NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Plant-level Control and Protection Modeling Task Force

Task Force Report

Introduction

Model construction forms the foundation of all power system studies, periodic verification, and identification of power system components. Models are paramount in accurate calculations of operating limits, events analysis, planning studies, and performance assessments. Major issues in power systems analysis are modeling the large varieties of components that make up complex interconnected systems and using acceptable model parameter values. Analysis tools and techniques provide useful information only when models accurately reflect component behavior over the simulation time span.

As part of its Modeling Improvements Initiative, NERC formed the Plant-level Control and Protection Modeling Task Force (PCPMTF) to review the effects of plant-level turbine controls, boiler controls, and protection systems on the response of power plants and to what extent components may need to be modeled for interconnection-wide modeling cases. The PCPMTF consists of turbine manufacturers, Generator Owners, Generator Operators, and the North American Generator Forum (NAGF), subject matter experts in power system dynamics and control, and stability simulation software vendors. The PCPMTF collaborates on model identification and modeling practices for plant-level turbine protection and control functions in order to identify any gaps in obtaining accurate stability study results.

The power generation industry has boiler and turbine simulators for many of its generating units that emulate the control system logic and the boiler and turbine process. The purpose of these simulators is generally for operator training, but some have the ability to be used to validate control strategies and control system tuning to a limited extent. For performing forensic analysis of grid events or planning power system simulations, the associated fluid levels, flow, temperature, and pressure of the boiler and turbine simulation are not significant during the simulation time frame; however, the task force reviews the effects of these controllers to address the need for development of models and/or modeling practices sufficient to capture the critical control functions.

The reaction of a generating plant and the way it interacts with other elements comprising the bulk power system (BPS) depends on a wide array of operating modes dependent on choices made by plant control room operators as well as automatic limiters and control systems. Moreover, there are many aspects of power plant control, protection, and operation that require generating plants to act, ensuring the reliable operation of the BPS in the immediate time frame following an event.

The task force took a comprehensive look at the short- and mid-term post-disturbance behavior of control and protection systems and outlined the impacts on unit reliability and system stability during grid disturbances. Additionally, this report identifies requirements for high-level monitoring that uses simulation tools in order to provide the user with a warning message of a possible control or protection action.

Events Involving Turbine and Boiler Controls

Boiler and turbine controls are increasingly recognized as contributing elements to the severity of system disturbances. There has been a number of events where generators that survived transient dynamics are tripped moments after the disturbance, and the tripping was not through the action of protective relays on the generators but by their dynamics associated with the boiler and turbine controllers. Based on the available models today,[1] there has been limited success in fully incorporating these controllers to recreate these events for forensic analysis. The goal of this task force is to have a comprehensive look at actions of boiler and turbine controllers and quantify their impact in power system simulation studies. Additionally, this examination will lead to development of models and/or modeling practices sufficient to capture the critical control functions as well as guidelines around these control functions. A summary of the moderate to severe system disturbances that the task force investigated are in Table 1.

Table 1: Events Investigated to Quantify Effects of Boiler and Turbine Controllers

Event	Event Description	Boiler/Turbine Control
1	Turbine hydraulic system pump tripped in part because of the acceleration detection circuit	Boiler/turbine controls could be improved to provide smooth transfer
2	Megawatt transducers were improperly scaled	Error in boiler/turbine controls scaling
3	Turbine PLU and transmission line protection schemes not tuned properly	Not a boiler/turbine control issue. The PLU is a form of over-speed protection.
4	Turbine intercept valve logic in error	Error in boiler/turbine controls logic
5	Dynamic models overestimate generator governing response	Not a boiler/turbine control issue
6	Aux bus under voltage setting may not take into account grid disturbance	Not a boiler/turbine control issue
7	GT high rate of change causes a “blowout”	Boiler/turbine controls could be improved to reduce rate of change
8	Turbine tripped due to acceleration detection circuit	Boiler/turbine control (see Arizona-Southern California Outages section in this report)
9	Turbine hydraulic system pump tripped due to capacity limits	Boiler/turbine controls should include primary frequency response (PFR) limits
10	Drum level trip due to lag in starting second BFP	Boiler/turbine control should include PFR limits

For a grid event analysis, the simulation for a generating unit would only need to model active and reactive generator power output. A proposed block diagram of the generating unit sub-model[2] is shown in Figure 1 along with the proposed inputs and outputs illustrated in Table 2. The inputs are a combination of real-time variables, unit-specific constants, and event-driven parameters.

[1] Historically, simplified modeling was used to reduce computational burden associated with more detailed modeling. Commensurate with the increased computational power of today’s computers, more detailed power system models can be developed and used in power system studies.

[2] Units capable of burning multiple fuels would also require inputs to the model based on the percentage of each type fuel being burned. Multiple models might be required for this purpose.

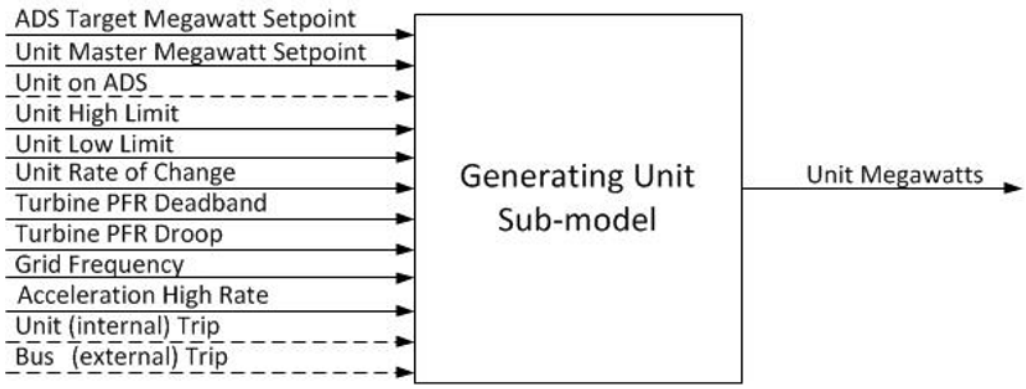

Figure 1: Generating Unit Sub-model Input/output

Table 2: Generator Unit Sub-Model Input/output	
Input/output	**Description**
ADS Target Megawatt Setpoint	A real variable in units of megawatts (MW) that represents the dispatcher megawatt setpoint to the generating unit
Unit Master Megawatt Setpoint	A real variable in units of MW that represents the local operator megawatt setpoint
Unit on ADS	A Boolean variable that indicates the generating unit's operating mode. 0 = local (local operator provides setpoint), 1 = ADS (ADS provides setpoint)
Unit High Limit	A real variable in units of MW that represents the local operator set boiler/turbine high load limit
Unit Low Limit	A real variable in units of MW that represents the local operator set boiler/turbine low load limit
Unit Rate of Change	A real variable in units of megawatts/minute (MW/min) that represents the unit's local operator set rate of change
Turbine PFR Deadband	A real variable in units of frequency (mHz) that represents the deadband of the turbine's primary frequency bias
Turbine PFR Droop	A real variable in units of percent (%) that represents the droop response of the turbine's primary frequency bias
Grid Frequency	A real variable in units of hertz (Hz) that represents the grid frequency
Acceleration High rate (optional)	A real variable in units of RPM/min that represents the trip value for the acceleration rate
Unit (internal) trip	A Boolean variable that initiates a unit trip: 0 = no trip, 1 = trip
Bus (external) trip	A Boolean variable that initiates a unit trip: 0 = no trip, 1 = trip

Figure 2 shows the functional requirement of the generating unit sub-model. Table 3 provides a brief description for each function.

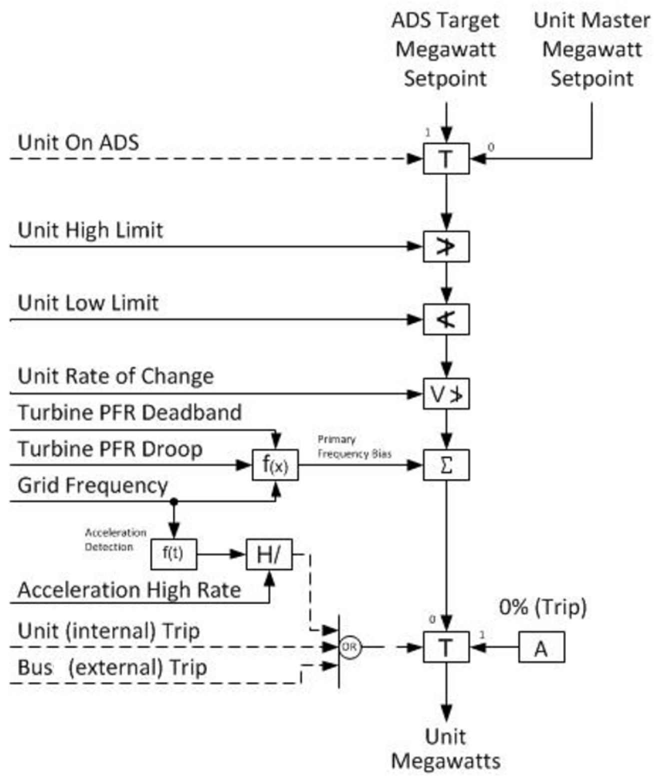

Figure 2: Functional Generating Unit Sub-model

Table 3: Functional Generating Unit Sub-model Operation	
Function	**Comments**
ADS Target Megawatt Setpoint	Signal should be developed by ADS sub-model
Unit Master Megawatt Setpoint	Signal is a constant (fixed) value or written by an event script
Unit on ADS	Signal is a constant (fixed) state or written by an event script
Unit High Limit	In practice, the boiler and turbine should have the same high load limit. If the load limits are different, then use the turbine high limit. If no high limits, then use 100 percent MCR value.
Unit Low Limit	In practice, the boiler and turbine should have the same low load limit if applicable. If the load limits are different, use the boiler low limit (For units that incorporate boilers rather than combustion turbines, the boiler low limit for combustion control automatic operation is normally between 40 and 50 percent of MCR. Steam turbine low limits are much lower than that).
Unit Rate of Change	Typically, a unit's rate of change (ROC) is a constant value defined by the local operator, but the ROC is defined by the ADS or is a variable (function of load) based on external logic. For simplicity, a constant value is proposed.
Turbine PFR Deadband	Signal is a constant (fixed) value.
Turbine PFR Droop	Signal is a constant (fixed) value
Grid Frequency	Signal should be developed by existing simulation model. Note that the primary frequency bias is shown downstream of the unit limits as this is the current industry practice; however, new industry practices should consider having the limits applied downstream of the primary frequency bias. Per Table 1 Event 5, the actual turbine response is, in some cases, overestimated. The overestimation is due to the withdraw behavior defined by NERC's Primary Frequency Response task force. While the actual primary frequency response will be slightly different for each unit (especially for mechanical turbine controls), developing a higher fidelity model might not be cost effective.
Acceleration High rate	Signal is a constant (fixed) value. This function should be updated based on this task force resolution to Recommendation 21 discussed below. If turbine controls do not include an acceleration high rate trip, then default constant should be a very large number.
Unit (internal) trip	A variable written by script. Default state is zero (no trip).
Bus (external) trip	A variable written by script. Default state is zero (no trip). An internal and external trip is proposed only for reports or script. These signals could be combined

Arizona: Southern California Outages

Recommendation 21: Acceleration Control Function

In April 2012, FERC and NERC issued the joint report, *Arizona-Southern California Outages on September 8, 2011*.[3] The sequence of events and causes of the Arizona–Southern California outages and 27 key findings and recommendations aimed at improving power system reliability are detailed in the joint report. Recommendation 21 of the joint report identified trips related to turbine control as an issue that exacerbated the consequences of that event, and it reads as follows:

> *"GOs and GOPs should evaluate the sensitivity of the acceleration control functions in turbine control systems to verify that transient perturbations or fault conditions in the transmission system resulting in unit acceleration will not result in unit trip without allowing time for protective devices to clear the fault on the transmission system."*

When the SONGS separation scheme operated, it resulted in the following:

- Having opened breakers within the San Onofre switchyard to leave SONGS Units 2 and 3 connected to the electric grid, five out of nine lines were disconnected from the SONGS units. The loss of the parallel lines increased the impedance seen by the generator and consequently reduced the power transfer according to the power-angle curve formula.[4] This sudden change in the impedance of the electric grid caused both SONGS units to begin to oscillate as illustrated in Figure 3. The oscillation of Units 2 and 3 was strong enough that each turbine's governor "rate of change of speed" logic detected an unacceptable acceleration, which then initiated turbine control actions.

[3] Arizona-Southern California Outages on September 8, 2011 – Causes and Recommendations.

[4] $\mathrm{P_e} = \frac{\mathrm{EV}}{\mathrm{X}} \sin(\delta)$

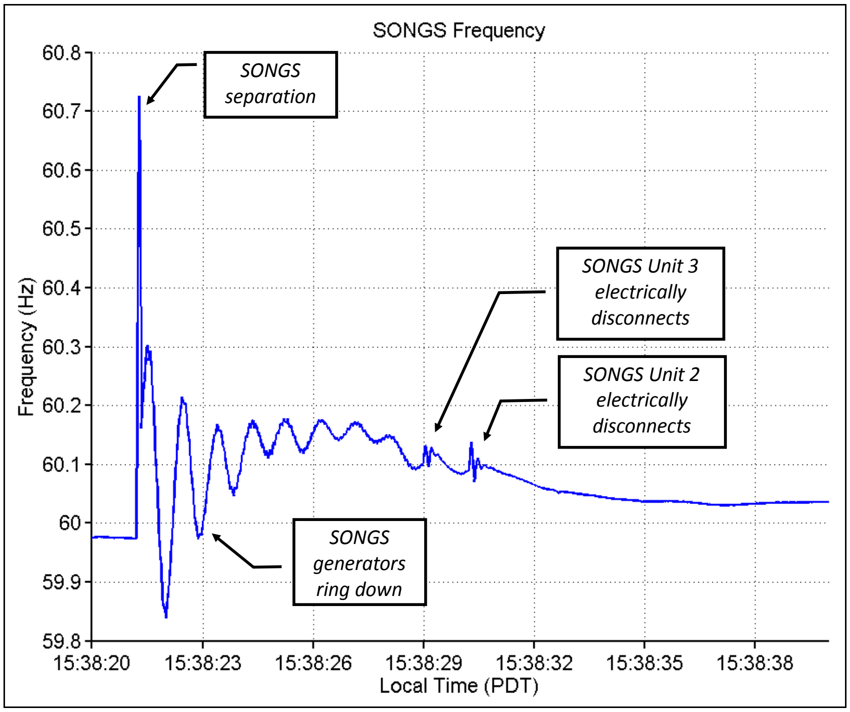

Figure 3: System Frequency Measured at SONGS Facility

- When digital turbine governor speed sensors measure an acceleration for a certain period of time, the high acceleration logic causes all of the high-pressure governor (steam admission) valves to close rapidly. This turbine control action made the SONGS main turbine speed governors react to the rapid increase in turbine speed; it closed all turbine main steam governor stop valves to prevent turbine shaft speeds above the over-speed trip set point.
- The heat energy produced by the nuclear fuel was no longer absorbed by steam flow into the main turbine. Primary system temperature increased rapidly, which caused primary system pressure to increase above the reactor protection system. The reactor protection system then sent trip signals to the reactor and the turbines at SONGS as they began to accelerate in excess of their control system settings and eventually caused both units to trip off-line.

The tripping of the SONGS units in this manner emphasized the importance of coordination between the sensitivity of the turbine control system's settings and turbine capability during system events. The units are expected to withstand severe faults on the transmission system and allow the transmission protection systems to operate without the generators tripping off-line. The coordination required for this protection is not a traditional relay-to-relay coordination; rather, the setting for the acceleration function should be coordinated with capabilities of the turbine and with the system response anticipated following operation of transmission protection systems for faults under various system conditions. The turbine control system acceleration function coordination is paramount to avoid generating unit trips during activation of separation schemes or during system disturbances.

Generally, acceleration control functions in turbine control systems are established by the turbine manufacturer to coordinate with the physical capability of the turbine to withstand torques associated with rapid speed acceleration.

Specifically, acceleration protection for large steam plants is important because of the need to handle the continued energy input when a system event occurs.

There are many aspects of power plant control, protection, and operation that require plants to act contrary to short-term grid needs to ensure the safety and integrity of the plant and to further long-term grid interests. Therefore, it is essential on the grid side to understand the realities of power plant operations.

It is helpful to separate conditions and events in a power plant into the following categories:

- Events and conditions where an immediate trip of a major plant component is mandatory, regardless of conditions on the transmission system outside the plant
- Events and conditions where the plant is unable to respond to grid conditions because of its inherent physical characteristics
- Events and conditions where the plant would be able to respond as grid control would expect, but only by taking elements of the plant into operational regimes
- Conditions where plant elements can continue to operate, and the plant can respond as the grid expects [5, 6]

Action for these conditions and events are always implemented by protective elements in the primary controls of the plant equipment. These protective actions are intended to be independent from the actions of operators' control or external transmission grid conditions. When they are called upon, these protections act quickly and decisively. However, the Generator Owner shall provide and coordinate its applicable generator protection trip settings with the Planning Coordinator or Transmission Planner that models the associated unit. Examples of equipment protection limitations for the generator and prime mover type are summarized in Table 4.

Table 4: Equipment Limit Protections

Heat Recovery Steam Generator / Balance of Plant	Steam Turbine	Gas Turbine	Generator
• High HP & Reheater Steam Temperature Trip/Runback • Temperature Failure Trip • High HRSG Pressure Trip • Stack Damper Not Open Trip	• High LP Exhaust Temperature Trip • High HP Exhaust Temperature Trip • High LP Stage L-1 Temperature Trip • Main /Reheat Steam Over-temperature Trip	• High Firing Temperature Trip/Runback • Partial Loss of Combustion Trip/Runback • Compressor Operating Limit Trip • Compressor Start Bleed Failure Trip/Load Step • Loss of Compressor Guide Vane Control Trip • Turbine Cooling System Failure Trip/Runback	• Stator Cooling Water System Failure Trip • H2 Seal Oil Failure Trip • Loss of H2 Purity Runback

[5] Standard PRC-024-2 — Generator Frequency and Voltage Protective Relay Settings
[6] Recognition of Power Plant Control, Protection, and Operation in Transmission System Simulation Studies

		• Fuel System Failure Trip/Load Step/Runback • Fuel Purge System Failure Trip/Runback • Inlet System Failure Trip/Runback	

Potential New Models for Use in Dynamic Simulations

Modeling of the type used in analysis of grid dynamics cannot anticipate the pre-event operating conditions of all parts of a power plant at any given time; they cannot be relied on solely to determine how a plant will react to a given grid disturbance.

Regardless of the effort made on modeling, grid studies cannot rely solely on modeling of plant components and must always include judgments. These judgments must be based on experience as to how plants actually react to grid events. Sensitivity studies that examine varied scenarios of plant behavior are essential in considering grid disturbances in the close vicinity of power plants.

The task force thoroughly reviewed turbine controls, boiler controls, and protection systems that may affect the predicted behavior of generation during system disturbances. It is not practical nor necessary to model all such turbine or boiler controls. A plant's behavior and the way it interacts with the grid during grid disturbances also depend on the status of a wide array of subsystems that have operating modes dependent on choices made by operators. These choices reflect factors like maintenance and temporary plant limitations. Many of these subsystems are not modeled in grid simulations largely because of the impracticality of maintaining the enormous database as well as simulation run times that would be required. If one considers the example list of events detailed in Table 1, which refers to units tripping due to various reasons that could not be modeled, it can be seen that these events can be broadly classified into the following categories:

- Equipment failure
- Expected protection action (correct action)
- Protection action that was not properly coordinated
- Complex dynamics of combustion/boiler systems

It is not possible to predict model equipment failure or practical to model all the nuances of the complex dynamics associated with combustion systems and boiler systems in thermal power plants. The additional modeling complexity for performing interconnection-wide planning studies would be insurmountable. Thus, the focus of the task force is to capture the potential actions of protection systems. Currently, a simple "generic" model of this nature exists in one commercial software tool called GP1/GP2[7] that can be expanded in other software platforms. The model representation of GP1 is depicted in Figure 4. This model has a basic representation of over- and under-voltage protections, over- and under-frequency protections, reverse power protection, and stator- and field-over-current protections. This model can be used to monitor generator models and warn the user if a generator appears to be entering regions of operation that may initiate a trip. The model can also be set to trip the generating unit if the unstable criteria is met. The task force recommends expansion of this model to include the following:

[7] GE PSLF™ User's Manual, General Electric International, 2016

- Loss of field protection
- Under- and over-voltage and frequency protections (already included in the model)
- Turbine power and load unbalance protection
- Voltage restraint over-current protection (revise the stator-over current protection model)
- V/Hz Limiter and protection

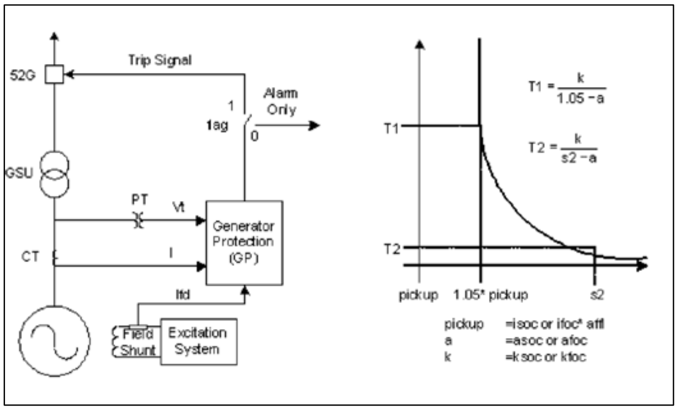

Figure 4: GP1 Model Representation

To observe generator behavior, the following variables in Tables 5 and 6 will need to be monitored in the simulation. These are typically available in all commercial simulation platforms. This generic model could then be used in two possible ways:

1. Set with typical settings and applied globally to all synchronous generators in a simulation and set to "monitor" only and not trip any generators. Thus, warning messages can be given to the users to warn them of generators that appear to be encroaching on trip zones for a given simulation.
2. In detailed local studies where actual protection settings are available, those settings could be used with this model to either monitor or set the trip function to look at the potential behavior of the protection systems for various simulations.

Option 1 would be the most suitable for interconnection-wide studies, similar to the practice already used in some interconnections, so as to warn the user of possible conditions where generators may trip and might warrant further investigation.

Table 5: Variables to be Monitored in Simulation Tools:

Parameter	Description
V_t	Stator Terminal Voltage
Pe	Electric Real Power
Qe	Electrical Reactive Power
If	Field current, or in the case of a brushless unit the field of the pilot exciter
Speed	Mechanical Speed
V_x	Station level voltage – Aux bus voltage
Pm	Total Mechanical Power

Table 6 : Protection Systems and Limiters:

Protection and Limiters	Description
V/Hz	Volts per Hertz limiter and protection per unit frequency and per unit generator terminal voltage
Overspeed protection	Shaft speed
Power/Load Balance	Electrical real power and mechanical power
Overvoltage/Undervoltage	Generator terminal voltage
Overfrequency/Underfrequency[8]	Frequency
Turbine valve rate of change limiters	How fast the unit is able to respond to a frequency deviation

[8] Speed is not exactly the same thing as frequency, but speed is essentially the same thing at the generator terminals and easier to monitor and work with (it is a known fact that the calculation of frequency in positive sequence stability programs presents mathematical difficulties when a fault is applied nearby since it is based on calculating the derivative of the bus angle.)

Turbine-Governor Models with Representation of Plant-level DCS Controls[9]

A recent IEEE task force document[10] gives a comprehensive and detailed account of the existing models for turbine-governors. Detailed accounts are given of vendor-specific models, and some detailed models incorporate the dynamic models associated with the boiler of steam-turbine generators and fast-valving schemes. All the models described are in one or more commercial software platforms; however, as concluded in the report for large-interconnected power system simulations, the use of simplified models such as GGOV1, IEEEG1, etc. are recommended. A previous IEEE task force report[11] showed that a reasonable match between actual and simulated interconnected power system frequency response can be achieved using simplified models in both WECC and ERCOT systems.

This section contains three brief summaries of the most common and widely used simplified models discussed in the IEEE task force document:

1. **Turbine Load Controllers**

   Several turbine-governor models in use include a representation of the turbine load controller that acts to maintain the active power (MW) output of a unit at a fixed value. The time constant of the turbine load controller is in the order of 10 to 30 seconds; therefore, the controller will initially allow the governor to adjust the unit's active power output in response to frequency deviations but will counter those adjustments shortly afterward as it restores the output of the plant to a designated active power (MW) set point. Governor models that represent a turbine load controller include:

   a. GGOV1

   b. GGOV3

   c. LCFB1 (this model represents only a turbine load controller and can be applied to most conventional turbine-governor models to represent a turbine load controller)

2. **Turbine Control Modes**
   Some models include the ability to represent the boiler dynamics and associated turbine control model. These are rarely used in interconnection-wide planning cases. Some examples are:

   a. TGOV5 (in Siemens PTI PSS®E) or ccbt1 (in GE PSLFTM) for large steam-turbines

   b. UHRSG (in Siemens PTI PSS®E) or ccst3 (in GE PSLFTM) for the heat-recovery steam generator in a combined-cycle power plant

3. **Power-Load Unbalance**
   There are models that include the effect of intentional fast-valving of the steam-turbine for the purposes of improving transient stability such as TGOV3 (in Siemens PTI PSS®E). Fast-valving is not very common. A more general (applied in many steam-turbine power plants) power-load unbalance (PLU) protection function can perhaps also be emulated with this model. The PLU function monitors both turbine mechanical power and electrical power. It sets an alert condition if the mechanical power is much larger than the electrical power

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[9] Model names listed in ALL CAPS (e.g., GGOV1) indicates a model available in Siemens PTI PSS/E and possibly other programs (e.g., PowerWorld, DSATOOLS). A model name listed in lower case (e.g., ccbt1) indicates a model available in GE PSLF but not available in Siemens PTI PSS®E.

[10] IEEE Technical Report, PES-TR1, Dynamic Models for Turbine-Governors in Power System Studies, January 2013.

[11] IEEE Task Force on Large Interconnected Power Systems Response to Generation Governing, Interconnected Power System Response to Generation Governing: Present Practice and Outstanding Concerns, IEEE Special Publication 07TP180, May 2007.

that indicates a loss of turbine electrical load. If a PLU alert is issued, the turbine controller and stop valves are closed; however, it is not explicitly modeled in any of the simplified steam turbine models.

Modeling Standards Review

PRC-019-2[12], PRC-025-1,[13] and PRC-027-1[14] require each Generator Owner and Transmission Owner with applicable facilities to perform the following:

- coordinate the voltage regulating system controls with the equipment capabilities and settings of the applicable Protection System devices and functions;
- set load-responsive protective relays associated with generation at a level to prevent unnecessary tripping of generators during a system disturbance; and
- coordinate protection systems to detect and isolate faults on BES Elements such that those protection systems operate in the intended sequence during faults.

However, the above standards do not require coordination for turbine control system settings and protection devices. The Arizona–Southern California Outages section of this report highlighted the importance of the coordination between the turbine control settings and the turbine capability taking into consideration the anticipated system response following operation of transmission protection systems for faults under various system conditions. Any modifications to a NERC standard must be made through the NERC standards process under the *NERC Rules of Procedure*. Regarding PRC-019-2 the task force recommends modifications to the standard to include the coordination of turbine control system settings and protection devices with the turbine capability.

MOD-026[15] and MOD-027[16] require Generator Owners to provide:

- a verified generator excitation control system
- plant volt/var control function model
- turbine/governor and load control or active power/frequency control model

The automatic controls of the plant such as the automatic voltage regulator (AVR), governor, and power system stabilizer (PSS) that affect the performance of the electrical machine will respond accordingly. A review of the Eastern-Western- and Texas interconnections planning models built in 2015 (Table 7) indicate a very limited number of Volt/Hz, over excitation limiter, under excitation limiter, and reverse power dynamic models.

Table 7: Model availability Percentages with Respect to Total Number of Machines in Each Interconnection[17]

	Reverse Power	Volt/Hz	Over Excitation	Under Excitation
Eastern Interconnection	0%	0%	1%	1%
Western Interconnection	16%	0%	11%	0%
Texas Interconnection	0%	0%	5%	7%

[12] PRC-019-2 — Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection
[13] PRC-025-1 —Generator Relay Loadability
[14] PRC-027-1 —Coordination of Protection Systems for Performance During Faults
[15] MOD-026-1 — Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions
[16] MOD-027-1 — Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions
[17] Some percentages may be zero because models are not available from software developer or not required.

The statistics show that the modeling practices and representations are incomplete. The task force recommends that the model builders, data owners, Planning Coordinators and Designee (per MOD-032) to incorporate and monitor processes for inclusion of such models in future year planning cases.

Recommendations

The task force took a comprehensive look at actions of boiler and turbine controllers by quantifying their impact to determine if there is value in modeling in grid dynamic analysis studies and what is needed to capture their influence if so.

The task force also reviewed recommendation 21 from the *Arizona-Southern California Outages on September 8, 2011* report. The recommendation is significant as it draws attention to the interaction between the plant-level, turbine, and boiler control and protection systems on power system stability. This task force report highlights the importance of modeling plant-level controls and protection systems that can influence a plant's response to an event accurately and sufficiently. Understanding the interactions between plant-level, turbine, and boiler control and protections systems will lead to improved tools, techniques, and models to quantify their impact and to determine what is needed to capture their influence with regard to plant operational capabilities and limitations.

The task force recommendations focused on improving protection system representation in grid simulation studies are summarized below:

- Through Modeling Notifications,[18] advise the industry to use the most accurate model representation of their generator. For instance, consider using models that represent PI controllers if such equipment is used in the plant. However, it is neither practical nor necessary to attempt to model all turbine and boiler controls.
- Encourage commercial software vendors to adopt a model similar to GP1 (and GP2) in GE PSLF™ that can monitor and provide warnings of potential unit tripping due to the generator encroaching on possible trip-zones of protection systems. The GP1 model should be revised or updated with the additional functions outlined in this report (e.g., the power-load unbalance protection).
- NERC SPCS should look closely at the reliability impacts of plant-level controls and protection on applicable NERC Reliability Standards.
- The model builders, data owners, Planning Coordinators and designee (per MOD-032) are to incorporate and monitor processes for inclusion of Volt/Hz, over excitation limiter, under excitation limiter, and reverse power dynamic models in future year planning cases.

[18] NERC Modeling Notifications available on NERC-MWG's Webpage