatt-hours received
- Megawatt-hours delivered
- MegaVar-hours received
- MegaVar-hours delivered
- Per phase and Three Phase Root-Mean Square ("RMS") Voltage
- Per phase and Three Phase Averaged RMS currents with at least two decimal points

- +/- Megawatts
- +/- Megavars

These quantities may need to be provided to various parties through various information/communication systems. Specific designs will be developed to meet those requirements.

All metering devices are to be pre-approved by GRU prior to installation. Revenue meters are to have an accuracy class of 0.3% or better. Three element meters are to be used on all effectively grounded power systems. Both primary and backup revenue meters are to be provided. Backup current transformers (CTs) and potential transformers (PT's) are not required.

Current Transformers

Instrument transformers are to have an accuracy class of 0.15%. Metering accuracy CTs and PTs are to be installed as close to the POI/delivery point as practical. CT ratios are to be selected to measure load in the high end of the ratio or in the rating factor range. Multi-ratio or split core CT's are not allowed. Metering CT's and PT's should not be used to feed non-metering equipment such as protective relays. Metering CT's are not to be connected in parallel. Auxiliary CT's are not to be used in metering circuits. When more than one point is to be monitored, individual metering is to be used. The impedance of the CT and PT cable leads is to be kept low and not impose burdens above that of the instrument transformer rating.

Revenue Metering Data Communication

The interconnection customer is to, at its own expense, install, operate, test, and maintain any communications equipment required by GRU to remotely retrieve revenue metering data from the interconnection customer's facility on a real-time or periodic basis. The communications capability of remote interrogation of the revenue data should be compatible with commonly used billing data systems such as MV-90. The interconnection customer is also responsible for any high voltage isolation equipment that the local telecommunications company may require at the interconnection customer's facility to protect their communications systems from damaging transient voltages that can occur in electrical substations and generation facilities.
GRU provides the interconnection customer access to bi-directional kWh and kVARh pulses from the GRU revenue meters installed at interconnection customer facilities. The pulses, which are provided upon request, are to be used to as the source of the revenue metering data where applicable. Alternatively, kWh and kVARh register accumulator data may be provided by other means, e.g. DNP, MODBUS, or similar protocol, to the interconnection customer facilities in lieu of or in addition to, analog kWh and kVARh pulses, if such arrangements are agreed upon by both parties.

Operational Metering Data from Revenue Meters

The interconnection customer is to, at its own expense, install, operate, test, and maintain any metering and communications equipment necessary to provide operational metering data from the interconnection customer's facility by one or more of the parties.

A continuous accumulating record of active and reactive energy flows are to be provided by means of the registers on the meters. The revenue meter(s) are to be capable of providing bi-directional energy data flow in either KYZ pulse signals format, or accumulated counters to RTU. Energy data flow accumulator counters may also include register accumulator data delivered to RTU via DNP, MODBUS, or similar protocol. All parties are to share the same data register buffers regardless of the types of employed data communication methods. For generation facilities that connect to GRU generation substations, this revenue meter data is to be shared across serial data links established between the two facilities. If the accumulation counter method is used, the owner of the meter is to be responsible for freezing the accumulator buffers and no other Party is to freeze them. The accumulator freezing signals are to be synchronized to Universal Time Coordination (UTC) within (½) seconds.

The revenue meters' internal clocks and real time Data Acquisition System equipment is to be synchronized with Universal Time Coordination (UTC) with 15 seconds resolution.

Revenue Metering Access, Security and Testing

Where GRU provides revenue metering equipment, the interconnection customer is to grant GRU employees and authorized agents' access to the equipment at all reasonable hours and for any reasonable purpose. Regardless of meter ownership, the interconnection customer is to not permit unauthorized persons to have access to the revenue metering equipment.

The meters, test switches, and any other secondary devices that could have an impact on the performance of the revenue metering are to remain sealed during operation and following maintenance or calibration testing. All parties are to be notified prior to removing seals. Seals are to be broken by the party responsible for the equipment only when tests, adjustments, and/or repairs are required. Calibration testing is to be performed annually and is to include all associated parties. Test equipment must be certified and traceable to the National Bureau of Standards. The revenue metering is to be tested for accuracy as specified by the applicable interconnection service agreement and GRU requirements.

If the interconnection facilities are owned by the neighboring utility, and that utility does not own the instrument transformers or meters, a structure and a location for mounting metering transformers and recording devices is to be provided by the facility owner.

At locations where ferroresonance can be a problem, metering accuracy capacitor coupled voltage transformers (CCVT) may be used if an alternate design configuration cannot be used. Designs that use ferroresonance dampening resistors connected to metering PT secondary circuits are not allowed.

When the metering location is different from the delivery point, compensation for losses is required for transformer losses and transmission line losses. Compensation should be performed internally by the installed metering equipment rather than by after-the-fact calculations.

I. R. Supervisory Control and Data Acquisition (SCADA) (Substation & Relay)

Each installation needs to be evaluated separately for SCADA requirements because of the many possible contractual agreements and interconnection configurations. Generally, the following quantities are to be provided. Megawatt-hours received, Megawatt-hours delivered, Voltage, Current, +/- Megawatts, and +/- Megavars, breaker and switch positions, breaker operation control, and equipment trouble alarms. These quantities may need to be provided to various parties through various information/communication systems. Specific designs will be developed to meet those requirements. Dual ported remote terminal units (RTUs) accessed by both parties may be used, provided the appropriate security levels are implemented. Equipment control of breakers, switches and other devices via SCADA is to be provided to only one responsible party.
Power for SCADA or metering communication equipment, if needed, is to be provided by the station battery. Office power systems and switching networks are not acceptable.

I. S. Ferroresonance (Substation & Relay)

Ferroresonance occurs on the power system under certain system configurations that may damage high voltage equipment. This phenomenon is usually caused when PT's are tied to a bus or line stub that may be energized through breakers having capacitors in parallel with the main contacts. Since interconnection facilities may contain shared equipment, such as metering PT's and high voltage breakers, care should be used to avoid configurations that could cause ferroresonance.

I. T. Future Modifications (Transmission Planning, Substation & Relay)

Any changes that affect an interconnection must be reviewed in advance. These include modifications to the metering or protection scheme as well as associated settings after the interconnection project has been completed. Information about expected increased load flows or higher fault currents levels due to system changes must be provided in a timely manner.

II. GENERATION FACILITIES[2]

This section addresses the technical requirements for connecting new generation to the GRU transmission system or substantially modifying existing generating facilities connected to the GRU transmission system. General overviews of functional requirements are described in this section. Detailed, project specific requirements will be developed as part of an Interconnection Study or a Facilities Study, or as referenced in other documents such as the NERC Planning Standards, the NERC Operating Standards, or the National Electrical Safety Code. Florida Public Service Commission Rule 25-17.087 shall apply for Qualifying Facilities wishing to interconnect and operate in parallel with GRU’s system.

II. A. Applicability (Transmission Planning, Power Systems Operations)

This section applies to all interconnections with the GRU system made at 138 kV or 230 kV where generation is installed behind the interconnection point and is capable of operating in continuous parallel with the GRU transmission system. It also applies to incremental additions of generation intended to serve GRU native load. GRU generators, cogenerators, qualifying facilities, merchant plants, and non-utility generators are covered under this section. The MW and MVAr capacity shall normally be limited to 200 MW and 100 MVAr respectively. Integration studies require extensive consideration involving a consultant service selected by GRU and fully paid for by the applicant. This section also covers utility-to-utility interconnections as specifically noted in Section III.

II. B. Configuration (Power Systems Operations, Substation & Relay)

Generating plants connected to the GRU transmission system are designed to minimize the impacts of the maintenance or unplanned outages of a generator, transmission line, transformer, circuit breaker or bus. The potential adverse effects of maintenance and equipment outages must be considered in the design of the generating plant and its connection to the GRU transmission system.

II. C. Operations (Power Systems Operations)

Operators of generating facilities must notify the GRU System Operator and obtain approval before synchronizing the facility to or disconnecting the facility from the GRU transmission system. Disconnection without prior approval is permitted only when necessary to prevent injury to personnel or damage to equipment. Generators must not energize a de-energized GRU transmission circuit unless such actions are directed by the GRU System Operator or are provided for in the interconnection agreement.

Each generating facility shall provide a point of contact to the GRU System Operator. This contact person shall have the authority and capability to operate the facility according to the instructions of the GRU System Operator to ensure that the reliability of the transmission system is maintained. A point of contact shall be reachable and available through telephone or other agreed upon means of communication at all times when the Facility is energized or in operation.

Generating facilities connected to the Peninsular Florida Transmission Systems must follow all applicable FRCC and NERC Operating Standards.

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[2] FAC-001-4 R1.1

In order to maintain the reliability of the GRU transmission system and meet FERC requirements for posting of Available Transmission Capability (ATC), planned outages of plant and transmission equipment must be coordinated. Notification of preliminary plans for overhauls and maintenance outages of generators must be submitted to the GRU Power Systems Operations Manager by July 31st for the upcoming year's outages. The plans must specify the start date of the outage, the return to service date of the unit, and the generation capacity affected. For forced outages the length of time of the outage and the expected return to service date shall be reported as soon as the information is known. Changes in schedules either accelerating or delaying the forecasted return to service date of generation shall be reported as soon as they are known. Permission to synchronize to the interconnected system must be requested of GRU system operator following any overhaul, unit trip or islanding.

When restoring interconnected generation facilities, it is GRU's practice to energize in the direction from the GRU system toward the de-energized generation facility. Synchronization of a generator to the energized GRU system is accomplished within the generation facility using the appropriate synch breaker. The design at generation sites must consider the speed at which the GRU transmission system is restored through auto-restoration following system faults. The generation facility owner must protect their generators from out of synch closures under such conditions.

II. D. Islanding (Transmission Planning, Substation & Relay)

It is the responsibility of the electric power system owner to ensure system protection, safety and quality of service within its boundaries. GRU ensures this through equipment design, operating procedures, protective relay settings and a variety of automatic and manual processes. Under an island condition, a portion of load becomes separated from the rest of the Peninsular Florida transmission systems and is served by a local area generation site. It is the responsibility of GRU to ensure that even under an island condition, power quality is maintained to its customers. Therefore, GRU does not allow generation to island with GRU load where GRU does not have control over the generator voltage, frequency, protective relays, and operating procedures. Thus, when an island situation occurs, the generation must be separated from the GRU load except under temporary and controlled conditions. This ensures the quality of service and orderly restoration to GRU customers.
Without such provisions the resynchronization between two separated power systems becomes uncontrolled.

An island scenario must be considered when the local area generation and associated area load is interconnected to the Peninsular Florida transmission systems with less than three effective transmission lines, and the generation is greater than 30% of the local area minimum load. For these situations, a special protective isolation scheme is required. Removal of the generation is accomplished through a combination of relays and/or remote communication devices. If the generation is less than 30% of the area load, then the generators are to be fast tripped from the GRU load, should the local area become separated from the rest of the Peninsular Florida transmission systems. This is normally done by a combination of over/under voltage and frequency relaying.

The tap connection of generators to GRU transmission system in which the capacitive susceptance (line charging) of the circuit is greater than the MVA rating of the generator is to be avoided. These types of connections may be subject to overvoltage and require special study.

II. E. Generator Protection Requirements (Transmission Planning, Substation & Relay)

Generators connecting to the GRU transmission system are responsible for protecting those facilities from electrical faults and other hazardous conditions. Generator interconnections must be equipped with circuit breakers to protect those facilities. The generator owner must provide and own the primary circuit breaker or other interrupting device that protects the facility and disconnects it from the GRU transmission system. The primary purpose of this interrupting device is to protect the generating plant facility. A joint use circuit breaker that protects both generating unit and transmission circuit facilities as its primary function is highly discouraged.

Synchronous generators connected to the GRU transmission system must be able to withstand certain temporary excursions in voltage, frequency, reactive and real power output without tripping. This is required to support the grid and avoid cascading events in the Florida peninsula. As such, Generator owners must follow generator coordination requirements outlined in the latest version of the FRCC Generator Requirements and Guidelines.

Documentation of the generator protection and controls that could respond to these conditions by tripping the generator shall be provided to GRU and the FRCC's Operating Committee ("OC"). In the event the generating equipment owner cannot correct or mitigate these potential generator trip conditions, a request for a waiver may be made to the OC. A waiver may be justified in certain special circumstances such as low adverse reliability consequences from generator tripping. In all cases, generators must be capable of performance as specified in Attachments 1 and 2 of NERC Reliability Standard PRC-024-3 and FERC Order No. 828 (Requirements for Frequency and Voltage Ride Through Capability of Small Generating Facilities [Docket No. RM16-8-000; Order No. 828] (ferc.gov)), and limited time operation for larger deviations as specified in applicable FRCC Standards and/or as individually specified in applicable interconnection Agreements.

Generators must be designed to remain on line for normal clearing system faults within the close proximity to the plant switchyard. Voltage may approach zero at the switchyard bus for five cycles for some types of faults. Control systems, contactors, motors and auxiliary loads that are critical to the operation of the plant must not drop out under these conditions. Critical 480 volt supply contactors must be provided with ride-through capability where required. Additionally, generator protection systems such as the Load Drop Anticipator, Early Valve Actuator or Power Load Unbalance should not be designed to trip a generator for normal clearing external faults or stable swings.

II. F. Support of the Grid (Power Systems Operations, Transmission Planning, Substation & Relay)

1. All synchronous generators connected to the GRU transmission system are to be equipped with automatic voltage regulators (AVR)[3]. Generators must operate with their excitation system in the automatic voltage control mode unless otherwise approved by the GRU system operator. Generating equipment owners shall maintain a log which records the date, time, duration and reason for not being in the automatic voltage control mode when operating in parallel with the GRU system. Generating equipment owners shall make this log available to GRU on request. Appendix B has additional details for reporting of AVR status and voltage schedule deviations.

2. All synchronous generators connected to the GRU transmission system must maintain a network voltage or reactive power output as specified by the GRU system operator within the reactive power capability of the generating equipment. Generating equipment owners shall maintain a log which records the date, time, duration, and reason for not meeting the network voltage schedule or desired reactive power output when operating in parallel with the GRU system. Generating equipment owners shall make this log available to GRU on request.

3. The generator step-up and auxiliary transformer tap settings shall be coordinated with GRU transmission systems voltage requirements. Generating equipment owners shall provide GRU with generator step-up and auxiliary transformer tap settings and available ranges.

4. The AVR's control and limiting functions must coordinate with the generator's short time capabilities and protective relay settings. The generating equipment owner shall provide GRU with the AVR's control and limiter settings as well as the protection settings which coordinate with AVR control and limiting functions.

[3] Per NERC VAR-002-4.1 R1

5 Poorly damped power oscillations have occurred in the Florida transmission systems and can be a major concern if not properly addressed. The installation of new generating plants has the potential to aggravate existing modes of oscillation or create new modes. All new synchronous generators connected to the GRU transmission system with a nameplate rating greater than 100 MVA shall be equipped with a power system stabilizer. Technical evaluations of oscillatory stability will be conducted for the interconnection of new generating plants. New generators that cause a decrease in the damping of an existing mode of oscillation or cause a poorly damped mode of oscillation will be required to operate with the power system stabilizer in service. The determination of the power system stabilizer's control settings will be coordinated with GRU. Typically this coordination would be to provide GRU with preliminary power system stabilizer settings prior to the stabilizer's field commissioning tests with the final settings provided after the field commissioning tests.

a. Where stabilizing equipment is installed on generating equipment for the purpose of maintaining generator or transmission system stability, the generating equipment owner is responsible for maintaining the stabilizing equipment in good working order and promptly reporting to the GRU System Operator any problems interfering with its proper operation.

b. System protection coordination with adjacent entities must be done in accordance with NERC Reliability Standard PRC-001, System Protection Coordination.

6 All new synchronous generators connected to the GRU transmission system with a nameplate rating greater than 20 MVA shall be equipped with a speed/load governing control that has a speed droop characteristic in the 3 to 6% range. The preferred droop characteristic setting is 5% as this is the typical setting for generators in peninsular Florida. Notification of changes in the status of the speed/load governing controls must be provided to the GRU System Operator as detailed in Appendix B.

II. G. Generator Testing (Power Systems Operations, Transmission Planning)

Prior to commercial operation, the generating equipment owner shall provide GRU with open circuit, step-in voltage test results. Recording of generator terminal voltage and field voltages shall be clearly labeled so that initial and final values can be identified in physical units[4].

Generating equipment owners shall annually test the gross and net dependable summer and winter capability of their units. These test results shall be provided to GRU.

Generating equipment owners shall test the gross and net reactive capability of their units at least every five years. These test results shall be provided to GRU.

Generating equipment owners shall inspect and test the AVR control and limit functions of their units at least every five years. An initial test result shall be provided to GRU prior to commercial operation and every five years thereafter. The initial test results shall include documentation of the settings AVR control and limit functions. Typical AVR limit functions are; maximum and minimum excitation limiters and volts per hertz limiters. Documentation of the generator protection that coordinates with these limit functions shall also be provided. Typical generator protection of this type includes over-excitation protection, loss of field protection.

II. H. Power Factor (Transmission Planning, Power Systems Operations)

For synchronous generators the facilities shall be designed, operated and controlled to provide reactive power requirements from 0.9 lagging to 0.95 leading power factor measured at the high side of the generator step-up transformer when the facility is operating at its maximum summer rating. Induction generators shall have static capacitors that provide at least 85% of the magnetizing current requirements of the induction generator field.

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[4] Transmission Operators shall specify a system voltage schedule in accordance with VAR-001-4.1 R1

Qualifying Facilities shall meet the power factor requirements established in Florida Public Service Commission Rule 25-17.087.

II. I. Interrupting Ratings (Transmission Planning, Substation & Relay)

There may be cases where adding generation will increase the available fault current above the present interrupting ratings of the existing breakers at a substation or stations. When this occurs, breaker upgrades are to be considered as part of the interconnection project. Similarly, the connection of new generators to the transmission system may increase fault current to a level which exceeds the short time rating of overhead ground wires. The rating of overhead ground wires is discussed further in GRU's Facility Ratings document. If equipment ratings will be exceeded, the appropriate modifications must be performed prior to the new generation coming on line.

II. J Source System Grounding (Transmission Planning, Substation & Relay)

When various switching devices are opened on an energized circuit, its ground reference may be lost if all sources are not effectively grounded. This situation may cause overvoltage that can affect personnel safety and damage equipment. This is especially true when one phase becomes short circuited to ground. Therefore, the interconnected transmission power system is to be effectively grounded from all sources. This is defined as $X0/X1< 3$ and $R0/X1< 1$. Interconnected generators should provide for effective system grounding of the high side transmission equipment by means of a grounded high voltage transformer.

An alternative design only for sites with less than 10 MVA is available in some limited cases but requires a special Electromagnetic Transients Program (EMTP) system study to determine applicability. Under this non-preferred option the system is not grounded at the source. However, the transmission system equipment insulation level in the area must be rated to withstand the amplitude and duration of all overvoltage caused by neutral displacement. Also the source must be removed rapidly when any overvoltage condition occurs. This includes isolation of the ungrounded source for system faults simultaneously with other relaying systems within the protected zone. Since the source provides no ground fault current, relay protection devices must operate for zero current. Some switching operations may cause the loss of all remote ground sources by islanding a part of the system even under non-fault conditions. The protection scheme must also be able to quickly remove the generation under this situation before any adverse effects occur. Some form of communication with remote transmission stations is usually required in order to accomplish this.

II. K Generator Telemetry (Power Systems Operations, Substation & Relay)

All generating plants connected to the GRU transmission system must provide real time telemetered data for individual generators to the GRU system control center. The required data includes generator MW, MVAR, terminal voltage and switchyard high side voltages. MW and MVAR data should be Net output values as measured at the low side of the generator step up transformer less any auxiliary load directly fed from the generator. These generator output quantities shall be telemetered at a two second scan rate. In addition, the status of individual generator circuit breakers and the status of the generators' automatic voltage regulator must be made available to the GRU control center.

Individual generator output data values may be aggregated when the generator is rated less than 20 MVA. Other metering requirements are addressed in section I.O.

A phasor measurement unit is a device which measures the electrical wave forms on the electricity grid in real-time, using a common time source for synchronization. GRU may require the installation of a PMU. GRU may collect and utilize data from phasor measurement devices, which include the standalone PMU device, or relays and digital fault recorders (DFRs) with phasor measurement capabilities from individual generators. Synchrophasor measurement devices (PMUs), with a measurement rate of at least 30 points per second may be required to be

installed at the low voltage side of all new generator interconnections 20 MW or larger. The cost of the PMU installation and maintenance will be the responsibility of the interconnection customer/Applicant. GRU and the interconnection customer will negotiate responsibility for the communication system which should be capable of carrying the phasor measurement data to a phasor data concentrator (PDC), and then transport the information continuously to GRU as well as storing the data locally for a minimum period of 30 days.
Details regarding requirements and guidelines for PMU placement and installation are available in NERC's Reliability Guideline for PMUs here:
https://www.nerc.com/pa/RAPA/rg/ReliabilityGuidelines/Reliability%20Guideline%20-%20PMU%20Placement.pdf

III. TRANSMISSION FACILITIES[5]

This section addresses the technical requirements for connecting new transmission lines to the GRU system as well as for new and existing delivery points. The GRU planning process is designed to ensure that GRU's transmission system will have sufficient capability for GRU to meet the expected loads at distribution substations/delivery points, and to fulfill GRU's contractual obligations with other entities to receive and deliver power. A utility/customer may elect to connect to GRU through a "delivery point" connection or an "interconnection point" connection.

A "delivery point" is a point of connection between GRU's transmission system and another entity's system or facilities which ultimately delivers the power to individual customers' loads. Two characteristics may be generally used to distinguish delivery points from interconnections: i) the protective schemes of the integrated transmission system are designed to either entirely or partially suspend service to a delivery point by disconnecting a transmission facility that serves such delivery point from the transmission system; ii) power normally flows only in one direction across the delivery point (i.e., from the transmission system to the delivery point), and thus the protective schemes at the delivery point may be designed taking into account this characteristic.

An "interconnection point", in contrast, is a point of connection between two entities' respective transmission systems. Interconnection points are normally operated in parallel with the transmission systems such that it is possible for power to flow in either direction. Protection systems for interconnection points are designed to prevent and/or minimize the possibility of an event within one of the systems affecting or cascading into the other system.

III. A. Applicability (Transmission Planning, Substation & Relay)

This section applies to all interconnections with the GRU system made at 138 kV or 230 kV. This includes utility-to-utility (entity) type interconnections used for power interchanges as well as delivery point type connections used to deliver power to end users. Subsections C through J apply mainly to transmission interconnections. The MW and MVAr capacity shall normally be limited to 200 MW and 100 MVAr respectively. Any greater capacity shall require extensive consideration involving a consultant service selected by GRU and totally paid for by the applicant. Detailed, project specific requirements will be developed as part of a System Impact Study, a Facilities Study or are referenced in other documents such as the NERC Planning Standards or the National Electrical Safety Code.

III. B. Process (Transmission Planning, Substation & Relay)

The connection of non-GRU transmission facilities to the GRU transmission system should follow the interconnection process outlined in Section V. GRU will perform the System Impact Study using power flow, transfer, stability, fault and other analyses as necessary and appropriate to determine whether sufficient transmission capability is available and to identify any system constraints resulting from the requested transmission service using GRU's normal continuous Rate A thermal ratings to flag against most TPL-001-5 Contingency Analysis results. If necessary, a Facilities Study will be initiated to determine the cost of the connection and all GRU equipment improvements needed to accommodate the new connection.

[5] FAC-001-4 R1.2

III. C. Configuration (Transmission Planning, Substation & Relay)

The interconnection point between utilities is typically through a transmission line or lines. The change of ownership is usually at a transmission line structure. The neighboring utility must have an effectively grounded transmission system. Three terminal lines are to be avoided for interconnections due to problems discussed in Section I.

III. D. Operations (Transmission Planning, Substation & Relay, Power System Operations)

Interconnections between GRU's transmission system and other transmission systems are normally operated in parallel unless otherwise agreed. However, if any operating condition or circumstance creates an undue burden on the GRU Transmission System, GRU shall have the right to open the interconnection(s) to relieve its system of the burden imposed upon it. Prior notice will be given to the extent practical. Each party shall maintain its system and facilities so as to avoid or minimize the likelihood of disturbances that might impair or interrupt service to the customers of the other party.

The GRU System Operator shall be notified prior to any maintenance work on a transmission interconnection. GRU switching and safety procedures shall be strictly adhered to when maintenance is being performed on an interconnection.

III. E. Metering (Substation & Relay)

Metering equipment may be located at either end of the transmission line but should be installed at the station closest to the change of ownership.

If the neighboring utility is within and under the GRU control area, GRU is to own, operate and maintain the metering installation equipment, including the instrument transformers, secondary conductors, cables, meters and transducers. If the interconnection facilities are owned by the neighboring utility, and that utility does not own the instrument transformers or meters, a structure and a location for mounting metering transformers and recording devices is to be provided by the facility owner. The neighboring utility may not connect additional devices such as relays or meters directly to potential or current transformer secondaries used for revenue metering.

It is the facility owner's responsibility to provide GRU approved telecommunication from the metering location to any point desired by GRU up to and including the GRU Systems Control Center (SCC) presently located at 4747 N Main Street, Gainesville, FL. If the Control Center moves prior to the metering installation, GRU will notify the proposed facility owner of the new location.

III. F. Protection (Substation & Relay)

Line Differential Protection and Permissive Over-Reaching Transfer Trip (POTT) scheme are the primary protection for the GRU Transmission System. These schemes provide high speed clearing with no intentional delay. Step-distance is the back-up protection. Any connection to a GRU Transmission line will have to accommodate and coordinate with these protection schemes.

III. G. Separations (Transmission Planning, Substation & Relay)

There are several controlled islanding special protection systems installed in the Peninsular Florida transmission systems. None are presently owned or operated by GRU. These special protection systems have been coordinated with the utilities involved and with the FRCC underfrequency load shedding program. Depending upon the location of the transmission interconnection, it may be necessary to install special relaying or transfer trip equipment.

Connections to the GRU transmission system which introduce the possibility of GRU load being isolated with non GRU generation must be evaluated to assure safety and quality of service. When there is a potential for GRU load to become islanded with non-GRU generation, a special protective isolation scheme may be required. See Section II.D for specific guidelines under islanding conditions.

III. H. Transmission Reclosing (Substation & Relay)

Automatic reclosing on interconnected transmission lines between utilities is handled on a case-by-case basis. Transmission interconnections between utilities may be restored from either direction depending upon a reclosing practice agreed to by the utilities involved.

III. I. Reactive Power Control (Transmission Planning, Power Systems Operations)

Entities interconnecting their transmission system with GRU's 138 kV or 230 kV transmission system shall endeavor to supply the reactive power required on their own system, except as otherwise mutually agreed. GRU shall not be obligated to supply or absorb reactive power for the other party when it interferes with operation of the GRU transmission system, limits the use of GRU interconnections, or requires the use of generating equipment or addition of reactive power control devices that would not otherwise be required.

III. J. Unbalance Phases (Power Systems Operations, Substation & Relay)

Unbalance currents and voltage are to be controlled by each party on their respective side of the interconnection. However, it should be realized that switching devices, such as breakers and switches, are three phase devices and can fail with only one or two poles closed. It is the responsibility of the facility owner to protect their own equipment such as generators or transformers from damaging negative sequence currents or voltage.

IV. END USER FACILITIES[6]

IV.A. Process (Transmission Planning, Electric Distribution Engineering)

The connection of new end-user load to the 138 kV or 230 kV System could be considered for a variety of reasons which may include:

- All end-user load exceeds 20MVA
- End-user load is remote from existing distribution facilities or distribution facilities are not adequate
- End-user load has non-standard voltage requirements
- End-user load has non-linear loads or highly specific service requirements (data centers, etc)

GRU can provide transmission service to wholesale delivery points throughout its service area under Transmission Service Agreement(s). The criteria for serving wholesale Interconnection Customers are the same as that used to serve GRU’s other customers and is predicated on “Good Utility Practice” and sound engineering and economic principles without regard for the ownership of the Facilities. Regardless of the generation source of supply to wholesale customers in GRU’s service area, all supplies are delivered over GRU’s transmission Facilities. Therefore, it is essential that wholesale Interconnection Customer load requirements be included in GRU’s planning process. The following criteria apply to all joint planning between GRU’s and its wholesale Interconnection Customers:

• Contractual obligations must be observed.
• Studies must be based on sound engineering and economic principles consistent with long range system plans.
• Coordination should be conducted periodically with each wholesale Interconnection Customer. This coordination includes a review of each end-user’s construction program based on annually updated load forecasts for their area.

[6] FAC-001-4 R1.3

The feasibility of serving end-users direct from transmission –like all other interconnections described in this document –require study and time-intensive coordination between the Parties. There will be instances where deviations from the long-range joint planning process are necessary to accommodate third party delivery point requests. In these cases, GRU and, as needed, entities interconnected with GRU Facilities, expedite review of appropriate elements of the long-range plan to address such projects. All delivery point requests are to include a completed "Customer Request Form" as shown in Appendix I.

Compliance R3.2
The Interconnection Customer is to notify GRU of planned additions of new Facilities, or modifications to existing electrical Facilities which have the potential to impact the reliability of the interconnected transmission systems. Interconnection Customers are to provide such notification as soon as it is feasible for them to do so, even if the information is in a preliminary form. Prompt notification is important so that GRU can begin any needed coordination with other entities responsible for the reliability of interconnected transmission systems. Appendix I, "Customer Request Form", is to be completed for initial requests as well as subsequent changes. The form is to be submitted with sufficient advance notice to allow GRU to:

• Review the proposed addition or modification,
• Conduct the necessary studies to assess the impact of the change on GRU's System and/or neighboring Facility owners,
• Respond to the requesting Facility owner
• Complete any necessary modifications to GRU Facilities including ownership demarcation of equipment and/or Protection System(s) Elements.

Subsequent changes to the approved design basis are interpreted to include, but are not limited to:

- Changes to electrical equipment ratings
- Changes to primary conductor(s) or connectors
- Changes to transformer tap settings
- Changes from circuit switchers to any protective device (with breakers requiring fiber installation and coordination of protection that meets GRU standards)
- Changes impacting Protection Systems such as:
- Significant source impedance changes at the interconnection point
- Modifications to Protection System communications equipment
- Modifications to Protection System relay settings
- Changes to breaker reclosing times
- Interconnection of new generating Facilities, including distribution connected generation

As modifications are determined to impact other parties, such as power generators, end users, and interconnect parties, GRU will make appropriate notifications and pursue mutually agreeable resolutions, as necessary.

The Interconnection Customer is responsible for providing a protection system that will protect its equipment against disturbances on GRU's system and minimize the effects of disturbances from its facilities on GRU's equipment and transmission system. Entities connecting to GRU's transmission system shall investigate and keep a log of all protective relay actions and mis-operations, as required by NERC. In addition, the interconnecting entities must have a maintenance program for their protection systems in accordance with NERC Reliability Standards. Documentation of the protection maintenance program as well as test reports shall be supplied to GRU upon request. At intervals described in the documented maintenance program and following any apparent malfunction of the protection equipment, the Interconnecting Customer shall perform both calibration and functional trip tests of its protection equipment as outlined by NERC.

IV.B. End User Interconnection Technical Considerations (Transmission Planning, Electric Distribution Engineering)

The technical requirements for connecting new Network Load to the 138 kV or 230 kV System shall be defined in the Interconnection Agreement executed by the Customer. Other general guidelines that shall be followed by the Customer shall include, without limitation, the following minimums:

- Load operating characteristics that comply with the Florida Public Service Commission’s standards for power quality.
- The MW load of 100 MW or less as specified in the Interconnection Agreement between the Parties, measured at the Point of Delivery.
- The load power factor as referenced in Section IV.C and specified in the Interconnection Agreement between the Parties, measured at the Point of Delivery.

IV.C. Delivery Point Power Factor (Power System Operations)

The Peninsular Florida transmission systems can, under some circumstances, be subject to voltage instability. An essential element in the reliability of the GRU transmission system is the installation of power factor correction capacitor banks that compensate for the reactive power demands of customer loads. GRU designs and operates its load connections so that the load power factor measured at the point where the load connection exits the GRU integrated transmission system is between 95% lagging and 99% leading during summer peak load conditions. In order to avoid transmission system overvoltage, load power factor compensation is controlled so that the load power factor measured at the point where the load connection exits the GRU integrated transmission system is unity or lagging during minimum spring load conditions. Delivery point connections to the GRU transmission system shall meet the power factor requirements listed above.

In order to assess power factor, the delivery point real (kW) and reactive demands (kVar) shall be recorded at the time of GRU’s transmission system summer peak load (June, July, or August) and at the minimum spring load (March, April, or May). For compliance assessment purposes, GRU and the customer can aggregate delivery points that are in close electrical/geographical proximity (by summing kW and kVar values)
GRU occasionally experiences unusually high loads outside of the summer period (e.g. 7 A.M. peak loads associated with winter cold fronts). Load serving entities should cooperate to the extent feasible with requests from the GRU System Operator to help support system voltage.

IV.D. Delivery Point Power Quality (Transmission Planning, Substation & Relay)

Generation of harmonics should be limited to values prescribed by IEEE Standard 519 when measured at the interconnection point of ownership. Additionally, the GRU transmission system should not be subjected to harmonic currents in excess of 5% of a transformer’s rated current as stated in ANSI/IEEE Standard C57.12.00 nor subjected to flicker in excess of the levels specified in IEEE Standard 1453.

Inverter-based generating plants have additional requirements –please refer to **Table 5** for details.

IV.E. Delivery Point Metering (Substation & Relay)

GRU is to own, operate and maintain the metering installation equipment, including the instrument transformers, secondary conductors, cables, meters and transducers. If the meter location is not part of GRU facilities, then a structure and a location for mounting metering transformers and recording devices are to be provided by the facility owner. End user devices are not to be connected directly to potential or current transformer secondaries used for revenue metering.

It is the facility owner’s responsibility to provide GRU approved telecommunication from the metering location to any point desired by GRU up to and including the GRU Systems Control Center (SCC) presently located at 4747 N Main Street, Gainesville, FL.

IV.F. Delivery Point Auto-Restoration (Substation & Relay)

End user facilities are energized in the direction from GRU to the load. Owners of interconnected load facilities are to be aware of GRU's automatic reclosing practices as stated in Section I. GRU's standard reclosing, 10 seconds after fault clearing on the weak source end of the transmission line, should be taken into account by end users with sensitive control systems or large motors. Ride-through capability and heavy motor inrush currents should be assessed in the design stages of the facility.

IV.G. Delivery Point Load Shedding Programs (Transmission Planning, Substation & Relay, Power System Operations)

Entities responsible for load serving delivery points shall implement and maintain an underfrequency load shedding program designed and coordinated with GRU and the FRCC. GRU has installed automatic emergency load shedding schemes at several locations in the GRU transmission system to minimize the potential for instability following severe contingencies. GRU has the right to require entities responsible for load serving delivery points to implement an emergency load shedding program to the extent that such a program is required and utilized by GRU to assure transmission integrity under adverse conditions. The amount of load to be interrupted by emergency load shedding programs will be distributed comparably among GRU's and other entities' customers in the applicable region.

IV.H. Delivery Point Generation (Electric Distribution Engineering)

Delivery point connections usually do not have generating facilities that operate in parallel with the GRU transmission system. Customers wishing to install generating facilities to be operated in parallel with GRU must notify GRU in writing prior to the commencement of any work. The technical requirement for the connection of generation outlined in Section II of this document must be followed. No generation shall be operated in parallel with the GRU transmission system without prior written approval of GRU.

IV.I. Delivery Point Parallel Operation (Substation & Relay, Electric Distribution Engineering)

The distribution and transmission facilities behind the designated delivery point with GRU's transmission system shall be operated as a radial system only. Operation in a mode which would tie two or more delivery points together in a manner which would cause the system behind the delivery points to be operated as a parallel network to the GRU transmission system is prohibited without the express written permission of GRU. The installation of such protective equipment may be required by GRU to ensure that parallel operation is automatically interrupted within the time frame allowed by GRU's standard.

IV.J. Grounding (Substation & Relay)

All grounding and grounding of equipment will be per IEEE 80 latest revision. Customer's neutral and ground (if applicable) and GRU's will be bonded at the point of interconnection. The high side connection of generation step-up transformers shall be wye solidly grounded.

V. PROCEDURE FOR INTERCONNECTION STUDIES, NOTIFICATION TO FRCC AND OTHERS

VI.A. Process (Transmission Planning)

Final design of facility connections to the GRU transmission system will be subject to GRU review and approval on a case-by-case basis. In the event of either GRU, another transmission owner, or an Independent Power Producer (IPP) developing and requesting a new facility to be added to GRU's Generation & Transmission System, the Leadership Team shall be notified of the proposed change by the Transmission Planning Engineer. In the event the request is granted permission, the notification of the above personnel will be made as to the project's estimated completion date.

The Applicant must provide a filled-out "Interconnection Request Application" and forward it to:

GRU Transmission Planning PO BOX 147117 Station A-130 Gainesville, FL 32614	GRU Electric Reliability Compliance PO BOX 147117 Station E3G Gainesville, FL 32614

Data that is required to properly model and study a proposed generation facility is outlined in the "Generator Interconnection Request" application shown in the Appendix F.

VI.B. Procedures for coordinated studies of new interconnections or existing interconnections seeking to make a qualified change as defined in Appendix L, and their impacts on affected system(s)[7] (Transmission Planning)

Applicants who wish to interconnect to GRU's system will begin appropriate studies (System Impact, Feasibility, Facilities Study, etc.) with GRU to determine the effect of the proposed interconnection on the GRU system. GRU reserves the right to hire an external consultant to perform these studies; thus those entities seeking to integrate new or to modify facilities must notify GRU as soon as possible –ideally at least 12 months' in advance –to allow time for vendor vetting, study design, and study completion.

If the proposed project meets certain criteria established by the FRCC, GRU will contact the FRCC to set up a joint study and the study will follow the FRCC Regional Planning Process. If the project does not meet the level of FRCC Review, GRU will still contact entities that may be impacted and have them review the project. The entities' review comments shall be treated in accordance with FRCC/FERC Standards of Conduct.

VI.C. Procedures for notifying those responsible for the reliability of affected system(s) of new interconnections or existing interconnections seeking to make a qualified change as defined in Appendix L[8] (Transmission Planning)

GRU as the Transmission Owner is responsible for the reliability of its own system. GRU's Transmission Planning Engineer will communicate internally to its System Protection, Power System Operations, Generation, and Metering staff for their technical input regarding any studies performed as part of the interconnection request.

If the project does not meet the level of FRCC Review, GRU will still contact entities that may be impacted and have them review the project. The entities' review/technical comments shall be treated in accordance with FRCC/FERC Standards of Conduct.

VI.D. Procedures for confirming with those responsible for the reliability of affected systems that new Facilities or existing Facilities seeking to make a qualified change as defined in Appendix L are within a Balancing Authority Area[9] (Transmission Planning)

Compliance R3.3
GRU is its own Balancing Authority.
An interconnection customer with new or materially modified transmission Facilities seeking interconnection to, or upgrade facilities on the GRU system must do so via submitting an interconnection application. Before proceeding with any Interconnection study, GRUs Transmission Planning Engineer shall confirm to the Applicant via email or certified letter if any proposed Transmission or Generating Facilities fall within GRU's Balancing Authority Area. GRU will notify the Applicant as soon as practicable, and this communication is evidence that can be used by the

[7] FAC-001-4 R3.1, R4.1
[8] FAC-001-4 R3.2, R4.2
[9] FAC-001-4 R3.3, R4.3

interconnection customer as confirmation that their new or materially modified Facilities are within the GRU Balancing Authority Area's metered boundaries.

VI. REFERENCES

These documents can be made available upon request with a deposit and agreement in place:

1. FRCC Generator Requirements & Guidelines, FRCC-MS-OP-020
2. FRCC Load Flow DataBank and Short Circuit Procedural Manual, FRCC-MS-PL-029
3. FRCC Data Specification & Collection Procedure, FRCC-MS-OPRC-004
4. FRCC Reliability Evaluation Process for Generator and Transmission Service Requests, FRCC-MS-PL-054
5. FRCC Guide to Performing Generator and Synchronous Condenser Reactive Capability Verification, FRCC-MS-OP-041

Appendix A: Table of Specifications for Customer's Interconnection Facilities

Included in this Specification are the minimum electrical and mechanical design data for substation, transmission line, and distribution line to be followed for interconnection with Gainesville Regional Utilities.

TABLE 1 –Substation Design Data
TABLE 2 –Transmission Line Design Data
TABLE 3 –Distribution Line Design Data
TABLE 4 –Relay Design Data
TABLE 5 –Solar Inverter Design Data

TABLE 1 Substation Design Data (Substation & Relay)

ELECTRICAL DESIGN CRITERIA

Substations shall be designed per the latest editions of the National Electrical Safety Code (ANSI C2), NEMA Standards, and ANSI standards.
Electrical circuit breakers are to be designed to meet or exceed the expected load and short circuit currents on the Interconnection customer's transmission system. High voltage circuit breakers and other current interrupting devices are to be designed to clear (interrupt) the worst-case short circuit fault calculated for the protection zone as determined using fault analysis engineering programs. Prior to specifying circuit breakers, you must contact GRU's Energy Delivery Department to verify the minimum fault interrupting duties that would be required for the site.

All current carrying equipment and devices are to be designed to carry the maximum loads that are predicted by load flow analysis. Loads exceeding nameplate or normal design capabilities are only acceptable when allowed by manufacturers design documentation or standard industry practices.

The typical minimum acceptable electrical design characteristics are listed below.

Nominal Voltage Rating (kV)	12.47	138	230
BIL (kV)	110	650	1050
Typical Fault Duty Design Requirements For Structures and Equipment	20kA	40kA	40kA

MECHANICAL DESIGN CRITERIA

Environmental Loading

The general loading requirements for substation structures shall be defined by the latest edition of ANSI C2 (NESC) approved by the Florida Public Service Commission's Bureau of Electrical Safety. Substation structures shall be designed to meet the requirements for transmission line structures, NESC light loading district with grade B construction and appropriate safety factors. GRU is not in the area of operation associated with extreme wind conditions, normally within 30 miles of the coast.

Grounding

All grounding and grounding of equipment will be per IEEE 80 latest revision. Customer's neutral and ground (if applicable) and GRU's will be bonded at the point of interconnection. The high side connection of generation step-up transformers shall be wye solidly grounded.

TABLE 2 Transmission Line Design Data (Transmission Planning, Substation & Relay)

ELECTRICAL DESIGN CRITERIA

Transmission facilities shall be designed per the latest edition of the NESC standards. The minimum acceptable electrical design characteristics are listed below:

Nominal Operating Voltage	138 kV	230 kV
Insulator Impulse Level (kV)	650	1050
Conductor Spacing		
Phase to Phase	7’-0”	10’-0”
Clearance Above Grade	Meets NESC Latest Edition	

MECHANICAL DESIGN CRITERIA

Environmental Loading

The general loading requirements for a structure shall be defined by the latest edition of ANSI C2 (NESC) approved by the Florida Public Service Commission’s Bureau of Electric Safety.

- NESC light loading district criteria shall be used with grade B construction and appropriate overload capacity factors.
- GRU does not have any facilities within 30 miles of the coast in either direction from Gainesville, Florida

Grounding

Customer’s neutral and ground (if applicable) and GRU’s will be bonded at the point of interconnection.
Actual impulse level, conductor spacing, and clearances shall be determined for each respective structure and conductor used during line design activities for the interconnection structures. All phases of the line design activities must conform to all current applicable standards.

TABLE 3 Distribution Line Design Data (Electric Distribution Engineering)

ELECTRICAL DESIGN CRITERIA

Distribution facilities shall be designed per the latest edition of the NESC standards. The minimum acceptable electric design characteristics are listed below:

Nominal Voltage Rating 15kV

BIL (Equipment) kV	138 kV
BIL (Line Construction) kV	650

Conductor Spacing

Phase to Phase	2'-6"
Phase to Neutral	5'-0"
Clearance above Grade	Meets NESC (latest edition)

MECHANICAL DESIGN CRITERIA

Environmental Loading

The general loading requirements for a structure shall be defined by the latest edition of ANSI C2 (NESC) approved by the Florida Public Service Commission's Bureau of Electric Safety.

1. NESC light loading district criteria shall be used with grade B construction and appropriate overload capacity factors.
2. GRU is not in the area of operation associated with extreme wind conditions, normally within 30 miles of the coast.

Grounding

Customer's neutral and ground (if applicable) and GRU's ground will be bonded at the point of interconnection. Note: Where grounding resistors are used, a transformer must isolate the Customer from GRU lines serving other customers.

Fault Current and Voltage

The maximum 3-phase fault current will be limited to approximately 10,000 amps symmetrical including both GRU's and the Customer's contributions. Voltage fluctuations will be limited in accordance with PSC/GRU guidelines. The total voltage harmonic distortion must not exceed proposed IEEE 519.

TABLE 4 Relay Design Data (Substation & Relay)

Protection Design Data

Transmission lines shall be designed per acceptable industry practices. The following table lists the acceptable protection requirements for transmission lines.

Scheme or Requirement	138 kV*	230 kV*
Phase & Ground Distance (N/A)		
Line Differential via Fiber Optic	#	#
Permissive Over-Reaching Transfer Trip via Fiber Optic	%	%

Legend

* -138kV & 230kV lines both require two sets of protective relays
# - The preferred protection at this voltage levels
% -Acceptable protection

Control Data

1. The customer shall provide an isolated "N' dry contact from all interface breakers.
2. The customer shall provide synchronizing capability and no "Dead-Line" reclosing on all interface breakers.

Transmission breakers are closed to connect two energized lines only after the phase angle across the breaker is verified. This is accomplished by utilization of an auto synchronizing relay (ANSI 25). The control scheme shall be designed to initiate a close only after a synchro-verifier relay determines that the angle and voltage are within preset limits. Manual closing may only be permitted at the discretion of the GRU Control Center in the event of a short term failure of the auto synchronizing relay.

Drawing and Equipment Data

1. The customer shall provide one-lines showing their system and generator protective equipment.
2. The customer shall provide impedances of the generator, step-up transformer and associated lines.

Telemetry Data

1. The customer shall provide space for mounting an RTU and Fiber Optic equipment whenever the metering point is located at the customer's end of the line.

TABLE 5 Design Data for Solar Photovoltaic ("PV") Generating Plants (Transmission Planning, Substation & Relay)

GRU will follow the recommended specifications for inverter-based resources outlined in NERC's Reliability Guideline for BPS-Connected Inverter-Based Resource Performance (https://www.nerc.com/comm/OC_Reliability_Guidelines_DL/Inverter-Based_Resource_Performance_Guideline.pdf) as well as this white paper https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/NERC_IRPTF_PRC-024-2_Gaps_Whitepaper_FINAL_CLEAN.pdf

Existing and newly interconnecting inverter-based resources should eliminate the use of momentary cessation. If any exception is made on a case by case basis, it must be pre-approved by GRU.

Control Data

Solar PV generating plants with total inverter nameplate ratings greater than 20 MVA must install a "power plant controller" or "PPC" to regulate and control the individual PV inverters so that the site behaves as if it were a single generator connected at the Point of Interconnection. The PPC and inverters together must provide grid support, including automatic voltage regulation (AVR).
PPC and inverter specs must be submitted and approved by GRU. Inverters must be compliant with IEEE 2800 or latest version.

Solar PV plants are variable generation resources and their maximum rated output is typically produced only for short durations at ideal ambient temperature and irradiance conditions. These conditions may not normally coincide with the time of the system peak, thus solar PV sites typically operate at much lower than the nameplate output value and can only be counted upon to provide 50-70% of nameplate real power output at the time of the system peak. For this reason, solar PV plants are typically "de-rated" for purposes of counting on them for reliable capacity. GRU reserves the right to determine the expected AC MW contribution of inverter-based resources using engineering judgment.

Modeling Data

The variable resource and inverter-based generator manufacturers should support the development of detailed 3-phase models required for special power system studies. GRU reserves the right to request short circuit strength studies to understand the reliability implications of integrating inverters into the GRU BES.

Central Station Solar (CSS) plant modeling parameters for power flow models, forecasted output by site, and Solar plant outages and limitations must be supplied to GRU in order to provide it to the Operations Planning Coordinator (OPC), RC Agent EMS, and TTC Engine vendor.

Telemetry/Real Time Data

Similar to conventional units, GRU must have real time monitoring capability of the solar facilities that measure the output (MW and MVAR) and also monitor the interconnecting BES associated facilities and be able to send the unit information to the FRCC Reliability Coordinator via ICCP.

GRU as the host BA will be expected to assess short term solar output variability resulting from potential weather patterns in the next-day and near term planning horizons such that solar variability does not emerge as an operational issue. As such, GRU must receive generation dispatch forecasts (MW) of native solar output for **all TTC Engine time horizons and all periods within a horizon** in accordance with TTC Engine requirements regardless of whether the solar plant has storage technologies designed to ameliorate or prevent solar variability problems.

All generators interconnecting to GRU's Transmission System with aggregate capacity of 20 MVA or larger shall install and maintain, at its expense, phasor measurement units (PMUs) or a similar DDR device to meet PRC-002-2 standards, installed on the Customer's Generation Facility side of the Point of Interconnection.

Since inverter-based generation resources are known to be a more significant source of harmonics and flicker than synchronous generators, the following requirements apply to inverter-based generating plants:

1. A power quality meter must be permanently installed at the POI. As specified by IEEE 519, the meter must comply with the specifications of IEC 61000-4-7 and IEC 61000-4-30. GRU shall solely select the PQ meter based on its on-board memory characteristics, data transfer/download rates, and other technical specs it deems important.

2. Power quality must be assessed and shown to be within applicable limits before commercial operations commence. Because of potential differences between inverter-based generation resources' expected and actual harmonic current spectrum levels, GRU shall also require a trial operation or harmonic performance evaluation period before the inverter resource can operate commercially in order to determine adherence with industry standards. The length of, scope of analysis performed during, and the method(s) to calculate values from sampled data obtained during the trial operations period will be solely determined by GRU.

a. Harmonic current injection at the POI shall be monitored to ensure harmonic-producing equipment adheres to IEEE 519-2014 or later versions. Inverter owner should provide the expected harmonic current spectrum at the Point of Interconnection.

b. Must meet IEEE 1453 system flicker limits and GRU's individual flicker limits as specified below:

The IEEE 1453 flicker limits represent the cumulative effect of all flicker sources; whereas, the individual flicker emission limits represent the flicker due only to the inverter-based generation. Flicker should be evaluated over a period of at least 1 week.

Flicker Quantity	IEEE 1453 System Flicker Planning Level	GRU Individual Flicker Emission Planning Level
Pst	0.8	0.35
Plt	0.6	0.25

Alarms for the following quantities must be provided via communication to the GRU Control Center as applicable limits are approached:

a. Individual harmonic current distortion
b. Total demand distortion
c. Individual harmonic voltage distortion
d. Total harmonic voltage distortion
e. Short-term flicker
f. Long-term flicker

Supporting data that trigger alarms should also be retained to the extent practical.

Instrument Transformer Limitations
Capacitively-coupled voltage transformers (CCVTs) should not be used for making harmonic voltage measurements.

Technical Resources

"Variable Energy Resources Generated Harmonic Distortion" Issue Paper, by the Variable Energy Resource Working Group/SERC Reliability Corporation.

NERC Reliability Guideline https://www.nerc.com/comm/OC_Reliability_Guidelines_DL/Inverter-Based_Resource_Performance_Guideline.pdf

https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/NERC_IRPTF_PRC-024-2_Gaps_Whitepaper_FINAL_CLEAN.pdf

https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/Short_Circuit_whitepaper_Final_1_26_18.pdf

https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Item_4a._Integrating%20_Inverter-Based_Resources_into_Low_Short_Circuit_Strength_Systems_-_2017-11-08-FINAL.pdf

Appendix B: Procedures for Notification of Generating Plant Operational Data & Control Status (Power System Operations)

Introduction

An essential part of operating a transmission system reliably is the coordination of reactive power sources to maintain an adequate transmission voltage profiles both for normal and contingency conditions. Reactive sources must be distributed throughout electric systems due to the large voltage drops associated with transmission of reactive power. Operators of transmission systems follow voltage control strategies to minimize the risk of exceeding equipment voltage limitations and the transmission grid's voltage stability limitations. Generators operating in parallel with the transmission system must operate with the automatic voltage regulator ("AVR") on and follow the established voltage schedule for the voltage control strategy to be effective.

Owners of generators connected to the GRU transmission system must coordinate with Transmission Operations to optimize generating plant transformer tap settings. By carefully selecting transformer tap ratios, it is possible to optimize generating plant voltages and reactive capabilities for the expected range of transmission voltages.

GRU has established these information and notification procedures to facilitate the coordination of reactive power and to comply with the NERC Planning Standards (Sections II.B Generator Data and III.C Generator Protection and Control).

Requirements

1. Notification of AVR status - All synchronous generators with MVA ratings larger than 20.0 MVA connected to the GRU transmission system shall operate with the generator's AVR on and in the voltage control mode to the extent practicable. The operator of the synchronous generator must contact the GRU Power System Coordinator when it becomes necessary to operate with the AVR off for more than 15 minutes, state the reason for operating with the AVR off and provide an ETA for returning to normal. In addition to verbal notification of the reason for operating with the AVR off, the AVR status should also be automatically telemetered to the GRU control center.

   Owners of generating equipment are responsible for maintaining records that a) provide a summary of the number of hours per month each generator was not in the automatic voltage control mode while operating in parallel with the GRU transmission system and b) provide the date, duration, and reason for each period of occurrence. These records must be available for the preceding 12 months and must be provided within five business days of request.

2. Notification of Deviation from Target Voltage - All synchronous generators connected to the GRU transmission system with ratings larger than 20.0 MVA shall maintain a target voltage at the point of interconnection as prescribed by the System Operator to the extent allowed by the capabilities and limitations of the generating plant equipment. This target is a nominal 138 kV.

   If there is a need to deviate from the nominal 138 kV voltage at the interconnection point, the GRU Power System Coordinator or designated agents will advise generating plant operators of such a need and the revised target voltage level.

   The operator of the synchronous generator must contact the GRU System Operator when the generator cannot maintain the target voltage at the point of interconnection as prescribed by the GRU System Operator for more than 30 minutes. The operator of the synchronous generator shall state the reason for deviating from the target voltage and provide the GRU System Operator with the generator's reactive limitations that exist at that time.

Owners of generating equipment are responsible for maintaining records that a) provide a summary of the number of hours per month each generator was not following the target voltage as prescribed by the System Operator and b) provide the date, duration, and reason for each period of occurrence. These records must be available for the preceding 12 months and must be provided within five business days of a request.

3. Notification of Plant Capabilities - Prior to commercial operation, the generating equipment owner shall notify the GRU Director of Production for Energy Supply of the expected generator capabilities as listed below.

Generator	**Summer Continuous MW**	**Generator Gross Capabilities Lagging MVAR**	**Leading MVAR**
__________	____________	____________	_____________

Winter Generator	**Continuous MW**	**Generator Gross Capabilities Lagging MVAR**	**Leading MVAR**
__________	____________	____________	_____________

Total Plant Auxiliary Power Usage	**MW**	**MVAR**
Summer	_________	__________
Winter	__________	_________

Updated information based on actual test results shall be provided to the GRU System Operator as it becomes available.

4. Notification of Turbine Governor Status - Owners of synchronous generators with ratings larger than 20.0 MVA connected to the GRU transmission system shall notify the GRU System Operator of changes in the status of the speed/load governing controls for the turbine. The GRU System Operator shall be made aware of nonfunctioning, partially functioning or blocked governor controls when these conditions are expected to persist for five days or more.

5. Notification of Available Transformer Ratios and Changes in Transformer Data – Owners of synchronous generators with ratings larger than 20.0 MVA connected to the GRU transmission system shall provide the GRU System Operator with the transformer data. Updated information shall be provided when transformer changes are made. In the event that operating experience indicates that transformer ratio changes are desirable, GRU will provide the generating equipment owner with a detailed study that documents the technical justification for making a transformer tap change. GRU's practice has been to select transformer ratios that will be acceptable for both summer high load conditions and Spring/Fall light load conditions so that seasonal adjustments are not necessary. Generating equipment owners are expected to make transformer tap changes during their next scheduled maintenance period.

6. Notification of Generator AVR Control and Protection Settings – Most synchronous generator AVRs are equipped with limiting controls that help protect the generator while also allowing the generator to support the grid during temporary excursions in transmission voltage. These limiting controls must be properly coordinated with generator protection and with the generator's short term voltage/reactive capabilities. Two common examples of these controls are the maximum excitation limiter (coordinates with overexcitation protection) and the minimum excitation limiter (coordinates with the loss of field relay). Prior to commercial operation, the owner of a synchronous generator with a rating larger than 20 MVA shall

provide the GRU System Operator with documentation that describes the functional operation and settings for the AVR's control functions. This documentation shall demonstrate the AVR's controls are coordinated with the generator protection and with the generator's short term capabilities. In cases where the AVR has been set to regulate a voltage other than the generator's terminal voltage or it has been set to regulate a compensated terminal voltage, sufficient data shall be provided to allow the AVR to be modeled accurately.

7. Provision of Generator Test Data – One of the standard generator commissioning tests is to introduce a step change in the AVR's reference voltage with the generator running at synchronous speed but not connected to the transmission system. This is referred to the open circuit, step in voltage test and is used to confirm the AVR is functioning properly.

   Prior to commercial operation, the owner of a synchronous generator with a rating larger than 20 MVA shall provide the GRU System Operator with open circuit, step in voltage test results. Recordings of the generator terminal voltage and generator field voltage magnitudes must be provided together with any calibration data necessary to equate the recordings with actual voltages. In situations where it is impractical to measure the generator field voltage (e.g. brushless excitation systems) alternate quantities with equivalent response characteristics can be provided. An estimate of the generator's field winding temperature during this test must be provided.

GRU should be notified within 5 business days or sooner of any addition or modifications to the generation, transmission, and end-user facilities. GRU will then notify those parties responsible for the reliability of the interconnected transmission system as soon as feasible.

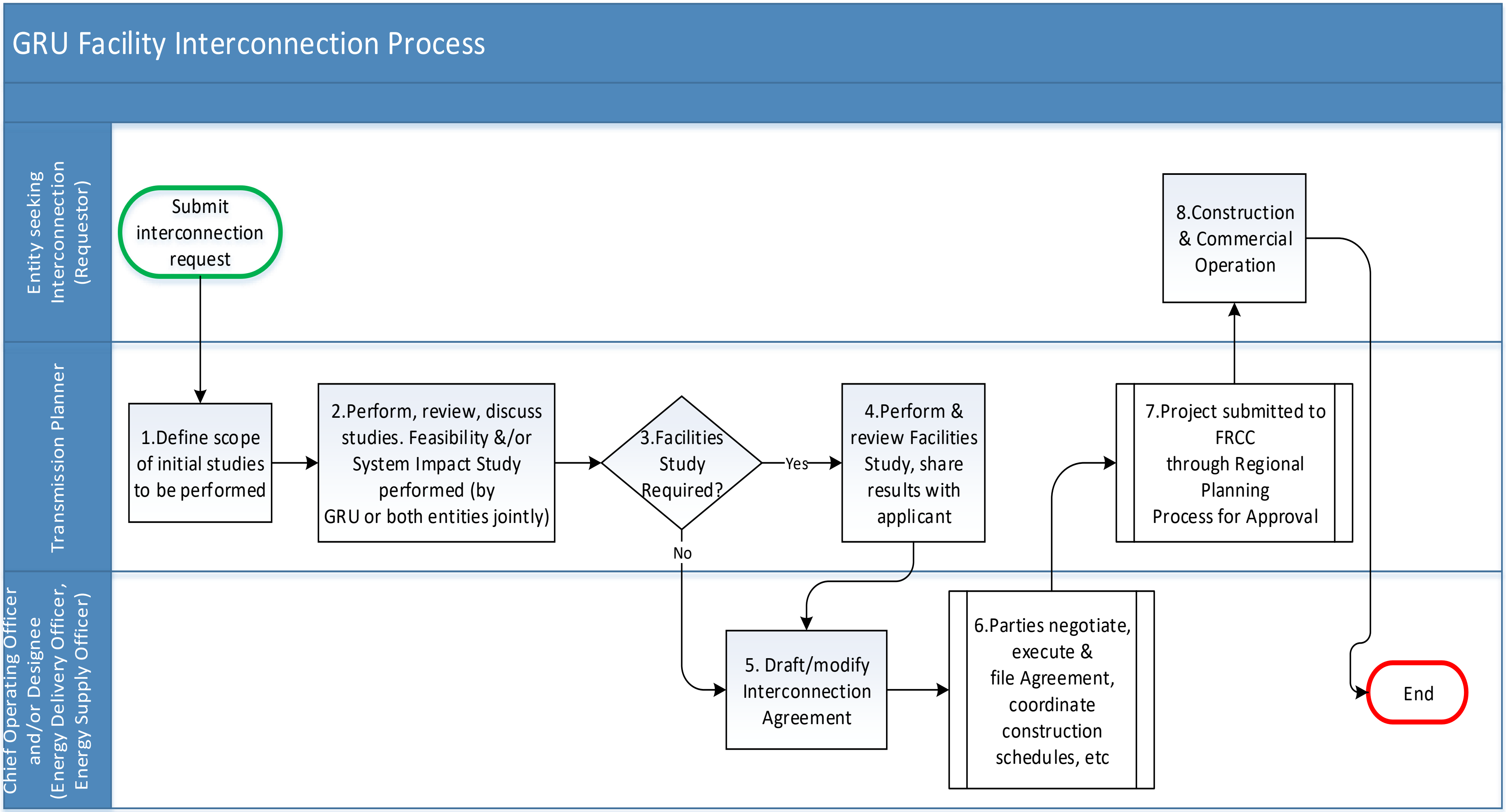
Appendix C: GRU Facility Ratings (Transmission Planning)

Separate Document; not included but available upon request with deposit.

Appendix D: FRCC Generator Requirements and Guidelines (FRCC-MS-OP-020)

Separate Document; not included but available upon request with deposit **(Transmission Planning)**

Appendix E: Process Flow Diagram: Interconnection Process (Transmission Planning)



Facility Interconnection Process Step Details:

Step	Description	Responsible	Input	Action / Procedure	Output
1	Define scope of initial studies to be performed	Transmission Planner	Interconnection Request received from entity at least 365 calendar days in advance of work commencement	Based on the Interconnection Request, coordinate with requestor to draft scope of initial studies. Studies may Include: • Feasibility • Contingency Analysis • Transfer Capability Evaluation • Short Circuit Analysis • Stability Analysis	Scope of System Impact Study, Benchmarks for comparison
2	Perform & review initial Feasibility Studies and System Impact Studies	Transmission Planner	• Databank, Dynamics, and Short Circuit Cases • Load & Auxiliary loads • Line impedances and sequence data • Generation output profiles & capabilities for model simulation • Facility modeling data in Siemens PTI PSS/E format as required or requested	Perform Impact Study(ies) per identified scope, and review results with applicable stakeholders, as determined jointly by GRU and Requestor. Submit project to FRCC for review (see Transmission Service and Generator Interconnection Service Request Regional Deliverability Evaluation Process)	System Impact Study results
3	Facilities Study Required?	Transmission Planner	System Impact Study results	Consult with Requestor to determine if further Facility studies are required. If yes, then proceed to step 4. If no, then proceed to step 5	Documentation of decision
4	Perform & review Facilities Study	Transmission Planner	Engineering design criteria, facility drawings, protection drawings, etc.	• Identify, perform, and review scope of Facility Studies with applicable stakeholders, as determined jointly by GRU and Requestor. Studies may Include: • Conceptual Design • Equipment • Engineering (System Protection & Coordination Studies, Insulation coordination, etc)	Facility Study Results

Step	Description	Responsible	Input	Action / Procedure	Output
				• Construction • Cost Estimate	
5	Draft/modify Interconnection Agreement	• Chief Operating Officer • Energy Supply Officer • Energy Delivery Officer	• System Impact Study results • Facility Study Results	Coordinate with Requestor to draft (if new) or modify (if materially modified existing) an Interconnection Agreement	Interconnection Agreement
6	Parties negotiate, execute & file Agreement, coordinate construction schedules, etc.	• Chief Operating Officer • Energy Supply Officer • Energy Delivery Officer	Interconnection Agreement, Project Milestone Schedules, Insurance Requirements, Milestones with Delay Damages, Guarantees, Purchase Options, etc.	Parties negotiate, execute & file Agreement and required legal documentation	Interconnection Agreement, written technical requirements if any, legal exhibits
7	Project submitted to FRCC through Regional Planning Process for Approval	Transmission Planner	Record of FRCC review & approval	Follow Databank process to model new or revised transmission and/or generation facility (ies) as per FRCC Load Flow DataBank and Short Circuit Procedural Manual.	Updated Databank models
8	Construction & Commercial Operation	• Chief Operating Officer • Energy Supply Officer • Energy Delivery Officer	Interconnection Agreement, Construction Schedule, Certificate of Commercial Operations, etc.	Construct/revise interconnection facilities	Revised facilities

Appendix F: Generator Interconnection Request Application

(Transmission Planning)

Interconnection Customer Information

Legal Name of the Interconnection Customer (or, if an individual, individual's name)
Name: ....
Contact Person:...
Mailing Address: ....
City: State: Zip: ....
Telephone:...
E-Mail Address: ....
Facility Address: ....
Facility GPS Coordinates (Lat/Long): ....

Requested commercial in-service date for the interconnection:..
Requested date for initial testing of the generation facility output: ....
Will the proposed Generating Facility be used to supply power to Others?
Yes ____ No ____
Entity that will provide balancing services for the Generating Facility: ....
Requested Point of Interconnection (“POI”): ....
Requested Point of Interconnection voltage level: ....
Is the proposed Generating Facility a QF[10]? Yes ____ No ____

Qualifying Facility (“QF”) as defined by the Public Utility Regulatory Policies Act of 1978 (“PURPA”). Provide proof of QF status.

Generating Facility Information

Data apply only to the Generating Facility, not the Interconnection Facilities.

Check Energy Source:

	Solar		Diesel		Battery Storage
	Wind		Natural Gas		Biomass
	Hydro		Fuel Oil		Other (state type)

Check Prime Mover:

	Fuel Cell		Gas/Steam Turb		Other (Explain below)
	Reciprocating Engine		Battery		
	Microturbine		PV		

[10] Refer to the Federal Energy Regulatory Commission (“FERC”) website for additional details.

Type of Generator: _________Synchronous __________Induction _________ Inverter
Generator/Inverter Manufacturer: ....
Model Name & Number: ....

Synchronous Generators:

Generator Max Gross Nameplate Rating: ________MW (summer at 95° @ ____ Power Factor)
Generator Min Gross Nameplate Rating: ________MW (summer at 95° @ ____ Power Factor)
Generator Max Gross Nameplate Rating: ________MW (winter at 59° @ ____ Power Factor)
Generator Min Gross Nameplate Rating: ________MW (winter at 59° @ ____ Power Factor)

Interconnection Customer or Customer-Site Load (inclusive of balance of plant/aux load):
Summer (based on Generator Max output) - Real _______MW Reactive ______MVAR
Winter (based on Generator Max output) - Real _______MW Reactive ______MVAR

List components of the Generating Facility equipment package that are currently certified:

Equipment Type	Certifying Entity
1.	
2.	
3.	
4.	
5.	

Is the prime mover/inverter compatible with the certified protective relay package?
____Yes ____No

Generating Facility Characteristic Data (for synchronous machines)

RPM Frequency: _____________ Number of Poles: _____________
MVA Base: ___________________________
Field Volts: ______________
Field Amperes: ______________
(*) Neutral Grounding Resistor (If Applicable): ____________

Synchronous Generators:

Direct Axis Reactances (P.U):
Synchronous Reactance, Xd: _______ P.U.
Transient Reactance (saturated), X'dv: ___________P.U.
Transient Reactance (unsaturated), X'di: ___________P.U.
Subtransient Reactance (saturated), X"dv: ______________P.U.
Subtransient Reactance (unsaturated), X"di: ______________P.U.

Negative Sequence Reactance, X2: __________ P.U.
Zero Sequence Reactance, X0: _____________ P.U.
Armature Leakage, XL: _____________ P.U.

Quadrature Axis Reactances (P.U.):
Synchronous, Xq: _______________P.U.
Transient, X’q: _______________P.U.
Subtransient (saturated), X”qv: _______________P.U.
Positive Sequence Reactace, X1: __________ P.U.
Negative Sequence Reactance, X2: __________ P.U.
Zero Sequence Reactance, X0: _____________ P.U.

Time Constants (seconds):
Direct:
Transient, T’do: _____________ sec.
Transient, T’d : _____________ sec.
Subtransient, T” do: _____________ sec.
Subtransient, T” d: _____________ sec.

Time Constants (seconds):
Quadrature:
Transient, T’qo : _____________ sec.
Transient, T’q : _____________ sec.
Subtransient, T” qo: _____________ sec.
Subtransient, T” q: _____________ sec.

Resistance (P.U.):
Positive Sequence, R1: _______________P.U.
Negative Sequence, R2: _______________P.U.
Zero Sequence, R0: _______________P.U.

Inertia Constant (H): __________

Saturation:
S (1.0): __________
S (1.2): __________

Please include saturation curves, capability curves (“D-curves”), and generator characteristics information from the OEM to validate the information supplied above.

Induction Generators:

Motoring Power (MW): _______________
K (Heating Time Constant): _______________
Rotor Resistance, Rr: _______________

Stator Resistance, Rs: ______________
Stator Reactance, Xs: ______________
Rotor Reactance, Xr: ______________
Magnetizing Reactance, Xm: ______________
Short Circuit Reactance, X''d: ______________
Exciting Current: ______________
Temperature Rise: ______________
Frame Size: ______________
Design Letter: ______________
Reactive Power Required In Vars (No Load): ______________
Reactive Power Required In Vars (Full Load): ______________
Inertia Constant (H): _____________

Note: Please contact GRU prior to submitting this Interconnection Request Application to determine if the specified information above is required.

Generator, Excitation System/Power System Stabilizer and Governor System Data for Synchronous Generators Only

Provide appropriate IEEE model block diagrams and completed models in Siemens PSS/E format of all applicable generator, inverter, battery, excitation system/power system stabilizer (PSS) and governor system. A PSS may be required to be tuned and commissioned via the results of applicable studies. A copy of the manufacturer's block diagram(s) may not be substituted.

Interconnection Facilities Information

Will a transformer be used between the generator and the point of common coupling?
___Yes ___No

Will the transformer be provided by the Interconnection Customer? ____Yes ____No

Transformer Data (for Interconnection Customer-Owned Transformer):

Is the transformer: ____single phase _____three phase? Size: ___________kVA
Transformer Impedance: _______% on __________kVA Base

If Three Phase:
Transformer Primary: _____ Volts _____ Delta _____Wye _____ Wye Grounded
Transformer Secondary: _____ Volts _____ Delta _____Wye _____ Wye Grounded
Transformer Tertiary: _____ Volts _____ Delta _____Wye _____ Wye Grounded

Transformer Fuse Data (If Applicable, for Interconnection Customer-Owned Fuse):

(Attach copy of fuse manufacturer's Minimum Melt and Total Clearing Time-Current Curves)
Manufacturer: __________________ Type: _______________ Size: ________

Speed: _______________

Interconnecting Circuit Breaker:

Manufacturer: ______________________________ Type: ___________
Load Rating (Amps): _______ Interrupting Rating (Amps): ________
Trip Speed (Cycles): ___________

Interconnection Protective Relays:

List of Functions and Adjustable Set-points for the protective equipment or software:

Setpoint Function	Minimum	Maximum
1.		
2.		
3.		
4.		
5.		
6.		

If Discrete Components:

(Enclose Copy of any Proposed Time-Overcurrent Coordination Curves)

Manufacturer: Type: Style/Catalog No.: Proposed Setting:
Manufacturer: Type: Style/Catalog No.: Proposed Setting:
Manufacturer: Type: Style/Catalog No.: Proposed Setting:
Manufacturer: Type: Style/Catalog No.: Proposed Setting:
Manufacturer: Type: Style/Catalog No.: Proposed Setting:

Current Transformer Data:
(Enclose Copy of Manufacturer's Excitation and Ratio Correction Curves)

Manufacturer: ....
Type: ____________________________Accuracy Class:__________Proposed Ratio Connection: _____

Manufacturer: ....
Type: ____________________________Accuracy Class:__________Proposed Ratio Connection: _____

Potential Transformer Data (If Applicable):
Manufacturer: ....
Type: ____________________________Accuracy Class:__________Proposed Ratio Connection: _____

Manufacturer: ....
Type: ____________________________Accuracy Class:__________Proposed Ratio Connection: _____

General Information

Evidence of Site Control.

Is Evidence Documentation Enclosed? ___Yes ____No

Enclose copy of site electrical one-line diagram showing the configuration of all Generating Facility equipment, current and potential circuits, and protection and control schemes. This one-line diagram must be signed and stamped by a licensed Professional Engineer if the Generating Facility is larger than 50 kW. Is One-Line Diagram Enclosed? ____Yes ____No

Enclose copy of any site documentation that indicates the precise physical location and layout of the proposed Generating Facility (e.g., USGS topographic map or other diagram or documentation).

Proposed location of protective interface equipment on property (include address if different from the Interconnection Customer's address)

Enclose copy of any documentation that describes and details the operation of the protection and control schemes. Is Documentation Enclosed? ___Yes ____No

Enclose copies of schematic drawings for all protection and control circuits, relay current circuits, relay potential circuits, and alarm/monitoring circuits (if applicable).

Are Schematic Drawings Enclosed? ___Yes ____No

Enclose check made out to Gainesville Regional Utilities or set up wire transfer arrangements toward GRU's costs for processing the application and studies. The amount payable shall be determined in accordance with estimated man-hours needed and prevailing engineering rates.
Is the check enclosed or wire transfer arrangement complete? ___Yes ____No

For a QF facility, enclose proof of having filed with FERC for QF status.
Is documentation enclosed? ___Yes ____No

Physical and/or electronic copies of this Interconnection Application, deposit for 200 Engineering design hours at prevailing rates including corporate overheads, and the supporting documentation shall all be submitted to the address indicated below:

Transmission Planning Gainesville Regional Utilities P.O. Box 147117 Station E2C Gainesville, FL 32614-7117 (352) 334-6047	NERC Reliability Compliance Gainesville Regional Utilities P.O. Box 147117 Station E3G Gainesville, FL 32614-7117

Applicant Signature

I hereby certify that, to the best of my knowledge, all the information provided in this Interconnection Request is true and correct.

Name of Interconnection Customer:
____

By (signature): ____

Name (type or print): ____

Title: ____

Date: ____

Please review the application and ensure that all required information under "General Information" is provided during the submission of the application to avoid a response of "incomplete application" once reviewed by Gainesville Regional Utilities.

Appendix G: Supplemental Inverter-Based Generator Interconnection Request Form[11]
(Transmission Planning)

A completed power systems load flow & dynamics data sheet must be supplied with the Interconnection Request. Literature for the inverter(s) and/or battery modules and the technical details associated with the applicable capacitor bank(s) along with this application must be supplied. The questions below are intended to guide the obtaining of this information.

1. Attach a Geographic Map Demonstrating the Project Layout and its Interconnection to the Power Grid. *(Specify the name of the attachment here)*

2. Attach a Bus-Breaker Based One-line Diagram (The diagram should include each of the individual unit generators, generator number, rating and terminal voltage.) *(Specify the name of the attachment here)*

3. Collection system detail impedance sheet
   If a collector system is used, attach a collector system data sheet in accordance with the one-line diagram attached above.
   The data sheet should include: the type, length Z0, Z1 and Xc/B of each circuit (feeder and collector string).
   Specify the name of the attachment here:
   ____

4. Collection system aggregate (equivalent) model data sheet
   Attach an aggregate (equivalent) collection system data sheet. The data table should include the type, length, Z0, Z1 and Xc/B of the equivalent circuits (feeders and collector strings).
   Specify the name of the attachment here:
   ____

5. Unit Detail Information

Unit Manufacturer Inverter Model	
Terminal Voltage	
Rating of Each Unit (MVA)	
Total Number of Inverters/Battery Modules in Solar/Battery farm to be interconnected pursuant to this Interconnection Request: __________Single phase__________ ___Three phase	
Is/are the Inverter(s) UL 1741 and IEEE 1547 compliant?	
Max Gross (AC) Nameplate Rating: ________MW (summer at 95° @ ____ Power Factor)	
Min Gross (AC) Nameplate Rating: ________MW (summer at 95° @ ____ Power Factor)	
Max Gross (AC) Nameplate Rating: ________MW (winter at 59° @ ____ Power Factor)	
Min Gross (AC) Nameplate Rating: ________MW	

[11] This form has been adapted from NE-ISO's Supplementary Wind & Inverter-Based Generating Facility Form

(winter at 59° @ ____ Power Factor)	
Maximum Gross Electrical Output (MW)	
Minimum Gross Electrical Output (MW)	
Lagging Reactive Power Limit at Rated Real Power Output (MVAR)	
Leading Reactive Power Limit at Rated Real Power Output (MVAR)	
Lagging Reactive Power Limit at Zero Real Power Output (MVAR)	
Leading Reactive Power Limit at Zero Real Power Output (MVAR)	
Station Service Load (MW, MVAR)	
Minimum short circuit ratio (SCR) requirement by manufacturer	
On which bus the minimum SCR is required by manufacturer	
What voltage level the minimum SCR is required by manufacturer	
Positive sequence Xsource	
Zero sequence Xsource	

6. Total Number of PV panels: ____________________
7. Output of each panel/battery: ____________ Watts
8. Are the panels fixed tilt or tracking?_______________________________
9. If tracking, single or dual axis? ___________________________________

10. Will the PV/Battery farm include capacitor banks at the POI? If yes, please state the size, number, location of the bank(s), and type (fixed/switched shunt) ____

11. List of adjustable set points for the protective equipment or software in the inverter: __________________________

12. Unit GSU:

Nameplate rating (MVA)	
Total number of the GSUs	
Voltages, generator side/system side	
Winding connections, low voltage/high voltage	
Available tap positions on high voltage side	
Available tap positions on low voltage side	
Will the GSU operate as an LTC?	
Desired voltage control range if LTC	
Tap adjustment time (Tap switching delay + switching time) if LTC	
Desired tap position if applicable	
Impedance, Z1, X/R ratio	
Impedance, Z0, X/R ratio	

13. Low Voltage Ride Through (LVRT) – ________(Specify the Manufacturer Model of this Unit)

Does each Unit have LVRT capability?
Yes____ No______
If yes, please provide:
____

14. Unit LVRT mode activation and release condition:
When operating at maximum real power, what is the Unit terminal voltage for LVRT mode activation?
____

When operating at maximum real power, what is the Unit terminal voltage for releasing LVRT mode after it is activated?
____

If there is different LVRT activation and release logic, please state here
____

15. Please provide technical manual from the manufacturer for the inverter-based generating facility including description of LVRT functionality:

Attach the file and specify the name of the attachment here:
____

16. Does the inverter-based generating facility technical manual attached above include a reactive power capability curve?
Yes_____ No______
If no, attach the file and specify the name of the attachment here:
____

17. Low Voltage Protection (considering LVRT functionality) (Specify the Manufacturer Model of this Unit)
*Add more rows in the table as needed

Low Voltage Setting (pu)	Relay Pickup Time (Seconds)

18. High Voltage Protection - _____________________________(Specify the Manufacturer Model of this Unit)
*Add more rows in the table as needed

High Voltage Setting (pu)	Relay Pickup Time (Seconds)

19. Low Frequency Protection - ________________________(Specify the Manufacturer Model of this Unit)
 *Add more rows in the table as needed

Low Frequency Setting (Hz)	Relay Pickup Time (Seconds)

20. High Frequency Protection - ________________________(Specify the Manufacturer Model of this Unit)
 *Add more rows in the table as needed

High Frequency Setting (Hz)	Relay Pickup Time (Seconds)

Please make sure the settings in sections 13 through 20 comply with NERC standards for generator protection relays.

21. Unit Reactive Power Control (Specify the Manufacturer Model of this Unit):
 ____

22. What are the options for the Unit reactive power control (check all available)?
 ____Control the voltage at the Unit terminal
 ____Control constant power factor at the Unit terminal
 ____Control constant power factor at the low side of the station main transformer
 ____Control constant power factor at the high side of the station main transformer
 ____Control voltage at the low side of the station main transformer
 ____Control voltage at the high side of the station main transformer
 ____Other options. Please describe if select
 others____

23. In all the control options selected above, please list the options in which the Unit is able to control its terminal voltage to prevent low/high voltage tripping.
 ____
 _____

24. What is the desired control mode from the selected options above?
 Specify the control plan in this mode. For example: control voltage at which bus to what schedule.

25. Wind or inverter-based generating facility Model

(All model files provided under this section should be compatible with Siemens PTI's PSS/E version currently in use at FRCC). Please see Appendix H below

Generating Facility Characteristic Data (for inverter-based machines)

Max design fault contribution current: ....
Instantaneous .... or RMS? ....
Harmonics Characteristics: ....
....
Start-up Requirements: ....

Appendix H: PSCAD Model Submittal Guidelines for Inverter-Based Generators

GRU has decided to adapt ERCOT's Electromagnetic Transient (EMT) model guidelines available here:

https://www.ercot.com/files/docs/2021/04/20/Model_Quality_Guide.zip

Appendix I –Delivery Point Request Form/Notification for Changes Impacting GRU Facilities

Customer shall initiate requests to install, modify, or remove GRU Facilities, or to modify the capacity or characteristics required at a Delivery Point, or to discontinue the delivery of electricity to a Delivery Point, in writing using this Customer Request Form. Customer shall also submit a Request Form when making changes to Customer's Facilities that are reasonably anticipated to (1) lead to a modification to GRU's Facilities, or (2) impact the operation of GRU's Facilities.

The Request Form shall be submitted by the interconnection customer as soon as practicable, with a nonrefundable deposit for 250 Engineering design hours billed at prevailing rates including corporate overheads. Deposit amount may be applied toward the total cost of the approved project at GRU's discretion. As additional or updated information becomes available, customer shall make timely submission of a revised request form. For Request Forms submitted with an estimated/uncertain energization date, the parties shall determine a schedule for the provision of complete and final information and GRU will provide a revised estimate and invoice for continuing the interconnection evaluation. GRU shall agree to a desired energization date that is plausible to all parties.

Customer shall, in accordance with the following requirements, provide, on a timely basis, information that is complete and accurate. On every request form submitted, each blank shall contain one of the following entries:

1) The firm (final) information
2) If no information is appropriate for a given item, the entry shall be "Not Applicable"
3) An entry as described below:
    a. In sections II, III, and IV, an entry with an estimated energized date. Such entries shall be revised with firm information as soon as it is available. If the "Requested Date to Energize" in Section IV is initially marked "Estimated" then the firm date ultimately supplied for "Requested Date to Energize" shall be on or after the estimated date unless an earlier firm date for "Requested Date to Energize" is mutually agreed-upon prior to submission of a revised request form.
    b. In section III, an entry may be "To be Determined/TBD by [date]". Additionally, each of the required attachments of section III shall be provided or shall be substituted by a page bearing the attachment description and the date by which the attachment shall be provided.
    c. Upon receiving a request, GRU shall evaluate the request within its ordinary course of business and consistent with the GRU requirements. The evaluation may include the investigation of alternate solutions or design to accommodating customer's needs. Customer to reasonably assist GRU's evaluation, including, without limitation, the provision of additional information and participation in a cooperative review and exploration of the request and its alternatives. GRU shall not be required to complete such evaluation until a reasonable time after the customer has supplied all information as firm information.

d. Upon concluding its evaluation, GRU shall provide a written response approving the request, approving the request with modifications, or denying the request. In the event of approval or modified approval, the response shall be consistent with the Agreement, any required construction or modifications by the Parties, any estimated Project costs, costs responsibilities between the Parties, and other actions the Parties must take to implement the request in its approved form.

Request/Notification for Changes Impacting GRU Facilities

Section I –General	Date:	Revision #
Requestor Name:		
Requestor Address:		
Name of Contact Person:		
Contact's Phone:	Contact's Mobile:	
Contact's Email:		

Signature below authorizes GRU to proceed with design, engineering, and estimation of Project cost as appropriate for GRU to evaluate and respond to this request. This authorization is pursuant and subject to all terms and conditions of the Agreement of which this Appendix is a part.

Authorizing Signature:	
Printed Name:	
Authorizer's Phone:	Contact's Mobile:
Title:	Authorization Date:

Section II –Description of Request

Name of Delivery Point
Brief Description of Request: (attach detail)
Brief Reasoning for Request:
Delivery Point Location (attach detail if new, include GPS coordinates)
Noteworthy load characteristics: (large motors, large fluctuating loads, large harmonic-producing loads, etc.)

Anticipated New Delivery Point Facilities Data:

New Delivery Point Voltage:				
New Peak KVA Capacity of Delivery Point Facilities:				
Peak kW and reactive kVAR ("kVAR") during first three years following implementation & highest peak within ten years:				
	Initial Year	2nd Year	3rd Year	Highest in first 10 Years
Enter Year				

Summer Peak kW				
Summer Peak kVAR				
Winter Peak kW				
Winter Peak kVAR				
Delivery Point Facilities GPS coordinates:				
Additional Comments				

Section III –Customer's Equipment

Transformer Primary Voltage:	Transformer Secondary Voltage:
Transformer Nameplate Capacity:	Temperature Rise:
Transformer Taps:	
Connection (e.g., Wye-Wye, or Delta-Wye, etc.):	
Transformer Impedance:	
Breaker and Isolation Switch Types and Ratings:	
Protection Relay Type, Settings, and Ratings:	

Required Attachments:

- One-line and/or three-line diagram
- Transformer Test Report
- Transformer Loss curve
- Operating procedures description
- Protection scheme functional diagram
- Protection device information (including device types, serial and model numbers, relay settings, etc.)

Customer Submittal Date:	
Expected Date Customer's Construction to Commence:	
Expected Completion Date of Customer Work:	
Date Requested for GRU Construction to Commence:	
Requested Completion Date of GRU Work (De-energized):	
Requested Date to Energize*	
Other Milestones	

*If the "Requested Date to Energize" is estimated, then the firm date ultimately supplied must be on or after the estimated energization date, unless an earlier firm date is mutually agreed-upon prior to submission of the revised request form.

Appendix J – Dynamic Model Quality Test Guideline

General

Dynamic data is the network data, mathematical models, and supporting information required for simulation of dynamic and transient events in the FRCC System. GRU has adopted certain requirements from ERCOT's Model Quality Guide, below.

Software

The current planning model software is PSS/E version 34 and PSCAD version 4.5 or higher. A planning model software transition from PSS/E version 34 to version 35 is in progress. Please contact GRU Transmission Planning to ensure model compatibility. During years where a PSS/E version change is being conducted, the previous PSS/E version user defined models shall also be provided until a full transition is completed.

Dynamic Models – General

Dynamic models must be compatible with PSSE (latest and PSCAD). Providers of dynamic models shall also adhere to the following requirements:

•Each dynamic device requires a model with model parameters that accurately represent the dynamics of the device over the entire range of operating conditions.

•PSCAD models shall be submitted to GRU for all inverter-based equipment.

•Where multiple models are provided (e.g,. PSS/E, PSCAD), the model response shall be consistent across software platforms to the extent of platform capability.

•All associated per unit dynamic model parameters for a given generating unit shall be provided using a base MVA (MBASE) in accordance with appropriate modeling techniques for the software platform, where the MBASE is typically the generator MVA rating.

•No model shall restrict the MMWG from using any integration time-step less than or equal to a ¼ cycle in simulations when using positive sequence simulation tools. If a model is unacceptable to the MMWG for any reason, it shall not be accepted.

Standard Dynamic Models

The use of standard dynamic models provided by the software is preferred when they can accurately represent the dynamic performance of the device being modeled.

User-Written Dynamic Models

A user written model is any model that is not a standard library model within the software(s) and version(s) listed above. When no compatible standard dynamic model(s) provided within the software can be used to represent the dynamics of a device, accurate and appropriate user written models can be used, if accepted by FRCC and the MMWG after being tested for compatibility with the flat start cases.

GRU has adopted ERCOT's "model guideline check sheet" to check PSS/E and PSCAD models to help determine compatibility; this check sheet shall be completed and submitted along with the model.
PSS/E User-written models for the dynamic equipment and associated data must be in dynamic linked library (DLL) format and must include a model manual. The model manual must show control block diagrams, design logic, descriptions of all model parameters, a list of which parameters are commonly tuned for site-specific settings, and a description of procedures for using the model in dynamic simulations.
All PSCAD models are considered to be user-written models.

Dynamic Model Quality Test Guideline

Submitted dynamic planning models must be accompanied with results from model quality tests performed by the facility owner. Please consult with GRU transmission planning to determine extent of tests and reports expected.

IBR Verification Reports

IBR Verification Reports are different from MOD-026/027 studies and are required from all IBR resources according to the following timeframes:

- New Resources (commissioning after 1/1/2024):
  - Within 30 days of receiving Resource Commissioning Date approval
  - No earlier than 12 months and no later than 24 months after receiving Resource Commissioning Date approval

- All resources (regardless of commissioning date)
  - A minimum of every ten years
  - Within 30 days of making a setting change at the plant

Generally, GRU should update both the dynamic and PSCAD models at the same time to ensure model consistency. However, if the PSCAD model is delayed then the applicant must provide the dynamic model (PSS/E) first with a time estimate for the PSCAD model.

The goal of the Verification requirement is to ensure our models match actual equipment settings. This augments MOD-026/027 studies which only check small signal behavior through measurements. The Verification requirement focuses on tunable numerical settings. A typical Verification report would consist of the following:

• Brief description of how and when the actual parameters were checked for the plant. For example, a renewable plant report may read: "On 4/6/2022, the wind turbine manufacturer / OEM logged into the turbine firmware and power plant controllers and obtained a parameter dump. A partial screenshot is shown below for evidence."

• Include a table listing tunable model parameters from either the PSS/E model or the PSCAD model (whichever is more convenient). In one column, list the parameter value from the dynamic model that was submitted and in the next column, list the setting value from the actual equipment. If the values do not match, explain why. For example, "Values are represented on different units of measure. This formula is used for the conversion…." Or "The following values were parameterization by the following procedure (curve fitting, statistical analysis, etc.) …"

• Reference to the dynamic model Template filename being verified. Dynamic model templates should be saved with the following naming convention, referenced in the report, and submitted together with the Verification report as a complete package. Include also any Model Quality Test reports required for model updates (for conventional facilities, MOD-026/027 studies may be submitted in lieu of an MQT report).

- [Plant name]_dyn_2023-12-31.xlsm, dynamic model template for [Plant name] prepared 12/31/2023

Screenshots of actual equipment settings provide the best evidence. GRU also accepts attestations from the OEM, commissioning or delivery reports, or curve-fitting or response matching exercises, etc. If the unit has been in service for a while and the commissioning report is old, additional evidence may be necessary to be ensure that the values have not changed since commissioning.

There are many parameters in each model. GRU requires the IBR project engineer's judgment regarding which parameters are site-specific or commonly tuned. These must be identified and verified.

Verification may be performed either on the PSS/E or PSCAD models. Note that PSS/E generic IBR models often have limited relation to actual equipment settings; GRU may request additional supporting evidence (OEM attestation or verification of the PSCAD model) if the verification appears insufficient.

Appendix K – Sample Model Quality Test Report from ERCOT

SAMPLE MODEL QUALITY TEST REPORT
LITTLE TURTLE WIND, 12INR0000
Date of Test: April 5, 2020

Resource Entities and Interconnecting Entities should submit a similar test report when submitting their dynamic model. Please refer to the Dynamic Model Submittal Guideline document for more info.

PROJECT DESCRIPTION

Name	INR or SITECODE	Size	Turbine Quantity and Type (for IRRs & Batt.) and MVA Size (for non-IRRS) by Unit/Resource Name
LITTLE TURTLE WIND	12INR0000	180 MW	Unit 1: 50 × 2 MW of Windtech 2000 Unit 2: 40 × 2 MW of Windtech 2000

Reason for this model update:

This is an updated model correcting a voltage ride through issue with the old model. This model improves the reactive power response during VRT.

Date of MOD 26/27 study (if applicable):

Future project. No MOD 26/27 study performed yet.

DESCRIPTION OF TEST PROCEDURE

These model tests were performed in PSSE using the DMVIEW tool. The simulation was set up with a controllable slack bus connected to the plant POI and the entire plant was tested at the same time. Following the DWG Procedure Manual, all tests were run initialized at full real power dispatch except the frequency tests which were initialized at 80% real power dispatch. Results were compared with the examples posted in the DWG Procedure Manual and one discrepancy was found regarding the Frequency Step with Headroom test. The following tests were run:

- Flatstart
- POI Voltage Step Down 3%
- POI Voltage Step Up 3%

- HVRT Leading and Lagging
- LVRT Leading and Lagging
- Frequency Step Down 0.03 Hz, No Headroom[1] Assumption (default)
- Frequency Step Down 0.03 Hz, With Headroom Assumption
- Frequency Step Up 0.03 Hz
- Short Circuit Ratio

Describe How to Enable Headroom for the Frequency Test (IRRs only)

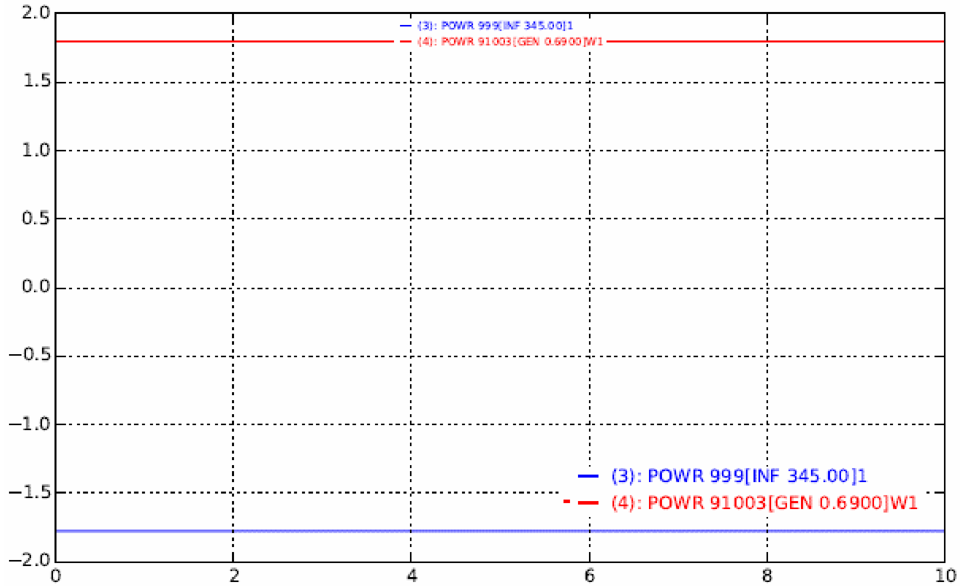
Headroom can be enabled by setting the PowerReserve parameter of the Windtech governor model (CON J+74) to 0.05, for example to indicate a 5% headroom.

Enclosures:

- Plant model files (Turtle.sav, Turtle.dyr, WindTech_2000_33.dll)

FLATSTART (no disturbance test)

The model flatstarted normally with no deviations (Figure 1).



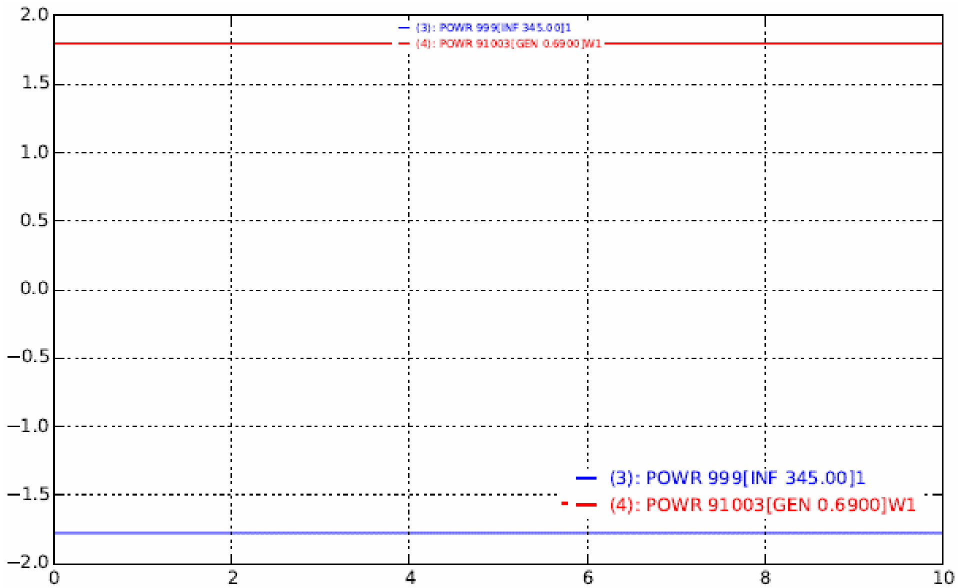


Figure 1: Flatstart test showing steady generator real (left) and reactive (right) flow indicating correct initialization.

VOLTAGE STEP DOWN

Under the stimulus of a 3% voltage drop at the POI, the plant increased reactive power output and maintained real power (Figure 2).

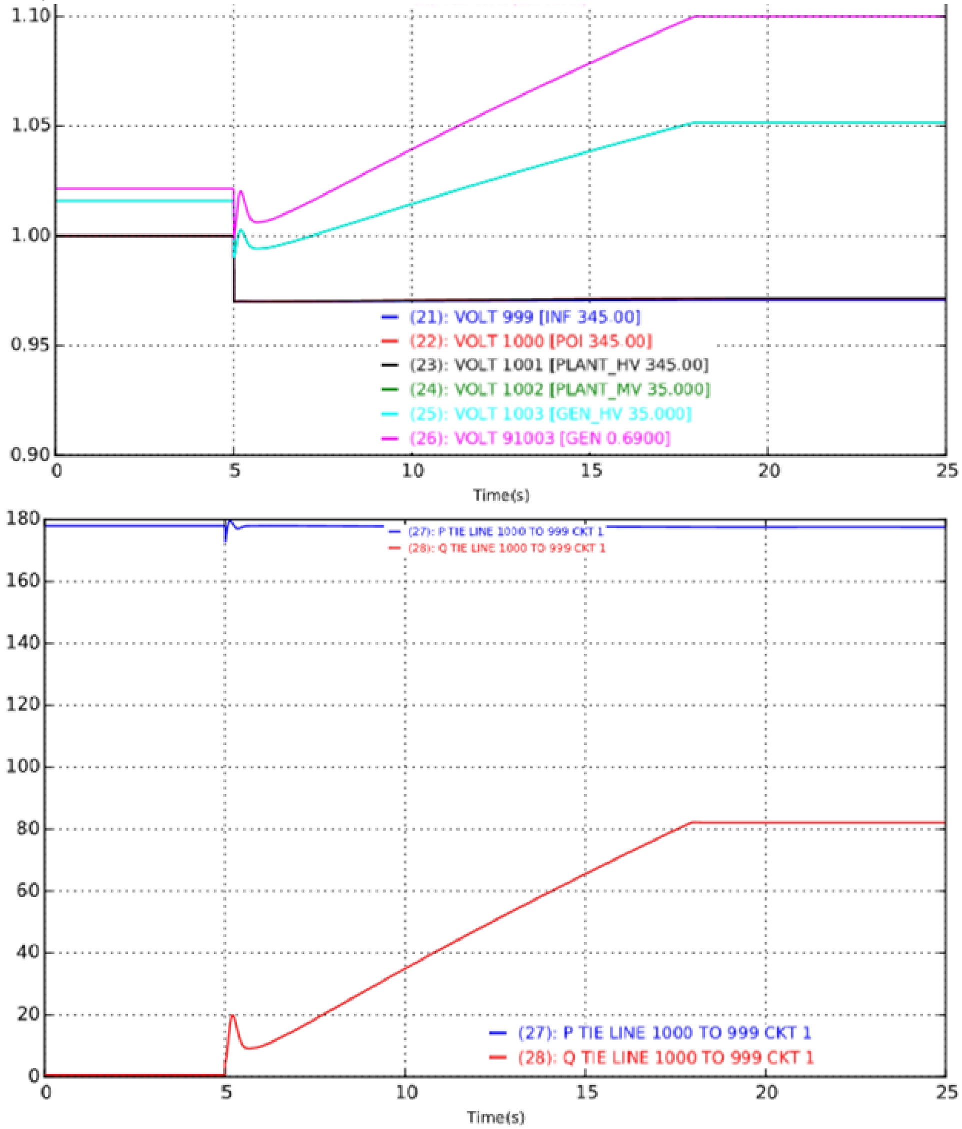


Figure 2: The voltage stimulus is shown at top while the plant real and reactive response is shown in the plot beneath. The plant correctly increased reactive output while maintaining real power.

VOLTAGE STEP UP

Under the stimulus of a 3% voltage rise at the POI, the plant decreased reactive power output and maintained real power (Figure 3).

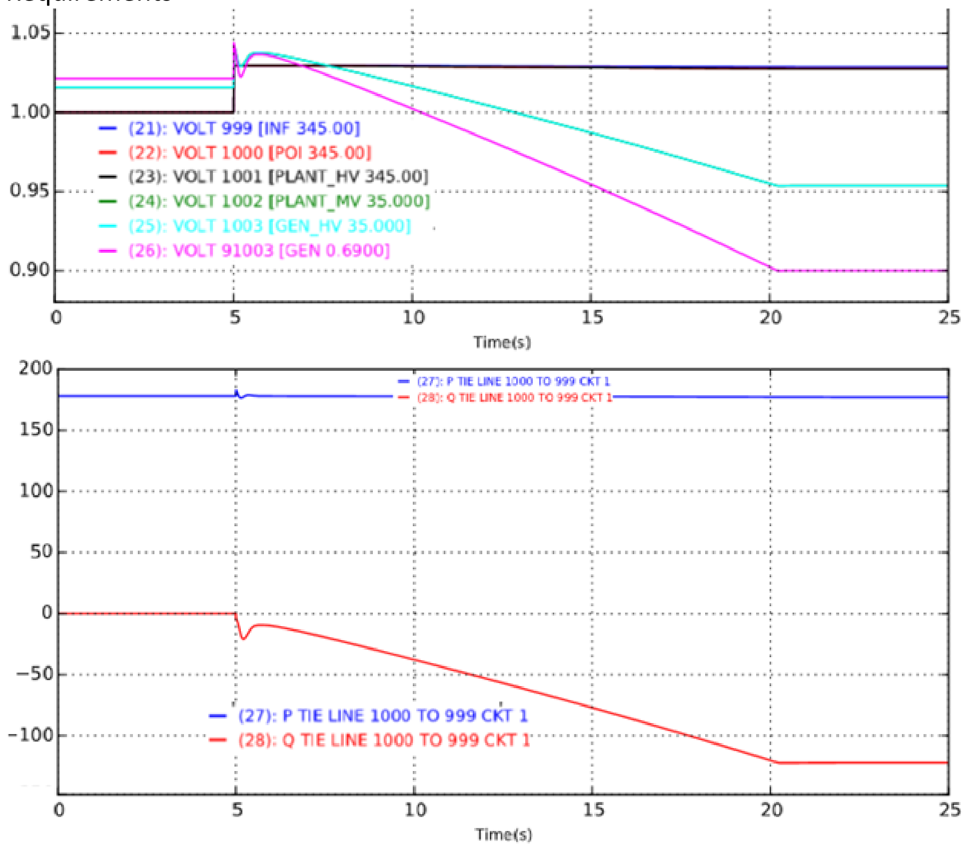


Figure 3: The voltage stimulus is shown at top while the plant real and reactive response is shown in the plot beneath. The plant correctly decreased reactive output while maintaining real power.

HVRT Leading

Running the HVRT curve depicted in ERCOT's Nodal Operating Guide 2.9, the real power is maintained and the reactive power absorption increases as a result of the high voltage transient (Figure 4). This "leading" test simulates plant initialized to 0.95 power factor leading at the POI. *Note: Generators initialized to Q_{MIN} may not see an increase in reactive absorption for the HVRT leading test.*

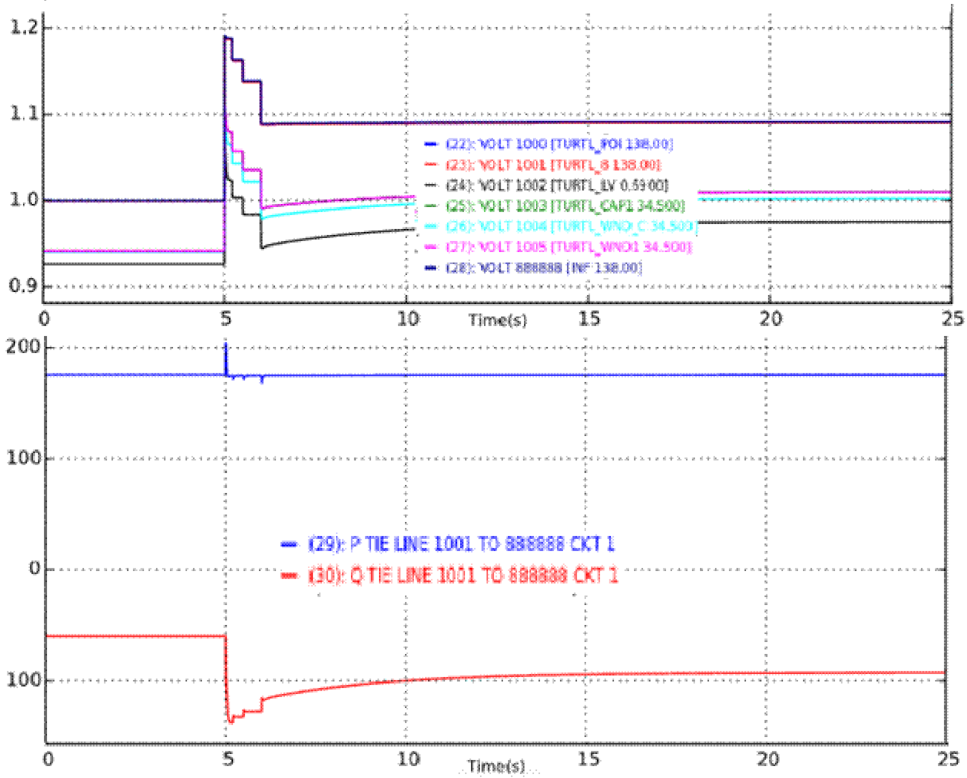


Figure 4: For the HVRT stimulus applied at the POI (top figure), the plant reactive power decreased promptly while maintaining real power (bottom figure).

HVRT Lagging

Running the HVRT curve depicted in ERCOT's Nodal Operating Guide 2.9, the real power is maintained and the reactive power absorption increases as a result of the high voltage transient (Figure 5). This "lagging" test simulates plant initialized to 0.95 power factor lagging at the POI.

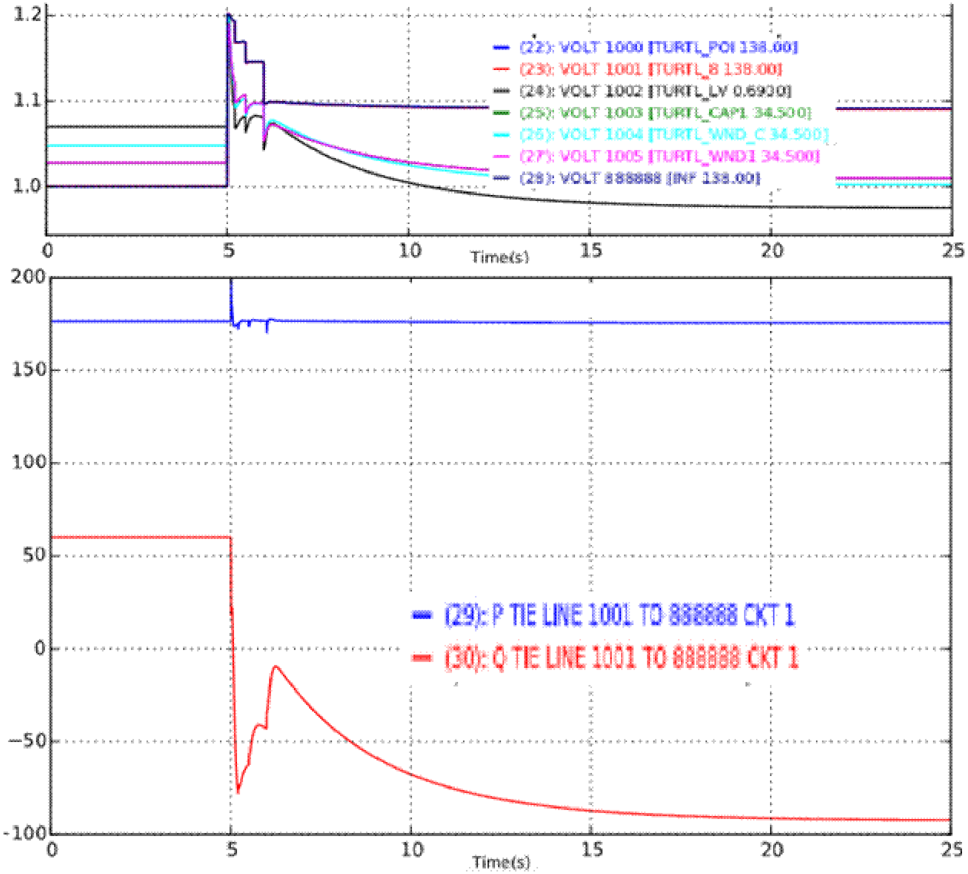


Figure 5: For the HVRT stimulus applied at the POI (top figure), the plant reactive power decreased promptly while maintaining real power (bottom figure).

LVRT Leading

Running the LVRT curve depicted in ERCOT's Nodal Operating Guide 2.9, the plant reactive power very quickly transitions to absorbing as a result of the high voltage transient (Figure 6). Real power recovery was acceptable. This "leading" test simulates plant initialized to 0.95 power factor leading at the POI.

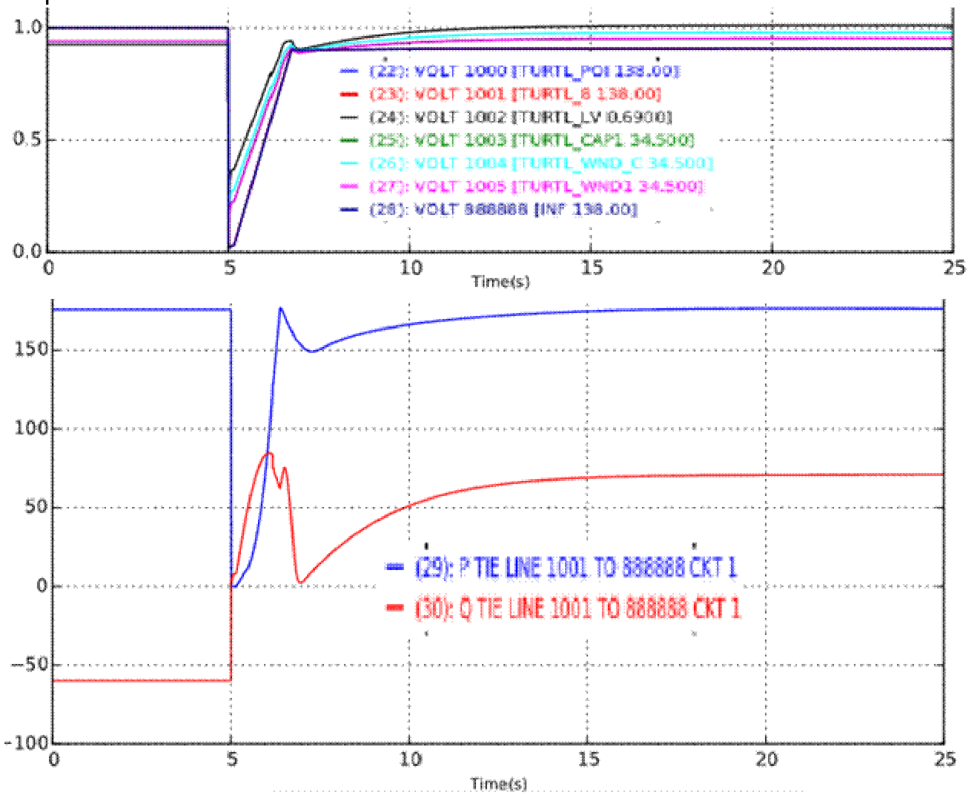


Figure 6: For the LVRT stimulus applied at the POI (top figure), the plant reactive power increased promptly (bottom figure). The real power started to recover prior to the voltage reaching 0.9 per unit and recovered quickly upon reaching 0.9 per unit and thus was acceptable.

LVRT Lagging

Running the LVRT curve depicted in ERCOT's Nodal Operating Guide 2.9, the plant reactive power very quickly transitions to absorbing as a result of the high voltage transient (Figure 7). Real power recovery was acceptable. This "lagging" test simulates plant initialized to 0.95 power factor leading at the POI. *Note: Generators initialized to Q_{MAX} may not see an increase in reactive production for the LVRT lagging test.*

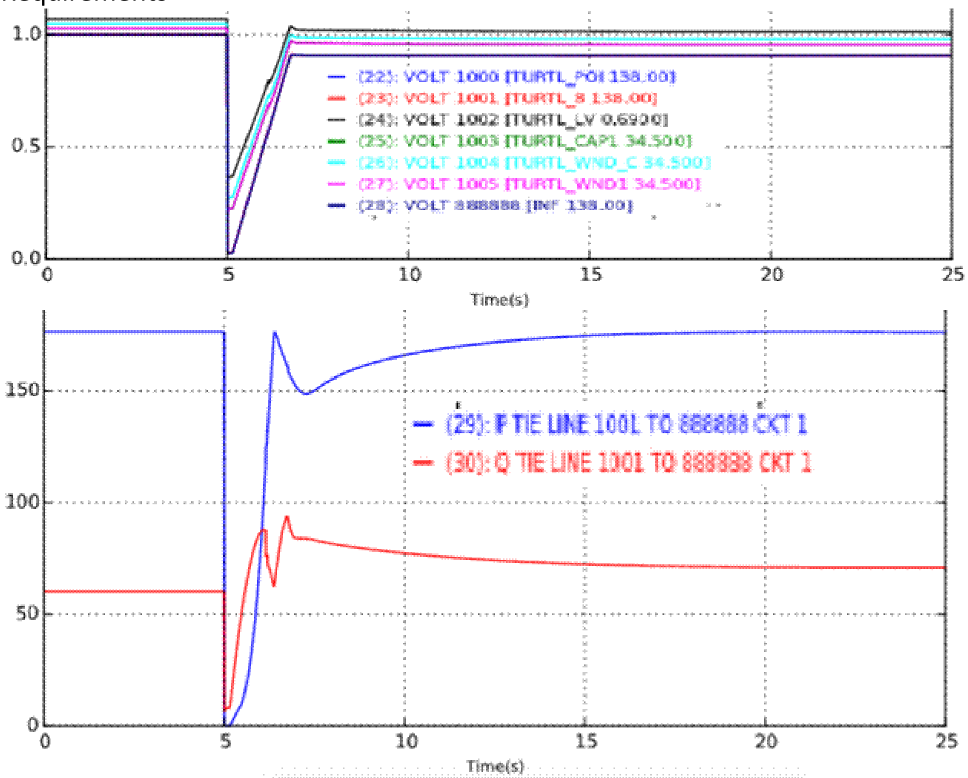


Figure 7: For the LVRT stimulus applied at the POI (top figure), the plant reactive power increased promptly (bottom figure). The real power started to recover prior to the voltage reaching 0.9 per unit and recovered quickly upon reaching 0.9 per unit and thus was acceptable.

FREQUENCY STEP DOWN, No Headroom Assumed (Power Availability State)

For a 0.03 Hz decrease in frequency, real power is maintained (Figure 8). Real power was initialized at 80% of nameplate (180×80% = 144 MW).

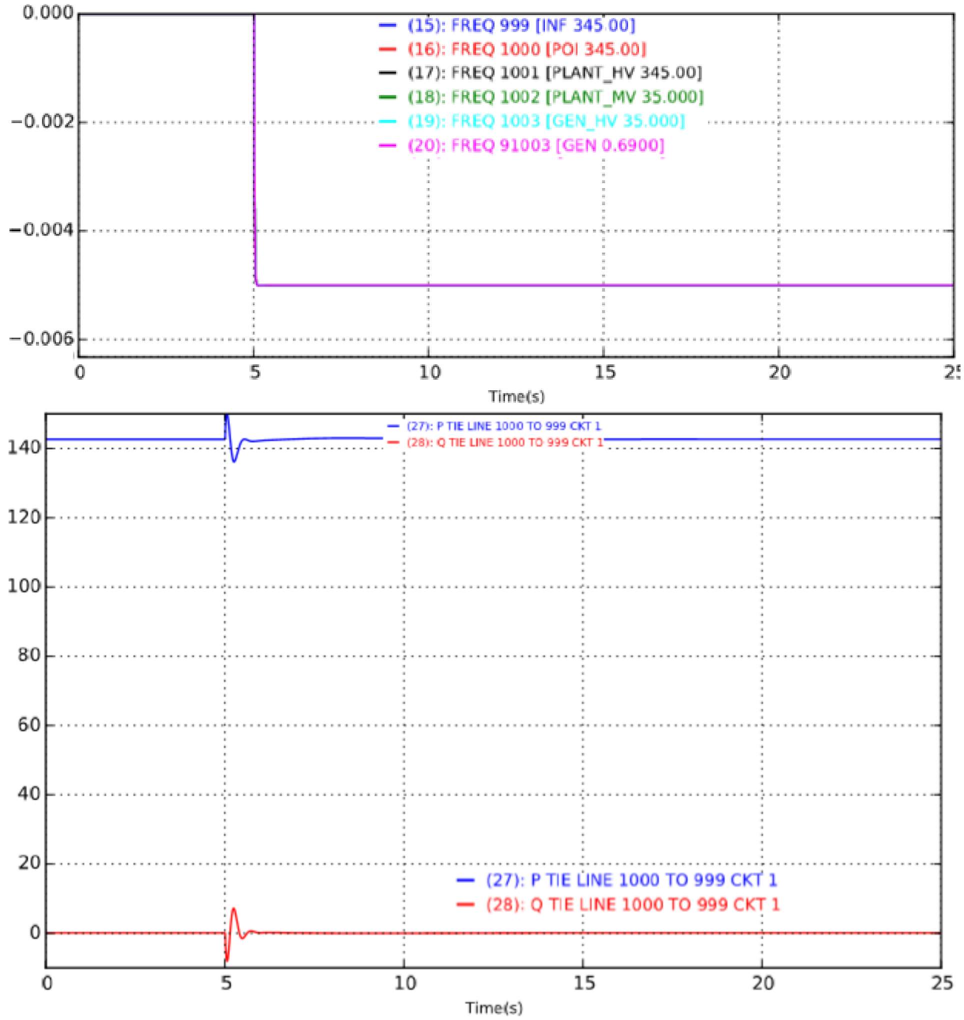


Figure 8: For a 0.03 Hz decrease in frequency, real power is maintained (bottom plot) which is correct assuming there is no headroom to increase real power.
Note: The vertical axis in the top plot depicts *Frequency Deviation Per-Unit*, thus -0.005×60 = -0.3 Hz.

FREQUENCY STEP DOWN, Headroom Assumed (Curtailed State)

For a 0.03 Hz decrease in frequency, the model did not increase real power (Figure 9) despite having the PowerReserve option enabled to represent a curtailed state. **[Because a shortcoming was identified, please follow the instructions in the ERCOT Model Quality Guide and work on submitting a corrected model.]**

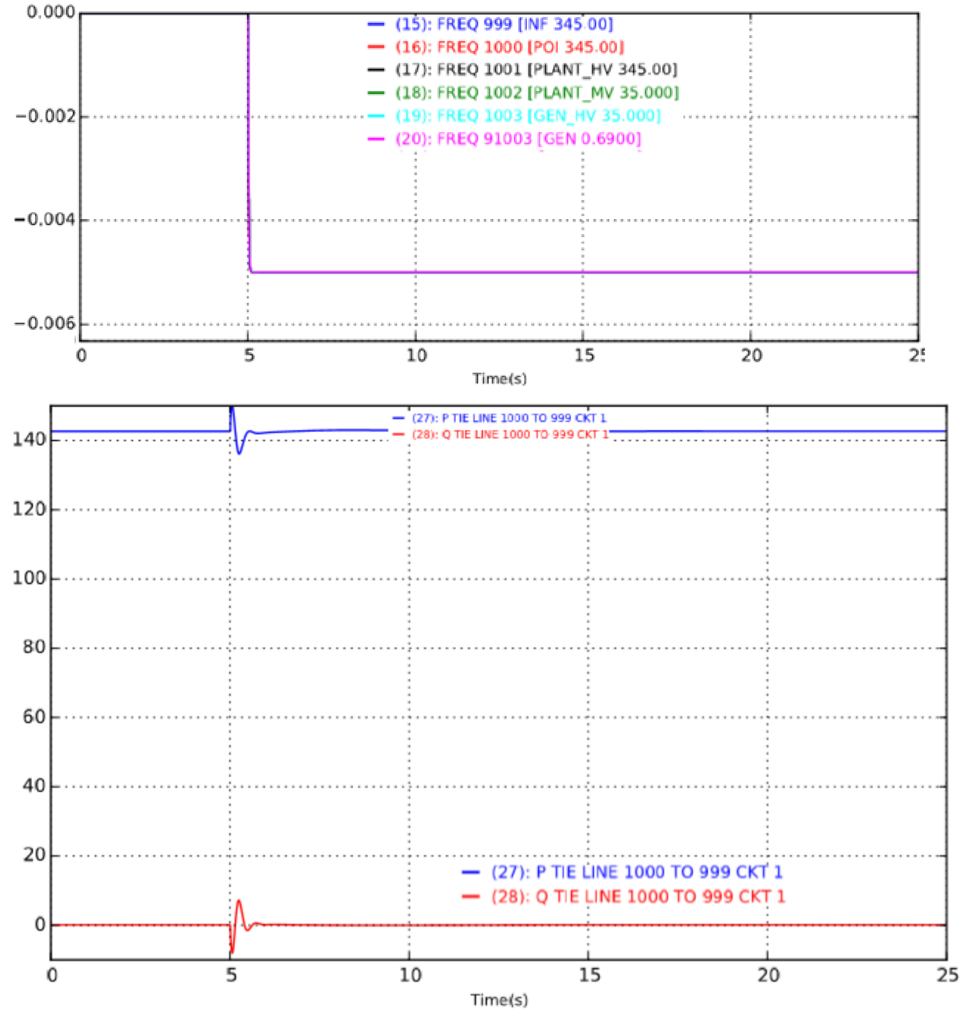


Figure 9: For a 0.03 Hz decrease in frequency, real power is maintained (bottom plot).

Note: The vertical axis in the top plot depicts *Frequency Deviation Per-Unit*, thus -0.005×60 = -0.3 Hz.

FREQUENCY STEP UP

For a 0.03 Hz decrease in frequency, real power decreased 18 MW or about 12% (Figure 10). Real power was initialized at 80% of nameplate (180×80% = 144 MW).

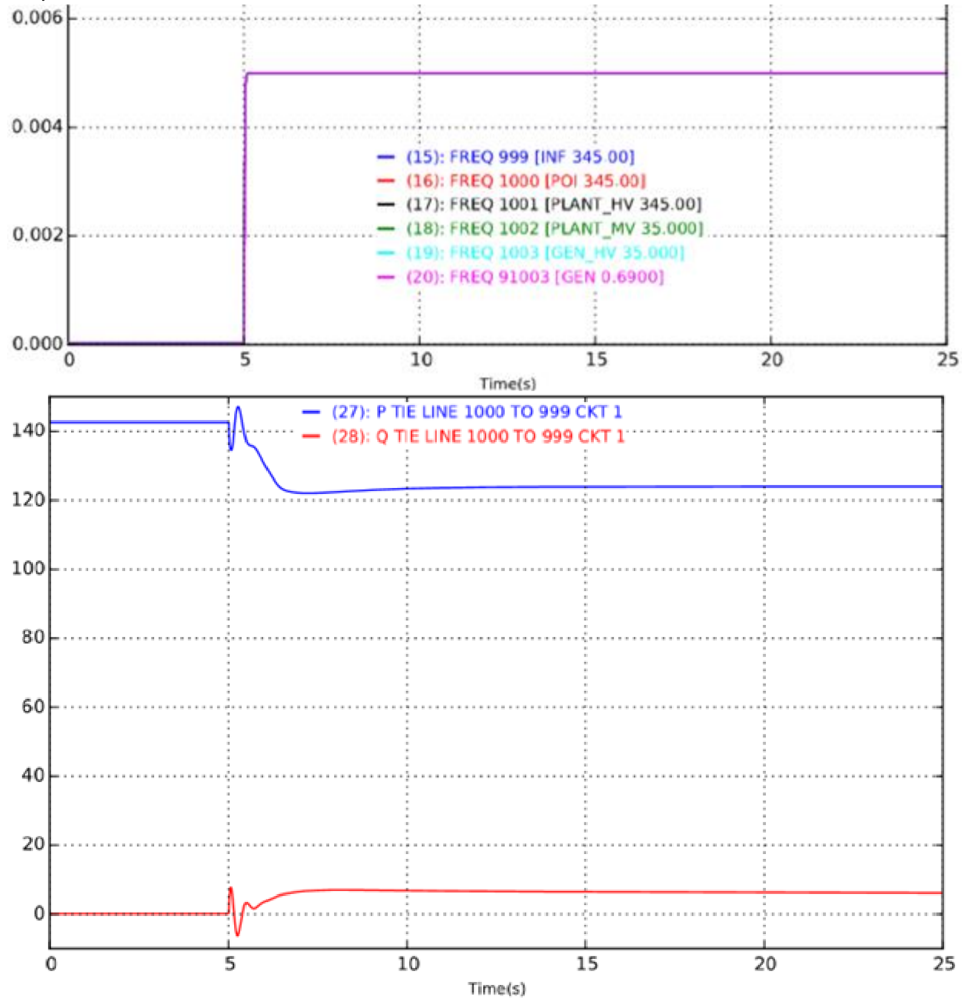


Figure 10: For a 0.03 Hz increase in frequency, real power decreased (bottom plot). Note: The vertical axis in the top plot depicts *Frequency Deviation Per-Unit*, thus +0.005×60 = +0.3 Hz.

SHORT CIRCUIT RATIO (SCR) TEST

Running the short circuit ratio test, Figure 11 indicates the model remained online and functional all the way down to a short circuit ratio of 1.2. This is indicated by stable behavior all the way to the conclusion of the simulation where the final SCR tested was 1.2. (*The decrease in real power is possibly a result of the test inadvertently creating a need for additional reactive power as a result of the increased sending impedance. Since this is likely a characteristic of the test, it will not be considered objectionable because the model is otherwise behaving in a reliable manner.*)

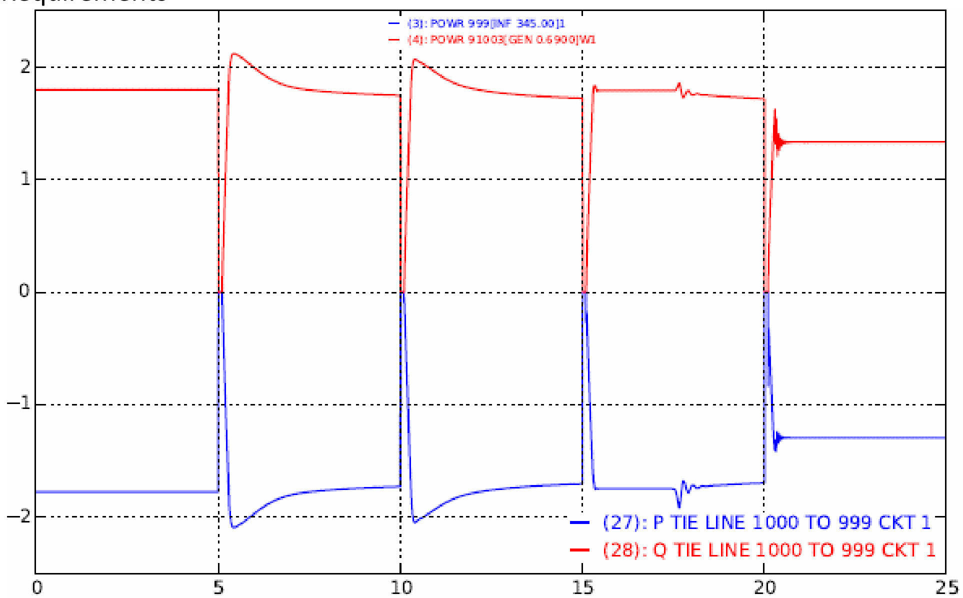


Figure 11: Short circuit ratio test. Each pulse represents a new test condition where the POI is briefly faulted and at the same time the sending branch impedance is increased to achieve the new SCR value. SCR values of 5, 3, 1.5, and 1.2 were tested. The test was initialized with SCR = 8, as depicted by the time 0 to 5 seconds prior to the first disturbance.

Appendix L Requirement R6, Definition of "Qualified Change"[12]

GRU has adopted a few of the recommendations set forth in the paper "Implementation Guidance for FAC-002-4 Requirement R6" published by NERC, available separately upon request. GRU staff has determined the following are appropriate for its system in defining "qualified changes" (where detailed examples are not provided, consult with GRU Transmission Planning staff to determine if change proposed would be "qualified"). These examples provided are for guidance only and reliability decisions will be determined on a case-by-case basis by qualified GRU Engineers and stakeholders.

Table 1.1: Qualified changes for End User Facilities		
Category	Description	Detailed Example(s)
1	Increase in Demand	Example 1: • Increase in Demand of 75 MW or greater within the next two years; or • Increase in Demand of 20 MW or greater within the next two years for a third-party Facility interconnected to a Generator Owner's Facility
2	Addition of equipment that would significantly impact the composite	Examples: • Installation of a motor 1,000 hp or larger where no motors previously existed; or

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	load model used to represent a Facility	• Addition of a motor exceeding the size of all other motors connected within a Facility with at least 500 hp of motors
3	A change in end-user Facility topology that may affect power flows on the BES	Examples: • Addition of distribution energy resources (DER) with nameplate capacity equal to or greater than 100% of the total MW load connected at the distribution substation the DER is connected to.

Table 1.2: Qualified changes for Transmission		
Category	Description	Detailed Example(s)
1	Change in Rating	Example 1: • Decrease in the facility thermal rating by greater than 50% • Change in the facility impedance by greater than 50% • Change in facility voltage class
2	Change in System Configuration/Topology	Change in the BES topology that would alter the way a facility would operate if change is expected to be permanent, for example, change from breaker and a half scheme to single breaker.
3	A change in end-user Facility topology that may affect power flows on the BES	Examples: • Addition of distribution energy resources (DER) more than 100% of the MW load of the distribution substation the DER is interconnected to.

Transformers at GRU switching stations are considered “facilities” under Table 1.2

Table 1.3: Qualified changes for generation These assume the generating unit is remaining in service and/or available for service		
Category	Description	Detailed Example(s)
1	Change in Generator Output	Examples • Change that affects its Seasonal Real Power or Reactive Power capability by 100 percent of the last reported verified capability and is expected to last more than a year. • Change in power factor capability of the generator
2	Change of GSU	Examples • Change of GSU that results in any of the following differences and is expected to last more than a year. ▪ Reduction in rating by more than 50% ▪ Impedance change by more than 50% o Change in transformer losses o Change in transformer saturation differences
3	Change in Generator Characteristics	Examples • Change in steady state transient and sub-transient reactance of the Generator or generator Interconnection Facilities by more than 50%

4	Inverter Based Resource (IBR) Only: Change in Inverter or inverter settings	Change of 50% or more of the inverter-based resource units at a facility that is not replacement in-kind. • Change in any control settings ▪ resulting in a difference in frequency or voltage support of the Inverter Based Resource ▪ resulting in a difference in when the IBR discontinues current injection to the GRID (i.e. blocking commands) • Change in any equipment or settings that would result in a change in the generator's electromagnetic transient models
6	Unplanned change in governor or governor settings	Examples Uncharacteristic changes that result in how the generator responds to grid frequency deviations and is expected to last more than a year.
7	Unplanned change in exciter or exciter settings	Examples Uncharacteristic changes that result in how the generator responds to grid voltage deviations and is expected to last more than a year.
8	Change in power system stabilizer	Examples • Addition or removal of power system stabilizer • Setting and/or tuning changes of power system stabilizer

Please refer to the ERCOT Model Quality Guide document note on headroom/power availability. Separate headroom / no headroom tests are only necessary for IRR (Wind / Solar) resources.

Revision No.	Effective Date	Description
15.0	8/7/2023	Document formatting updated due to Document Management site migration to a new SharePoint site. Added language to meet FAC002-4 R6 and FAC-001-4
14.0	8/16/2021	Minor corrections and Modifications
13.0	05/01/2020	Added EMT data requirements in Appendix H, edited Appendix G
12.0	05/13/2019	Minor corrections and Modifications
11.0	01/01/2019	Document moved to updated template format. Signature Block and Roles added. GRU System Operator replaced with GRU Power System Operator Updated references to new requirements R3.3 and R4.3 in FAC-001-3, added language to address PRC, BIL, solar PV inverters, flicker, PMUs
10.0	01/15/2016	Updated Appendix references
9.0	12/10/2015	Changed document formatting and name, updated references to FRCC documents, FAC001-2, FAC-008-3 & TPL001-4 references
8.0	05/16/2011	Revised Appendix B, Section 2 to better clarify target voltage of 138 kV
7.0	04/01/2009	Minor changes to facilitate and clarify
6.0	02/12/2009	Realignment to better match searching matrix
5.0	03/07/2008	Minor Corrections from B. Stormant for clarity
4.0	01/16/2008	Minor Corrections from B. Stormant for clarity
3.0	01/08/2007	Changes to align with compliance requirement & approval
2.0	05/23/2006	Review changes and corrections
1.0	04/28/2006	Minor Corrections and Modifications
0.0	11/21/2005	Initial Release