WECC

Inverter-Based Resources Power Plant Modeling and Validation Guideline

Modeling and Validation Committee

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Introduction

Over the last two decades, the WECC Modeling and Validation Subcommittee (MVS), formerly known as the Modeling and Validation Work Group (MVWG), has facilitated the development of generic renewable energy system (RES) dynamic models and published many documents on the modeling and validation of various types of inverter-based resources (IBR) power plant modeling and validation. As MVS continues facilitating the development of these models for emerging technologies, this guideline intends to provide a centralized repository of information for appropriate use of the models.

The scope of this document encompasses:

- the common principles in modeling all types of IBR power plants
- IBR power flow modeling
- a summary of the generic RES dynamic models and applicability of the models
- reference to modeling guidelines for specific technologies

Applicability

This guideline focuses on IBR power plants connected to the WECC transmission grid at 60 kV or higher voltage with a single generating unit capacity of 10 MVA or larger, or the plant aggregate capacity of 20 MVA or larger.

1. Background

The WECC MVS, formerly the Modeling and Validation Work Group (MVWG), has been actively developing models and modeling practices for IBRs. As renewable energy technologies—like solar photovoltaic (PV) and wind power—were integrated into the bulk electric system starting in the early 2000s, the industry initially relied on manufacturer-specific, user-written models to represent these resources in interconnection-wide studies. While these proprietary models provided detailed representations of individual technologies, their growing number posed significant challenges. Sharing models across software platforms and across the entire WECC region (nondisclosure agreements often restrict sharing such proprietary models), debugging the models when initialization or other problems occur were just some of these challenges. The lack of standardization made it difficult to manage and validate models across interconnection and regional planning studies. Seeing a need for a unified approach, the MVS, working closely with equipment manufacturers, utilities, research entities (EPRI, PNNL, NREL and Sandia National Labs), and generation developers provided an open forum to help lead the development of standardized (generic) IBR models. These models are designed to be flexible and broadly applicable and can represent a wide range of IBR technologies through appropriate parameterization. The adoption of generic models has delivered several key benefits:

- **Improved scalability**: Standard models reduce the complexity of managing numerous custom implementations, enabling more efficient study processes.
- **Enhanced interoperability**: A common modeling framework facilitates collaboration among stakeholders and ensures consistency across different simulation platforms.
- **Reliable validation**: Standard models, when properly parameterized, can accurately reflect the dynamic behavior of various IBR technologies, supporting robust system analysis.
- **Regulatory and planning support**: These models are now integral to interconnection wide studies and regional transmission planning, helping to ensure compliance with reliability standards and regulatory requirements.

The development of the generic models started with the wind turbine generators (WTG). As early as 2008, MVWG (through the Renewable Modeling Task Force) published a wind power plant power flow modeling guide [1]. Industry initiatives led by WECC between 2010 and 2014 culminated in development of the WECC second generation wind turbine models [2] [3]and central station PV system model [4] [5]. The work established the model structure for all IBR power plants upon which the models for battery energy storage systems (BESS) were developed [6] [7]. Since then, MVS has published many documents to guide the use of the RES models and added new modules to enhance functionality. During these years, research entities such as EPRI, PNNL, NREL and Sandia National Laboratories were quite engaged, as well as all the major power system simulation software vendors, many WECC utility members, consultants and several equipment vendors. All collaborated within the WECC MVS (and its predecessor MVWG). The forum was open to all comments and contributions.

- **RES modeling specification updates** [8]: developed model specification for a new set of modules to be added to the RES model library, including REGC_B, REGC_C, REEC_D, REPC_C, WTGWGO_A, WTGP_B,WTGT_B and WTGIBFFR_A.

- **Retirement of REEC_B model and conversion of REEC_B to REEC_A/D** [9]: discussed the limitations of REEC_B, the decision to retire REEC_B and the instructions to convert REEC_B model to REEC_A or REEC_D.
- **Modeling hybrid power plant of renewable energy and BESS** [10]: developed specification of power plant controller (PPC) power flow model and provided guidance on both power flow model and dynamic model for the hybrid power plants.
- **Clarification on proper use of REPC models** [11]: clarified the use of REPC_A and REPC_B models.
- **New plant controller and electrical controller models** [12]: developed model specification for REEC_E and REPC_D

More recently, MVS, in collaboration with PNNL, EPRI, manufacturers and many other industry groups, approved and implemented grid-forming (GFM) inverter and plant controller models.

- Model specification of droop-controlled GFM inverters [13]
- Model specification of virtual synchronous machine GFM inverters [14]
- Model specification of GFM hybrid control [15] [16]

2. Applicability of Generic Dynamic Models

The WECC generic models for IBR plants are based on the following technical specifications:

- The models shall be non-proprietary and accessible to transmission planners and grid operators and shall be open and public for use by all.
- The models shall provide a reasonably good representation of the dynamic electrical performance of IBR plants at the point of interconnection (POI) with the bulk electric system, and are not intended to capture internal collector-level details within the IBR plant itself.
- The models shall be suitable for studying system response to electrical disturbances, not solar irradiance transients or wind disturbance (i.e., available solar/wind power is assumed to be constant through the duration of the simulation). Electrical disturbances of interest are primarily balanced transmission grid faults (external to the IBR plant), typically 3—9 cycles in duration, and other major disturbances such as loss of generation or large blocks of load.
- Plant owners, inverter manufacturers and model users (with guidance from the integrators and manufacturers) shall be able to represent differences among specific inverter and/or plant controller responses by selecting appropriate model parameters and feature flags.
- Simulations performed using these models typically cover a 20-to-30-second period, with integration time steps in the range of 1 to 10 milliseconds.
- The models shall be valid for analyzing electrical phenomena in the frequency range of roughly 0.1 Hz to approximately 10 Hz.
- The models shall incorporate protection functions that trip the associated generation represented by the model or shall include the means for external modules to be connected to the model to accomplish such generator tripping.
- The models shall be initialized from a solved power flow case with minimal user intervention required in the initialization process.

- Power level of interest is primarily 100% of plant nominal rating in the steady state. However, performance shall be valid, within a reasonable tolerance, for the variables of interest (current, active power, reactive power and power factor) under multiple operating conditions within the operating range.
- Except for the GFM inverter models, the models shall perform accurately for systems with a short circuit ratio of approximately three and higher at the POI with proper parameterization.
- External reactive compensation and control equipment (i.e., external to the inverters) shall be modeled separately using existing WECC-approved models.

As stated in a WECC white paper on the value and the limitations of the generic models [17], the generic models were developed for good numerical behavior when using a reasonable integration time step for area-wide stability analysis. There is always a compromise between accuracy and detail. Inordinate accuracy demands for any individual power system component lead to excessive complexity and does not necessarily lead to better planning decisions. The limitations of the generic model fall into the following categories:

1. They are not intended for use in performing studies of phenomena outside of the typical range of frequencies of interest in power system stability studies (i.e., 0.1–10 Hz). Therefore, these models are not adequate for studying phenomena such as switching transients, torsional interactions, harmonics, and other electromagnetic transients.
2. They are not intended for detailed analysis of unbalanced phenomena.
3. They are not intended for detailed local studies associated with control tuning and design for the interconnection of IBR plants to very weak systems (i.e., short-circuit ratios below approximately two or three). However, once an IBR plant has been tuned for weak systems, the parameterization can be mapped onto these generic models.

The use of standardized generic models does not eliminate the need for user-written models, which utilities may still require. These custom models, when tuned with field data, can more accurately represent specific control and protection schemes, making them particularly valuable for localized or stressed system studies. However, it is important to note that in the context of this document, user-written models, like generic models, operate in the phasor domain and share the same inherent limitations.

3. Power Flow Representation

3.1. General Modeling Requirements

The WECC Data Preparation Manual [18] states that single generating units 10 MVA or higher, or aggregated capacity of 20 MVA connected to the transmission system (60 kV and above) through a step-up transformer(s) should be modeled as distinct generators in WECC base cases. It also states that collector-based systems, such as wind or solar plants connected to the transmission grid, may be represented as an equivalent generator, low voltage to intermediate voltage transformer, equivalent collector circuit, and transformer.

MVS recommends that each IBR power plant (aggregated capacity ≥ 20 MVA and connected to 60 kV and above) is modeled explicitly in the power flow model. The power flow representation includes:

- An explicit representation of the interconnection transmission line if one exists
- An explicit representation of all substation transformers and other main substation equipment (e.g., shunt compensation at the substation)
- An equivalent representation of the collector systems
- An equivalent representation of inverter step-up transformers (i.e., from inverter low-voltage terminals to collector medium-voltage) with a scaled MVA rating
- An equivalent representation of the IBR units (generators) scaled to match the total capacity of the plant
- An explicit model of the PPC

Typically, each technology behind a substation transformer is represented by one set of equivalent generators, unit step-up transformer, and equivalent collector unless the technologies are dc-coupled. DC-coupled technologies are represented by a single equivalent set since they share a common inverter.

Figure 1 illustrates a simple IBR power plant with one substation transformer. It could be a wind, solar, battery storage or dc-coupled hybrid power plant. Figure 2 illustrates a more comprehensive arrangement. There are multiple substation transformers, each modeled explicitly. Equivalent Generator 1 could be single technology or dc-coupled hybrid technology. Equivalent Generator 2 and 3 are different technologies coupled on the ac side of the inverters, or they could be the same technology of different makes. In this latter case, different makes of the inverters have different reactive capability, control setup and protection setup. Therefore, a multi-generator representation is appropriate.

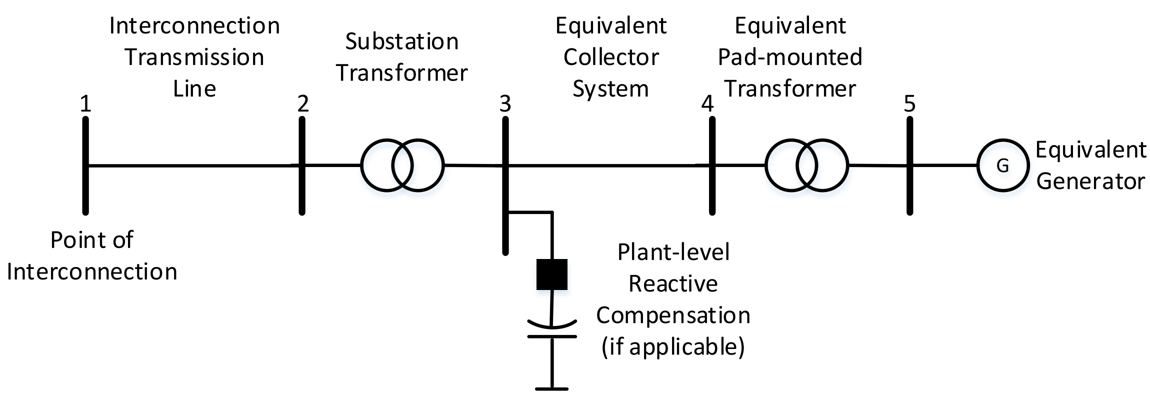

Figure 1: Illustrative Single-generator Equivalent Power Flow Representation for an IBR Power Plant

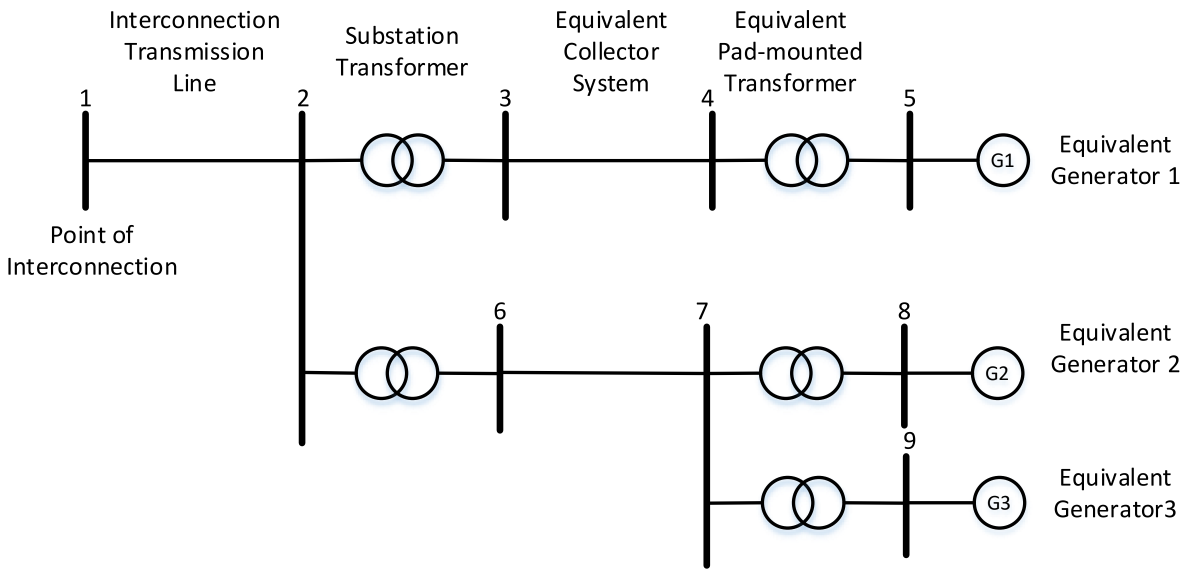

Figure 2: Illustrative Multiple-generator Equivalent Power Flow Representation for an IBR Power Plant

In these models, an equivalent generator represents the total generating capacity of a group of inverters, the equivalent unit step-up transformer represents the aggregate effect of all inverter to mid-voltage transformers, and the equivalent collector system branch(es) represents the aggregate effect of the collector system. With the proper model parameters, this model should approximate plant load flow characteristics at the interconnection point, collector system real and reactive losses and voltage profile at the terminals of the “average” inverter in the plant. Each component of the equivalent model is discussed below.

3.1.1. Implications of Collector System Equivalencing

Due to collector system effects, terminal voltage of individual inverters could vary somewhat, especially in very large PV or WTG plants where the electrical distance between inverters may be significant. Inverters that are closest to the interconnection point may experience significantly different terminal voltage compared to inverters that are electrically farthest from the interconnection point. In actual operation, terminal voltage of some inverters may reach control or protection limits, resulting in different terminal behavior, or tripping. Hence, during the design stage, or in special cases, it may be reasonable to use a more detailed representation of the collector system to capture these details.

3.1.2. Interconnection Transmission Line

Standard data includes nominal voltage, positive-sequence line parameters (impedance and charging) and line normal and emergency ratings.

3.1.3. Substation Transformer

Transmission-connected IBR plants require one or more substation transformers. Each substation transformer should always be represented explicitly. Standard data includes transformer nominal voltage of each winding, impedance, tap ratios, regulated bus and set point, and ratings. Positive-sequence impedance for station transformers is in the range of 6–10%, and X/R ratio in the range of 20 to 50. It is also important to properly model the fixed-tap position of the substation transformer in power flow, and, in the case of on-load tap-changers (OLTC), to model the OLTC in power flow.

3.1.4. Plant Level Reactive Compensation

IBR plants could have fixed and/or switched capacitors installed on the collector system, and more typically at the substation level. If present, these shunt capacitors should be explicitly modeled in power flow. The *WECC Data Preparation Manual* states that each switched capacitor/reactor should be modeled explicitly. Standard data includes nominal rating, impedance, and controlled device, if applicable. Operation of the shunt devices is coordinated with the plant-level reactive controller (see equivalent generator representation).

3.1.5. Equivalent Collector System

IBR plants collector systems consist of one or more medium voltage feeders. Factors considered in feeder design include cost, real power losses, and voltage performance. A typical design goal is to keep average real power losses below 2–4% when the plant is at full output. The collector system network is typically underground. For that reason, the equivalent collector system X/R ratio tends to be low compared to typical overhead circuits. However, for large wind power plants, segments of the collector system may also be overhead distribution lines. The equivalent collector system impedance tends to be small compared to the substation transformer impedance, but it is significant.

A simple method developed by NREL [19] can be used to derive equivalent impedance (Z_{eq}) and equivalent susceptance (B_{eq}) of a collector system consisting of radial elements. The computation is as follows:

$$Z_{eq} = R_{eq} + jX_{eq} = \frac{\sum_{i=1}^{I} Z_i n_i^2}{N^2},$$

$$B_{eq} = \sum_{i=1}^{I} B_i ,$$

where

I is total number of branches in the collector system,

Z_i is the impedance ($R_i + jX_i$) for ith branch,

n_i is the number of inverters connected to the ith branch, and

N is the total number of inverters in the whole collector system.

Branch impedance data can be obtained from collector system design (conductor schedule) for the project. As stated before, the equivalent impedance computed in this manner approximates real and reactive losses seen by the “average inverter” in the plant. This calculation can be easily implemented in a spreadsheet. Figure 4 shows a simple example with nine branches (I = 9), and 21 inverters (N = 21). The corresponding calculations are shown in Table 1. In this example, the inverters are 7 clusters of 3 inverters. In general, larger IBR power plants would have lower Z_{eq} and higher B_{eq} considering that more parallel feeders would be required.

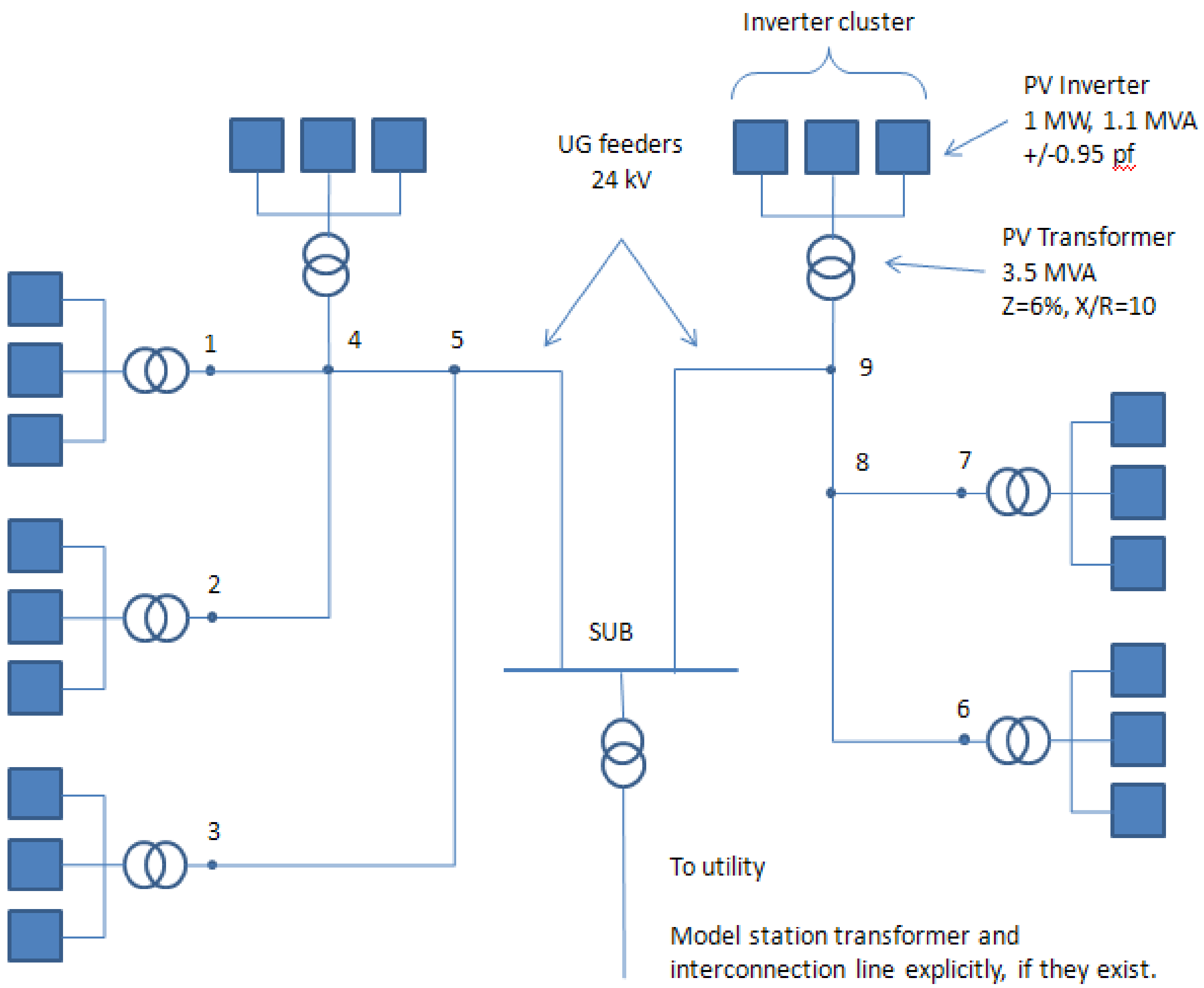

Figure 3: Sample Utility-Scale IBR plant topology

Table 1: Computation of collector system equivalent parameters for the sample system in Figure 4

From	To	R	X	B	n	R n^2	X n^2
1	4	0.03682	0.00701	0.000000691	3	0.33136	0.06307
2	4	0.02455	0.00467	0.000001036	3	0.22091	0.04205
4	5	0.02455	0.00467	0.000001036	9	1.98816	0.37843
3	5	0.02557	0.02116	0.000000235	3	0.23016	0.19042
5	**SUB**	**0.02557**	**0.02116**	**0.000000235**	**12**	**3.68251**	**3.04673**
6	8	0.03747	0.00868	0.000000561	3	0.33726	0.07809
7	8	0.02455	0.00467	0.000001036	3	0.22091	0.04205
8	9	0.02109	0.02501	0.000000199	6	0.75925	0.90025
9	**SUB**	**0.02109**	**0.02501**	**0.000000199**	**9**	**1.70831**	**2.02555**

RESULTS

Partial R sum	9.4788
Partial X sum	6.7666
N	21

Collector System Equivalent
(Same units as R, X & B data)

Req	0.021494	pu
Xeq	0.015344	pu
Beq	0.000005	pu

3.1.6. Equivalent Unit Step-Up Transformer

IBR plants have many medium-voltage step-up transformers, each connected to one or more IBR inverters.

Assuming that all step-up transformers are identical, and each connects to the same number of inverters, the per-unit equivalent impedance (Z_{Teq}) and the equivalent MVA rating (MVA_{Teq}) can be computed as follows, where N is the total number of inverters in the whole collector system:

$$Z_{Teq} = Z_T$$

$$MVA_{Teq} = N \times MVA_T$$

In these equations, Z_T is the impedance of one transformer on its own MVA base (MVA_T). For the example system discussed above, the equivalent transformer impedance would be 6% on a 21 MVA base (7 X 3 MVA), with an X/R ratio of 10. If there are different transformer sizes or a different number of inverters are connected to each transformer, the method shown in Table 1 can be applied to calculation of the equivalent transformer impedance. Step-up transformers associated with utility-scale IBR plants are in the range of 500 kVA to 5 MVA, and have impedance of approximately 6–10% on the transformer MVA base, with X/R ratio of about 8.

More recently, certain inverter manufacturers will integrate the inverter unit transformer with the inverter, then the unit is tested, and all data and models are provided, as referenced to the medium voltage level. Moreover, the inverter control inputs are also taken from the terminal of the integrated unit. Thus, the unit is essentially directly connected to the medium voltage collector system. In such cases, the integrated unit transformer is not explicitly modeled in the power flow model. The unit is modeled as an equivalent generator directly connected to the collector system medium voltage.

3.1.7. Equivalent Generator Representation

For load flow simulations, the equivalent generator should be represented as a standard generator. Active power level and reactive power capability must be specified according to the guidelines below. According to the WECC data preparation manual, the following turbine types are used for IBR equivalent generators:

23 = type 3 wind turbine (onshore only)

24 = type 4 wind turbine (onshore only)

25 = wind turbine (offshore)

31 = photovoltaic (unknown or mix)

32 = photovoltaic (fixed)

33 = photovoltaic (tracking)

42 = energy storage—battery

43 = energy storage—flywheel

44 = energy storage—other

46 = energy storage—compressed air

48 = fuel cell

Modeling considerations for hybrid resources are discussed in section 3.1.7.3 below.

3.1.7.1. Active Power Capability

It is common that an IBR plant installs more gross capacity than needed for its contracted MW capacity value. The MW capacity, i.e., PMAX in the base case model, of the equivalent generator shall be set to the maximum output allowed by its interconnection agreement with the utility, instead of the physical capacity. The MVA base of the equivalent generator, on the other hand, represents the sum of the physical MVA base of all the inverters.

For energy storage resources, the negative PMIN in the power flow model reflects the maximum charging power allowed by its interconnection agreement.

3.1.7.2. Reactive Power Capability

Interconnection requirements and performance standards addressing reactive power capability from large IBR systems was established in FERC Order 827 [20]. Newly interconnecting non-synchronous generators are required to maintain a composite power delivery at continuous rated power output at the high side of the generator substation. At that point, the non-synchronous generator must provide dynamic reactive power within the power factor range of 0.95 leading to 0.95 lagging, unless the transmission provider has established a different power factor range that applies to all non-synchronous generators in the transmission provider's control area on a comparable basis. Non-synchronous generators may meet the dynamic reactive power requirement by utilizing a combination of the inherent dynamic reactive power capability of the inverter, dynamic reactive power devices (e.g., Static VAR Compensators), and static reactive power devices (e.g., capacitors) to make up for losses.

The inverter reactive power capability depends on the inverter dc voltage, inverter ac apparent current limit, ambient temperature, as well as the operating condition in terms of terminal voltage and active power current. Figure 4 shows an example of reactive capability curves for PV inverters at nominal voltage under different ambient temperatures. The temperature-dependent capability rating may cause derate of the active power capacity Pmax. Depending on the scenario of the power flow case, PMAX of the solar PV generators may be adjusted to represent the appropriate rating under the temperature condition. For example, PMAX at higher temperature should be used in a summer peak base case and PMAX at average temperature could be used in a spring day-time off-peak base case. The reactive capability of inverters at PMAX under the temperature shall be represented as Qmax/Qmin for the equivalent generator.

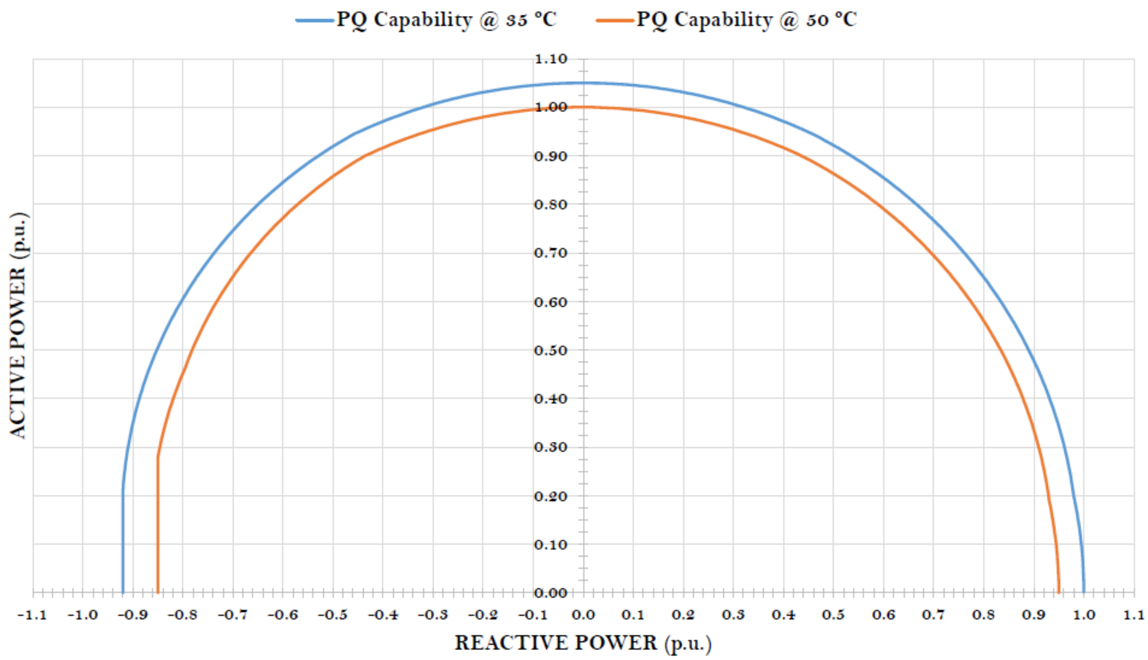

Figure 4: Sample Inverter Reactive Capability Curve

The plant reactive capability at the point of measurement (POM) includes the capability from all other reactive devices accounting for the plant internal reactive sources. Figure 5 illustrates plant reactive capability with and without the capacitor banks on, as well as the reactive capability requirement per FERC Order 827. At lower active output, the reactive capability requirement is lower as dictated by the power factor and shown as the V-shape curve in Figure 5.

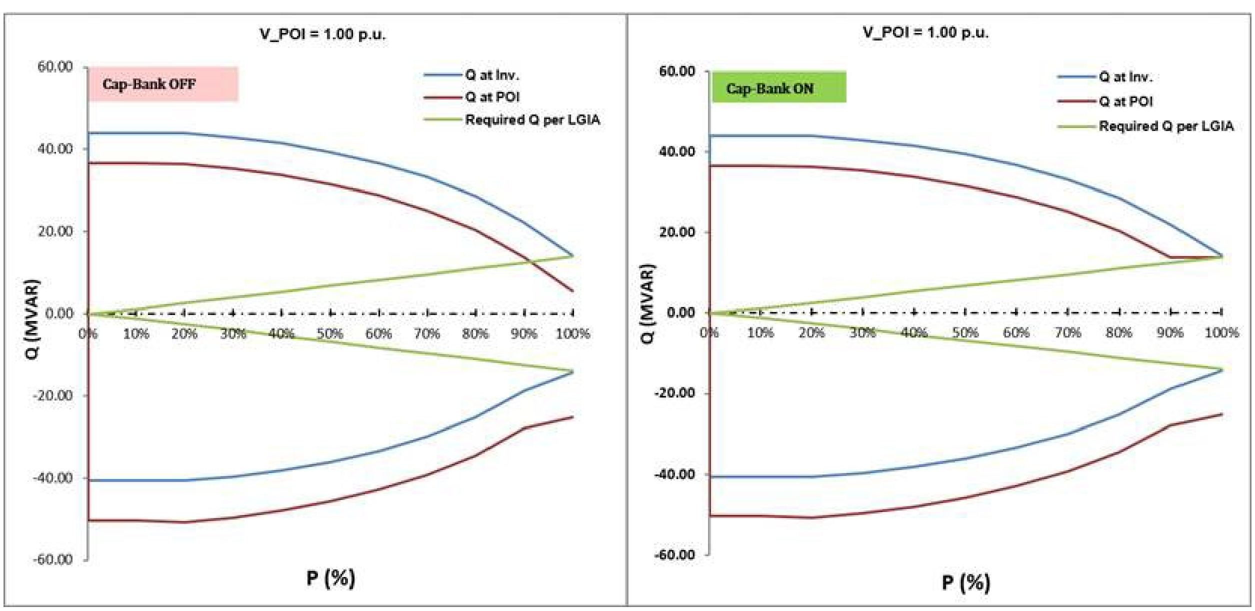

Figure 5: Sample Plant Reactive Capability Curve

Many utilities within WECC (and elsewhere) have adopted IEEE Standard for Interconnection and Interoperability of Inverter-based Resources Interconnecting with Associated Transmission electric Power Systems, i.e., IEEE Std 2800™-2022, which has more stringent reactive capability requirements. Except for Type 3 WTG plant, an IBR plant is required to maintain the reactive capability of ±0.95 power factor at the rated continuous active power output regardless of the active power output. To explain this more clearly, consider an IBR plant that has a rated continuous active power output of 100 MW. Then according to IEEE Std 2800™-2022, the reactive power capability at the POM, which is the high-voltage side of the substation power transformer, should be ±32.9 Mvar for the entire active power range of the plant from 0 to 100 MW. For type 3 wind turbines, the reactive power capability may drop linearly starting from 10 MW (10% of rated power) down to 0 Mvar at 0 MW output. For a BESS, the reactive capability must be symmetrical for both charging and discharging. There are further details related to the reactive capability as a function of system voltage—the interested reader should consult IEEE Std 2800™-2022. Presently, most entities are adopting requirements similar to IEEE Std 2800™-2022 and so this is the recommended path for new facilities.

When required, the power factor of individual inverters can be adjusted via a plant-level reactive controller to meet operating requirements at the POM[1]. Several control modes are possible:

- Closed-loop voltage control—Maintain voltage schedule within the reactive power capability of the IBR plant, over a certain range of real power output. A small voltage hysteresis or dead band may be appropriate in some situations. For instance, the requirement may be to regulate voltage at the interconnection point within 1% or 2% of schedule.
- Voltage droop control—Increase or decrease reactive power output linearly, as a function of voltage. This type of control allows the plant to provide voltage support while avoiding large reactive power swings that a small plant would see when connected to a relatively strong transmission system and ensures all local generators response to the voltage changes in a coordinated way. A small dead band may be implemented.
- Power factor control—Maintain power factor at the interconnection point close to a specified level. For instance, the requirement may be to maintain power factor between 0.98 lead and unity at the interconnection point.
- Reactive power control—Maintain reactive power flow within some specified limits. For instance, the requirement may be to limit reactive power flow at the interconnection point to 5 or 10 MVAr, in either direction.

It should be noted that in general all utility connected IBR plants should be in either closed-loop voltage control or voltage-droop control. Power factor and constant reactive power control is not allowed per NERC VAR-002 unless an exemption is granted for well documented reasons.

Representation of reactive power capability of the equivalent inverter depends on the reactive range of the inverters, and how that range is used in operations. If the reactive capability is used up to the requirement, the equivalent generator load flow model should be set to power factor control mode, i.e.,

[1] The plant level controller also coordinates operation of the switched capacitors, if present.

the actual Qmax/Qmin is limited by the power factor at the active power output. If the full reactive capability is used, the best modeling approach is to use the Q-table or the option to calculate Qmax/Qmin from MVA rating and active power output. The power flow software could calculate the actual Qmax/Qmin at the current active power output.

3.1.7.3. Consideration for modeling hybrid plant

Hybrid power plants are becoming increasingly popular due to cost savings, flexibility, and higher energy production by sharing land, infrastructure, and maintenance services. Hybrid power plants, or hybrid resources, are defined as [21]:

> **Hybrid Power Plant (Hybrid Resource):** A generating resource that is comprised of multiple generation technologies that are controlled by a single entity and operated as a single resource behind a single POI.

There are many types of hybrid power plants, some include combined heat and power with solar PV and possibly energy storage. However, the predominant type of hybrid power plant seen in interconnection queues across WECC is the combination of renewable energy (solar PV or wind) and battery energy storage technologies. The configuration of the hybrid plant can be classified as one of the following:

- **AC-coupled Hybrid Plants:** An ac-coupled hybrid power plant couples each form of generation after it has been converted through a power electronics interface from dc to ac. For example, a BESS system will be coupled with a wind or solar PV facility on the ac-side of the inverters' interfaces, often at the medium voltage bus on the low-side of the main power transformer for the plant. The conversion from dc to ac occurs at each solar inverter or wind turbine, as with other inverter-based generating resources. Figure 7 shows a simple illustration of an ac-coupled hybrid power plant where a BESS is coupled with a solar PV or wind power plant on the ac side.
- **DC-Coupled Hybrid Plants:** A dc-coupled hybrid power plant couples both sources on the dc side of each inverter, prior to its conversion to ac. Each individual dc-ac inverter has a BESS and generating resource coupled at the dc bus, which is then simultaneously converted to ac for the combined BESS and generating component. Figure 7 shows a simple illustration of a dc-coupled hybrid power plant, where the energy storage component is coupled to each individual inverter on the dc side.

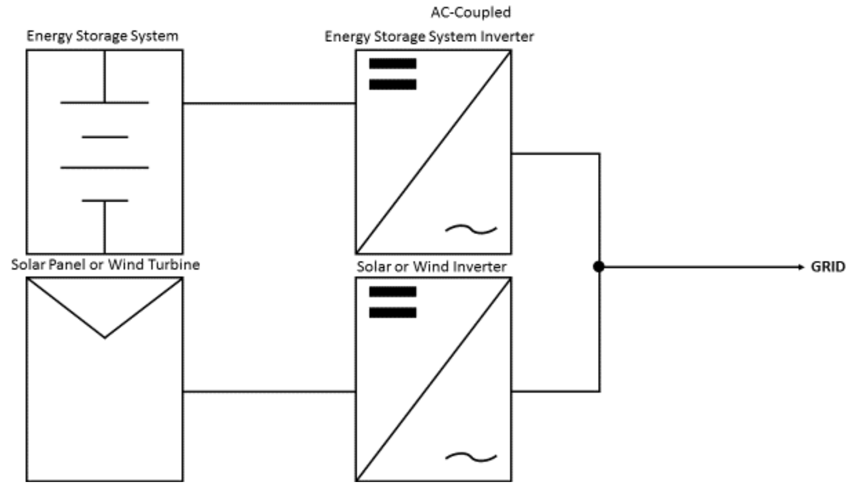

Figure 6: AC Coupled Renewable Resource and Energy Storage

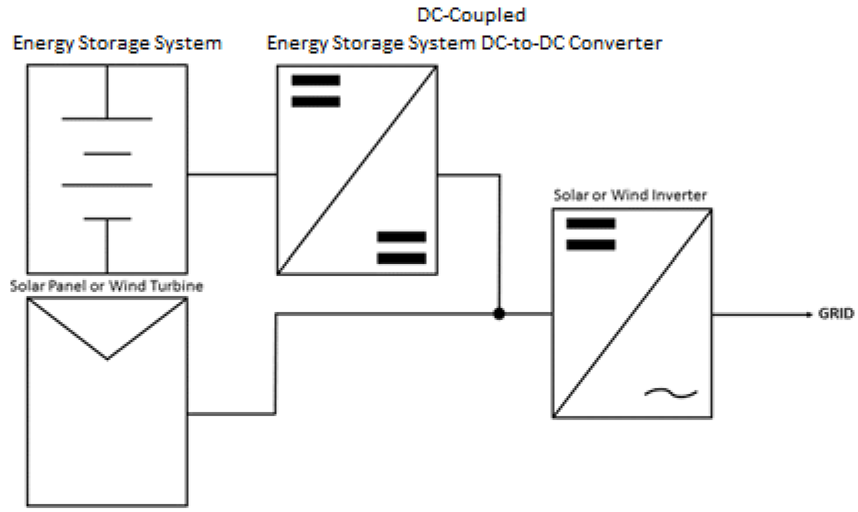

Figure 7: DC-coupled Renewable Resource and Energy Storage

If the renewable resource and battery storage each has its own set of inverters, i.e. ac coupled (Figure 6), the renewable resource and battery storage should both be modeled explicitly by separate equivalent generators, equivalent pad-mounted transformers and equivalent collectors. The reactive capability requirement applies to the entirety of the renewable resource and battery storage generators at the POM.

If the renewable resource and battery storage are dc-coupled (Figure 7), one equivalent generator will represent the inverters for both renewable resource and battery storage. A negative Pmin of the equivalent generator represents the maximum charging power if the battery storage charges from the grid.

To properly model the hybrid power plant, the PPC should be represented in the power flow. The PPC model is detailed in the next section.

3.1.8. PPC Representation

A PPC power flow model is needed for IBR plants to implement voltage droop control and facilitate MW control at the POI. Each PPC model is associated with one or more generators. The PPC model includes active power monitoring and voltage/var control.

3.1.8.1. PPC active power monitoring

The active power monitoring requires three parameters:

- Limit Bus: bus where the plant MW injection limit is applied.
- Pmax: maximum active power for the plant.
- Pmin: minimum active power for the plant.

The PPC model will calculate and indicate if the MW being injected at the Limit Bus from the devices in the PPC are exceeding the Pmax/Pmin limits.

3.1.8.2. PPC voltage/var control

Controllable reactive devices, in addition to the generator(s), can be assigned to a PPC for voltage/var control. The PPC has a Regulated Bus and a voltage droop curve at the Regulated Bus.

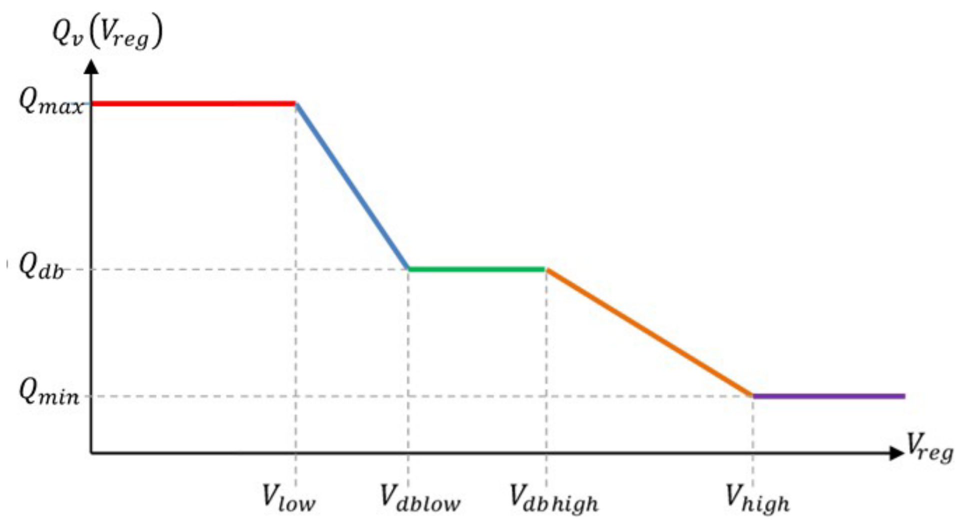

Figure 8: Voltage Droop Curve in PPC

Parameter	Description	Example
RegBus	The bus where plant voltage regulation is done	High side of the substation transformer
Vdblow	Low end of the voltage regulation deadband	0.99 (-0.01)
Vdbhigh	High end of the voltage regulation deadband	1.01 (0.01)
Qdb	Reactive power at the RegBus when the voltage is within the regulation deadband	0

Qmax	Maximum reactive power at the RegBus being contributed by the devices in the PPC	0.329 x PPC Pmax
Vlow	Voltage at the RegBus when the plant reactive power reaches Qmax	0.95 (-0.05)
Qmin	Minimum reactive power at the RegBus being contributed by the devices in the PPC	0.329 x Lower of (- PPC Pmax, PPC Pmin)
Vhigh	Voltage at the RegBus when the plant reactive power reaches Qmin	1.05 (0.05)
Vdeviation	The flag that determines how Vlow, Vdblow, Vdbhigh and Vhigh are treated: No (0): the parameters are absolute voltage in per unit value. Yes (1): the parameters are deviation from RegBus voltage schedule	0 (1)
Qauto	The flag determines how to use Qmax and Qmin: User (0): User inputs of Qmax and Qmin are used. This option can be used to model the IEEE 2800™-2022 reactive capability requirement. Auto (1): Qmax and Qmin are sum of the individual device qmax and qmin; Qdb=0 PF (2): Qmax and Qmin are calculated from the PF and the sum of Pgens of all participating generators. This option can be used to modeled the FERC 827 reactive capability requirement.	0
PF	Power factor required at the RegBus; used to calculate Qmax and Qmin if Qauto = 2.	0.95

3.2. Modeling during post transient power flows

Modeling of IBR generation and reactive compensation components should be consistent with WECC post-transient methodology. Control devices that can complete switching or operation within 3 minutes (e.g., SVCs, STATCOMS and shunts under automatic control) should not be blocked. Devices that require operator action should be blocked. The equivalent generator should have the Base Load Flag set to “1” if the output should not increase during a governor power flow or set to “2” if the output should not change during a governor power flow.

4. Dynamic Modeling

4.1. Active Power / Frequency Control

Average irradiance over a large PV plant or wind condition can change appreciably during the span of a typical dynamic simulation (up to 30 seconds). By default, the WECC generic models assume a fixed reference generator output in the solved power flow case. Presently, there is no provision for incorporating simulation of irradiance or wind variability in large-scale system studies. This approach is prudent given that the effect of AGC is not included in dynamic simulations. The generic models do allow for the specification of active power control, including ramp rate limits, frequency response and active/reactive power priority during voltage dips. Primary frequency response is required for the IBR resources within their operating limits. Solar PV and wind resources typically operate at the full output allowed by the radiance and wind condition. Therefore, they do not have an upward headroom for primary frequency response. For such a situation, both the power flow model and the dynamic model shall reflect the downward only primary frequency response (i.e., Base Load Flag set to “1”). However, the solar PV and wind resources may provide upward frequency response if operating below maximum available output during a low-frequency event.

4.2. Reactive Power / Voltage Control

Reactive power capability and response characteristics are important considerations in system studies. A variety of reactive power control modes can be implemented in an IBR power plant. Typically, IBR plants are required to maintain the voltage at the POM at the given voltage schedule, up to the required reactive power capability. Implementation of such requirement varies among different utilities. The dynamic models should reflect the implementation by coordinating the plant controller model and the inverter electrical control model. During a dynamic event, the reactive power response is the net result of fast inverter response and slower supervisory control by the plant controller. Under large disturbance, as indicated by abnormal voltage conditions, the slower plant control freezes and the fast inverter control takes over. The inverter reactive power output during the transient period is not limited by the power factor requirement. Instead, it is limited by the inverter current rating and the priority between producing active current and reactive current.

4.3. Fault Ride-through and Representation of Protection Limits

An important part of a dynamic performance evaluation is whether the IBRs trip offline for a given voltage or frequency disturbance. The equivalent representation and simplified dynamic models described here are not recommended for evaluation of fault ride-through. Whether or not an inverter will ride through a voltage disturbance depends on the type of fault and the magnitude of the remaining voltage at the inverter terminals. The control actions that affect the behavior of the inverter during the span of a short fault are generally not modeled in detail in the generic dynamic models. This limitation is acceptable because system studies focus on the characteristics of dynamic recovery, rather than on system conditions during the fault. Considering that terminal voltage can vary significantly across the plant, a single machine representation has obvious limitations with respect to assessment of voltage ride through.

Some older solar PV inverters blocked the inverters (momentary cessation) for even remote faults (e.g., voltage dips > 10% of nominal voltage) as a means of ride-through. The inverters remain connected but stop current injection into the grid during low or high voltage conditions outside the continuous operating range (i.e., when voltage deviated outside of 0.9 pu < V < 1.1 pu). This inverter-blocking behavior can be modeled with voltage-dependent current limits in the dynamic models. Since the equivalent generator and collector system are modeled, the model can only be an approximation. Furthermore, when a mix of inverters deploying different settings for inverter-blocking are installed in the plant, modeling all inverters by one equivalent generator would introduce significant inaccuracy. It is better practice to model each group of inverters by one equivalent generator.

5. WECC Generic Models

The WECC Model Validation Subcommittee (MVS) has developed a set of dynamic models for renewable energy power plants using a modular approach. The models are available as standard-library models in commercial simulation platforms used in WECC.

5.1. Summary of 2nd Generation Generic RES Dynamic Models

WECC MVS has been developing over the past ten years a series of modularized, standard and publicly available sets of dynamic models for use in large system planning studies for the main forms of RESs [2] [4] [6] [8] [12] . These model structures are called "generic" models since they are not specific to any particular vendor and can be parameterized to adequately emulate the dynamic behavior of many vendors' equipment.

5.1.1. Model Structure

Dynamic representation of IBR plants requires the minimum use of three renewable energy (RE) modules listed below and shown in Figure 9. A fourth set of modules are needed to represent the WTG. In addition, there are auxiliary controller modules recently developed.

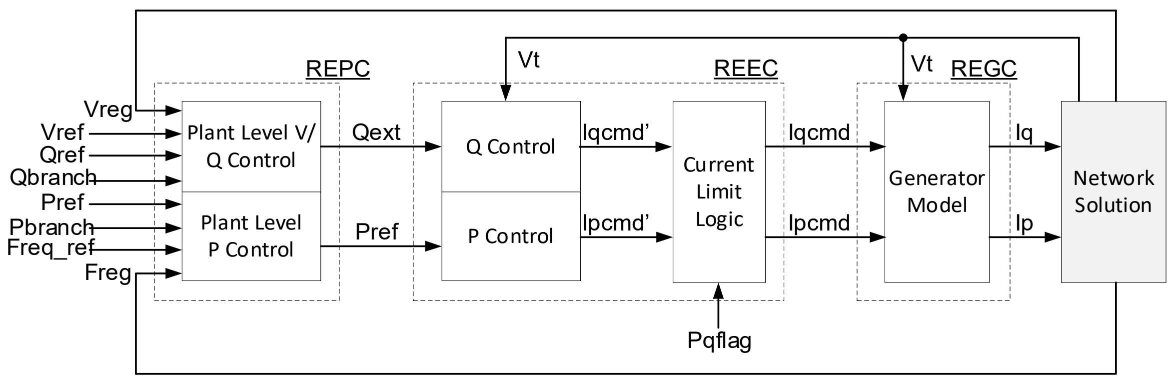

Figure 9: Block Diagrams of Different Modules of the WECC Generic Models

1. **Renewable Energy Generator/Converter (REGC_*) models**: These modules are used to model the electrical generator and/or power converter interface between the generation unit and the grid. There are three (3) such modules:
   a. **REGC_A**—this is the original model developed many years ago. It is a current-source model. It is quite adequate for modeling the generator dynamic behavior of the generator/converter interface. It is not suitable for weak-grid connection points, where the short-circuit ratio (SCR) of the POI may be around 2-to-3 or less.
   b. **REGC_B**—this is a newly developed and approved voltage-source generator/converter interface model. It is better suited to weak-grid conditions, and if parameterized appropriately has been shown to behave numerically down to SCRs close to 1.
   c. **REGC_C**—this is a new model available in most of the software platforms, but not approved for use in WECC. It incorporates a generic representation of the phase-locked loop (PLL) and inner-current control loops, as well as being a voltage-source model. It intends to offer a

more detailed model for circumstances where an RES plant is connected to an extremely low short-circuit ratio node (e.g., SCR < 2 or 3).

REGC_A and REGC_B are both approved models on the WECC approved model list, and both can be legitimately used for modeling the generator/converter interface of a RES. The choice of the model should be based on the location of the plant being modeled (weak connection point versus strong connection point) and the best data currently available for the plant being modeled. Also, it may be possible in some cases that the point-of-interconnection of the plant becomes weak over time (e.g., additional IBRs come into the network in the vicinity of the plant). In such cases there may be a need to transition from an REGC_A model to an REGC_B model.

2. ***Renewable Energy Electrical Controls (REEC_*) models***: These modules are used to model the electrical controls at the individual generating unit level, i.e., individual wind turbine generator, individual PV inverter, etc. There are three (3) such modules:
   a. ***REEC_A—***this is the original model developed and can be used, if appropriately parameterized for wind and PV generators.
   b. ***REEC_C—***this module was developed specifically for battery-energy storage systems (BESS) or can also be used to model hybrid PV-BESS systems, particularly when the BESS and PV and coupled on the dc-side of the inverter and share one common inverter.
   c. ***REEC_D—***this module contains new features, such as extended voltage-dependent current limit tables. As such, when modeling new facilities this model may offer greater flexibility and features. It can be used to model wind, PV and BESS.
   d. ***REEC_E—***this module is identical to the REEC_D model with a few additions, namely local PI control of reactive power or power factor, local PI control of active power and a new P/Q-priority flag during fault.
3. ***Renewable Energy Plant Controller (REPC_*) models:*** These modules are used to model the plant level controls that monitor the point of common coupling (PCC) or POI of a plant and issues real and reactive power commands to all the individual generating units in the plant to control the real and reactive power at the PCC (or POI). The are three such models:
   a. ***REPC_A—***this is the original simple plant level controller. It allows for volt/var control and active power control. It does not include power factor control.
   b. ***REPC_B—***this is a complex-plant controller to be used primarily for hybrid plants, which include multiple technologies, e.g., a combination of two different wind turbine technologies, or wind and PV, etc. It does also allow for power factor control at the PCC (or POI). REPC_B has many limitations that require special attention of the user [22]. It is recommended that all new facilities useREPC_D and refrain from using REPC_B in the future, due to its limitations.
   c. ***REPC_C—***this module presents significant additional features and flexibility including, power factor control at the PCC (or POI), ability to have coordinated and automatically switched shunt devices at the PCC (or POI), and extra features for active power control.
   d. ***REPC_D—***this model builds on REPC_C to control multiple aggregated renewable system models downstream, but without some of the limitations of REPC_B. An important note is that while removing the limitations of REPC_B, it introduces a significant burden on the user

to ensure that the initial power flow solution for the plant is reasonable. For example, the initial Q output of all the downstream aggregated units in general should be in proportion to their respective MVA bases.

4. ***Mechanical Element Models for Wind Turbine Generators:*** specifically for WTGs, there are a series of mechanical side models. Presently, for type 4 WTGs the only mechanical model used is an emulation of the drive-train dynamics [8]. All the other models are used only for type 3 WTGs. The models are:
   a. ***WTGT_A***—this is a two-mass model of the WTG drivetrain.
   b. ***WTGA_A***—this is a very simple aero-dynamic model for the type 3 WTG based on [24].
   c. ***WTGP_A***—this is a simple model of the pitch control system.
   d. ***WTGQ_A***—this is a simple model of the torque control system.
   e. ***WTGT_B***—this is a new two-mass model to be used for type 4 WTGs [8]. The model incorporates a small modification to mitigate a problem seen in the WTGT_A model when used with type 4 WTGs—see [8] for more details.
   f. ***WTGP_B***—this is a new refined pitch-controller model, which provides added flexibility in the limits of the pitch controller [8].

   WTGT_A, WTGA_A, WTGP_A, WTGP_B and WTGQ_A are all currently approved models in WECC and should be used when modeling a type 3 WTG (Note: for the pitch-controller only one of the two models WTGP_A or WTGP_B is needed). When modeling a type 4 WTG, due to the full-converter interface, for stability simulations, it has been shown that none of these models are necessary. In some cases where one may desire to emulated the torsional ripple seen in the electrical power of the WTG following a close-in fault, the WTGT_B model may be used. Note: WTGT_B is not to be used for a type 3 WTG.
5. ***Auxiliary Controllers:*** These are new modules being developed and yet to be fully benchmark tested and approved by WECC. Yet they have already been tested as user-written models (see [8]).
   a. ***WTGWGO_A***—this is an auxiliary controller model, used primarily on type 4 WTGs, for improving the post-fault recovery of type 4 wind power plants for PCC (or POI) connection points that have low SCR. The WGO stands for weak-grid option.
   b. ***WTGIBFFR***—This is another auxiliary control module that is available from many wind turbine manufacturers and is called the inertial-based, fast-frequency response (IBFFR) controls.

5.1.2. Summary of WECC Approved Generic Models

Table 2 summarizes the models associated with each type of IBRs. These modules do not include inverter or plant protection. However, existing generator protection models can be used to represent time-delayed voltage and frequency protection settings. Table 3 shows the list of modules implemented in the simulation platforms commonly used in WECC. Although the internal implementation may differ across simulation platforms, the modules have the same functionality and parameter sets.

Table 2: Generic Models for Each Type of IBR

RES	Model Combination
Type 3 WTG	regc_a/b, reec_a/d/e, repc_a/c/d, wtgt_a, wtga_a, wtgp_a/b, wtgq_a
Type 4 WTG	regc_a/b, reec_a/d/e, repc_a/c/d: wtgt_b
PV plant	regc_a/b, reec_a/d/e, repc_a/c/d
BESS	regc_a/b, reec_c/d/e, repc_a/c/d

Note: In some cases the more appropriate plant controller model to use may be *repc_d*, for example, for hybrid-plants, plants that have two or more aggregated inverter-based generating units, where plant level power factor control is used, etc.

5.2. WECC Generic Model for Transmission Connected IBR Plants

5.2.1. Model Invocation

The model invocation varies according to the software platform. Users must follow the instructions provided with the appropriate software documentation. The example described below is for the GE Vernova PSLF™ platform, using the simple test system shown in Figure 10. This example is for a plant rated 110 MVA plant, which would correspond to a PV plant rated 104.5 MW and inverters sized for 0.95 leading or lagging power factor at rated power and rated voltage.

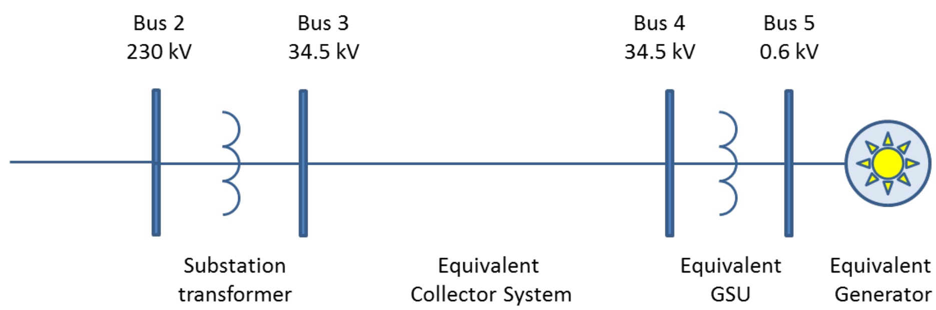

Figure 10: Test System for a Large-scale PV Plant Model

```
regc_a 5 "Test" 0.6 "1 " : #9 mvab=110.0 "lvplsw" 1.000000 "rrpwr" 1.40000 "brkpt"
0.900000 "zerox" 0.500000 "lvpl1"   1.0000 "vtmax"   1.1000 "lvpnt1" 0.050000
"lvpnt0" 0.01 "qmin" -1.000000 "accel" 0.7 "tg" 0.020000 "tfltr" 0.01000 "iqrmax"
20.00000 "iqrmin" -20.00000 "xe" 0.0

reec_a 5 "Test" 0.6 "1 " : #9 "mvab" 0. "vdip" 0.500000 "vup"   1.1000 "trv"
0.01000 "dbd1" -0.05 "dbd2" 0.05 "kqv"   2.0000 "iqh1" 1.000 "iql1" -1.000 "vref0"
1.0 "iqfrz" 0.0 "thld" 0.0 "thld2" 0.0 "tp" 0.01000 "qmax" 0.6000 "qmin" -0.6000
"vmax"   1.2000 "vmin" 0.800000 "kqp" 1.0000 "kqi" 1.00000 "kvp" 1.0000 "kvi"
1.00000 "vref1" 0.0 "tip" 0.01000  "dpmax" 1.00000 "dpmin" -1.00000 "pmax" 1.000000
"pmin" 0.0 "imax" 1.000000 "tpord" 0.01000 "pfflag" 0.000000 "vflag" 1.000000
"qflag" 1.00000 "pflag" 0.0 "pqflag" 0.000000 "vq1" -1.0 "iq1" 1.0 "vq2" 2.0 "iq2"
```

```
1.0 "vq3" 0.0 "iq3" 0.0 "vq4" 0.0 "iq4" 0.0 "vp1" -1.0 "ip1" 1.0 "vp2" 2.0 "ip2"
1.0 "vp3" 0.0 "ip3" 0.0 "vp4" 0.0 "ip4" 0.0
```

```
repc_a 5 "Test" 0.6 "1 " 2 "GSU_HV" 230.0 ! ! 2 "GSU_HV" 230.0 1 "POI" 230.0 "1 " :
#9 "mvab" 0. "tfltr"     0.02 "kp"        18.00 "ki" 5.00 "tft" 0.00  "tfv" 0.05
"refflg" 1.00     "vfrz" 0.00 "rc"       0.00 "xc" 0.00 "kc" 0.02 "vcmpflg" 0.00
      "emax" 0.50 "emin" -0.50 "dbd"        0.00 "qmax" 0.575 "qmin" -0.575  "kpg"
0.10 "kig" 0.05 "tp" 0.25      "fdbd1"       -0.0006 "fdbd2" 0.0006 "femax" 99.00
"femin" -99.00 "pmax" 1.00 "pmin"       0.00 "tlag" 0.10 "ddn" 0.05 "dup" 0.05
"frqflg"  1.00
```

The parameters shown are intended for illustrative purposes only and do not represent the performance of any particular plant or equipment. The monitored branch in the repc_a model should be in the direction from the plant to the grid and it must not be a jumper. In case the gen-tie has very low impedance, set the impedance just above the jumper threshold.

5.2.2. Scaling for Plant Size and Reactive Capability

Model parameters are expressed in per unit of the generator MVA base (mvab parameter in the regc_a module in the example above). The specification of MVA base is implementation-dependent. For example, in the PSLF™ if the MVA base for those modules is zero, the MVA base entered for the regc_a module applies to the electrical controls (reec_b) and plant controller (repc_a). A different MVA base can be specified for those modules, if desired.

To scale the dynamic model to the size of the plant, the generator MVA base parameter must be adjusted. The active and reactive range are expressed in per unit on the scaled MVA base. Normally, the MVA base is the same as in the power flow model. The reactive range could be wider than the Qmax/Qmin range in the power flow model.

5.2.3. Reactive Power / Voltage Control

The plant-level control module allows for the following reactive power control modes to be represented:

- Closed loop voltage regulation (V control) at a user-designated bus with optional line drop compensation, droop response and dead band.
- Closed loop reactive power regulation (Q control) on a user-designated branch, with optional dead band.

Different function calls are required to specify the regulated bus or branch. In the electrical control module, additional reactive control options are available:

- Constant power factor (PF), based on the generator PF in the solved power flow case.
- Constant reactive power, based either on the equivalent generator reactive power in the solved power flow case or from the plant controller.
- Open-loop reactive current injection during a user-defined voltage-dip event.

Various combinations of plant-level and inverter-level reactive control are possible by setting the appropriate parameters and switches. Table 4 shows a list of control options, and the models and switches that would be involved. The entry "N/A" for vflag indicates that the state of the switch does not affect the indicated control mode. The entry “N/A” for refflag means repc model is not present.

Table 3: Reactive Power Control Options for IBR Plant Generic Model

Functionality	Required	pfflag	vflag	qflag	refflag
Constant local power factor	REEC	1	N/A	0	N/A
Constant Q control	REEC	0	N/A	0	N/A
Local V control	REEC	N/A	0	1	N/A
Local coordinated Q/V control	REEC	0	1	1	N/A
Plant level Q control	REEC + REPC	0	N/A	0	0
Plant level V control	REEC + REPC	0	N/A	0	1
Plant level Q control & Local coordinated Q/V control	REEC + REPC	0	1	1	0
Plant level V control & Local coordinated Q/V control	REEC + REPC	0	1	1	1
Plant level PF control	REEC + REPC	0	N/A	0	2
Plant level PF control & Local coordinated Q/V control	REEC + REPC	0	1	1	2

The control flags should be obtained from the original equipment manufacturer (OEM) and verified against the actual field settings of protection and controls.

There are reactive control limits in REGC, REEC and REPC modules representing different control limits at plant level and inverter level:

- REPC.qmax/qmin (or qvmax/qvmin): PPC reactive power or voltage limits. The same parameter could be either a reactive power limit or a voltage limit depending on the reactive power/voltage control mode of the downstream REEC model. If the downstream REEC models require reactive power reference, qmax and qmin are reactive power limits; otherwise, they are voltage limits. As reactive power limits, they should reflect the reactive capability requirement at the POM and account for the reactive losses between the inverters and the POM[2].
- REEC.qmax/qmin: inverter reactive power limits. They represent the steady-state limits for the equivalent generator. The range of [qmin, qmax] should match or be wider than the generator Q-limits in the power flow model.
- REGC.qmin: instantaneous reactive power limit for transient high voltage.

To model voltage droop control, the REPC module should have

- Refflag = 1, Vcmpflag = 0 and
- Kc = Voltage Droop x Model MVA Base / Voltage Droop Mvar Base

Take an example of an IBR plant with 100-MW-rated active power output and 32.9 Mvar plant Qmax. Assume the model MVA base is 105.26. The voltage droop is set to 15% on the base of the plant Qmax. Then Kc in the model is 0.15 x 105.26 / 32.9 = 0.48.

[2] A new model REPC_E is under development, which allows for reactive power limits at the POM.

5.2.4. Active Power Control

The plant controller allows a user to specify the active power control options listed below. In conjunction with the BaseLoad flag in the power flow model, different active power control modes can be represented as shown in Table 5.

- Constant active power, based on the generator output in the solved power flow case: the plant has no frequency response.
- Primary Frequency Response (PFR) droop response for down-ward regulation only: the plant has the capability to regulate the frequency in both directions. However, the plant does not carry operational headroom and operates at the maximum output allowed by the solar radiance or the wind condition. In this case, the BaseLoad flag in the power flow model is set to 2.
- PFR droop response in both directions: the plant has the capability to regulate the frequency in both directions and carries operational headroom if Pgen < Pmax in the power flow.

Table 4: Active Power Control Options

Functionality	Required	frqflag	ddn/dup	BaseLoad
No governor	REEC	0	0	1
Governor	REEC +	1	>0	2
Governor	REEC +	1	>0	0

Ddn and dup in the model are on the model MVA base. Frequency droop is defined on the Pmax base. Ddn and dup are calculated from the frequency droop as:

Ddn/dup = 1/Frequency Droop x Frequency Droop MW Base / Model MVA Base

5.2.5. Current Limit Logic

The electrical control module first determines the active and reactive current commands independently according to the active power control option and reactive power control option. Each command is subject to the respective current limit, 0 to *Ipmax* for active current and *Iqmin* to *Iqmax* for reactive current. Then the total current of $\sqrt{Ipcmd^2 + Iqcmd^2}$ is limited by *Imax*. In situations where current limit *Imax* of the equivalent inverter is reached, the user should specify whether active or reactive current takes precedence, by setting the *pqflag* parameter in the REEC module.

5.2.6. Representation of Voltage and Frequency Protection

Frequency and voltage ride-through are required for transmission-connected IBR plants. Because they are simplified, the WECC generic models may not be suitable to fully assess compliance with voltage and frequency ride-through requirement. The same limitation applies to other positive-sequence models. Voltage ride-through is engineered as part of the plant design and requires far more sophisticated modeling detail than is possible to capture in a positive-sequence simulation environment. It is recommended that a standardized (existing) protection model with voltage and frequency thresholds and time delays can be used to indicate the minimum disturbance tolerance requirement that applies to the plant. Also, the frequency calculation in a positive-sequence simulation tool is not accurate during or immediately following a close-by fault. It is recommended to use the frequency protection relay model in monitor only mode and always have some time delay associated with any under/over frequency trip settings [23].

6. Model Validation

The goal of the model validation process is to verify that the results of time domain simulation agree with measured data and hence, are consistent with actual system performance. Proper modeling of a plant, as explained in all the previous sections, dependent upon the fidelity of both the power flow and dynamic models. All of the necessary parameters in power flow models are known or can be directly calculated with a high degree of certainty. Hence, the focus of this section will be on configuring the structure and selecting the parameter values of dynamic models.

In general, the best practice for model validation is to obtain the baseline model parameters for the plant, as designed, from the original equipment manufacturer (OEM) and plant owner/operator, and then to perform model validation and identify if any discrepancies exist and tuning/adjustments needed. To the extent possible, the parameters of the model should also be verified against actual field settings of protection and controls. Also, the individual IBR unit models should be type tested and validated by the OEM. The IEEE Std P2800.2, which is presently under development, once published will present a comprehensive account of all such steps. Nonetheless, below is a simple guide for model validation.

6.1.1. Data Collection

The types of data useful for model validation can be roughly divided into two categories. The first corresponds to the system's response to repeatable tests, and the second corresponds to spontaneously occurring disturbances. Repeatable tests, such as performing a step-test with a switched capacitor, can be an effective method of characterizing a plant's response. The controlled nature of the test makes it easier to distinguish the plant's response from noise in the measurement channel. However, data collected during actual grid disturbances help demonstrate the accuracy of the model when subject to uncontrolled perturbations in a way that tests cannot. The intent is for the modeled and measured output to agree on contingencies that occur in the field.

To isolate the behavior of the typical inverter in the plant, measurements may be taken at either the terminals of the inverter or the generator step-up transformer. For plant-level model validation purposes, measurements may be taken at either the POI or the station. In the context of bulk system dynamics studies, the bandwidth of interest for the equipment models spans a range between approximately 0.1–10 Hz. Using a multiple of the Nyquist rate as a guide, the sample rate of measurements used for model validation should ideally be 30 Hz or greater. For phasor measurement units (PMU), a sample rate of 60 Hz is preferred. In modern implementations, PMU measurements are typically taken at both the primary and secondary of the station transformer(s). Digital Fault Recorders (DFR) and PMU-capable DFRs can capture valuable data for dynamic model validation as well.

6.2. Defining the Mode of Operation

With the generic models, an IBR plant can be configured in over 30 unique modes of operation. Because there are a myriad of different ways the models can be configured, selecting the appropriate model structure is a vital first step in the parameter estimation process. Each unique model configuration corresponds to a particular control scheme. Table 4 and Table 5 in the previous section provide a breakdown of commonly employed reactive and real power control options, respectively.

6.2.1. Setting the REPC Model Flags

The plant controller module, REPC, has three control flags. The reference flag, **refflag**, selects either plant-level voltage or reactive power control. If plant-level voltage control is selected, the voltage compensation flag, **vcmpflag**, selects either voltage droop or line drop compensation. The real power reference flag, **frqflag**, determines whether the real power output of the plant is modulated to support system frequency and/or to maintain a constant plant-level real power output.

1. Does the plant feature a plant-level controller?
    - If yes, move on to Step 2. Otherwise, do not include the REPC_A module in the dynamic model and skip ahead to 5.2.2.
2. What plant-level volt/var control is implemented?
    - If plant-level voltage control, set **refflag** = 1.
    - If plant-level reactive power control, set **refflag** = 0.
    - If plant-level power factor control, set **refflag** = 2.
3. If plant-level voltage control is implemented, does it use line drop compensation?
    - If yes, set **vcmpflag** = 1. If voltage droop compensation is implemented instead, set **vcmpflag** = 0.
    - With **vcmpflag** = 1, if the measured voltage is not compensated, set he compensation resistance and reactance to zero, **rc** = 0 and **xc** = 0.
4. Does the plant modulate its real power output to support system frequency and/or maintain a constant plant-level real power output?
    - If yes, set **frqflag** = 1. Otherwise, set **frqflag** = 0.
    - With **frqflag** = 1,
        - if the plant responds to high frequency by reducing real power output, set **ddn** to the actual plant downward frequency droop; otherwise, set **ddn** = 0.
        - If the plant responds to low frequency by increasing real power output, set **dup** to the actual plant upward frequency droop; otherwise, set **dup** = 0.

6.2.2. Setting the REEC Model Flags

The renewable energy electrical control model for PV systems, REEC, has four flags which allow the user to fine-tune its control structure and select real or reactive power priority. The combination of the power factor (**pfflag**), voltage (**vflag**), and reactive power (**qflag**) control flags dictates the reactive power control scheme of the plant. For information on how to map a given control scheme to a flag combination, please see Table 4.

The purpose of the current limit logic is to allow the plant to properly allocate its current capacity upon saturation. Priority is given to either the active or reactive current command depending on the value of the current limit logic priority flag (**pqflag**). The first priority command is bounded only by the current rating of the converter. Hence, the second priority command is bounded by whatever capacity is leftover after generating the first priority command.

The instructions for how to set the REEC module flags are broken down into two sections, one for plants with strictly local control (i.e., no plant controller) and one for plants with plant-level control. Be careful to follow the correct procedure for the plant being modeled.

6.2.3. Strictly Local Control—No REPC Module

1. Does the plant regulate its output to maintain a constant local power factor?
   - If yes, set **pfflag** = 1 and **qflag** = 0 except for REEC_E and qflag = 2 for REEC_E. Skip to Step 5.
   - If no, set **pfflag** = 0. Go to Step 2.
2. Does the plant regulate its output to maintain a constant reactive power level (constant reactive power control)?
   - If yes, set **qflag** = 0. Skip to Step 5.
   - If no, go to Step 3.
3. Does the plant regulate voltage at the inverter terminal bus (local voltage control)?
   - If yes, set **vflag** = 0 and **qflag** = 1. Skip to Step 5.
   - If no, go to step 4
4. Does the plant operate in local coordinated Q/V control using the cascaded PI loops depicted in Figure 11?
   - If yes, set **vflag** = 1 and **qflag** = 1.
5. Does the plant operate in real or reactive power priority mode?
   - For real power priority, set **pqflag** = 1. For reactive power priority, set pqflag = 0.
   - REEC_E model provides additional modeling capabilities for power priority. The plant could have different priority setups between the fault conditions and no-fault conditions. Set pqflagFRT = 0 for Q priority and 1 for P Priority under fault conditions.

Next section describes how to set the REEC parameter flags for IBR plants with plant-level control (i.e., the REPC module is included). This procedure is different because the mode of operation and flag settings must be compatible across the REEC and REPC modules.

6.2.4. Plant-level Control—Model Includes REPC Module

1. Set **pfflag** = 0. Local power factor control should not be used with the plant controller module.
2. Does the Qref Volt/VAR output of the plant controller correspond to a voltage reference?

- If yes, set **vflag** = 0 and **qflag** = 1. Skip to Step 6.

3. Does the Qref Volt/VAR output of the plant controller correspond to a reactive power reference?
   - If yes, set **vflag** = 1. Go to Step 4.
4. Does the plant employ local coordinated Q/V control using the series PI loops depicted in Figure 11?
   - If yes, set **qflag** = 1. Skip to Step 6.
5. Does the plant compute a reactive current command by dividing the reactive power reference by a voltage?
   - If yes, set **qflag** = 0. In this configuration, the series PI loops depicted in Figure 11 are bypassed.
6. Does the plant operate in real or reactive power priority mode?
   - For real power priority, set **pqflag** = 1. For reactive power priority, set **pqflag** = 0.

6.2.5. Setting the REGC Model Flags

The generator converter module REGC_A has one flag that enables or disables the low voltage power logic (LVPL) feature. The **lvplsw** flag set to 1, together with **brkpt**, **zerox** and **lvpl1**, defines an active current limit reducing from lvpl1 to 0 between voltage brkpt and zeros.

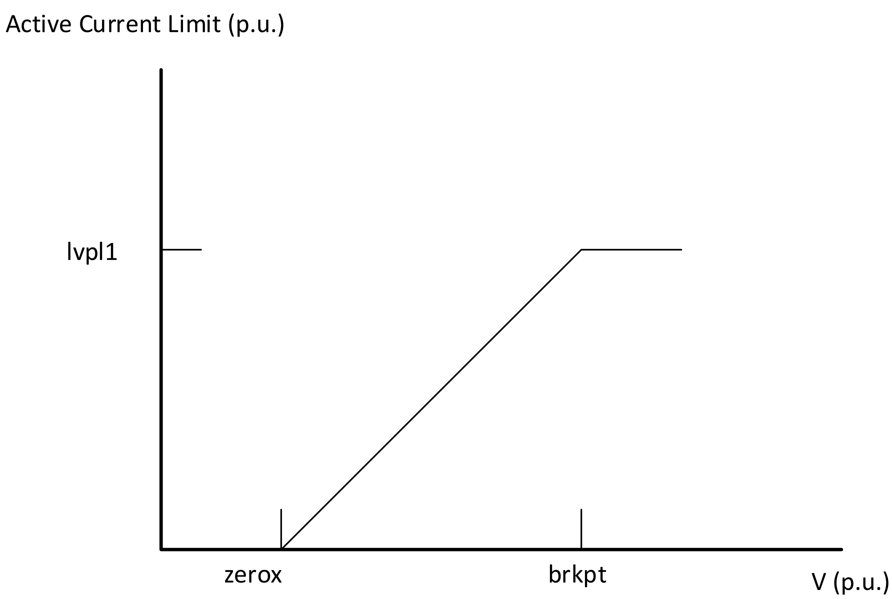

Figure 11: Low Voltage Power Logic

1. Are both active and reactive current limits voltage-dependent?
   - If yes, set **lvplsw** = 0 and use VDL blocks in REEC model for the voltage-dependent current limits.
   - If no, go to Step 2.

2. Is the active current limit voltage dependent as illustrated in Figure 11?
   - If yes, set **lvplsw** = 1. Otherwise, set **lvplsw** = 0 and the VDL1 block in REEC model may be used to represent piece-wise linear dependence of active current limit on the voltage.

Lvplsw flag is removed from REGC_B model. The active and reactive current limits are defined in the REEC VDL blocks. REGC_B has two flags: RateFlag and dqflag.

1. Is the rate limit provided as rrpwr active current ramp rate limit or active power ramp rate limit?
   - If current limit, set RateFlag = 0.
   - If power limit, set RateFlag = 1.
2. Set dqflag and Imax consistently with the REEC model.

After setting the model parameter flags as described in this section, check to ensure that the selected flag combination corresponds to a valid mode of operation.

6.3. Valid Model Parameter Flag Combinations

6.3.1. Strictly Local Control—No REPC Module

This section discusses the possible flag combinations for plants with strictly local control. The distinguishing feature of strictly local control is that the plant has no plant-level controller. Hence, the overall dynamic model consists only of the REGC and REEC modules. Table 5 lists the possible flag combinations for plants with strictly local control and indicates whether each combination is valid or invalid. Only valid flag combinations are permissible for model data submissions.

The choice of real or reactive power priority via the **pqflag** does not influence whether a particular flag combination corresponds to a valid control mode. Hence, the **pqflag** may be set to either 0 or 1 for any case.

Table 5: List of Flag Combinations for Local Control

REEC		Notes	
pfflag	**vflag**	**qflag**	**No.**
0	0	0	1
0	0	1	2
0	1	0	3
0	1	1	4
1	0	0	5
1	0	1	6
1	1	0	7

Notes:

1. Constant reactive power control (equivalent to Combination #3).

Local voltage control.

Constant reactive power control (equivalent to Combination #1).

Local coordinated Q/V control.

Constant local power factor control.

Local voltage control.

Constant local power factor control (equivalent to Combination #5).

6.3.2. Plant-level Control—Model Includes REPC Module

This section discusses the possible flag combinations for plant-level control. Only valid flag combinations are permissible for model data submissions. The overall plant model comprises three modules: REGC, REEC, and REPC. The plant controller module contains three parameter flags: **refflag**, **vcmpflag** and **frqflag**. A brief description of the REPC flags follows:

refflag — Determines whether the plant-level Volt/VAR control loop regulates voltage (=1), reactive power (=0) or power factor (=2)

vcmpflag — Determines whether the plant controller employs line drop compensation (=1) or voltage droop (=0) when **refflag** = 1

frqflag — Determines whether the real power control functionality of the plant controller is enabled (=1) or disabled (=0)

The position of the voltage compensation flag, **vcmpflag**, only has an impact when the plant-level Volt/VAR control loop is regulating voltage (i.e., when **refflag** = 1). Although the value of **vcmpflag** does not affect the validity of a flag combination, care must be taken to coordinate its setting with the plant's mode of operation and the REPC model invocation.

Table 6: List of Flag Combinations for Plant and Local Control

REEC			REPC	Notes
pfflag	vflag	qflag	refflag	No.
0	0	0	0	**1**
0	0	0	1	**2**
0	0	1	0	**3**
0	0	1	1	**4**
0	1	0	0	**5**
0	1	0	1	**6**
0	1	1	0	**7**
0	1	1	1	**8**
0	0	0	2	**9**
0	0	1	2	**10**
0	1	0	2	**11**
0	1	1	2	**12**

Notes:

1. Plant-level reactive power control (equivalent to Combination #5)

Plant-level voltage control (equivalent to Combination #6)

Plant-level reactive power control and local voltage control

Plant-level voltage control and local voltage control
Plant-level reactive power control (equivalent to Combination #1)
Plant-level voltage control (equivalent to Combination #2)
Plant-level reactive power control and local coordinated Q/V
Plant-level voltage control and local coordinated Q/V control
Plant-level power factor control (equivalent to Combination #11)
Plant-level power factor control and local voltage control
Plant-level power factor control (equivalent to Combination #9)
Plant-level power factor control and local coordinated Q/V

6.4. Dynamic Model Invocation Considerations

This section discusses important things to consider when selecting the correct dynamic model invocation for an IBR plant. A dynamic model invocation is an entry or series of entries in a dynamic data file that specifies which modules will be employed to represent a plant and what their respective parameters are. Model invocation conventions vary somewhat between software platforms, so consult the appropriate user manual for guidance.

The precise details of the model invocation can affect the operation of the modules. For example, the manner in which the plant controller module is invoked specifies which bus is regulated and which branch is monitored. It is crucial to consider not only how the parameters of the REPC module are populated, but how the model itself is invoked.

6.4.1. REPC Module Invocation Considerations

In the REPC module invocation, the user specifies which bus is regulated by the plant. In addition to declaring which bus is regulated, the user has the option of specifying a monitored branch. For central station PV plants, this branch is typically selected such that it reflects the total output of the plant as measured on either side of the collector system equivalent.

The **Ibranch**, **Pbranch**, and **Qbranch** inputs to REPC seen in Figure 23 are determined from the flows on this branch. Hence, in order to model real and/or reactive power control at the plant-level, a monitored branch must be specified. Notice that for plant-level voltage control, line drop compensation is performed using the current magnitude on this branch and the user-specified compensation resistance and reactance.

Key Points

- Define the terminal bus to which the equivalent generator/converter is connected.
- Define the bus that is regulated by the plant, if other than the terminal bus.
- Define the monitored branch from which the **Ibranch**, **Pbranch**, and **Qbranch** inputs to REPC are derived.

6.5. Populating Model Parameters

Once the field tuning of the controls is done, most of parameters in the generic models are fixed and can be obtained from the Original Equipment Manufacturer or from the actual controller settings. There are some parameters to be calibrated from the field test and the measured data as the control block in the generic model may not have a direct association with an actual controller.

Before the generic model parameters are populated, it is essential to complete three key prerequisites:

- Create a power flow representation of the plant as described in Section 2 of this document.
- Define the mode of operation for the plant as discussed in Sections 5.2 and 5.3.
- Determine the correct dynamic model invocation for the plant based on the mode of operation, the regulated bus, and the monitored branch as described in Section 5.4.

Unless these three prerequisites are successfully completed, the correct parameter values will still not yield the desired model behavior.

After the power flow representation for the plant and the proper dynamic model invocation have been established, it is time to begin populating the parameters of the dynamic model.

A plant's mode of operation determines the model structure and which parameters have an impact on its model behavior. Most of the parameters are fixed such as control deadbands, time constants, error limit, ramp rate and etc. The tunable parameters are usually control gains. There are eleven control gains in the three renewable energy modules. Table 7 categorizes those parameters according to whether they affect real or reactive power. The columns of the table indicate whether a parameter belongs to the electrical control module (REEC) or the plant controller (REPC). Very few, if any, implementations should require all of these gains to be tuned. For example, the value of **kqv** can be directly set from the inverter control implementation. If the voltage proportional control under abnormal voltage condition is not implemented, **kqv** should be 0; otherwise, the value from the field control tuning should be used. **kqp** and **kqi** are tuned if vflag is 1. **kvp** and **kvi** are tuned if qflag is 1. The values of **ddn** and **dup** are also directly based on the field implementation and would not require parameter tuning.

Table 7: Tunable Control Gains

Real Power		Reactive Power	
REEC	REPC	REEC	REPC
kpp	kpg	kqv	kp
kpi	kig	kqp	ki
-	ddn	kqi	-
-	dup	kvp	-
-	-	kvi	-

6.5.1. Dynamic Model Parameter Sensitivity

In most circumstances, the control loops which affect a plant's real and reactive power response are independent of one another. As a result, a majority of the tunable parameters directly influence either the real or reactive current command, but not both. An example of where this clear delineation breaks down is when the converter's output approaches its current rating. Under saturation, the REEC current limit logic engages, and the active and reactive current commands are allocated according to the limit scheme and the priority selection made with **pqflag and pqflagFRT**. However, the real and reactive power responses can generally be tuned independently.

A plant's dynamic response can be roughly divided into four components which characterize its real and reactive power response to voltage and frequency variations, respectively. The following section aims to explain the key factors which influence each of those four elements. Along the way, we will attempt to highlight the role of important model parameters.

6.5.2. Real Power Response to Voltage Variations

In the REEC electrical control module, the active current command is generated by dividing the real power reference by the terminal voltage magnitude of the equivalent converter in REEC_A/C/D. This operation will cause the real power response of the plant to be dependent on voltage. The ability to tune this response within REEC is limited. The key factors influencing a plant's real power response to voltage variations are the current limit logic in the REEC module and low voltage power logic in the REGC_A module. These features should be set according to how a particular plant's active current output is limited in response to terminal voltage variations.

Key parameters: **imax, VDL2** (REEC)

kpp, kpi (REEC_E)

lvplsw, zerox, brkpt, lvpl1, lvpnt0, lvpnt1 (REGC_A)

6.5.3. Real Power Response to Frequency Variations

Many of the IBR plants have the capability to control the active power output to regulate frequency. This capability is required by FERC Order 842 on all the newly interconnected IBR plants. However, the stand-alone solar PV and wind plants typically do not preserve headroom for upward frequency regulation. The control is modeled in REPC module. Three of the key parameters, **frqflag**, **ddn** and **dup**, are determined by the control implementation. Two control gains, **kpg** and **kig**, shall be tuned to match the measurement data.

Key parameters: **frqflag, kpg, kig, ddn, dup** (REPC)

6.5.4. Reactive Power Response to Voltage Variations

The plant-level reactive power control loop and the majority of the REEC electrical control module are dedicated to shaping a plant's reactive power response to system voltage variations. Everything discussed in Sections 5.2 to 5.4 about a plant's mode of operation and its dynamic model invocation will affect the relationship between reactive power and voltage.

Key parameters: **kp, ki** (REPC)
kqv, kqp, kqi, kvp, kvi, vdip, vup, qmax, qmin, imax, VDL1 (REEC)

6.5.5. Reactive Power Response to Frequency Variations

Inverters are designed such that their pre- and post-disturbance reactive power output is insensitive to system frequency variations. Furthermore, there is no supplemental control loop which modulates reactive power in response to frequency error. Hence, there are no key control features or parameters that impact this element of a plant's response.

Key parameters: Not applicable

6.5.6. Properly Coordinated Plant Control and Inverter Control

The majority of the controls represented by the generic models is about reactive power control. The plant control loop, inverter PI control loops and the inverter proportional control shall be properly coordinated through field tuning and accurately reflected in the models. In addition to the key parameters above, the following parameters play an important role in modeling the control coordination.

Key parameters: **vfrz, qmax, qmin, kw** (REPC)
vdip, vup, qmax, qmin (REEC)

6.5.7. Parameter Estimation Example

This section presents an example of a successful parameter estimation procedure. This case was constructed using simulated data for purposes of demonstration. As such, the model data and plant response are not associated with any specific PV plant. The necessary preliminaries discussed in Section 5.5 were executed prior to beginning the parameter estimation procedure.

Figure 12 presents the one-line diagram corresponding to the plant's power flow representation. The plant was configured to control voltage at the plant level and employ local coordinated Q/V control. Hence, both interior PI loops of the REEC module were used.

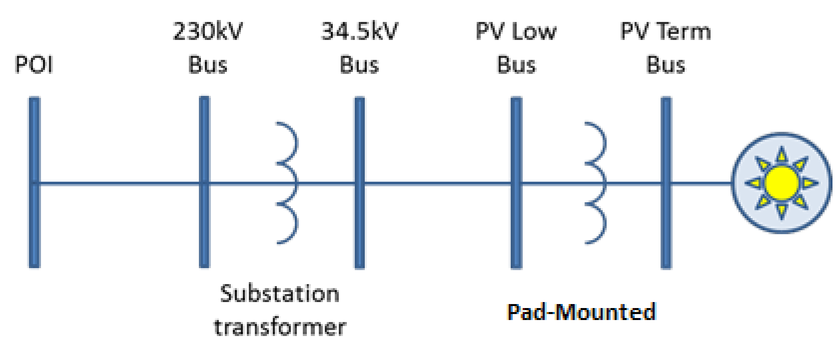

Figure 12: One-line Diagram for the Parameter Estimation Example

The aim of the procedure described here was to characterize the plant's real and reactive power response to system voltage variations. A six-cycle fault was simulated on the grid side using the playback feature in PSLF. Although this data was simulated, field measurements can be played in using this approach as well. During the fault, the voltage at the POI was depressed to approximately 50% of its pre-disturbance level. Data was recorded to simulate PMU measurements taken on the primary and secondary of the substation transformer. Figure 13 shows the voltage measurements taken on the primary (high-voltage side) of the substation transformer during the fault. These signals served as the inputs to the PV plant model. Figure 14 shows the real and reactive power output of the plant as measured at the station. These signals served as the outputs. The tunable parameters of the model were adjusted such that the output matched the measurements displayed in Figure 14 for the inputs displayed in Figure 13.

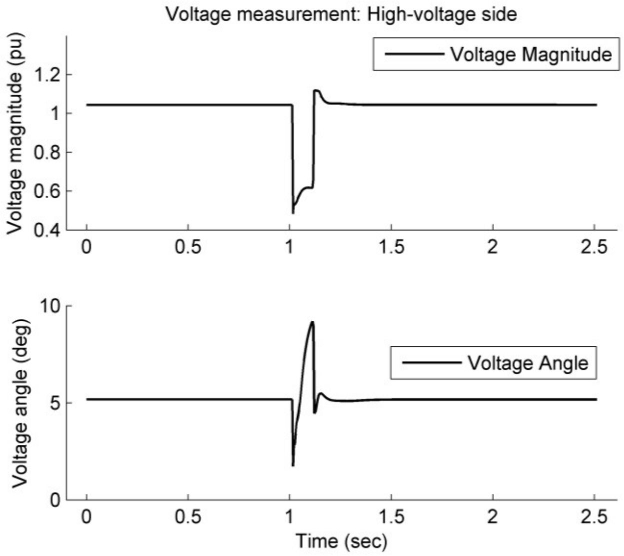

Figure 13: Inputs—Station Voltage Measurements

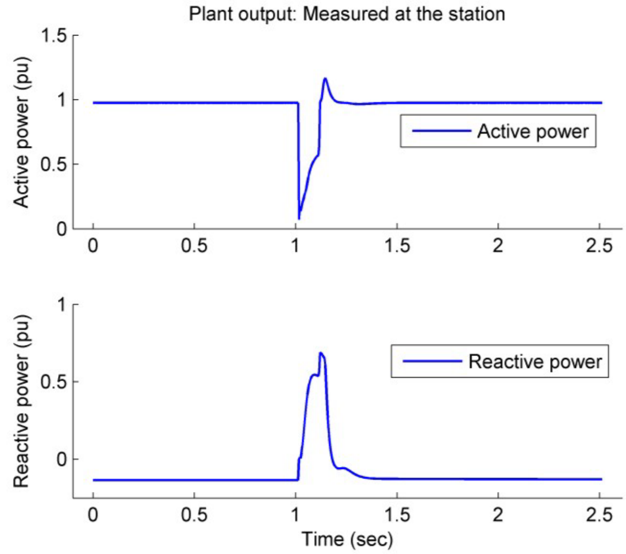

Figure 14: Outputs—Plant Real and Reactive Power

For this plant, the selected mode of operation was plant-level voltage control with local coordinated Q/V control. The parameter flag combination for this control mode, as shown in Table 3, is:

pfflag = 0, **vflag** = 1, **qflag** = 1, **refflag** = 1

Because this is a control mode that requires a plant controller, the set of the control gains to be estimated included:

kp, ki, kqp, kqi, kvp, kvi

For the purposes of the example, the actual parameters used to generate the simulated data depicted in Figure 14 were effectively erased. That is, the parameter estimation routine was stripped of all information about their values. Although the tunable parameters of the dynamic model were unknown, it was necessary to postulate an initial guess about their values to seed the parameter estimation routine. The initial guess for the unknown parameters was used to produce the preliminary model output depicted in Figure 15, in contrast to Figure 14, which shows the plant output at the POI, Figure 15 shows the real and reactive power output measured at the PV Low Bus. These signals represent the output of the equivalent generator/converter. Notice that the modeled response does not match the measured data particularly well for the initial guess. This is to be expected because the control gains were not known with certainty.

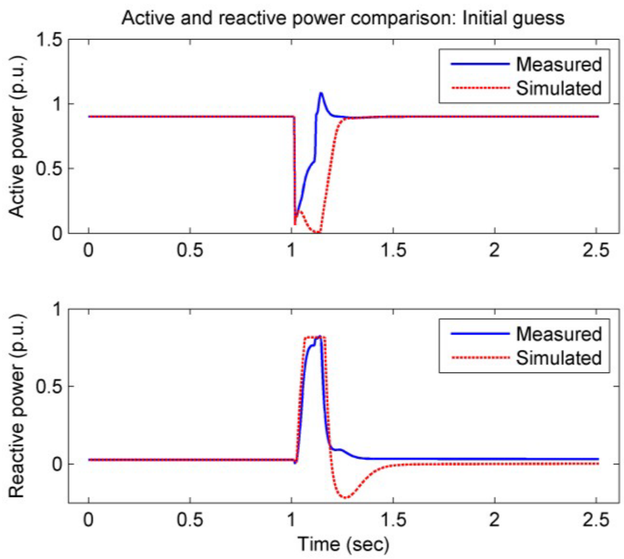

Figure 15: Initial Guess Output Comparison

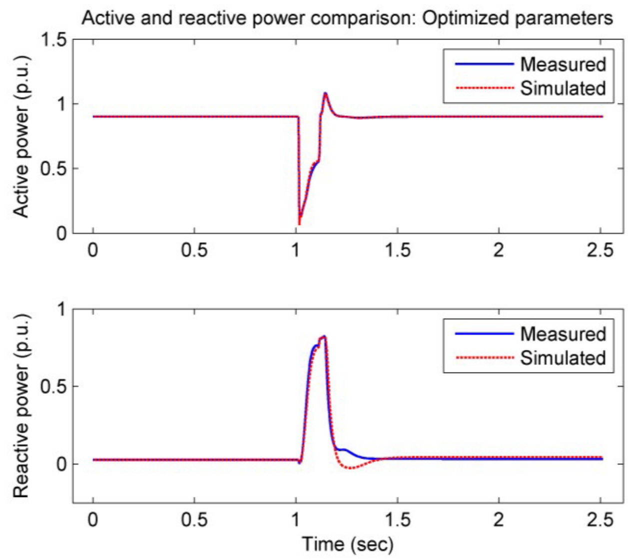

Figure 16. Optimized Parameter Output Comparison

For this example, the parameters were estimated using an optimization algorithm. The algorithm yielded a set of estimated (or optimized) parameters and the modeled plant output generated with those parameters. The results of the parameter estimation routine are summarized in Table 8. The table presents the initial guess at the tunable parameter values, the actual values used to generate the data, and the estimated (or optimized) parameter values. Because this example was created in simulation for demonstration purposes, the actual parameter values are known with certainty. This allows us to assess how well the actual and estimated parameters agree.

Table 8: Initial, actual, and optimized model parameters.

Model	Param.	Initial guess	Actual	Estimated
REPC	Kp	15.0	10.0	10.9
	Ki	1.0	5.0	4.3
REEC	Kqp	0.0	0.1	0.0
	Kqi	0.0	0.1	0.0
	Kvp	12.0	5.0	4.1
	Kvi	2.0	1.0	1.2

The extent to which the modeled output matches the measured data in Figure 16 is representative of what is achievable using field data. The modeled output does not exhibit any significant bias error, and it tracks the data well during the disturbance. While the aim of a parameter estimation routine is to make the modeled output match measured data as well as possible, it is unrealistic to expect an exact fit. If the modeled output matched the measured data exactly, that would be an indication of overfitting. The intention is to track the physical response of the plant and disregard the process noise.

In the case of model validation for IBR plants, the criterion by which parameterizations are judged is difficult to codify. Mathematical norms, such as the sum of squared error or the Euclidean norm, can serve as useful metrics for describing how well the modeled output matches measured data. That said, it is the opinion of the MVS that it is counter-productive to attempt to reduce the model validation criteria to a rigid mathematical definition. Model validation for power systems is as much an art as a science, and engineering judgment plays a significant role in the process. As such, this document does not prescribe any tests of goodness of fit that neatly separate "good" model parameter sets from "bad." In the end, the above is just an example. Mathematical optimization and parameter fitting is not the recommended practice. The ultimate approach is to use the proper model structure, good baseline data from the OEM and plant owner/operator, then proper engineering judgement to perform the necessary model validation work.

6.5.8. Importance of Power Flow Representation

The importance of a plant's power flow representation was discussed in Section 2. To elaborate on the subject, the figures below illustrate that a plant's response is based on both its power flow representation and its dynamic model. Figure 17 shows the case in which the dynamic model parameters and power flow representation match the master data precisely. Figure 18 shows the case in which the dynamic model parameters match exactly, but the impedance of the collector system equivalent is incorrect. This type of result could lead one to believe that the dynamic model parameters are incorrect, when in reality it is the power flow representation that is deficient.

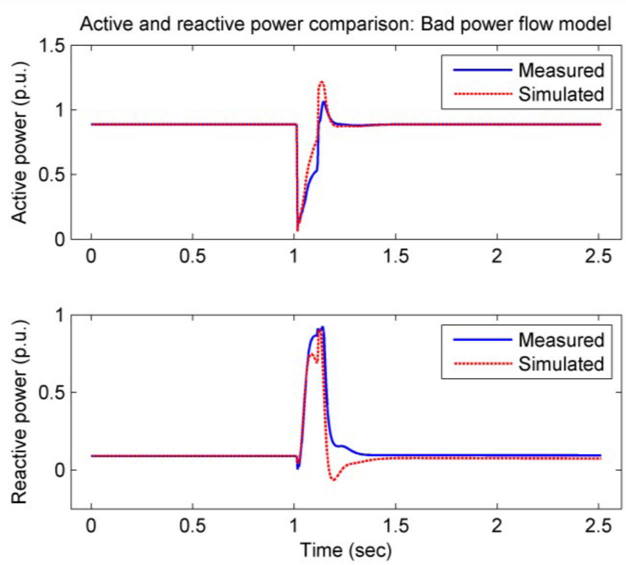

Figure 17: Accurate Power Flow Model Output Comparison

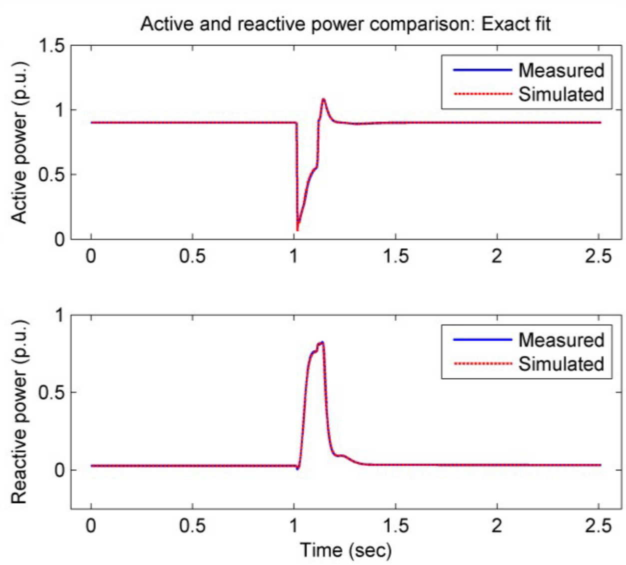

Figure 18: Bad Power Flow Model Output Comparison

6.5.9. Model Performance for Various Disturbances

A satisfactory IBR plant model produces simulated output that matches measured data for an array of different disturbances and power output levels, not just a select data set used to train the model. A good practice is to reserve certain data sets and use them for model evaluation only, meaning they are not used to tune the model parameters. When performing model validation using multiple data sets, one must confirm that the plant's mode of operation and control settings are consistent across the different cases.

7. Conclusion

This guideline is intended to clarify the goals and requirements of the model validation process rather than to serve as a rigid procedure. There are many different ways to arrive at a satisfactory model parameterization for an IBR plant; however, all successful approaches have certain characteristics in common. Modeling an IBR plant begins with establishing an accurate power flow representation of the plant. Without one, it is very difficult to accurately assess the performance of the dynamic model. Next, the plant's mode of operation is defined, and the corresponding dynamic model invocation is specified. The generic models developed by the MVS possess tremendous flexibility, and the control structure must be configured in a way that is consistent across the various modules. Because the dynamic model for an IBR plant contains between 45-75 parameters, it is critical to minimize the set of tunable parameters by holding fixed as many of them as possible based on OEM data and actual plant design. Then, and only then is it appropriate to adjust the parameters of the dynamic model to bring the modeled and measured output into agreement. Irrespective of the method used to estimate the unknown parameters, sound engineering judgment is required to discern a satisfactory dynamic model representation.

Emerging areas of interest in RES modeling include GFM inverters and offshore wind turbines, both of which are under active development by the Model Validation Subcommittee (MVS) with support from manufacturers whose GFM systems are being installed in the field.

7.1. GFM IBR Models

As IBRs become a larger share of the generation fleet, GFM control strategies are increasingly necessary to provide stable operation in weak grids, islanded systems, and high-IBR penetration scenarios. MVS, in collaboration with national laboratories, manufacturers, and utilities, has developed generic GFM inverter and plant controller models to support system studies. The table below summarizes the current GFM inverter models.

Table 9: Comparison of GFM Models

Model	Control Philosophy
REGFM_A1	Droop-controlled GFM (P–f and Q–V droop) [13]
REGFM_B1	Virtual synchronous machine (VSM) emulation with inertia and damping terms [14]
REGFM_C1	Hybrid model with both a GFM branch (VSM-based inertia and damping) and a GFL branch (current control with PQ-priority) operating simultaneously [15] [16]—a current-limiting

Model	Control Philosophy
	algorithm constrains total inverter current to Imax while maintaining phase angle consistency.

The previously developed PPC models (REPC_A through REPC_D) could be used to simulate plant-level controls together with the GFM models where the outputs of the REPC model match the reference signals required by the REGFM model. In addition, a new model, REPCGFM_C1, extends the functionality of REPC models to coordinate multiple GFM units at the plant level.

1. Integration with REGFM models: REPGGFM_C1 provides supervisory references, including frequency, voltage, active power, and reactive power signals, to REGFM_C1 inverters. The inverter-level models determine how these references are used internally, whether through GFM, grid-following (GFL), or a combination of control branches. In particular, REGFM_C1 contains both a GFM branch (VSM-based droop) and a GFL branch (PQ-priority current control) that operate simultaneously. Their outputs are reconciled through a current-limiting algorithm, so the final inverter current reflects both GFM support and PQ dispatch in a physically consistent way.
2. Contrast with REPC_A–D: REPC_A/B/C/D primarily manage GFL inverters and hybrid-plant dispatch, whereas REPCGFM_C1 includes additional logic for frequency and voltage references consistent with GFM principles.
3. Validation: Validation of GFM models should follow the same principles applied to other generic models. Model behavior should be confirmed against available evidence, which may include field measurements, OEM test data, OEM user-defined positive sequence model simulations, or EMT simulations. The objective is to ensure that inverter-level REGFM responses and plant-level REPCGFM coordination are consistent with expected performance at the POI.

7.2. Off-Shore Wind Plant Modeling

With respect to offshore wind power plants, the generic models discussed in this document are still suitable for representing the wind turbines, when appropriately parameterized. The major additional component needed is the model for the HVDC transmission system typically used for offshore wind that is more than approximately 50 miles offshore. For offshore wind that is relatively close to land, a proper ac power flow model for the submarine cables and platforms, together with properly parameterized generic models, all of which have been discussed here, is fully applicable. EPRI, working with MVS, has already proposed a generic model, called vhvdc3 HVDC, for modeling offshore wind. The specifications for this model have been approved, and, in due course, the model is to be adopted by the software vendors and benchmark tested. Also, feedback has been received from two major HVDC OEMs. Finally, a new effort is underway with PNNL in the lead, supported by ERPI and others to further advance these HVDC models.

7.3. Weak Grid Considerations

The dynamic performance of IBRs is strongly influenced by the electrical strength of the grid at the POI. When grid strength is low relative to plant size, commonly referred to as weak-grid conditions, conventional positive-sequence models may not fully capture the relevant dynamics.

Key challenges under weak-grid conditions include:

1. **Phase-locked Loop (PLL) Instability and Loss of Synchronism**
   GFL inverters use a PLL to track grid voltage angle and frequency. In weak grids, the reference waveform can be distorted, causing the PLL to oscillate or lose synchronism.
2. **Current Saturation and Limited Fault Current Injection**
   Inverters are limited in fault current delivery (typically 1.1–1.3 pu of the rated current). In weak systems, this limit may be reached quickly, reducing support for protection and voltage recovery.
3. **Sensitive Interactions Between Inverter Controls During and After Fault Recovery**
   Weak grids provide little "stiffness." As a result, even small mismatches among inverter control loops (PLL, current controllers, plant controller) can trigger oscillations or unstable recovery after disturbances.
4. **Protection Behavior that Depends on Fast Sub-cycle Phenomena**
   Many protection functions act within milliseconds, faster than phasor models can represent. This includes momentary cessation, fault recovery, and inverter tripping logic, all of which may behave differently in weak grids.

Short-circuit Ratio (SCR) as an Indicator:

One of the most common ways to describe grid strength is through the short-circuit ratio (SCR) at the POI. A lower SCR generally indicates weaker grid conditions, where inverter stability and fault recovery become more challenging. In this guideline, SCR is not used as a hard threshold, but rather as a screening indicator: cases with lower SCR values should trigger closer review and may require EMT studies or consideration of GFM resources.

A more detailed description of grid strength and SCR calculations can be found in [24].

Role of GFM Inverters (GFM):

The above challenges primarily affect GFL inverters, which depend on a PLL for synchronization. GFM inverters mitigate many of these issues by establishing their own voltage and frequency references, reducing reliance on external grid strength. GFM units can:

- Eliminate PLL-related instabilities.
- Provide a more predictable fault response.
- Anchor the system voltage during fault recovery.
- Improve coordination among multiple inverters in weak systems.

The WECC REGFM models (REGFM_A1, REGFM_B1, REGFM_C1) and the REPCGFM_C1 plant controller are intended to represent these behaviors in stability studies.

Study Guidance:

- Use positive-sequence models for interconnection-wide planning and regional screening studies.
- Apply EMT simulations when grid strength is marginal, SCR is low (less than 2 to 3), or when mixed GFM and GFL resources must be coordinated.

- Adopt a hybrid workflow: use phasor-domain models for wide-area studies and EMT for weak-grid cases and project-specific validation.

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