ELECTRIC POWER RESEARCH INSTITUTE

Power Plant Modeling and Parameter Derivation for Power System Studies

Present Practice and Recommended Approach for Future Procedures

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PRODUCT DESCRIPTION

The report documents results of a literature review, surveys, and experience in performing synchronous machine testing and model validation and, thus, documents present practice in the industry and offers potential refinements to the procedures.

Background

Generator model validation and testing is not a new subject. Efforts have been ongoing in this area for many decades. In 1997, the Western Electricity Coordinating Council (WECC) started a major effort in the aftermath of the 1996 system breakups to improve system planning models. One aspect of this was mandated testing of generating units. The North American Electric Reliability Corporation (NERC) is presently working to bring similar mandates to bear nation wide. This document addresses the need and type of power plant testing required per the NERC standards. In addition, recommendations are made on best practices and what really needs to be tested.

Objectives

- To discuss two major plant owner objections to the testing required for power plant model validation: 1) the cost of the exercise (potential loss of opportunity to sell power while the unit is being tested) and 2) the potential risk of damage to the unit.
- To propose a procedure to minimize the potential risk and time taken to perform the work, concentrating on identifying only key parameters that have maximum benefit with minimum effort.

Approach

The approach taken was to rely on past experience in performing this type of work for WECC plants, to review the literature (particularly recent Institute of Electrical and Electronics Engineers, or IEEE, and other publications), and to perform a worldwide survey of utilities for insights into their experience with this type of testing. These sources of information were consolidated for a proposed best practices approach.

Results

The result presented here is a proposed procedure to minimize the potential risk and time taken to perform testing work, concentrating on only the key parameters that need to be identified that have maximum benefit with minimum effort. In addition, recommendations are given on future efforts that can further minimize the intrusion on power plants while obtaining the necessary data for model validation, such as using disturbance monitor data (this, however, will require work planned for base-funded EPRI research in 2008). The next stage of the current project is to refine tools for post-processing and automating the parameter-fitting exercise.

EPRI Perspective

EPRI's involvement in synchronous machine parameter testing goes back to the 1980s and 1990s with Stand Still Frequency response-based parameter estimation techniques and the Parameter Identification Data Acquisition System (PIDAS) project. This report is part of an ongoing effort by EPRI to investigate state-of-the-art power plant model parameter derivation. The project's goal is to keep such efforts focused on meeting industry needs as dictated by reliability standards while keeping the approach to such work as simple and effective as possible.

Keywords

Generator testing
Field testing
Generator model validation
Synchronous machine testing

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1 INTRODUCTION

1.1 Background

The use of power system simulation models for performing system wide planning and operational studies is a well established practice in today's utility industry. In the present day power systems, new generation technologies such as wind generation, photovoltaic, and many other types of dispersed and distributed generation (e.g. fuel cells) are beginning to account for an ever increasing portion of the generation mix – however, the bulk of generating facilities in most systems are still conventional large scale power plants that incorporate one (or in the case of combined-cycle, two) of the following means of generating electrical power:

1. Conversion of thermal energy in high temperature/pressure steam to electrical power through the use of a steam turbine-generator.
2. Conversion of thermal energy in high temperature/pressure combusted gas to electrical power through the use of a gas turbine-generator[1].
3. Conversion of energy in a mass of water to electrical power through the use of a hydro turbine-generator.

All of these three types of power conversion methods primarily use synchronous generators. The generator is coupled mechanically in tandem with the turbine and is connected electrically to the power system. Thus, the rotational power imposed by the turbine is converted to electrical power. Figure 1-1 shows a block diagram of all the major components in a power plant of this type. This document deals with the modeling and parameter derivation of these major components in conventional power plants. This document does not present any discussion of renewable energy conversion systems such as wind turbines, photovoltaics etc. or dispersed generation systems such as micro-turbines, fuel cells etc.

Figure 1-1 shows a rather simplified, and generic, overview of the main control loops in a power plant. The turbine-generator shaft rotates at synchronous speed and is driven by the mechanical turbine (steam, gas or hydro). The power output of the turbine is determined by the flow rate of the working fluid (steam, gas fuel to be combusted or water), which is regulated by the turbine governor control system. The terminal voltage of the generator is regulated by changing the field voltage and current through the excitation system. Finally, the generator step-up transformer, transforms the lower voltage/higher current electrical power (typically, between 13.8 kV to 25 kV) at the generator stator terminals to the extra high voltage (EHV) level of the transmission system (typically, between 115 kV to 765 kV in the US). In a broad sense, for the purposes of

[1] In the industry and literature the terms "gas turbine" and "combustion turbine" are used interchangeably to mean the same thing. A turbine running on the Brayton cycle that converts the energy is hot combusted gas into mechanical rotational energy, which can then be coupled with an electrical generator.

power system simulation studies, it is these three major components that need to be properly modeled in the appropriate simulation tools, namely:

1. The electrical generator
2. The excitation system controls
3. The turbine-governor controls

The two control systems often include other supplemental control loops (e.g. power system stabilizer, overexcitation limiter etc. in the excitation system), which also require modeling. Standard models for all of these components are available in most of the widely used commercial power system simulation software. What are needed are the necessary parameters for each model that properly represent a given power plant. This document presents a detailed overview of current practice in deriving these parameters, through field tests and model validation techniques. In addition, proposed recommendations are given for ongoing efforts to refine and better focus efforts in model validation

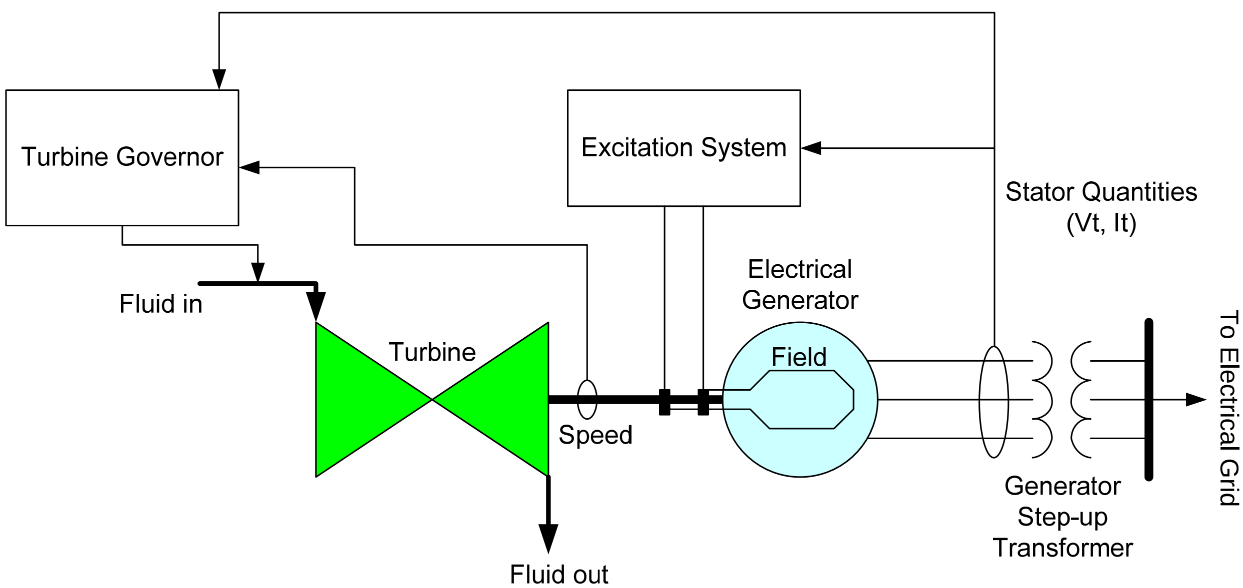

Figure 1-1
Simplified Representation of the Main Control Loops in a Power Plant

1.2 Purpose for Power Plant Field Testing and Model Validation

Power plant field testing[2] for the purpose of model parameter derivation and validation is not a new concept – work has been done in this area for decades. EPRI has also performed a few previous research endeavors in this area [1], [2], [3].

What is the purpose of field testing? Appendix B presents the results of a survey conducted during the course of this work. It clearly shows that the main objective, from a system planner/reliability council perspective, is to ensure proper and valid power plant models in power system models used for planning and operational studies. Though there may be other tangible and intangible benefits (see subsections below) the clear and main objective is to improve simulation models used to predict and plan the performance of the power system. The survey results in Appendix B show, particularly outside of the US, that some utilities/reliability councils use testing as a means of identifying plant performance, correcting control problems and/or verifying plant compliance with mandated control regimes (e.g. primary frequency control, automatic voltage regulation etc.). These objectives, however, can and are typically met through different types of tests than what is the main theme of this report (this is shown in the survey results).

It is emphasized again that the key objective of model validation testing is to validate power plant models in power system models used for planning and operational studies. Inadequate power system models can lead to disastrous consequence – a classic example is the WECC August 10th, 1996 event that showed a clear disparity between actual system response and the then available power system model (Figure 1-2).

It is, however, important to realize one central fact. Disparities between simulation models and actual system response as seen in Figure 1-2 are not due solely to potentially inappropriate power plant models, but are a result of two main factors:

1. Inadequate modeling of the power plants and transmission equipment
2. Inadequate modeling of the load

The second of these two factors was clearly demonstrated in [4], and is the subject of other research work by EPRI, WECC and other entities. The first factor, which is the subject of this report, has been demonstrated clearly in some recent publications that have identified inadequacies in models of turbine-generator controls in power system simulations that lead to optimistic results related to system performance based on simulations [5], [6]. In all this, it is of course assumed that the steady-state power flow and generation dispatch scenarios modeled in a simulation program, when comparing an actual disturbance recording to a simulated one, match reasonably well with actual system conditions as captured prior to the disturbance by SCADA, PMUs and other monitoring systems.

[2] In this report we refer to "power plant field testing" as opposed to some of the more commonly used phrases such as "generator testing" or "machine testing" since in fact in the context of modern system analysis the intent is to capture the behavior of the entire plant with all its controls and not such the electrical generator. However, all these phrases in the present context refer to the same thing.

With this brief discussion, the motivation for testing is clear. Below we discuss some of the most commonly debated risks and benefits.

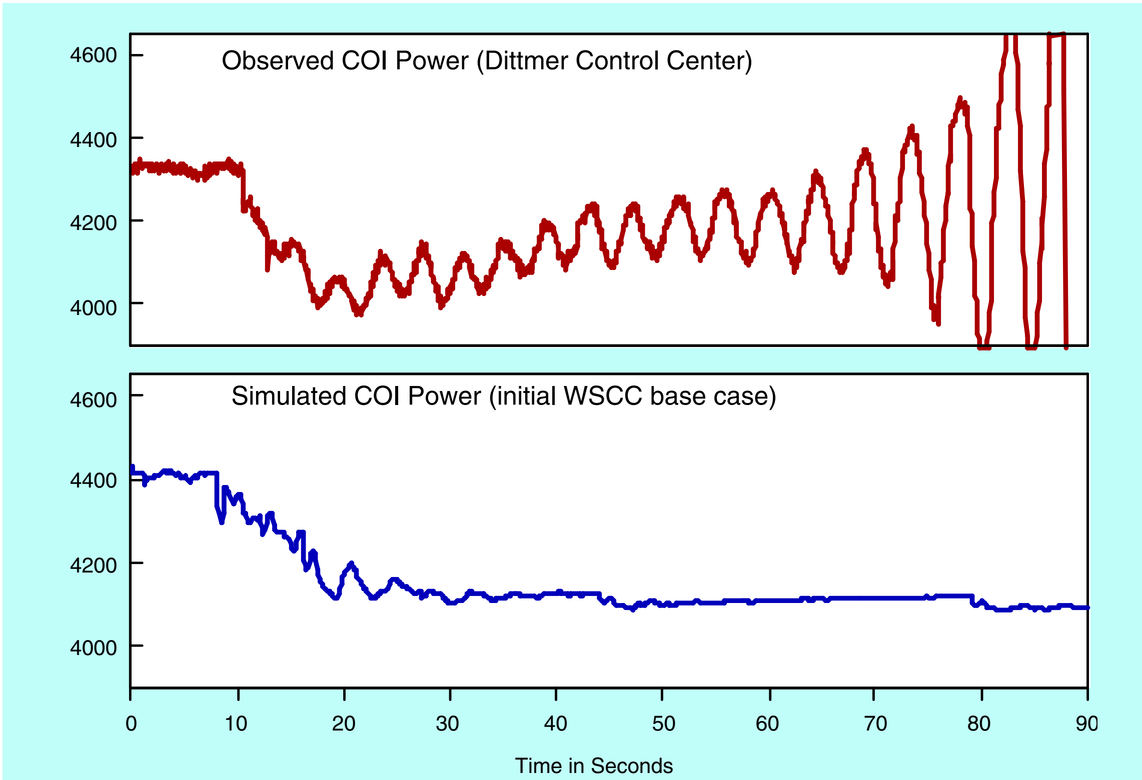

Figure 1-2
Growing Power Oscillations That Occurred During the August 10, 1996 Western-Interconnected System Separation. The top trace shows actual recorder power oscillations on the California – Oregon Interface (COI), while the bottom trace shows the simulated event based on the then available Western System Coordinating Council[3] (WSCC) Power System Model Data Base. This disparity was the motivation for the vast amounts of modeling and power plant testing activities that have since continued. (Reproduced With Permission from [7] IEEE © 2006)

[3] The Western System Coordinating Council is now known as the Western Electricity Coordinating Council (WECC).

1.3 Potential Risks of Performing Power Plant Testing

Power plant testing can be conducted in one of several established means [8], [9], [10], [11], [12], [13], [14] and [15]. The most common risks are as follows (based on survey results in Appendix B, [16] and the author's experience):

1. Possible impact on system security due to the unavailability of large, and thus critical, turbine-generators while being tested. As such, this will limit the times of the year when a unit is available to be tested. Test are thus conducted at one (or all) of the following times:

    a. During initial commissioning of a plant

    b. Immediately prior to a maintenance outage

    c. Immediately prior to coming out of a maintenance outage

    d. Immediately after a major retrofit (e.g. changing the unit's excitation system).

    As seen from the survey results in Appendix B, more often the unit is tested under conditions a, b and d. One of the reasons for this may be that the most common risk/problem with testing is that it may result in delays in returning the unit to service. This means significant financial risk due to the subsequent cost of replacement power while the unit is still not available. The causes of such delays are two fold. Firstly, the testing procedure may exercise an aspect of the unit and its controls that is typically not tested and thus identify a major problem or defect in the units controls that requires maintenance. This can of course be frustrating for all involved since it will likely mean the inability to complete the testing work and delays in fixing the problem. For example, on one occasion a failed excitation system circuit board, which resulted in an inability of the excitation system to fully exercise its dynamic range, was found during a test. This had gone unnoticed for an unknown duration. No replacement part existed in the plant and so it had to be ordered. A second source of delays is simply that the testing procedure might take longer than anticipated. This is typically caused by unfamiliarity of the plant staff with the operation of the unit under the special conditions needed for the tests and/or external factors outside of the control of any of the plant or testing staff – for example, on one occasion during the particular day that testing was planned, poor pressure on the gas pipeline feeding the plant affected the availability of the unit for testing. Thus, one more reasons why it may be convenient to perform tests just prior to a planned maintenance outage is that if such problems are encountered (e.g. identifying faulty equipment) it may at least offer an opportunity for the plant staff to work on and rectify the problem during the maintenance outage – this of course assumes that spare parts are readily available for the identified problem, which may not be the case.

2. To a far lesser extent, there is the potential risk of damage to the equipment. In [16] it is reported that a unit in New Jersey was destroyed as a result of a combination of a mishap and equipment failure during an overspeed test. This type of event is very rare, nonetheless such events have reduced the credibility of staff performing tests and raised the flag in-terms of a fear of damage to units during proposed tests. Based on the survey results presented in Appendix B, none of the respondents reported any major concerns or reported damage from tests performed in their regions (in total these constitute testing of many hundreds to thousands of units). Of course there may have been cases that were not reported. Nonetheless, this observation from the survey in Appendix B does indicate the quite low probability of such occurrences, assuming of course that testing staff are training, experienced and capable of the task.
3. The type of test does also invite greater concern. For example, here are some typical contentions/concerns related to specific tests:
   a. Damage to the unit due to overspeed during load rejection tests. This risk is very low if the testing staff take the necessary precautions to ensure that the amount of load rejected is small (10% or less of the units rating) and perform some initial calculations to estimated the expected overspeed and ensure that this is limited and well within the overspeed protection settings of the unit.
   b. Damage to control loops and equipment due to intrusive procedures. This risk is extremely low when non intrusive methods are used such as staged tests that do not require opening closed-loop controls for injection of test signals from external sources, but rather rely on recording the units close-loop control response to staged events, e.g. reactive power rejection or self induced (i.e. internal to unit’s digital control system) voltage reference steps.
   c. The potential for tripping the unit while at full load. Of all the potential risks, this is the most probable. It can be significantly minimized by careful preparation and following some simple guidelines:
      i. Avoid using intrusive measurement devices, e.g. use clamp on current meters for connecting to the unit’s CTs.
      ii. If possible, wire up the test equipment when the unit is off-line (or near no-load) and then slowly bring the unit on-load. Most of the tests tend to be done at or near no-load and so this methodology reduces the exposure of the unit to tests during full-load conditions.
      iii. Take time to monitor the unit’s conditions and anticipate alarms and limits as much as possible when performing reactive capability tests and PSS test near full-load. Avoid large test signals, e.g. when performing test of the units response to voltage reference steps, keep the voltage reference step as small as possible, also start with small steps and gradually increase the step size as necessary.

1.4 Benefits of Performing Power Plant Testing

Based on the survey results in Appendix B, the most common reason for the type of model validation testing discussed in this report is to help identify and improve the models used for representing power plants in power system planning studies. There are clear benefits of this nature derived from such tests, namely:

1. That manufacturer supplied design data is confirmed, or often improved upon (see section 4.1 for a more detailed discussion of this issue)
2. Actual control modes of operation and types of controls in use at the plant are identified and modeled, as opposed to assumed or "generic" models. This is not to say that models so derived from tests are "perfect" representations of the actual plant controls – far from it – but rather that such tests help facilitate more fitting representation of the plant controls than might otherwise be assumed. For example, "generic" or assumed models of the plant controls may represent the unit's excitation system as a static exciter, while in fact the unit is fitted with a brushless rotating-ac exciter.

In addition to these clear and intended benefits, there are many consequential benefits of power plant field testing. Here is a list of the most commonly experienced benefits, based on the survey in Appendix B, [16] and the author's own experience:

1. Often the plant staff, particularly unit operator, appreciate the testing work after the fact. This is because as a consequence of the range of operating conditions and maneuvering necessary to perform the tests, they become more familiar with the unit's capabilities and various control modes, which they would otherwise have rarely exercised or appreciated.
2. Many of the risk factors noted in the previous section actually lead to significant benefits. For example, often erroneous control settings, malfunctioning controls etc. are identified during such tests that would go unnoticed for months, possibly years and thus put both the unit and system at potential risk. In fact, this benefit is the primary reason for testing activities in many countries outside of the US (see survey results in Appendix B). Some examples include:
   a. Improper tuning of the excitation system. On many occasions, the excitation system tuning has been identified to be less than desirable where for example lack of transient gain reduction (or rate feedback) settings lead to an under damped and somewhat oscillatory response of the excitation system. Such issues are easily identified and rectified by the type of testing discussed here.
   b. For older analogue excitation systems, blown fuses or faulty circuit elements that lead to improper functioning of the excitation system (e.g. in one case encountered during tests performed by the author, the fuse in the machine terminal voltage feedback loop was blown, thus the unit was not actually regulating terminal voltage as intended. This was quickly noticed and fixed in a matter of tens of minutes).

c. Improper settings/coordination of controls and protection. For example, in one case encountered by the author the units overexcitation protection was incorrectly set to trip the unit while the unit was producing MVAr but well within the manufacturers specified reactive capability. This was identified and thus an action item was set by the plant staff to investigate this with the OEM and subsequently fix it. Such errors can lead to the unit tripping while at base load during system peak load conditions, when unit reactive output is needed the most, and thus result both in system security concerns as well as significant loss of revenue for the plant.

d. Faulty control/communication cards.

e. Power System Stabilizer turned off.

f. Unit being operated in improper control modes (e.g. in power factor or reactive power control mode rather than automatic voltage regulation).

These benefits are clear tangible benefits for the plant as much as they are benefits for the power system at large. This is because many of the problems listed above could easily lead to tripping of the unit due to improper control action following a system disturbance. Thus, there is a significant financial impact to the plant owner in terms of lost opportunity to sell power while the unit is off-line for the problem to be identified and rectified. Similarly, the cascading lost of a unit following a system disturbance further exacerbates system stability concerns.

1.5 Objectives of this Project

The objectives of this project are:

- To document and explain the present practice for power plant testing and model validation in the industry.
- To make recommendations on how such work should be pursued in the future based on the experience thus far.
- To further develop and enhance a MATLAB® based software tool previously developed by EPRI [3] (called Synchronous Machine Parameter Derivation – SMPD) for the purpose of deriving model parameters for power plant equipment (i.e. generator and its controls) based on measured field tests. This is to also be documented.
- To perform specific cases studies, for utilities that sign up for this optional task, of testing and developing validated models for a single power plant in a utility system. This is to be done as an illustration of the proposed methodology of power plant testing and the usage of the SMPD software.

This report constitutes the fulfillment of the first two bullet items above. The development and documentation of the SMPD software will be reported on in a separate EPRI Technical Report. The optional case study will also be reported upon in separate reports for each specific utility that signs up for this task.

1.6 Report Layout

The layout of the remainder of this report is as follows:

Section 2 – This section presents in detail the present practice for power plant model validation testing throughout North America and the world.

Section 3 – This section presents the various testing techniques currently used and also provides a brief overview of possible future approaches that are under discussion in the industry.

Section 4 – This section of the report presents the key components and their parameters that require validation. In addition, discussions are provided on what parameters are most likely to change during the life of a power plant and what parameters most influence system dynamics. This helps to facilitate the discussion in section 5 by clearly identifying what are the most important components that require validation.

Section 5 – This section pulls on the rest of the report to summarize and provided recommendations on best practices for power plant model validation.

Section 6 – This section provides a brief discussion of the remaining work in this research project and work that might be considered for future endeavors.

The **Appendices** of the report provide some additional information in support of the main body of the report.

2
PRESENT PRACTICE

Presently there is significant activity worldwide in the performance of power plant field testing. In the USA much of this effort is in the Western Interconnection and began following the major grid outages that occurred in the Western Electricity Coordinating Council (WECC) in 1996. As part of this research project, a public survey was performed, the results of which are presented in Appendix B. Here a review is provided of the present practice in the US and worldwide with respect to power plant field testing based on this survey, our experience and other sources as referenced.

2.1 US Reliability Councils and NERC

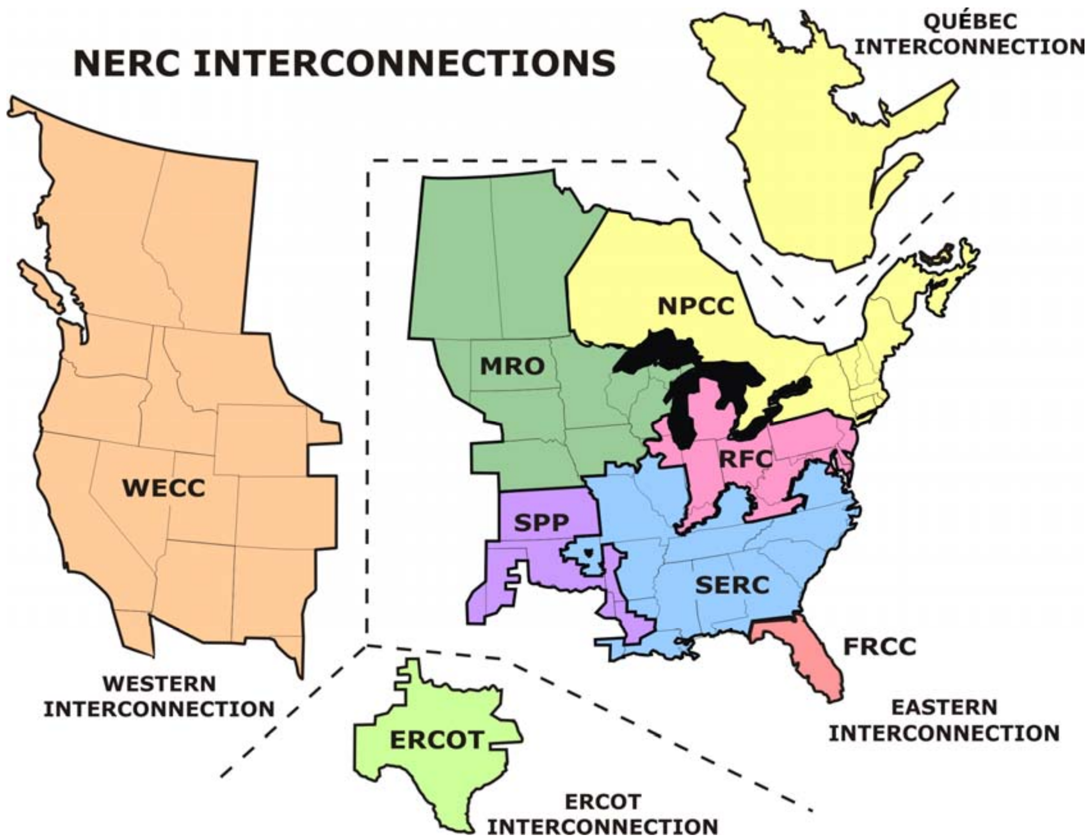

Figure 2-1
North American Regional Reliability Councils (with Permission from NERC © 2007, www.nerc.com)

The Energy Policy Act of 2005 authorized the creation of a self-regulatory electric reliability organization (ERO) that spans the North American continent. NERC Corporation[4] was certified by the Federal Energy Regulatory Commission (FERC) on July 20, 2006 as the ERO. Thus, subject to audits by FERC and Canadian governmental authorities, NERC Corporation develops and monitors reliability standards mandatory and enforceable in the United States.

NERC's members are the eight regional reliability councils (RRC) shown in Figure 2-1.

2.2 The Present NERC Standards

Presently (as of February 2007), NERC is in the process of developing standards for verification of models and data for generator excitation system, generator unit frequency response and other pertinent dynamic performance issues. In particular, the two key documents are:

MOD-26: Draft Standard MOD-026-1 – Verification of Models and Data for Generator Excitation system Functions, and

MOD-27: Draft Standard MOD-027-1 – Verification of Generator Unit Frequency Response

These are both presently under review and test, with a number of utilities having offered up their units to be tested and evaluated under these requirements. There is presently no proposed effective date for these standards. The purpose of these standards is to "ensure accurate information on generator excitation system functions … is available for models used to assess Bulk Electric System reliability" [17] and "To provide verification of generator unit frequency response (other than Automatic Generation Control) for use in models for reliability studies." [18]. These documents do not outline in detail any specific testing procedure or methodology but rather indicate the following requirements:

1. That each Regional Reliability Organization (RRO) establish and maintain adequate procedures for addressing such model verification and data management.
2. To document generating units that are exempt from such requirements and the criteria for such exemption.
3. To periodically schedule such verification
4. To report the following information:
    - For the Excitation System
        a. Verify manufacture and type of equipment.
        b. Verify model for each piece of equipment (exciter, AVR, PSS etc.).
        c. Verify static setpoints for under- and overexcitation limiters.
        d. Verify line drop compensation settings.
        e. Open circuit test response data showing generator field voltage and generator terminal voltage (exciter field voltage and current data for brushless units).

[4] www.nerc.com/about

f. Verify models and parameters for PSS.

g. Document verification procedure and data of verification.

- For the Turbine-Governor

h. Verify manufacturer and type.

i. Verify models and model parameters.

j. Verify frequency response[5] and mode of control operation (i.e. blocked governor, on base-load etc.)

k. Document verification method.

Presently one of the RROs (the WECC) has had such a mandate in place since 1997. The other RROs are following through. This is discussed in the next subsection.

Finally, it should be noted that many other NERC MOD's are also being put into place. One other MOD that is pertinent to the discussion in this report is MOD-025 – Verification of Reactive Power Capability. This is also addressed in this report.

2.3 Western Electricity Coordinating Council

The Western Electricity Coordinating Council (WECC) covers all of the Western Interconnection in North America (see Figure 2-1). During July and August of 1996 the WECC experience two major system disturbances that resulted in a total split-up of the system and tens of thousands of megawatts of interrupted load and generation. They were among some of the worst system disturbances within the past several decades in the North American continent. As shown in Figure 1-2 one of the key findings of the postmortem analysis of the event was that system planning models had not adequately captured the actual performance of the system. The particular disparity in Figure 1-2 has been discussed in a number of publications; one pertinent reference is [19]. This disparity was one of the chief drivers behind the impetus in the WECC (previously WSCC) to establish mandated procedures for power plant field testing and model validation [11].

The WECC testing procedures are well established and have been exercised since 1997. The document [11] on the WECC website describes in detail the WECC requirements[6]. In short, these testing procedures are based mainly on staged testing procedures, although other methodologies such as frequency response based techniques and the recent move towards on-line monitoring data based verification of thermal-governor response [5] are also pursued. The testing approach described in section 3.1 is a typical approach used in the WECC.

[5] Although not explicitly stated in the document, by frequency response they presumably mean droop characteristic no "transfer function frequency response"

[6] http://www.wecc.biz/modules.php?op=modload&name=Downloads&file=index&req=viewsdownload&sid=30

The salient points of the WECC testing procedure are as follows:

1. All units at or above 10 MVA are subject to generator model validation testing.
2. This testing needs to be performed once every 5 years.
3. The testing aims to provided models and parameters for the models for the generator, the excitation system and the governor. In addition, the generator reactive power capability limits should be identified as well as key limit setpoints of limiters that play a key role in stability studies (such as overexcitation limiters, as these derive mid-term dynamics associated with voltage stability studies [20]).

A very interesting recent development in the WECC testing effort has been the move to performing some model validation through recorded monitoring data, such as SCADA or DFR recordings. This is mainly limited to the validation of the operating mode and response of turbine-governors. A detailed account may be found in [5], [21]. The intent here is to attempt to capture the actual behavior and mode of operation of turbine-governors during system events that lead to turbine-governor response.

2.4 Eastern US Interconnection

The Eastern Interconnection, in contrast with the Western Interconnection, is made up of several RROs. With the exception of SERC[7], none of the other RROs presently have enforced testing in place. However, all are working towards this end. A summary is given of the present status of these regions in the survey results of Appendix B.

The SERC effort warrants some discussion. Starting with the SERC Generator Testing Workshop of 2000 [22], [16], [23], [24] an effort was started in SERC to address the imminent need for power plant testing and model validation. What has culminated from this effort are a set of mandates that went into effect in 2005[8]. The mandates essentially state that units above 75 MVA (connected at or above 100 kV) should be tested within the first seven years of the establishment of the mandate (i.e. by 2012) for reactive capability and excitation system performance. Thereafter, these should be re-evaluated every five years. Presently not many units have been tested and SERC is phasing in the testing by performing the tests on units volunteered by member utilities to gain experience with the procedure. There are a few interesting aspects to the SERC methodology that sets is somewhat apart from the WECC approach:

1. Testing and validation of the generator electrical parameters are not explicitly requested.
2. There is an effort to exempt Nuclear units from intrusive (staged or frequency response based) testing and to develop on-line monitoring techniques for validating the models and parameters for these units.

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[7] http://www.serc1.org/Pages/DocumentSearch.aspx?FN=SERC%20Supplements/Planning/Active%20Supplements%20(Wholly%20or%20Partially%20Reference%20Current%20NERC%20Reliability%20Standards)

[8] http://www.serc1.org/Pages/DocumentSearch.aspx?FN=SERC%20Supplements/Planning/Active%20Supplements%20(Wholly%20or%20Partially%20Reference%20Current%20NERC%20Reliability%20Standards)

3. The SERC proposed procedures [25] explicitly state that the first step in validating the reactive capability of a unit should be an “engineering assessment” (this is understood to mean through engineering calculations rather than actual field testing). Then if the reactive capability based on engineering assessment can be validated through comparisons with recent operational experience (e.g. recorded unit reactive output from the power plant digital control systems) then nothing further is need be done to test the unit’s reactive capability.

There is some limited testing done in other regions in the Eastern system also. For example, one respondent utility in RFC presently performs voltage reference step tests on large units to validate excitation system response. In addition, reactive capability is tested. Nuclear units are not tested unless there is clear justification for doing so.

2.5 Electric Reliability Council of Texas

Presently there is significant activity in reviewing and assessing the need for power plant testing in ERCOT, however, there is no mandate or procedures in place for performing such work (see survey results in Appendix B).

2.6 Québec Interconnection

The Québec province in Canada is essentially an electrical island system, connected to its neighbors (US and Ontario) through HVDC links. Québec engineers did not respond to the survey (see Appendix B). Nevertheless, based on a literature review ([26]) power plant testing is performed in Québec. Furthermore, they primarily perform frequency response based tests (described in section 3.2).

2.7 Outside of North America

Internationally, there is significant effort in power plant testing in some parts of Europe and in Australia. Most international respondents to the survey (see Appendix B) indicated that power plant testing is not mandated in their system. The main exceptions were Italy and Australia. Both these latter systems mandate tests, however, driven by slightly different objectives. Mandated testing in Italy began in 2006 and is focused on turbine-governor response. Units above 100 MVA must be tested and the key objective is to ensure proper operation and response of turbine-governors during frequency excursions. Moreover, every 6 months thermal units greater than 200 MVA must demonstrate their ability to reject load and select hydro and gas turbines must demonstrate their ability to black start. In fact, a very specific emulated frequency transient is imposed on units and they must demonstrate their ability to respond and stay connected to the system. The primary impetus for this activity was the aftermath of the September 28th, 2003 blackout in Italy [27]. Postmortem analysis of the event showed that the primary reason for the system collapse was an inability to restrain frequency decline after a series of cascading outages led to islanding Italy from the rest of continental Europe. The islanding left Italy with a 6.8 GW power deficit. This lead to heavy load shedding, however, due to the loss of a significant number of generators along the way (which should not have tripped based on expected control behavior) the frequency decline could not be restrained and the system eventually collapsed when frequency fell enough to result in massive loss of generation due to under-frequency protection.

Similarly, tests are performed on large important units that are relied upon for black start within Switzerland since 2004. Again, presumably some of the impetus for this was the 2003 blackout of their neighbor.

The Australian system operator and market management company (NEMMCO) also mandates quite extensive testing on power plants. In addition, they are moving quickly to define testing procedures for wind generation, something currently not done in a systematic way anywhere in the US. The Australians perform both staged and frequency response based testing. In fact in one utility PSSs are subject to quite detailed frequency response based testing to verify their performance. Much of this is driven by the unique nature of the Australian interconnection. The system historically has been quite susceptible to lightly damped or undamped electromechanically inter-are oscillations [28], thus the loss or improper functioning of key PSSs can be a drastically detriment to system security.

Some international systems are actively looking into testing mandates for power plant testing. A summary of the survey results are given in Appendix B.

3 TESTING METHODS

First it is important to reemphasize that the subject mater here is the performance of tests to determine and validate the parameters used in computer simulation models of power plants for the purpose of power system simulation studies. Thus, any reference to tests is not intended to have connotations of verifying plant performance or proper operation of equipment, though this may be a significant secondary benefit.

In this section a discussion is provided of the presently accepted and most widely used methods for performing power plant testing. Also, at the end of the section a discussion is provided on possible future avenues for model validation using on-line monitoring.

In this report, short-circuit test methods for deriving generator electrical parameters are not discussed. The practice of such tests purely for the purpose of deriving generator electrical parameters is unwarranted and rarely practiced presently, due to the fact that such tests subject the unit to significant stress. Short-circuit factory tests may still be performed as part of acceptance testing by original equipment manufacturers (OEMs).

3.1 Staged Tests

The most common methodology for performing power plant testing is through staged tests. A generic test plan for this type of testing procedure is presented in Appendix A. Examples of this type of test methodology may be found extensively in the literature, some examples are [29], [30], [12], [22], [15], [31], [32] and [23].

The basic concept behind the staged testing procedure is that a series of pre-designed tests are preformed on the generating unit with the expressed intention of resulting in enough of a response by the generator and its controls to allow simulation of the same event and thus to extract model parameters. The tests are also designed to have a minimum risk of resulting in any damage or unintentional tripping of the unit.

The advantages of staged testing are:

- They are the most direct way of extracting the desired model parameters, since they directly invoke a response in the very systems one is intending to model – i.e. generator, exciter and governor.
- They are generally simpler and less time consuming than other test procedures. This tends to typically mean a shorter time period during which the generating unit is not available to the system and is under test.

- They tend to in general be the least intrusive types of tests. That is, none of the plant control systems need to be disabled, dismantled or disconnected. Some minimal protective systems (e.g. unit reverse power relays, and any intentional transfer trips on the excitation system and turbine-boiler) may have to be disabled for some of the tests, but this is done under a controlled environment and actually with the purpose of avoiding unintended turbine/boiler trips.

The basic theory behind these types of tests is as follows.

Generator Parameters

The most typical staged test for obtaining the generator electrical parameters is the reactive power rejection test. In this test the generator is operated at near zero megawatts while absorbing reactive power from the system. It can be easily shown, based on the standard generator machine equations [33], that under this condition (P = 0 MW, and Q = $Q_{inductive}$ MVAr) the internal flux of the machine is purely on the direct axis (d-axis) – note: flux is at quadrature (90 degrees) to voltage (Faraday's Law) and thus the internal voltage is on the quadrate axis (q-axis). This is shown in Figure 3-1. Therefore, if we place the machine under manual control (i.e. the excitation system is holding field voltage constant, not regulating terminal stator voltage), then if the generator is suddenly disconnected form the system (generator main breaker is opened) the response will be a subtransient voltage decay, followed by a transient voltage decay. Terminal voltage will decay because by initially operating the machine such as to absorb reactive power from the system, the internal machine magnetic flux is being sustained partially from energy exchange with the system. Thus, once the connection with the system is severed, the flux will decay and likewise the terminal stator voltage. Since, the machine flux is purely on the d-axis, this test facilitates estimation of all the d-axis machine parameters. A list of the typical set of machine parameters required for synchronous machine modeling is shown in Table 3-1. The parameters that can be estimated based on this test are Xd, X'd, X''d, T'do and T''do. The corresponding q-axis parameters can be extrapolated through typical relationships between the two sets of parameters, for round rotor and salient pole machines (see Table 3-2). Also, the stator leakage reactance (Xl) may be assumed to be 80% of X''d (by definition, Xl < X''d). Figure 3-2 shows an example of this type of test.

Alternatively, the q-axis parameters can be estimated by performing a combined megawatt/megavar rejection test (i.e. the unit generating MW and MVAr in such a way as to align the generator flux along the q-axis) and then recording rotor angle in order to estimate q-axis parameters based on the rotor angle transient. The approach has two draw backs. One is that an initial guess of the q-axis parameters is needed to be able to estimate a condition for aligning the generator flux along the q-axis. Multiple trials of the test may be needed in order to reasonably align the units flux along the q-axis (i.e. try to make rotor angle equal to the power factor angle of the machine). Secondly, to perform this test an additional complication is the need to measure shaft mechanical speed directly to be able to estimate rotor angle – this requires bringing the unit to a standstill to mount a sensor near the generator shaft (unless an existing sensor can be used).

The discussion in section 4.1 highlights the fact that generator electrical parameters tend to be relatively constant (at least to within measurement tolerances) and are rarely significantly at variance with the manufacturer supplied numbers. Therefore, unless the generator is refurbished (e.g. rotor/stator rewind etc.) tests of the generator parameters are perhaps only require once for verification purposes.

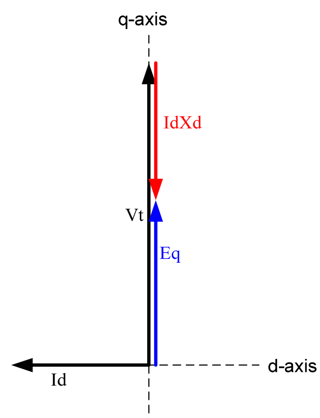

Figure 3-1
Synchronous Generator Phasor Diagram for Zero Power Factor (i.e. Zero Megawatts) Operation While Absorbing Reactive Power from the System (Note: Armature Resistance Has Been Neglected Here)

Table 3-1
Synchronous Machine Model Parameters

Parameter	Description
Xd	d-axis reactance
X'd	d-axis transient reactance
X''d	d-axis subtransient reactance
Xq	q-axis reactance
X'q	q-axis transient reactance
X''q	q-axis subtransient reactance
Xl	leakage reactance
T'do	Open circuit transient d-axis (field) time constant
T''do	Open circuit subtransient d-axis time constant
T'qo	Open circuit transient q-axis time constant
T''qo	Open circuit subtransient q-axis time constant
ra	Armature resistance
S1.0	Saturation constant at 1.0 pu terminal voltage
S1.2	Saturation constant at 1.20 pu terminal voltage
H	Combined generator-turbine inertia (MWs/MVA)

Table 3-2
Typical Relationship Between d- and q-Axis Parameters

Parameter	Round Rotor Machine	Salient Pole Machines for Hydro Units
Xq	≈0.9 Xd	≈0.6 to 0.7 Xd
X'q	≈1.5 X'd	0
X''q	≈X''d[9]	≈X''d
T'qo	≈0.3 T'do	0
T''qo	≈T''do	≈T''do

[9] In some models (such as the GENROU model in both PSS/E® and PSLF®) X''q is set equal to X''d by definition.

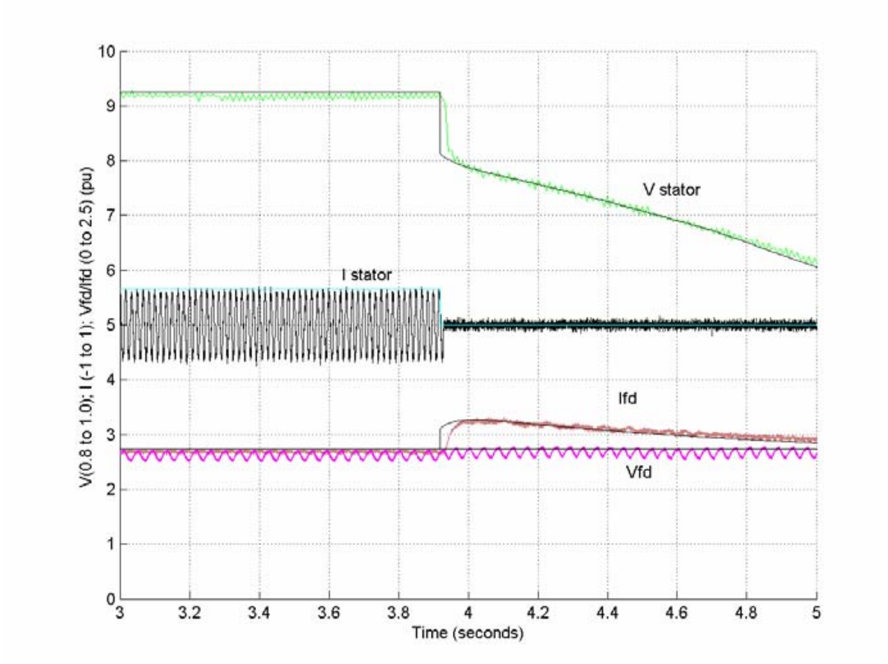

Figure 3-2
Typical Result of a Reactive Power Rejection Test With the Unit's Exciter in Manual Regulator Mode in Order to Estimate Generator Electrical Parameters. The somewhat "noisy" traces are measured field quantities during the staged tested, shile the smooth lines are simulated results based on fitted parameters to the fenerator model. (Reproduced From [15] IEEE©2004)

Open Circuit Saturation Curve

To determine the saturation parameters for the generator (parameters S1.0 and S.12 in Table 3-1) a simple test needs to be performed with the unit off-line (disconnected from the system) and running at full-speed no-load. The generator terminal voltage is started at roughly 70 to 80% of rated voltage and stepped up in small (few percent) increments up to roughly 110% voltage. At each point the unit's terminal voltage and field current are recorded. Then by plotting terminal voltage versus field current one can easily calculated the parameters for the saturation model, as shown in Figure 3-3.

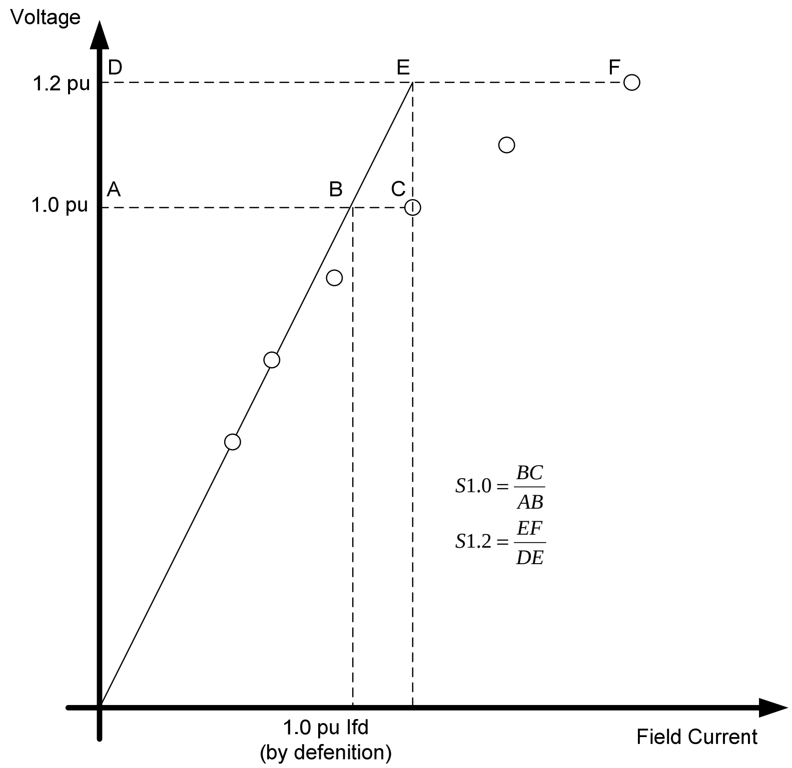

Figure 3-3
Open Circuit Saturation

Excitation System Parameters

The excitation system has the most influence on angular stability of a power plant [34]. The proper modeling of the excitation system is perhaps the most important factor in power plant modeling. This can be done one of several ways through staged tests. The two most common methods are (i) using a voltage regulator step response, or (ii) performing a reactive power rejection test (similar to the generator test above).

With the voltage regulator step response, this test can be done with the unit on- or off-line. Most modern voltage regulators have this capability. So one simply injects a small (few percent) step in reference into the voltage regulator and records the unit's response. Then the excitation system parameters can be estimated based on this recorded response. Of course, the correct excitation system model needs to be chosen, i.e. whether it is static, static-compound, brushless etc. An example of this type of test is shown in Figure 3-4.

Alternatively, by repeating the reactive power rejection test described previously for estimating the generator parameters, this time placing the unit in automatic voltage regulator mode, the excitation system parameters can be estimated. This is because after opening the generator main breaker, the generator terminal voltage will again start to drop. However, this time the automatic voltage regulator (AVR) will react to correct this and return the terminal voltage back to its initial value (minus any line drop or droop compensation). Thus, the behavior of the excitation system can be observed and its parameters estimated.

These tests will facilitate the estimation of most of the key parameters of the excitation system such as gain, rate feedback/transient gain reduction, time constants, etc. However, the engineer must still recognize and properly select the appropriate exciter model and control features (e.g. brushless exciter with a PID regulator versus a static exciter with straight proportional control and rate feedback, etc.). The exciter limits, however, typically must be calculated from its nameplate ratings. Although it is sometimes possible to force the exciter to its ceiling during one of these tests, it is not necessary and in some cases not desirable (e.g. the case shown in Figure 3-4 was for a brushless unit with a permanent magnetic generator as the power source of the excitation system, the calculated exciter ceiling for this design was 47 pu).

Power System Stabilizer

Another key supplemental control, often found in the excitation control cabinet, is the power system stabilizer (PSS). The staged testing of a PSS typically involves nothing more than performing a voltage reference step test (as shown in Figure 3-4) but simply doing the test both with and without having the PSS in-service. Then the corresponding electrical power oscillations are compared to establish if indeed the PSS is performing its task of providing additional damping. Note, it is meaningless to “fit” or “estimate” the PSS parameters based on tests in the same way as has been discussed above for the generator and excitation system. This is because the sole purpose of a PSS is for providing additional damping in the range of electromechanical modes of rotor oscillation. Thus, a PSS is tuned with predetermined/calculated parameters for this purpose.

The PSS parameters can typically easily be read off of the dial settings on the PSS card (for analogue units) or in some cases they must be extracted from the digital controls (this may require interfacing with the controls). The intent of such a test is to confirm the setting and functioning of the PSS. Should the PSS be found not to be providing additional damping, or if the tests are being performed upon the initial installation of the PSS, the PSS may need to be tuned and then the test described here performed to confirm its functionality. Techniques for tuning PSSs can be found in the literature [35], [36], [37].

Note: One issue that the author and others performing such tests have come across is improperly designed PSSs. That is, PSSs that do not have suitable design to allow them to be effectively tuned to significantly enhance damping. Addressing such concerns is outside the scope of this present project. However, this much can be said that this is a problem on the OEM side and should be addressed by the OEM.

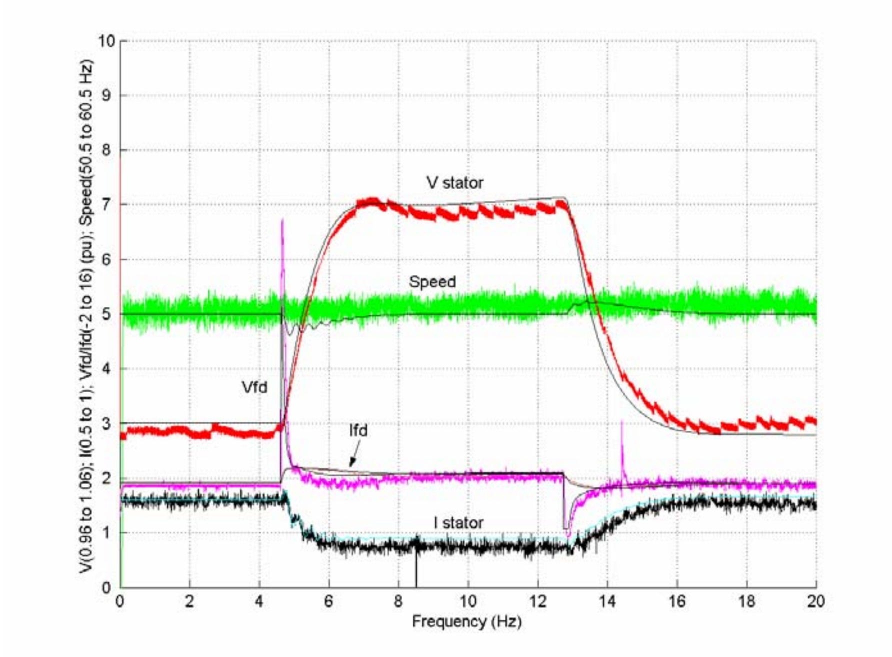

Figure 3-4
Example Result of a Voltage Reference Step Test. Noisy traces are measured quantities, while smooth lines are simulated results based on estimated model parameters. (Reproduced With Permission from [15] IEEE©2004)

Turbine-Governor and Unit Inertia

There are three key features that need to be identified for turbine-governor controls. The droop setting of the turbine-governor, its typical mode of operation (i.e. unit is base loaded, on outer loop megawatt control, on automatic generation control, or governing) and the nature of the turbine-governor response time.

Determining the turbine-governor droop can be achieved one of several ways. The simplest method is to record the main steam valve/fuel valve/wicket gate position for steam/gas/hydro units, respectively, versus turbine megawatt output. Then the governor speed-load reference setpoint can be recorded for a range of turbine speed while the unit is off-line. Thus, we can calculate MW per percent speed change as a ratio of the slope of the two lines, which provides turbine-governor droop. In mathematical terms:

Droop (r) is the percentage change in speed for a 1 pu change in turbine power = $\dfrac{\dfrac{\Delta\omega}{\Delta\omega_{ref}}}{\dfrac{\Delta P}{\Delta\omega_{ref}}}$

where $\Delta\omega$ is the change in speed off-line for a $\Delta\omega_{ref}$ change in speed reference and ΔP is the change in unit power for the same change in speed reference when on-line. This of course assumes that droop is constant throughout the megawatt range of the turbine. For gas turbines, by designing a linear response of the fuel valve [6], both lines (speed reference versus speed off-line and megawatts versus load-reference on-line) are linear. This leads to a uniform droop characteristic. For hydro turbines in particular, there is a non-linear relationship between wicket gate opening and turbine megawatt output, which will lead to some difficulty in determining droop. Also, hydro turbines have specially designed governors that have both a "temporary" and a permanent" droop, this is due to the "non-minimum phase" response of the hydro turbine driven by the water time constant [33]. For steam turbines equal complications exist since the steam inlet conditions (pressure and temperature) will change as a function of turbine loading – this will thus affect the droop calculation. For combined-cycle power plants, depending on the design of the plant the effective total droop must consider the subsequent (thought many minutes time frame) response of the steam turbine following a change in the output of the gas turbines [6].

Determining the mode of operation of the unit is a simple case of identifying this one site. The turbine-governor response can be assessed through a megawatt rejection test or a speed-load reference step test. If a megawatt rejection test is performed this can also facilitate an estimation of the combined generator-turbine shaft inertia, by calculating the initial rate of rise of speed.

Deadband

One other aspect of turbine-governor characteristic is the turbine-governor deadband. For modern gas turbines using digital governors an intentional deadband is often introduced into the governor controls [6]. Typically, this is of the order of +/- 0.025% speed (on a 60 Hz system this corresponds to 15 mHz) – this can be easily simulated. Steam and hydro turbine governors, however, can have actual physical deadband due to "stiction" and "backlash", respectively. Measuring such deadband is difficult at beast; for one thing it may vary with time.

Reactive Power Capability

A discussion of this test is provided in [24] and [22]. In some ways this is the simplest of all tests, and yet in other ways it is the most difficult. It is the simplest since it requires no instrumentation to be connected to the unit or any special disturbance monitoring. What is required is simply to take the unit to its rated megawatt output (for the given conditions) and to then demonstrate that the unit can supply its rated reactive capability both leading and lagging (as specified from the manufacturers capability curves, taking into consideration the underexcitation limit for leading VArs and V/Hz/OEL for lagging VArs). The difficult part is that more often than not it is not possible to realize this full reactive capability in the field. The reason for this is manifold. Here are the most typical reasons for not being able to reach the full reactive capability of the unit during testing:

1. Testing is always performed during light load conditions when the units under test are not needed for secure system operation. As such, system voltage tends to be healthy. Thus, taking the unit to its peak reactive power output would result in unacceptably high voltages both within the power plant (auxiliaries) and also possibly on the transmission system.
2. Similarly, absorbing reactive power at the full capability of the unit may also lead to unacceptability low auxiliary bus voltages under some conditions.

3. Most modern excitation systems have limits on the voltage reference setpoint of the AVR. As such, under the system conditions during which the tests are being performed, this limit may not allow for the generator terminal voltage to be raise high enough to push the generator reactive output to the machine capability. This is actually the correct and desired behavior of the controls since otherwise the generator may be pushed to an unacceptability high steady-state terminal voltage.
4. During the test for lagging VArs the volts/hertz alarm may become engaged and for leading VArs the underexcitation limiter may prevent further reduction in field voltage/current.

None of the above reasons are necessarily an indication of improper plant control settings[10]. Rather the issue is that the reactive limits of the unit are only needed (and exercised) under extreme conditions (e.g. severe under voltage conditions on a system). Therefore, they cannot be demonstrated for the particular test conditions. Thus, typically this test is done by taking the unit to whatever reactive output that can be safely achieved, on the day and for the time of the test. Then based on engineering calculations it is determined if any of the limiters (overexcitation or underexcitation limiter, etc.) might prevent the unit from achieving its reactive capability for severe system conditions – if not, the calculation based limits are quoted. Alternatively, where possible, sister units in the same plant might be used to off set the reactive power generated (or absorbed) by the unit under test to demonstrate its reactive capability. Shunt reactive devices in nearby substations may be used for this same purpose. Such flexibility, however, may not be available or allowed by system operators during the test.

Ideally, the reactive capability of the unit should be measured at a few different load levels (e.g. 0 MW, 25% MW, 50% MW and base load MW). However, the most valuable and important values are those at base load (rated megawatts), particularly for units that are typically base loaded. If these values can be confirmed and validated against the OEM supplied unit reactive capability curve (without hitting limiters or protection), there is little reason to believe that the units reactive capability is likely to be limited at lower loads.

One important note here is the disparity in the time required for this test. For example, in WECC [11] the requirement is to take the unit to its rated reactive capability (leading and lagging) and to hold the unit at that level for at least 15 minutes (30 minutes is preferred, but not required). In the recent SERC document [25], the requirement varies based on the type of unit, however, it states that the unit should be kept at it reactive limit for between 2 to 4 hours. One observation here is that since the reactive capability of the machine is primarily associated with the electrical controls of the generator (i.e. excitation system controls/limiters/protection and heating of the stator and rotor), it is not believe that the 2 to 4 hour time frame for such tests is necessarily warranted. If the unit is able to hold constant reactive power for 15 minutes or more with the rotor and stator temperatures settling down and without reaching or hitting any limits, there is no reason to believe this could not be sustained for hours should the need arise. Furthermore, the complication with such prolonged test durations is that it may be difficult to maintain the unit at a constant reactive and real power output for such a prolonged period, particularly when dealing

[10] It should be noted, however, that at least on a few occasions exceedingly conservatively set limiter and protection controls that unnecessarily limited the unit's reactive capability were found. In these cases the plant owner was advised to engage the OEM to discuss the issue and identify if there were any extenuating circumstances to warrant this for the particular unit and thus change the settings to more appropriate values.

with units that are not base load units or if system conditions change requiring a change in the unit's reactive/real power output. The SERC document [25], actually does acknowledge this latter concern and indicates that in these cases a more suitable duration for the test should be identified.

Protection and Limiters

Often limiters can play a significant role in power system dynamics. A classic example is overexcitation limiters (OEL) and there action in determining dynamics associated with voltage collapse in power systems [38]. Thus, another item often reviewed during testing work is to confirm the setpoints of the OEL and underexcitation limiter (UEL). Per the IEEE Std 42.15-2005 [8], the OEL is modeled in power system studies using a "functional" model (like the *oel1* model in the GE PSLF© program). That is, the details of the transient dynamics of the OEL are neglected since these do not play a major role in system dynamics. Instead what are modeled are the actual limit and the nature of the limit (e.g. inverse time characteristics). This is because the importance of OEL action is primarily for voltage stability studies where the action of the OEL limit may lead to long-term voltage instability – this phenomenon may take many tens of second to several minutes, and thus the nuances of short term (fractions of a second) transients in the actual action of the OEL are not relevant. The IEE Std [8] also discusses the modeling of the UEL. In this case the dynamics of the UEL can be quite important, particularly for system events that may lead to the generator being under excited. The reason is that the UEL can significantly affect the unit's transient stability as it will override the exciter to boost excitation in such situations to prevent loss of excitation. Also, the UEL can interact with the PSS. This is an area for further work, since presently (as of writing this report) at least one of the major power system simulations tools used by system planners in the US does not have any UEL models. Thus, it is difficult to translate any test results into models for power systems analysis.

Testing Sister Units

In the case of testing a group of units in a single power plant, which are nominally "identical", there are some time and money saving procedures that may be adopted. One simple approach is as follows:

1. Perform all of the tests listed above on one of the units.

2. Then repeat only the excitation system, PSS and reactive capability tests on the sister units.

3. Also identify and verify the OEL/UEL and turbine-governor droop on the sister units.

Once simulations have been performed to derive and validate the model parameters for the first unit for which all the tests were performed, this can be used as a starting point for the simulation of the excitation system and PSS response for the other units. Thus, if one can illustrate that these same models and model parameters can demonstrate a good fit between simulation and measured response for all the units then this establishes a basis for having estimated and validated models and model parameters for all the units. Otherwise, some iterative analysis may show some slight differences in the excitation system settings for each of the group of machines. This approach has been successfully used on many occasions where sister units have been tested.

The Parameter Derivation Process

An important note here is that the process used for deriving the model parameters once tests have been performed using the above techniques is an iterative one. For example, in Figure 3-2 the recorded event is simulated in a power systems simulation program (for the example shown this was done using GE PSLF®). Then the simulation result is compared with the measured results. Then the engineer, based on his/her experience, iteratively makes changes to the various model parameters until a good/reasonable match is obtained, as shown in that figure. This is true also of the excitation system test and to some extent of the turbine-governor response test. As discussed in section 6.1, the aim of the next phase of this project is to successfully automate as much of this process as possible.

3.2 Frequency Response Based Techniques

Frequency response methods (also more commonly known as Stand Still Frequency Response or SSFR methods) are quite detailed and by their inherent nature result in a direct derivation of the model parameters based on a pre-specified model structure. In essence all components, including the electrical generator itself, in a power plant can be modeled by transfer functions. The fundamental theory and methodology behind this technique is described in [1], [10] and [13]. Some other publications on the subject are [39], [40], [41], [42], [43]. Also, [9] may be consulted for discussions on excitation system parameter estimation using frequency response techniques. For the sake of completeness, we will provide a brief description of the methodology for these techniques.

The general concept of this approach may be explained by a simple diagram, as shown in Figure 3-5. The component to be modeled must first be isolated. For example, in the case of the electrical generator, it must be brought to a standstill and the rotor safely locked into position to avoid movement which might result in equipment damaged. Then the stator and rotor (field) winding terminals must be disconnected form the rest of the power plant equipment and connected to a spectral analyzer. The spectral analyzer, typically, consists of an amplifier and signal generator that will generate precise sinusoidal voltage waveforms over a range of frequencies at precise voltage amplitudes. This is then injected into the input of the component under test (e.g. field winding in the case of a generator) while monitoring the output. By plotting the observed gain (ratio of the amplitude of the input and output waveform) and phase (difference in phase angle between input and output wave form) one can obtain a Bode plot that characterizes the transfer function of the component. In the case of the generator, this must be done under various conditions, particularly for salient pole machines [13]. That is, for example, by first positioning the rotor (when locked) to be align along the d-axis (to facilitate derivation of d-axis parameters) and then rotating the rotor through 90 electrical degrees, locking the rotor and repeating the test for derivation of q-axis parameters. This can be slightly challenging. In the case of modeling the components of the excitation system (e.g. AVR, PSS etc.) this same approach is used in isolating each of the components and injecting a sweep of varying frequency sinusoidal voltage into the components input (e.g. AVR reference, or PSS input) and recording the subsequent output to derive the transfer function of the device.

The parameter estimation process is automated and through the use of algorithms such as recursive least-squares estimation techniques or maximum likelihood optimization techniques [26]. To facilitate this, the model structure must be known. This is not a problem since models for generators are well established [33]. One note is that the models available in most commercial software used in North America and throughout the world for power system studies, use what are termed 2nd order flux equations (i.e. two rotor circuits modeled on the d- and q-axis). However, many of the frequency response methods have suggested that third order models (i.e. modeling up to three rotor/stator circuits) are necessary to achieve more accurate representation of the generator [13] and [26]. In the context of the present discussion, however, it is not believed that this added level of complexity is sufficiently warranted. There is little consensus in the industry or literature that suggest such 3rd order models would substantially improve large power system planning study results. This is a subject for future discussion and research. In the end, the other present limiting factor is that the most widely used and adopted simulation tools, particularly in North America, do not have 3rd order generator models in the standard model libraries.

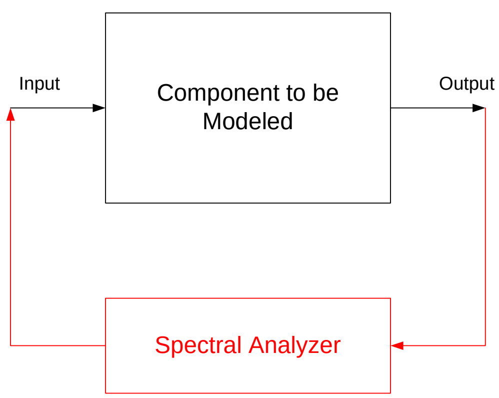

Figure 3-5
Frequency Response Testing

3.3 Other Techniques

In should be noted that there is significant published research on other methods such as techniques based on adaptive and Kalman filters (and other optimal control and parameter estimation algorithms) that use for example the injection of test signals into the generator excitation system for the purpose of extracting on-line generator response for parameter estimation (e.g. [44]). To our knowledge these techniques are not presently widely used. In a sense the ultimate proposed approach here is similar in that staged on-line tests are performed to recorded data, and this is then to be fed to optimization algorithms for estimating model parameters.

3.4 Pros and Cons of the Two Main Testing Methodologies

The main advantages and disadvantages of the two dominant testing methodologies discussed here are highlighted in Table 3-3.

Very briefly it can be said that the frequency response methods tend to be more time consuming and more intrusive on the plant. That is, each component needs to be tested separately and the entire unit under test shut down with the major control loops opened. On the other hand staged test are generally simpler and quicker without the requirement to dismantle any equipment or to even shut down the unit. One of the key disadvantages of the staged testing approach is the need for extensive experience by the testing engineer(s) to be able to start and quickly bring to fruition the iterative process of estimating the parameters of the power plant model. Although in the end some key experience and expertise is of course needed for any such engineering task, if would be helpful to try to automate some of the parameter estimation process – this is a key objective of this research project (see section 6).

In North America (and particularly when dealing with Independent Power Producers) the preferred methodology has been staged tests. This is driven by the fact that there is an inherent resistance by plant owners to have outside engineering groups manipulating and maneuvering their unit. Thus, if this is further extended to a desire to dismantle and disconnect power plant equipment to perform frequency response tests, the impending resistance is markedly elevated. Thus, historically, frequency response methods were more prominent in vertically integrated utilities. Today, the frequency response techniques are still in use in many places around the world including Canada, Australia and some other countries.

Table 3-3
Pros and Cons of the Two Testing Approaches

Testing Method	Advantages	Disadvantages
Staged Tests	- the testing equipment and methodology is relatively simpler – there is no need to dismantle or open up control loops. Measurement points are directly off of readily available test points (unit PTs, CTs, field shunt etc.) - the testing work usually takes less time than SSFR based approaches - the unit's behavior is tested and validated for conditions that to some extent mimic system events that the unit is expected to respond to (e.g. step-changes in voltage and power, effectiveness of PSS to damp oscillations resulting from a small-signal event etc.)	- the main disadvantage is the potential for damage or unintentional tripping of the unit (mainly a concern for large fossil fuel steam turbines) if a staged test is either not performed correctly or done too aggressively - the parameter estimation and model validation task (once recorded data has been obtained from the tests) heavily relies on the experience of the test engineers, since the model validation process is an iterative one
Frequency Response Methods	- The parameter estimation process is mostly automated (using optimization algorithms) - very specific and high order models may be obtained for the equipment rather than fitting the unit's response to existing standard model structures (this might also be viewed by some people as a disadvantage since it means having to write user written models rather than being able to use a standard model available in a simulation program) - for the generator both d- and q-axis parameters may be identified through the same test methodology - provides a very detailed and thorough coverage of the plant control systems	- more intrusive; requires dismantling generator and control connections to perform tests (unit at stand still). - signal to noise ratio can be a significant barrier or challenge for obtaining high fidelity results - the optimization process is dependant on initial parameter estimates and can converge to 'local minima' (that is, there are multiple potential solutions to the optimization problem) - the testing process can be considerably more time consuming than staged tests due to the need to dismantle equipment - the method cannot be directly used to determine governor droop, unit inertia, excitation system limits (and other control limits); these still have to be derived through different means

3.5 Parameter Estimation Based on Disturbance Monitoring

Due in part to the nature of the NERC MODs (requiring periodic evaluation of plant models) and more importantly due to the concerns over staged testing of power plant equipment (particularly nuclear units), many in the industry have started a dialogue on the potential for model validation thought the use of disturbance monitoring. That is, using data recorded by digital fault recorders (DFR), SCADA/EMS systems, PMUs and other such recording devices present on the transmission system. As an example, SERC is actively perusing this potential option particularly for nuclear power plants. WECC in a sense already exercises this approach with regards to validating the performance of primary governing and unit turbine-generator response to frequency disturbances [45]. In general, however, much effort is needed yet to implement mature techniques for validating all aspects of the power plant model using this approach. More specifically, the following comments may be made:

1. The need for postmortem analysis of any significant system event such as a major transmission fault or generator tripping (whether it results in major cascading outages or not) is evident and most certainly a best practice. The value of such analysis is clearly evident by efforts in the WECC and the Eastern Interconnection, particularly in the aftermath of major system split-ups and blackouts, which have resulted in a better understanding of both power plant and load modeling. Such efforts are ongoing in a systematic way by groups such as the WECC Modeling and Validation Working Group.
2. There is certainly much benefit to be gained from using recorded system disturbance data in validating models of everything from loads[11] to generators and other transmission equipment models (see e.g. reference [46] that shows model validation for an SVC using DFR data). However, to be able to do this effectively and in a useful way one needs to be able to start with a system wide model that is already reasonably accurate. Then, the use of recorded system data (bus voltages, frequency etc.) and knowledge of the event and prior conditions of the event may then be used to compare measured to simulated performance and thus fine tune the "system" model. This can be understood by considering, for example, that in a typical WECC or Eastern Interconnection power system model there are over several thousand generators modeled (and even more loads and lines). It is an insurmountable task to expect to be able to validate on a cases by case basis all of the power plant models for a given disturbance recording. The more prudent approach is to have the basic information in a reasonable form to begin with and to use the disturbance recording to attempt to fine tune the model (e.g. for a loss of a large generator in the southern part of the system one might see from recorded disturbance monitor data that power flow over a major north south inter-tie ends up being greater from the north to the south than what is predicted by simulations, this would provide a hint that perhaps the spinning reserve and primary governing response of units in the north are greater than actually modeled.).
3. Given item two above, it is felt that although there is huge potential in using disturbance monitoring for model validation, this must be done in a complementary way to specific and focused model validation on a power plant by power plant basis.

[11] Presently EPRI is engaged in a parallel project related to load modeling that is using system disturbance data for load model validation.

In summary, it can be said that the steps in validating power system models should perhaps follow a systematic path that can be described in a few steps:

1. Ensure that one starts with a reasonable load forecast for the study period and has a good power flow case that adequately captures the generation dispatch, loading of major transmission paths, overall system load level and condition of switched shunt devices.
2. Ensure that power plant equipment (generator, exciter, turbine-governor, limiters, power system stabilizer, etc.) are adequately modeled with verified parameters – this is the context of this project.
3. Ensure that loads are adequately modeled with a proper mix of static and dynamic (motor) components.
4. Now that a complete system model is at hand, developed based on sound data input, take the full system model and validate it against a recorded system disturbance. This would then provide guidance as to where further model refinements are necessary.

Such a bottoms up approach is likely to result in the most fruitful outcome since having performed tasks 1, 2 and 3 to the best of ones capability, then one can fine-tune the entire system model by comparing simulation results with recorded system disturbances.

There is certainly significant potential in validating the models and parameters for power plant equipment using data from disturbance monitors that are "local" to the plant. This would require high-fidelity (i.e. sampling rates of many hundreds to thousands of samples per second) recordings of the key generator and control variables within the power plant by a dedicated recorder such as a digital-fault recorder (DFR). In the discussion above what is being said is that if we only have recordings of power, voltage, bus frequency and angle on the transmission system (as is typically captured by DFRs, PMUs, and other monitoring devices) this cannot be readily used to validate models for a specific power plant or plants. However, if during a major system disturbance DFR type recordings are made of the 3-phase generator terminal voltages and currents, as well as the generator field voltage and field current, this information could be potentially used to validate the models and parameters for the generator and its excitation system. One place to have such monitoring would be within the excitation system itself. This is in fact a recommendation in [29]. For example, in [46] the recordings from a dedicated DFR of a system disturbance (3-phase fault) were used quite effectively to validate the model and model parameters for a static-VAr compensator (SVC) installation – the DFR (which in this case is a part of the SVC controls) recorded key variables of the device that facilitated this validation process. Similar validation for power plants may be possible if such detailed and dedicated recordings are performed at the power plant. This is a subject for future investigation. EPRI intends on pursuing this in next years base funded research work on this area.

4 THE KEY PARAMETERS FOR POWER PLANT MODELING IN POWER SYSTEM SIMULATIONS

In this section we will take a look at some of the key elements of equipment and equipment parameters within a power plant to help clarify some of the recommendations made in section 5.

4.1 Variation of Parameters between Tests and Manufacturer Supplied Data – Based on Experience of Testing

If we look at the survey results in Appendix B, as well as consider the experience of people involved in this type of testing work, there is a general consensus that there does exist some significant variance often between test derived parameters and the data typically provided by the original equipment manufacture (OEM) when the power plant equipment was first acquired. It is helpful, however, to discuss here what the typical variations are and what the typical sources of these variations are.

The Generator Parameters

The generator electrical parameters (impedances and time constants), if provided by the OEM for the specific unit (rather than a generic data sheet) have been found to generally be in good agreement with properly conducted test results. Typically, the deviation between the field test derived parameters and the OEM provided numbers is ±10% or less[12]. The one exception to this rule is the field time constant (T'do), which can vary quite significantly with rotor winding temperature, and so if a unit is being tested right after it has come out of a prolonged maintenance cycle as opposed to when it has been running under full-load conditions for quite some time, the differences in winding resistance, due to temperature effects, can have a significant effect on the estimated T'do.

Such a variation (±10%) as shown in section 4.5, typically has little impact on system stability. In fact, proper planning studies should consider various sensitivity conditions (e.g. prior outage of a major line or generator, or various levels of motor load content etc.) that would overshadow such variations in generator electrical parameters.

[12] This statement pertains to relatively modern units, i.e. those manufactured and installed in the last two decades or so, and of course any units manufactured today. Very old units (e.g. more that three decades old) may not have high fidelity calculated OEM data sheets.

Also, one commonly forgotten fact is the errors involved in the measurement process. Measurements are taken off of the generator potential transformers (PTs) and current transformers (CTs) for the unit voltage and current during tests. The PTs and CTs have an inherent error tolerance of a few percent. In addition, the actual test equipment will have absolute and relative measurement errors. Some of this can be taken out through judicious calibration. However, it is a fact of life that all measurements do have errors associated with them (even when excluding the potential for human error). Even with the most precise modern measurement devices it is typically not possible to achieve parameter estimation much better than ±3 to 5%. This is due to the cumulative tolerances in the generator PTs & CTs, the measurement equipment, electrical noise on measured signals and imbalance in the unit load for tests done on-load. Also, as discussed in section 3.2 there is a body of literature that contends that there are also errors in the commonly used and available 2nd order flux dynamics equations for generators as opposed to using more sophisticated 3rd order models.

It should be noted that the above discussion obviously assumes that there has been no alteration of the generator between the time of testing and actual installation, when the OEM parameters were supplied. For example, if the unit is rewound for increased rating etc. then there may be significant differences between OEM data provided when the unit was first installed and any subsequent parameter estimation based on field tests.

Typically, manufacturer supplied electrical parameters, for the generator, are often provided as both "unsaturated" and "saturated" quantities. For the purposes of dynamic simulations, the unsaturated quantities should be used since saturation is explicitly modeled using the parameters S1.0 and S1.2.

The Generator Saturation Curve

This is one place where there may be some significant variation between field measured data and OEM data. The reasons, however, are as follows:

1. Hysteresis – if the unit's voltage is raised and lowered a number of times prior to performing the saturation test, hysteresis effects will have an impact on the calculated saturation parameters. Also, if residual flux is not properly accounted for in the calculation of saturation parameters, once again this will affect the calculated saturation parameters.
2. Shorted Rotor Windings – if a rotor winding becomes shorted, this will grossly affect the open circuit saturation curve of the machine. This is actually one way of detecting such a problem[13].

Finally, reference [33] indicates that there is a significant error in simulated steady-state on-load rotor angle and field current if the difference in d- and q-axis saturation is ignored. Although, q-axis saturation may be estimated by making on-load steady-state measurements of P, Q, field current and stator voltage (the open-circuit saturation curve provides a measure of d-axis saturation), at present there is little benefit to be gained from this since the major commercially

[13] In all the testing work the author has done, he has never encountered this problem. However, others who perform testing work have reported finding such cases.

available and used software tools for power system analysis (GE PSLF®, Siemens PTI PSS/E®, and even many of the European tools) do not have a means of modeling d- and q-axis saturation separately (at least not at the time of writing this report).

The Generator Inertia

The measured value of generator inertia has rarely ever been found to vary more than ±5 to 10 % from the OEM supplied value. Again, the exception is where changes have been made to the rotor following turbine installation, such as retrofitting turbine blades etc. One common error is to not include the turbine inertia in the total calculated inertia – often the OEM will quote the inertia of the generator by itself in the generator data sheet. Nevertheless, calculated values of inertia by the OEM, particularly, since the OEMs will often need to analyze the rotor for torsional oscillations, are quite accurate.

In general, unless the unit is retrofitted to substantially change an electrical or mechanical system (e.g. rewound for higher MVA rating, turbine retrofits etc.) none of the generator electrical or mechanically parameters are likely to substantially change for the lifetime of the unit.

The Excitation System – Exciter, AVR, PSS, OEL and UEL

It is not surprising that this is where the greatest variation is found between field measured and verified data versus OEM supplied data sheets. There are several reasons for this:

1. Often the OEM supplied data sheet, at the time of installation of the generating unit, will include "typical" parameters for the excitation system gain, rate-feedback (or transient gain reduction), etc. This is also particularly true for the PSS, OEL and UEL. However, when the unit is actually field commissioned, the commissioning engineer will "field tune" the gains and lead/lags to obtain a reasonable response from the unit. These field tuned values rarely find their way back into planning models unless model validation testing is specifically requested.
2. "Tweaking" or adjusting the AVR gain is relatively easy for many modern digital systems. Thus, on occasion during the life of a plant repeated tests have been found to identify changes in the gain between tests – presumably adjusted on an occasion by a field engineer.
3. On several occasions, testing in a plant has revealed that PSSs were inadvertently switched off and neglected to be switched back on.
4. In some cases, the actual excitation system controls differ significantly from available IEEE standard models in the power system simulation programs. As such, OEMs will select the closest matching model and adjust parameters to attempt to suitably capture the behavior of the unit. Field tests (by the author and others) have revealed that the response in these cases is often not very satisfactory. The recent revision of the IEEE Std [8] has addressed most of these issues.

If one considers all the units presently in-service in the North American power system, there are a plethora of excitation systems in-service including static, brushless, dc, GE Generex and Althyrex, GE SCTP static, Amplidyne etc. Many of these designs are no longer supported or manufactured and so in time they will be replaced with modern excitation systems. Nonetheless, presently they need to be and are modeled in the power system database. The reference [8] provides a sufficient variety of excitation system models to cover this range of possible excitation system designs.

Modern excitation systems are typically one of two kinds (i) static, or (ii) brushless. What is of paramount importance is that the excitation system model should properly reflect the actual control design. That is, for example if the excitation system is a brushless, PMG supplied exciter with a PID regulator then that is the way it should be modeled (EXAC8B in this example case) rather than trying to force feed parameters into an older IEEE Std model to represent the excitation system (as has been found to be done in some cases in manufacturer supplied data sheets).

The Turbine Governor

Unlike the generator excitation system where there has been recent updates of the IEEE Std [8] for models and model structures for excitation controls, there is no equivalent IEEE Std on governor modeling. IEEE Working Group reports exist on this subject [47] and [48], however, they have not been updated in recent years to fully address technologies such as combined-cycle power plants and simple-cycle gas turbines. A recent CIGRE report [6] addresses combined-cycle power plants and gas turbines.

Part of the issue is the comparatively immense complexity of the mechanical controls associated with the turbine and energy source as compared to the electrical controls. If one considers a typical modern excitation system such as a static exciter, the full response and behavior of the system (including limits, etc.) can be captured in the domain of interest for power system studies through the use of several transfer function and limits. No major control loop or functionality is neglected in such models (see [8]). In comparison, consider the mechanical and energy source controls in a large coal-fired steam turbine power plant. Here we have controls associated with transportation of the pulverized coal (on conveyer belts) to the combustion chamber in the boiler. The controls associated with the combustion process. The controls associated with the feedwater system that circulates water from the condenser to the boiler. The controls associated with the boiler drum. The controls associated with the main, intercept, by-pass and stop steam valves, etc. There are models that attempt to capture this level of complexity [49], however, they are rarely used in bulk power system studies for two reasons, (i) the complexity of the model makes populating and maintaining databases for parameters for such models prohibitive for large systems such as the WECC and Eastern Interconnection, and (ii) recent studies such as [5] have shown that this level of complexity is perhaps not essential for capturing total system response.

In general, the key parameters that are of importance for being properly captured in modeling the turbine controls are:

1. The governor droop – that is, the MW/Hz (often expressed in per unit on the turbine MW rating) response of the unit to changes in system frequency (see section 3.1).

2. Proper modeling of the specific type of turbine. One common problem in databases is modeling turbines with inappropriate models. An example of a commonly encountered mistake is representing, for example, a steam turbine in a combined cycle power plant that is operated under sliding pressure control as a standard steam turbine with droop. Care should be taken to use the most appropriate model and to reasonably capture the turbine response time.
3. To ensure that the mode of operation of the turbine is correctly capture. That is, if it is base-loaded, on temperature limit (for gas turbines), on outer-loop megawatt control (and if so a fair representation of the speed of response of this outer-loop controller [5]).

In the case of the turbine-governor, thought most of this can be captured through staged tests, this is on example where the data is and can presently be captured using on-line disturbance monitoring data. WECC presently exercises this [5]. Similarly, NYISO has also confirmed unit droop from monitoring the actual turbine-generator response during system events [50].

As for comparisons between tests and manufacturer supplied data, the most commonly found issues are as follows:

The model supplied sometimes does not truly reflect the controls in the plant. For example, as stated above using a IEEEG1 model that depicts a boiler-follow steam turbine with droop to represent a steam turbine in a combined-cycle power plant, which is typically operated under sliding pressure control.

Not capturing the actual mode of operation of the plant. That is, the unit under test may be typically operated under an outer-loop megawatt controller, which defeats the governor response [5], whereas in the manufacturer supplied model this may not be depicted.

An error sometimes encountered is that the turbine governor data is entered on the generator MVA rating into the power system model database not recognizing the fact that the turbine MW rating may in fact be significantly less than the generator electrical MVA rating. For example, a common modern peaking gas turbine unit installed in many US systems typically has a 40 MW turbine with a 70 MVA electrical generator. Also, the typical droop on this unit is 5% on the turbine MW rating; that is, 13.3 MW/Hz. If the turbine controls were mistakenly modeled on a 70 MVA base instead of a 40 MW base[14] then the simulation model would instead be representing a unit capable of significant response capability and able to produce up to 70 MW, which is clearly not correct.

<u>Note:</u> the context of this report we have not discuss wind turbine generators. These generators are unique in their design and performance and are outside the scope of the discussion in this document. A recent CIGRE document [54] may be consulted for more detail on this subject.

[14] Note: some power system simulation tools allow for the turbine model and electrical generator model to have different per unit bases. In these cases (e.g. GE PSLF®) each component should be preferably modeled on its own base. In some programs (e.g. current versions of PSS/E®) all models associated with the single unit are on the same per unit base, the generator MVA. In this case the turbine model parameters need to be properly scaled to reflect the turbines actual MW capability.

4.2 Generic System Sensitivity Analysis

In this section a presentation is given of some limited sensitivity simulations performed on a generic system simply to illustrate some salient points with reference to power plant modeling. The system used is described in Appendix C. It is a purely hypothetical system not intended to represent any actual power system. Nonetheless, the data and models used are quite typical and so what is illustrated is quite plausible and typical of actual power systems.

The condition of the system is what might be considered a heavy load condition (see Appendix C). The event simulated in all cases is a 3-phase fault at the bus 3 end of one of the parallel 500 kV lines from bus 3 to 10 (see Figure C-1 in Appendix C); the fault is cleared by tripping the line in 3 cycles (a typical fault clearing time at such extra-high voltages).

Numerous sensitivity simulations were performed relative to machine parameters, parameters of controllers and the status of controllers. The results are summarized in detail in Appendix C. Figure 4-1 serves as a quick graphical summary of all the results. This figure shows the speed of one of the critical units in the system as a function of time for this event for all the sensitivity cases simulated. A detailed perusal of the results of Appendix C and a review of Figure 4-1 allows one to make the following general observations:

- Small variations (e.g. 10% or less) in a single machine electrical parameter, even if applied system wide, is not likely to have an appreciable affect on the bulk power system response.
- Of all the generator machine parameters, those that have the most impact on rotor angle stability (transient or small-signal[15]) are the d-axis parameters and the combined turbine generator inertia. Note: the q-axis parameters and machine saturation are also very important, as they will affect rotor-angle stability. What is being said here is simply that variations in d-axis parameters appear to have a relatively greater impact.
- The status, tuning and responsiveness (gain, time constants etc.) of the generator controls (such as the PSS and the AVR) are perhaps the most critical components as far as rotor angle stability is concerned.

Other studies in the literature [5] have shown (on the actual US grid) how critical the mode of operation and responsiveness of the turbine-governor controls are in determining the system frequency response to a loss of generation/load.

[15] For a definition of rotor angle stability see [51].

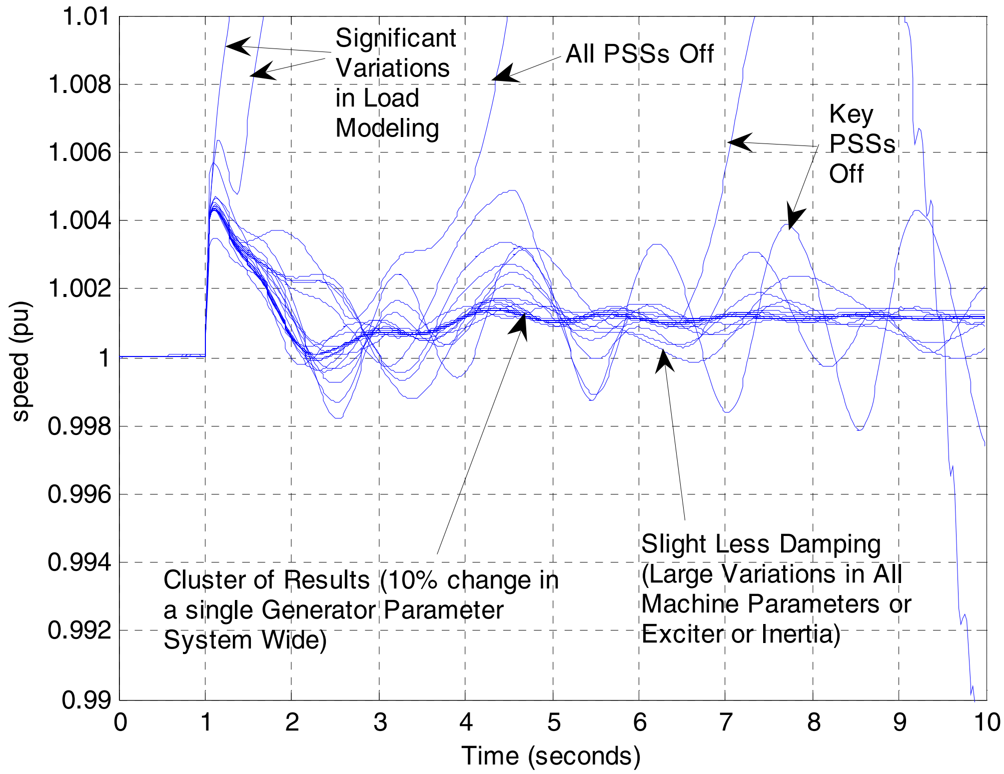

Figure 4-1
Summary of Sensitivity Simulations on a Generic System

4.3 Discussion

Based on the material presented above, we can make the following observations:

- The most critical components of the power plant to be tested are the excitation system and its associated supplemental controls (i.e. PSS, OEL, UEL).
- The responsiveness, droop and mode of operation (base loaded, on outer-loop megawatt control etc.) of the turbine-governor needs to be known.
- Good estimates of the synchronous generator electrical parameters and combined turbine-generator inertia are needed. The manufacturer provided numbers (if calculated and furnished specifically for the unit, rather than being generic) are typically within ±10% of measured values and thus quite adequate for bulk power system studies. For verification purposes, one might require testing upon commissioning to verify the generator parameters, however, once this is done there is no need to retest the generator electrical parameters and inertia unless the actual turbine-generator is significantly varied (e.g. unit rewound, up-rated etc.). Also, when testing the generator, it is adequate to verify the d-axis electrical parameters.

Notice also (as shown in Appendix C and Figure 4-1) that the assumptions related to load modeling have as much (if not more) of an impact on the system response. This is why it is equally important to have reasonable load models as well as to perform sensitivity studies related to load and other model assumptions.

5 RECOMMENDATIONS FOR A PROCEDURE FOR TESTING AND VALIDATING POWER PLANT MODELS

This section is intentionally concise. It outlines a recommended approach to generator model validation testing based on the discussions in section 3, 4 and the survey of present industry practice.

5.1 Key Components to be Modeled

The key components in a power plant that should be appropriately modeled for power system studies are:

1. The electrical generator
2. The excitation system and associated automatic voltage regulator
3. The over- and under-excitation limiters
4. The turbine-governor

In some specialized studies (e.g. islanding studies, voltage stability, particularly of radial systems) it may also be necessary to consider protection setting such as the units over- and under-frequency and voltage trip settings.

5.2 Times to Test and Frequency of Testing

The following appear to be best practice recommendations:

- It is highly recommended to perform staged tests during commissioning of a power plant, e.g. as described in section 3.1 and Appendix A. Such tests are significantly less intrusive than many of the standard acceptance tests that are necessarily performed on a power plant during the commission period. Working a test plan into the commissioning period well in advance is unlikely to have a significant cost or time impact. However, it should be planned well in advance and made part of the commissioning exercise. Trying to schedule testing after commissioning has started can often be problematic since the commissioning site manger will have concerns related to how such work may impact his/her schedule. In fact, many of the standard tests that need to be performed during commissioning (e.g. open and closed circuit AVR step tests, turbine overspeed protection tests etc.) can easily be adapted to also serve the purpose of model validation if proper planning is done ahead of time to facilitate adequate and proper monitoring and measurement. **Note:** during commissioning there is of course testing performed to verify the settings and ensure proper operation of all controls, protection, relays etc. – the testing being discussed here is different and is in the context of modeling and model parameter derivation for power system studies.

- Units should be re-tested routinely to ensure models are kept up to date. Presently, most utilities that do perform testing do so typically once every five years.
- Manufacturer calculated and supplied electrical machine parameters for the generator (Table 3-1) and the combined turbine-generator inertia (H) are typically accurate and do not need to be determined by field tests[16]. If staged tests are performed during the commissioning of the power plant, these can be verified through tests. Re-testing on a routine basis is not necessary for re-estimating these electrical generator parameters, unless the generator is substantial altered (e.g. re-wound, replaced etc.).
- In the event that testing of the generator electrical parameters is deemed necessary, it is typically adequate to verify the d-axis parameters by tests only and to extrapolate the q-axis parameters based on manufacturer data (or expected relationship between the d and q-axis parameters).
- In testing the power plant for model validation and parameter estimation for power system studies, emphasis should be given to validating the model and parameters of the excitation system and the power system stabilizers[17] (if any). These two controls are perhaps the most important components in properly assessing rotor angle stability.
- It is also important to identify the settings of the OEL and UEL. These controls are of vital importance during severe system conditions. OEL action is primarily important for voltage stability studies where the action of the OEL limit may lead to long-term voltage instability – this phenomenon may take many tens of second to several minutes, and thus the nuances of short term (fractions of a second) transients in the actual action of the OEL are not relevant [8]. The UEL can be quite important, particularly for system events that may lead to the generator being under excited. The reason is that the UEL can significantly affect the unit's transient stability as it will override the exciter to boost excitation in such situations to prevent loss of excitation. Also, the UEL can interact with the PSS. This is an area for further work, since presently (as of writing this report) at least one of the major power system simulations tools used by system planners in the US does not have any UEL models. Thus, it is difficult to translate any test results into models for power systems analysis.
- The reactive power capability of the generator should be verified. As a first step, based on engineering calculations (from the generator D-curves, hydrogen cooling pressure where applicable etc.), the reactive limits of the unit should be determined while operating at rated megawatt output. The calculated field current/voltage for the unit when operating at these rated values should then be compared to the appropriate limiter settings (OEL, UEL etc.). If based on this engineering assessment it is estimated that the unit can achieve its reactive capability without exceeding any limits and based on recent operational experience (e.g. recorded unit reactive and real power output during operating hours) this can also be confirmed, then actual field testing of the unit's reactive limits is perhaps unwarranted.

[16] This statement pertains to relatively modern units, i.e. those manufactured and installed in the last two decades or so, and of course any units manufactured today. Very old units (e.g. more than three decades old) may not have high fidelity calculated OEM data sheets.

[17] The importance of the PSS is well know and documented in the literature [52], [53], [33] and techniques for robust tuning of the PSS are equally well documented [35]. Proper tuning of the PSS is crucial.

Otherwise, where possible and operationally safe (see description of process in Appendix A) the unit's reactive limits should be tested. It is believed (per presented WECC [11] standards) that for such tests maintaining the unit at its reactive limits (while at rated megawatts) for at least 15 minutes is sufficient evidence of its reactive capability.

- The turbine-governor should be tested for its droop and to identify the mode of operation (i.e. unit is typically based loaded, on AGC, on outer-loop megawatt control etc.).

5.3 Size of Unit to Test

It is generally agreed that the size of unit to be tested should essentially reflect the size of unit that is expected to have a significant influence on overall power system dynamics behavior. However, there appears to be no general consensus on what this size is. This is understandable since this value is also dependant on the total size of the interconnected system under study. For example, a 1 MVA unit would be of little significance in a system such as the WECC, which has an installed generation capacity in excess of 130 GW. On the other hand, 1 MVA constitutes as significant component of generation on the Big Island of Hawaii, where during the evening the total generation capacity on-line is in the range of only several tens of MW. Thus, size is very much subjective.

Presently, WECC requires that all units above 10 MVA be tested. MRO is considering the same size limit. SERC is proposing that units above 75 MVA that are connected to voltages at or above 100 kV should be tested. NPCC is considering a size limit of 100 MVA or above.

Internationally, in Italy units above 100 MVA are tested and in Australia units ranging from 35 to 50 MVA and above are tested.

This issue is perhaps open to further debate. In the end it is a question of total system modeling detail versus expense. As indicated in [29] as the size of unit decreases the benefits of testing decreases while the cost per MW of testing increases. However, we believe that a 50 MVA threshold is certainly reasonable within the context of the North American system. One important caveat is that testing standards should address the special case where for example a power plant may be composed of several small units (less than 50 MVA) but the total MVA capacity of the plant is quite significant to overall system dynamic performance (e.g. total plant MVA is more than 50 MVA). In these special cases, the units should be tested – where the units are identical one may take advantage of the procedure for testing sister units (see subsection below).

5.4 Sister Units

One way of minimizing the number of tests required on units is through the realization of "sister units". For example, it is not uncommon in many power plants to have nominally identical "sister units" operating side by side. In these plants it is often quite simple to go through the units control cabinets (and with digital controls to peruse through the actual control settings) and verify that the control settings for all units are identical. In fact, upon commissioning it is common practice to coordinate and set all such sister units to have identical control settings. Thus, it is acceptable to perform the full set of tests on one unit, and to perform limited tests on the other units simply to verify that they behave similarly. For example, a single excitation system step response test on the remaining units for verification purposes. Then for the sake of power system simulations, all sister units in the plant can be modeled with the same set of models.

5.5 Testing Procedures

Presently, staged tests (such as described in Appendix A) are perhaps the least intrusive and most effective way of performing power plant tests. If adequate manufacturer supplied turbine-generator inertia information is available, the megawatt rejection test can perhaps be avoided.

As discussed in section 3.4, there is significant potential for using disturbance monitored data for estimating and validating power plant model parameters. However, this remains presently as a subject for future work.

5.6 Summary

In essence the best practices procedure for generator testing may be summarized as shown in Figure 5-1. Table 5-1 lists the key parameters that require testing.

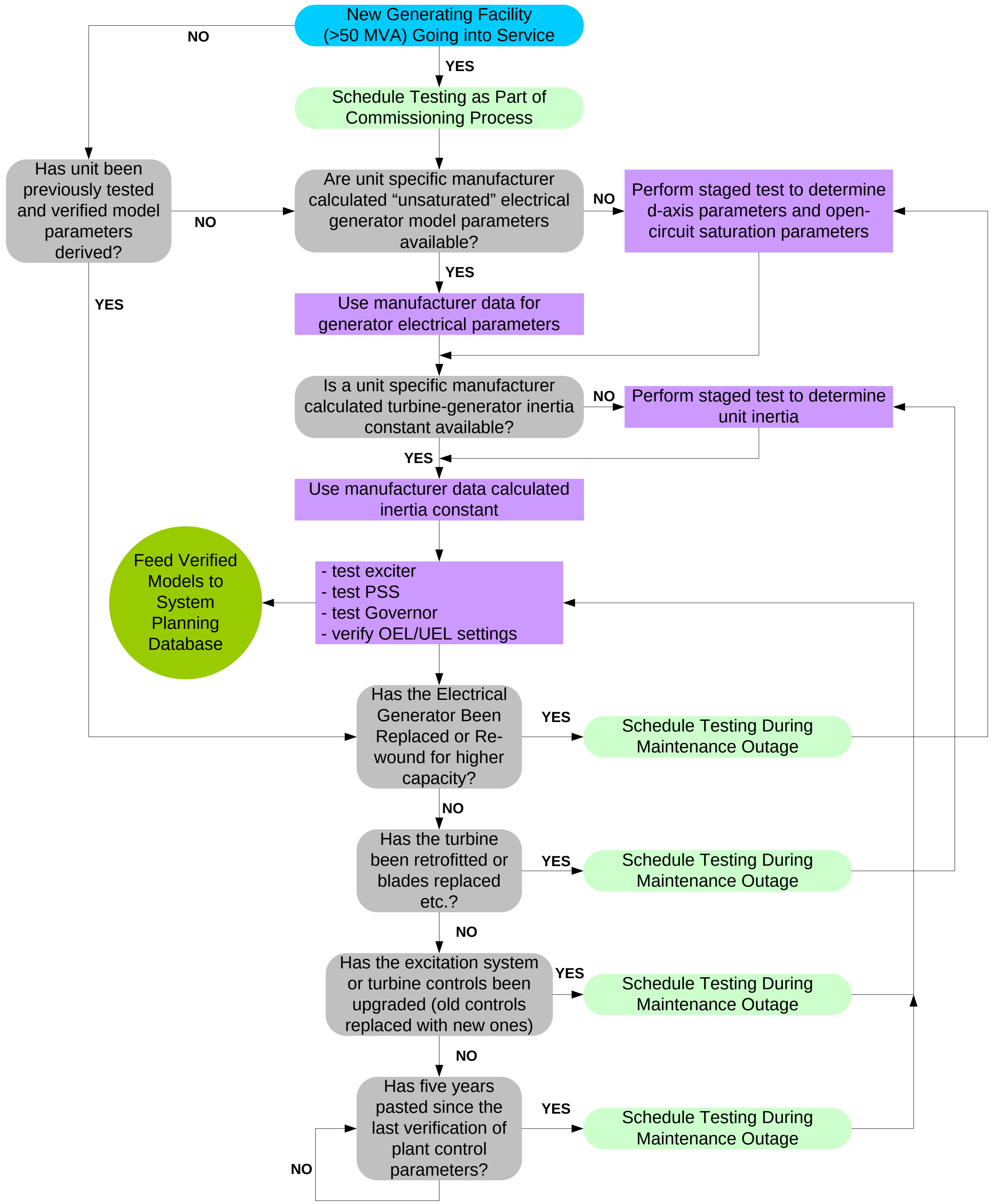

Figure 5-1
Conditions for Testing Power Plant

Table 5-1
Critical Parameters to be Verified by Tests

Component	Critical Parameters to Test	Parameters Derived
Generator	Xd, X'd, X''d, T'do, T''do, S1.0, S.12 (need to be tested only if verified, unit specific, OEM data not available)	Xq, X'q, X''q, T'qo, T''qo (base on ratio of d- to q-axis parameters from original manufacturer data or Table 3-2)
Exciter	- Choose the correct model structure - Estimate, based on test, the AVR gain(s), rate feedback or transient gain reduction, exciter time constant, exciter armature reaction, rectifier regulation factor etc. - Determine the current compensation setting on the excitation system	- Calculate excitation limits base on rated power supply (or rating of PMG, etc.)
PSS	- Tuned parameters should be verified to provide damping	
Governor	- Choose the correct model structure - Estimate droop - Determine most common mode of operation (i) base-loaded, (ii) on droop, (iii) on outer-loop megawatt control, (iv) on AGC	

6 ON-GOING WORK AND RECOMMENDATIONS FOR FUTURE WORK

6.1 Brief Description of the Next Phase of the Work – the SMPD Software Tools

The next phase of this research project, which is presently under way, is to refine and/or modify the previously developed software [3] to facilitate a systematic and automated (as much as possible) way of estimating model parameters for the generator, excitation system and turbine-governor models. These tools are being developed in MATLAB®. The tool is referred to as the Synchronous Machine Parameter Derivation (SMPD) tool.

6.2 Potential Future Work – Beyond the SMPD Tool

Beyond the SMPD Tool, one very beneficial exercise would be to see how this Tool (once finalized under the present project) could be extended to facilitate model parameter estimation based on recorder disturbance monitor data at power plants (e.g. DFR recordings). This was discussed briefly in section 3.4. This is a focus for work to be done under the base funded R&D program of EPRI for 2008.

Another aspect of generator modeling that may be worth revisiting is the impact of q-axis saturation and more complex generator models on overall bulk system stability studies. Some work was done in this area in the 80's and early 90's, however, most modern power system simulation tools do not have models capable of capturing such details.

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8
GLOSSARY

AVR – Automatic Voltage Regulator. This is the automatic control system that supervises the generator excitation system in order to automatically regulate the terminal voltage of the generator.

d-axis – To simplify the modeling of synchronous machines, the Park's Transform (a mathematical transformation) is used to transform all machine quantities to a rotating reference frame on the machines rotor. The d-axis is one of the two axes (the direct axis) in this rotating reference frame, and is the axis aligned with the machine's field winding.

Droop – Refers to the regulation setting of the turbine-governor. Droop represents the percentage change in system frequency that would result in a 100% increase in the turbine power output. That is, a 5% droop means that if the turbine-generator were originally at 0 MW, then a 5% drop in system frequency would cause, through turbine-governor action, the turbine output to be raised to its full capacity.

Excitation System – This is the control system in the power plant that produces and regulates the dc current and voltage that is needed to be supplied to the field winding of the synchronous generator.

Gas Turbine-Generator – These are turbine-generators that typically burn either liquid petroleum gas or natural gas in a combustion chamber that mixes the fuel with highly compressed air. The hot, high pressure flue gas of the combustion process is then expanded through a turbine to do work and thus transfer power to the electrical generator. (These turbines are also referred to as Combustion Turbines).

Hydro Turbine-Generator – These are turbine-generators that run based on the flow of water, either from a dam (high head units) or on a river (low head units).

OEL – Overexcitation Limiter. Sometimes also referred to as the maximum excitation limiter, this is a supplemental control loop within the excitation system that limits the field current (and/or voltage) beyond a certain limit to avoid over heating of the generator field windings.

Open Circuit Tests – These are tests performed when the generator is disconnected from the power system (i.e. the generator main breaker is open), however, the unit is running at full-speed no load with excitation.

PSS – Power System Stabilizer. This is a supplemental controller that acts on the reference input to the AVR and helps to maintain small-signal rotor angle stability of generators by adding damping over the range of electromechanical modes of rotor oscillation.

q-axis – This is the second axis in the rotating reference frame of the machine. The q-axis (quadrature axis) is at 90 degrees to the d-axis.

Saturation – Refers to the physical phenomenon where the core of the generator becomes “saturated” by the magnetic fields of the stator and rotor such that any further increase of current in the circuits does not result in a significant change in magnetic flux density.

Short Circuit Tests – These are tests, typically performed by the OEM under a strict controlled factory environment, that involve subjecting the generator to short circuits at it stator terminals.

SSFR – Stand Still Frequency Response tests are based on estimating the transfer function of the generator while at stand still (see section 3.2).

Steam Turbine-Generator – These are turbine-generators that typically burn pulverized coal in a large boiler that boils water to generate steam, which in turns runs the turbine connected to the electrical generator.

Turbine-Generator Inertia – This is the total polar moment of inertia of the combined rotating mass of the electrical generator and mechanical turbine. For power system simulation studies, the inertia constant H is expressed in MWs/MVA.

Turbine-Governor – This is the primary controller that regulates the mechanical power output of the turbine based on measured system frequency and a desired power output reference setpoint.

UEL – Underexcitaiton Limiter. Sometimes also referred to as minimum excitation limiter, this is a supplemental control loop within the excitation system that limits the minimum level of field current (and/or voltage). This limiter prevents the excitation level from going down too low such that it may reach the stator core end-region heating limit or the small-signal stability limit of the generator.

A
TYPICAL TEST PLAN – FOR STAGED TESTS

This appendix is a brief generic outline for a test plan for testing of the generating units at a power plant strictly with the aim of identifying parameters for dynamic models for the purpose of power system simulations. The actual sequence of test may be varied on site, after discussions with the operator and plant staff, in order to facilitate the most effective and efficient testing session possible.

Note: the following deals only with large (i.e. typically, 10 MVA and greater) conventional synchronous generating facilities.

A.1 Prior to Testing

Collect all of the following data for the purpose of helping to identify test points and to establish the starting point for the parameter fitting exercise:

1. Any existing models for the generator, excitation system, turbine-governor and where applicable power system stabilizer. This will typically be manufacturer supplied data sheets, or it may be validated models from a previous test.
2. Plant drawings showing all test points (i.e. unit potential-transformers (PTs), current-transformers (CTs), field shunt etc.) in order to facilitate quick identification of test points on site as well as obtaining the PT, field shunt and CT ratios.

A.2 Connecting the Test Equipment

The test equipment can be any properly designed and calibrated measurement device capable of recording from (at relatively higher frequencies, e.g. 1 kHz/channel and above) isolated differential inputs that can accept ac and dc signals generally up to 1000 V. Testing staff should take all the necessary precautions associated with handling dangerous sources of electricity. The signals may need to be stepped down further through potential dividers, or however appropriate, to facilitate their connection to the actual test equipment. Such equipment is all provided by the testing staff. The following table shows the typical test points to be connected to the recording device for various types of generating units.

During the tests, particularly for the megawatt and megavar rejection tests, the units reverse power relays and any transfer trips of the exciter or turbine-boiler due to a generator main breaker opening, should be disabled.

Table A-1
Test Points

Generator Type	Test Points
Steam Turbine	- Three ac terminal voltages off of PTs - At least two terminal currents off of CTs (typically use clamp-on current transducers, which have a wide bandwidth) - Field current (off of field shunt) – exciter field current for brushless units - Field voltage – exciter field voltage for brushless units - Main steam valve position
Gas Turbine	- Three ac terminal voltages off of PTs - At least two terminal currents off of CTs (typically use clamp-on current transducers, which have a wide bandwidth) - Field current (off of field shunt) – exciter field current for brushless units - Field voltage – exciter field voltage for brushless units - Main fuel valve position
Hydro Turbine	- Three ac terminal voltages off of PTs - At least two terminal currents off of CTs (typically use clamp-on current transducers, which have a wide bandwidth) - Field current (off of field shunt) – exciter field current for brushless units - Field voltage – exciter field voltage for brushless units - Wicket gate position - *Optional* – for added verification, the machines mechanical speed can be recorded in order to derive rotor angle and thus be able to directly estimate q-axis parameters for salient pole hydro-generators

A.3 The Tests

Perform open-circuit saturation curve test: While the unit is at full-speed no-load, with the generator main circuit breaker open, the open circuit stator voltage is measured as a function of field current. This is then plotted and from it the unit's saturation parameters are derived.

Perform VAr rejection test for generator data and exciter data: With the unit's voltage regulator in manual mode, i.e. regulating exciter field voltage instead of generator terminal voltage[18], take the unit to approximately 0.1 per unit (10 % of rated MVA) absorbing reactive power with as close as possible to 0 MW (that is absorbing reactive power from the system an generating no or near zero megawatts). Then open the generator main breaker and record the necessary data. Repeat the test with the unit in automatic voltage regulator mode. The subtransient and transient decay in voltage for the manual trip test facilitates estimation of the machine d-axis parameters. The terminal voltage response for the automatic voltage regulator test facilitates estimation of the excitation system parameters.

Governor Droop and Turbine Gain: With the unit on-line plot the unit's MW output versus main steam valve/main fuel valve/wicket gate position and versus the governor speed/load reference setpoint from near 0 MW to base load. Similarly, with the unit off-line plot units speed versus valve/gate position and the governor speed reference setpoint for a range of speed variation (say from 100% speed to 105% speed – make sure you do not approach over speed protection). The ratio of the slope of the two lines will provide a measurement of governor droop. The nature of the MW versus valve/gate position will identify non-linearities in the turbine gain, particularly for hydro turbines. For gas turbines both lines are typically straight. Note: for a combined cycle power plant, particularly a multi-shaft plant, one will also need to estimate the response time of the steam turbine. This can be done in the following way. Record both the power output of the gas turbine(s) and the steam turbine (or entire unit if single-shaft). Then affect a step increase in the gas turbine governor speed/load reference. Continue to record the response of both units for several minutes until the steam turbine has fully responded. Once the gas turbine speed/load reference change has been effected it should be held constant throughout the test to avoid any skewing of the results. Also, the steam turbine should ideally be in valves wide-open operation (sliding pressure), to give a good indication of the heat-recovery steam generator time constant. The test may be repeated with the steam turbine under steam inlet pressure control in order to assess the difference in response for varying operating conditions.

Perform MW rejection test for unit inertia and governor response: With the unit supplying roughly 0.05 to 0.1 per unit real power (5 to 10% of rated MVA), open the generator main circuit breaker. The recorded speed and valve/gate position response will give an indication of the governor response time. The recorded initial rate of rise of speed will provide a measure of the unit inertia.

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[18] This is typically an easy control mode change off of the exciter main control cabinet terminals. However, in some cases it may require changing a setting within the excitation control cabinet.

Perform VAr capability test: Bring the unit to or near base load. Then, based on the manufacturer VAr capability curve, take the unit to maximum allowable lagging VAr. Keep at this point for 15 minutes. Take recordings. Then take unit to maximum leading VAr. Keep at this point for 15 minutes. Take recordings. If limiters, alarms or excessive system/auxiliary bus voltage prevent reaching these limits, then promptly stop at a safe point and record the limiting item. It is then satisfactory to, based on engineering calculations, establish the unit's reactive capability clearly showing the limiting factor under the given testing conditions. This of course assumes that the limiting factor is something that is unlikely to result in the unit's reactive capability being held back under transient conditions. For example, often when testing a unit one may not be able to raise the units MVAr output up to the actual reactive capability due to reaching excessive system voltages (particularly where sister units or e.g. nearby shunt reactors are not available to offset the MVAr injection from the unit). In such cases, if calculations and a review of relay settings clearly show that the full reactive capability could have been achieved under system conditions were voltages were significantly lower, then this should be adequate.

Perform voltage reference step test with and without the PSS in-service (if PSS installed): This test can serve as another or alternative means of estimating the excitation system parameters. In addition, the comparative swing in the unit's megawatts for the voltage reference step with and without the PSS will help to confirm the ability of the PSS to better damp power oscillations and thus also confirm the PSS parameter settings. This test should be performed with the unit on-line and carrying load, preferably near base load. The test involves simply injecting a step change (up or down, or both) in the voltage regulator reference setpoint. This feature is typically provided on most modern excitation systems.

B
SURVEY RESULTS

A simple survey was sent out to all the Regional Reliability Organizations (RRO) in the US[19] as well as many transmission system operators and reliability organizations overseas. Of the surveys sent out sixteen replied. Table B-1 and Table B-2 summarize the survey results.

The following general observations are pertinent:

1. Most regions are seeking to mandate testing, presumably in anticipation of the NERC MOD's becoming binding and mandatory.
2. The main purpose of testing (actual or intended) is for improving power system planning computer models. However, many do also state the potential benefit of finding or fixing problems in plant controls. In the case of some international transmission owners, it is interesting to note that the main focus is on verifying plant performance and ensuring compliance with performance criteria. Italy is a prime example. This is not surprising since the recent blackout in Italy exposed many weaknesses and control issue related to power plants tripping during the frequency excursion that occurred, thereby exacerbating the frequency decline and culminated in a total system blackout [27].
3. As expected, the main reasons for not testing power plants were fear of damage and the actual cost of testing.
4. One rather interesting observation, for regions that do perform testing or starting to, is that there is not a clear consensus on the size of unit that requires testing. In fact, one might say that the results of the survey are somewhat counter intuitive. Notice that in the WECC which is clearly the largest of the systems listed, the size unit required to be tested is 10 MVA and above. While in Australia the size is between 35 to 50 MVA (not exact number was given). In comparison, the total interconnected Australia system is roughly one fifth to one sixth of the size (total megawatts of load and generation) of the WECC system. So one would logically assume that the size unit that would be perceived large enough to be of concern on the WECC system would be relatively larger than that in the Australian system. Nevertheless, we see the opposite in terms of mandated test policies. This simply indicates that the size is chosen perhaps more arbitrarily then based on a specific criterion. For SERC, the units that are required to be tested are 75 MVA and above (that are connected at 100 kV and above).

[19] The survey was sent in many cases to utility members of the RRO. In some cases it was sent directly to the RRO itself.

Table B-1
Survey Comments

Region	Benefits of Testing	Bad Experiences	General Comments
WECC	- Better planning models - Corrected equipment problems - Better system reliability	None Reported	Some are concerned about staged unit tripping, so performance monitoring options have been developed. The testing effort was started after learning from the 1996 major system disturbances that the models needed improvement.
NPCC	In couple of cases where tests have been done, improper relay settings were found.		If the plant controls and equipment settings are not treated like say relay settings, and procedures are not in place to document any changes and provide them to Planners, test data is not going to be valid for long.
RFC	Clearly better modeling of exciter response.		Exciters and Reactive Capability is currently tested by the one respondent in this region though they are not mandated by the regional reliability council; Nuclear units not tested unless can justify that the plant benefits from the tests.
SERC	No substantial tests yet, too early to tell.		In the process of developing and phasing in testing procedures. Plans to have Nuclear units validated using continuous on-line monitoring, to avoid intrusive tests (this may cost more). Testing requirements do not currently exist for generator model parameter validation. Reactive power limits must be validated - though it is possible to validate this without testing (e.g. on-line monitoring etc.). SERC is mainly investigating an event based approach for model validation and requiring step-tests for excitation system model validation.
ERCOT			There is significant activity in reviewing/assessing the need, however, for testing to become mandated either: (i) it must be mandated by NERC, or (ii) there must be consensus among market participants

Table B-1 (continued)
Survey Comments

Region	Benefits of Testing	Bad Experiences	General Comments
SPP			Currently reactive capability testing is required. No other tests are presently mandated.
MRO	See comments.		When Voluntary tests were performed this resulted in improved study models and in some cases equipment problems were identify. Similar benefits are expected when mandated test being.
TERNA	Improved system security; governor parameter tuning	None Reported	The Italian TSO also requires a test, every 6 months, about the capability to perform load rejection for thermal units above 200 MVA and black start up for suitable hydro and Gas turbine units.
New Zealand			Would like to have tests for improved models and so that a better assessment can be made of instantaneous reserve.
NEMMCO			In some states frequency response tests are mandated on AVRs and PSSs. Generally tests are required following commissioning of a plant and then once every 3 to 4 years as a confirmation/compliance revisit during scheduled outages.
ETRANS			Testing is based on the importance of the unit (i.e. size, though actual size not specified). Primarily, on units relied upon for black-start.
Nordel			Testing is currently no mandated or performed. Tests might be done during commissioning. Total system model is validated following major system events using postmortem analysis.
Japan			Currently only PSSs are tested on-line by company policy. All other data is validated by manufacturers in factory tests witnessed by the utility engineers.

Table B-2
Survey Summary

		Testing Mandated					Units Tested						Reasons for Testing				Reasons for not Testing					Other Methods Used for Dynamic Model Data				What Components Are Tested (or want to be tested)								Type of Testing			Time of Testing				
Respondants Region	Respondants Country	Yes	No	No (but seeking to mandate)	As Of	Frequency of Tests	Steam	Hydro	Gas	CCPP	Nuclear	Other	Better Models for Planning	Ensure Unit are Compliant	Identify Control Problems/Troubleshooting	Other	Too Expensive	Fear of risk (potentially damage units)	Not convienced that it is necessary	Opportunity Cost (i.e. cost of fuel and time lost for sale of power)	Planning Models are accurate	Manufacturer Supplied Data	Plant Survey of Equipment	Generic/Assumed Models	Other	Generator	Exciter	Turbine-Governor	Power System Stabilizer	Reactive Capability	Other	Unit Size Above Which Units Must be Tested (MVA)	Standard Document In Place for Testing	Staged Tests (requires unit to come off-line for some tests)	Frequency Response Tests (requires unit to come off-line and control loops opened)	Other	During Commissioning	When coming down on maintenance cycle	When going back up after maintenance	After major retrofits (e.g. change of exciter etc.)	Other
WECC(1)	USA	X			1997	5 years	X	X	X	X	X		X									X	X	X		X	X	X	X	X		10	Yes	X	X		X		X	X	
NPCC(2)	USA			X	N/A	N/A	X						X				X	X				X	X			X	X		X	X		100	No	X			X	X		X	
RFC(2)	USA			X	N/A	N/A	X	X	X	X	X		X	X	X		X	X				X	X	X	X		X		X	X		N/A	Yes	X	X		X	X	X	X	
SERC(3)	USA	X			2005	see (4)	X	X	X	X	X		X					X				X	X	X			X		X	X	X	75	Yes	X			X			X	
FRCC	Did not receive a response to survey.																																								
ERCOT(2)	USA			X	N/A	N/A							X	X			X	X		X		X											No								
SPP	USA		X		N/A	N/A																																			
MRO(2)	Canada			X	N/A	N/A	X	X	X	X	X		X	X			X					X		X		X	X	X	X	X		10	Yes	X	X	X	X	X	X	X	
TERNA	Italy*	X			2006	3 years	X	X	X	X				X	X	X												X				100	Yes			X	X		X	X	
New Zealand(2)	New Zealand*			X	N/A	N/A	X	X		X			X	X						X		X		X		X	X	X		X			No	X			X			X	
NEMMCO(1)	Australia**	X			2000's	3 to 4 years	X	X	X			X	X	X	X							X				X	X	X	X	X		30 to 50	No	X	X		X			X	X
ETRANS(1)	Switzerland	X			2004	2 years		X					X	X	X							X		X			X	X					Yes							X	
Nordel	Sweeden		X		N/A	N/A	X	X	X	X	X		X	X								X		X									No				X				
Japan	Japan		X		N/A	N/A	X	x	X	X	X			X								X							X				No			X					X

* three are no nuclear units in these countries/regions by law

** three are no nuclear units in this country; by other here is meant wind turbine generators

(1) Other methods for dynamic data gathering used when units have not yet been tested

(2) Reasons for testing and components tested are based on the intented objectives, since presently there is no mandate

(3) Three response were received from this region, what is shown is a combination of the responses.

(4) Initially within 7 years to establish reactive capability (can be done in ways other than testing); initial AVR step-test to confirm exciter parameters within 7 years and reevaluate every 5 years thereafter.

C
GENERIC SYSTEM MODEL

A generic system was developed in order to perform some limited sensitivity analysis to illustrate the importance of various plant controls and models.

The system is shown in Figure C-1. It does not represent any real system nor was data used from any specific source. None-the-less, all the line and plant data was based on typical (and physically realizable) data.

The Table C-1 below summaries the types of units in each power plant. The units shown in the system diagram that show only reactive power output are actually SVCs (and modeled as true SVCs in dynamics). All 500 kV and 230 kV lines were modeled using typical transmission line impedances. The impedances used were R=0.0981 /mile, X= 0.581 /mile and B=0.019 F/mile for the 500 kV lines (this assumes a typical triple-conductor bundle 954 ACSR conductor and tower structure). For the 230 kV lines the values used were R=0.099 /mile, X= 0.798 /mile and B=0.0141 F/mile (this assumes a typical single conductor 954 ACSR conductor and tower structure). The lines range from 50 miles in length to 200 miles. Many of the longer lines have been series compensated. Also, shunt capacitors and reactors have been used throughout the system to help maintain the voltage profile. The system condition shown is not intended to be optimal, but rather reflect a heavy loaded scenario.

The event simulated in all cases is a 3-phase fault at the Bus 3 end of one of the parallel 500 kV lines from bus 3 to 10; the fault is cleared by tripping the line in 3 cycles (a typical fault clearing time at such extra-high voltages).

Numerous sensitivity simulations were performed relative to machine parameters, parameters of controllers and the status of controllers.

The results are shown in figures below. Each plot shows machine speeds (for key generators in the system) – this is indicative of the stability of the entire system. In addition, Table C-2 below summarizes all the results. The cases simulated, in the order shown below, are:

- Initial Base Case (all loads are assumed to be constant current P and constant impedance Q – note: it is well known that this is a quite optimistic load assumption, however, the intent here is to show the sensitivity of results to various parameter variations).
- Simulation after increasing all machine Xd by 10%.
- Simulation after increasing all machine X’d by 10%.
- Simulation after increasing all machine X’’d by 10%.
- Simulation after increasing all machine Xq by 10%.

- Simulation after increasing all machine X'q by 10% (note: the salient pole hydro units by definition have no X'q).
- Simulation after increasing all machine X''q by 10%.
- Simulation after increasing all machine T'do by 10%.
- Simulation after increasing all machine T''do by 10%.
- Simulation after increasing all machine T'qo by 10% (note: the salient pole hydro units by definition have no T'qo).
- Simulation after increasing all machine T''qo by 10%.
- Simulation after increasing all machine Xl by 10%.
- Simulation after increasing all machine electrical parameters by 10%.
- Simulation after increasing all machine d-axis parameters by 25%.
- Simulation after increasing all machine q-axis parameters by 25%.
- Simulation after increasing all machine electrical parameters by 25%.
- Simulation after increasing all machine inertia constants (H) by 25%.
- Simulation after decreasing all machine inertia constants (H) by 25%.
- Simulation after increasing all machine exciter AVR gains by 25%.
- Simulation after decreasing all machine exciter AVR gains by 25%.
- Change load model (60% constant P, Q load, 20% constant Impedance and 20% constant Current)
- Change load model (34% constant P, Q load, 33% constant Impedance and 33% constant Current)
- Change load model (27.2% constant P, Q load, 26.4% constant Impedance, 26.4% constant Current and 20% Motor Load)
- Turn off all Power System Stabilizers on Machines
- Turn off all PSSs on Gen1 and Gen4
- Turn off all PSSs on Gen1, 9 and 10
- Turn off all PSSs on Gen1, 4, and 10
- Turn off all PSSs on Gen1, 4 and 8
- Turn off all PSSs on Gen 2, 3, 6 and 12

Note: in the simulation plot one might notice that the speed of all machines seems to settle down just above 1 pu (at 1.001 pu). This is because the simulated event results in a small decrease in steady-state voltage at many load buses. Since the load models are voltage dependant, this means that the total effective system load is less after the even, thus system frequency rises ever so slightly.

Table C-1
Generator Types in Generic System Model

Generator	Bus and Number of units	Type of Plant	Type of Generator	Type of Exciter	PSS
GEN1	10 units at Bus 1	Hydro	Salient Pole	Static	Yes
GEN2	2 units at Bus 8	Coal Fired Steam	Round Rotor	Static	Yes
GEN3	1 unit at Bus 9	Coal Fired Steam	Round Rotor	Static	Yes
GEN4	10 units at Bus 15	Hydro	Salient Pole	Brushless	Yes
GEN5	2 units at Bus 22	Aero-derivative Gas Turbine	Round Rotor	Brushless	Yes
GEN6	2 units at Bus 21	Coal Fired Steam	Round Rotor	Brushless	Yes
GEN7	4 units at Bus 27	Combined-Cycle (2 GT and 1 ST[20]) + One Stand alone Coal Fired Steam Turbine	Round Rotor	Static (CCPP); Brushless (Steam)	Yes
GEN8	2 units at Bus 28	Nuclear	Round Rotor	Static	Yes
GEN9	2 units at Bus 34	Coal Fired Steam	Round Rotor	Brushless	Yes
GEN10	2 units at Bus 36	Nuclear	Round Rotor	Static	Yes
GEN11	3 units at Bus 13 (connects radially to Bus 11)	Combined-Cycle (2 GT and 1 ST)	Round Rotor	Static	Yes
GEN12	1 unit at Bus 10	Coal Fired Steam	Round Rotor	Brushless	Yes

[20] GT – gas turbine and ST – steam turbine.

Table C-2
Simulation Results

Load				PSS	Machine	Exciter	Governor	Disturbance	Description	Difference in Behavior Compared to Base Case
Const P	Const I	Const Z	Motor							
0	100% (P)	100% (Q)	0	All In-Service	Base	Base	Base	3ph at 3, trip 3-10	System Stable and settels in 5 seconds.	None
0	100% (P)	100% (Q)	0	All In-Service	Xd*1.1	Base	Base	3ph at 3, trip 3-10	System Stable and settels in 5 seconds.	None
0	100% (P)	100% (Q)	0	All In-Service	Xpd'*1.1	Base	Base	3ph at 3, trip 3-10	System Stable and settels in 5 seconds.	None
0	100% (P)	100% (Q)	0	All In-Service	Xppd''*1.1	Base	Base	3ph at 3, trip 3-10	System Stable and settels in 5 seconds.	None
0	100% (P)	100% (Q)	0	All In-Service	Xq*1.1	Base	Base	3ph at 3, trip 3-10	System Stable and settels in 5 seconds.	None
0	100% (P)	100% (Q)	0	All In-Service	Xpq'*1.1	Base	Base	3ph at 3, trip 3-10	System Stable and settels in 5 seconds.	None
0	100% (P)	100% (Q)	0	All In-Service	Xppq''*1.1	Base	Base	3ph at 3, trip 3-10	System Stable and settels in 5 seconds.	None
0	100% (P)	100% (Q)	0	All In-Service	Tpdo''*1.1	Base	Base	3ph at 3, trip 3-10	System Stable and settels in 5 seconds.	None
0	100% (P)	100% (Q)	0	All In-Service	Tppdo''*1.1	Base	Base	3ph at 3, trip 3-10	System Stable and settels in 5 seconds.	None
0	100% (P)	100% (Q)	0	All In-Service	Tpqo''*1.1	Base	Base	3ph at 3, trip 3-10	System Stable and settels in 5 seconds.	None
0	100% (P)	100% (Q)	0	All In-Service	Tppqo''*1.1	Base	Base	3ph at 3, trip 3-10	System Stable and settels in 5 seconds.	None
0	100% (P)	100% (Q)	0	All In-Service	Xl''*1.1	Base	Base	3ph at 3, trip 3-10	System Stable and settels in 5 seconds.	None
0	100% (P)	100% (Q)	0	All In-Service	All*1.1	Base	Base	3ph at 3, trip 3-10	System Stable and settels in 5 seconds.	Noticably less damped
0	100% (P)	100% (Q)	0	All In-Service	All*1.25	Base	Base	3ph at 3, trip 3-10	System Stable and settels in 5 seconds.	Significantly less damped
0	100% (P)	100% (Q)	0	All In-Service	Qs*1.25	Base	Base	3ph at 3, trip 3-10	System Stable and settels in 5 seconds.	Noticably less damped
0	100% (P)	100% (Q)	0	All In-Service	Ds*1.25	Base	Base	3ph at 3, trip 3-10	System Stable and settels in 5 seconds.	Significantly less damped
0	100% (P)	100% (Q)	0	All In-Service	H*1.25	Base	Base	3ph at 3, trip 3-10	System Stable and settels in 5 seconds.	Noticably more damped
0	100% (P)	100% (Q)	0	All In-Service	H*0.75	Base	Base	3ph at 3, trip 3-10	System Stable and settels in 5 seconds.	Noticably less damped
0	100% (P)	100% (Q)	0	All In-Service	Base	K*1.25	Base	3ph at 3, trip 3-10	System Stable and settels in 5 seconds.	Noticably more damped
0	100% (P)	100% (Q)	0	All In-Service	Base	K*0.75	Base	3ph at 3, trip 3-10	System Stable and settels in 5 seconds.	Noticably less damped
60%	20%	20%	0	All In-Service	Base	Base	Base	3ph at 3, trip 3-10	System Transiently Unstable	System Transiently Unstable
34%	33%	33%	0	All In-Service	Base	Base	Base	3ph at 3, trip 3-10	System Stable and settels in 5 seconds.	Not much
27.2%	26.4%	26.4%	20%	All In-Service	Base	Base	Base	3ph at 3, trip 3-10	System Transiently Unstable	System Transiently Unstable
0	100% (P)	100% (Q)	0	All off	Base	Base	Base	3ph at 3, trip 3-10	System Transiently Unstable	System Transiently Unstable
0	100% (P)	100% (Q)	0	Gen1 and Gen4 PSSs off	Base	Base	Base	3ph at 3, trip 3-11	System stable but oscillatory.	Significanltly Less Damped
0	100% (P)	100% (Q)	0	Gen1 and Gen9 and Gen 10 PSSs off	Base	Base	Base	3ph at 3, trip 3-10	System Unstable (Unstable Inter-Area Mode)	Entire System Unstable
0	100% (P)	100% (Q)	0	Gen1, 4, and 10 PSSs off	Base	Base	Base	3ph at 3, trip 3-10	System stable but oscillatory.	Significanltly Less Damped
0	100% (P)	100% (Q)	0	Gen1, 4 and 8 PSSs off	Base	Base	Base	3ph at 3, trip 3-10	System stable but oscillatory.	Significanltly Less Damped
0	100% (P)	100% (Q)	0	Gen 2, 3, 6 and 12 PSSs off	Base	Base	Base	3ph at 3, trip 3-10	System Oscilatory; 2 machines unstable	System Unstable

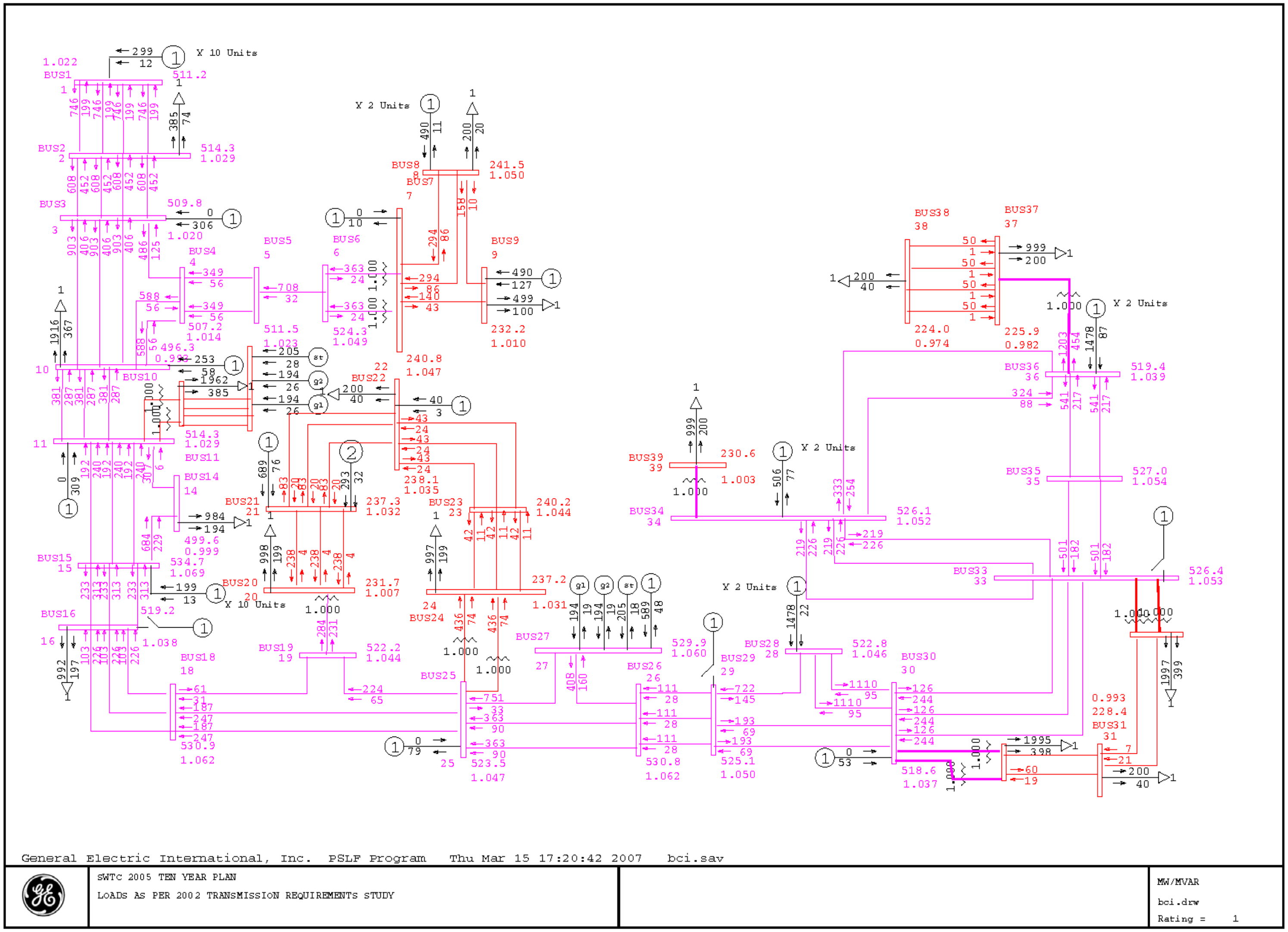
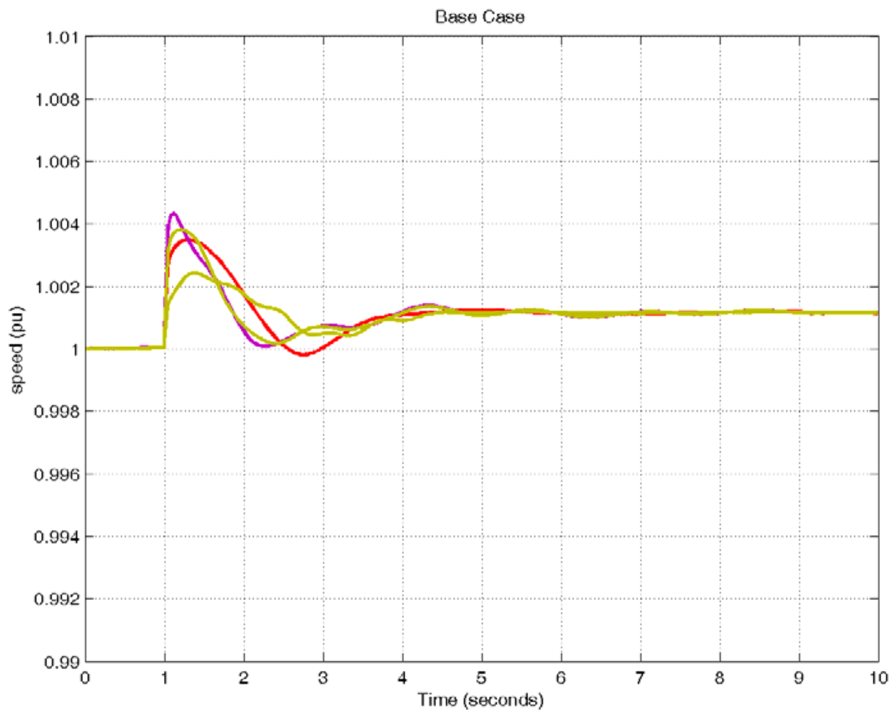
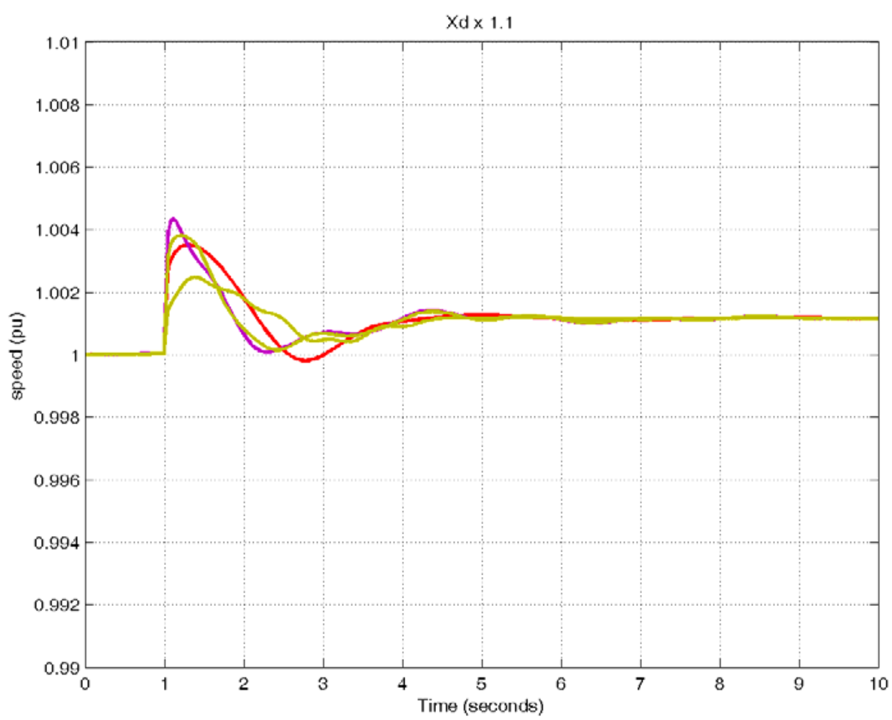


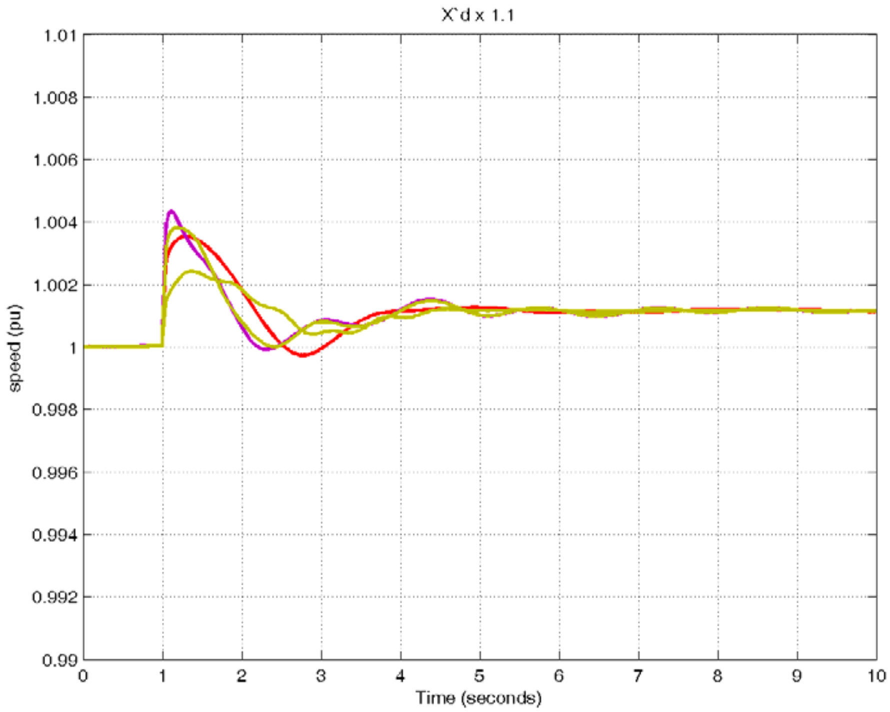
Figure C-1
Power Flow Condition for the Generic System Model

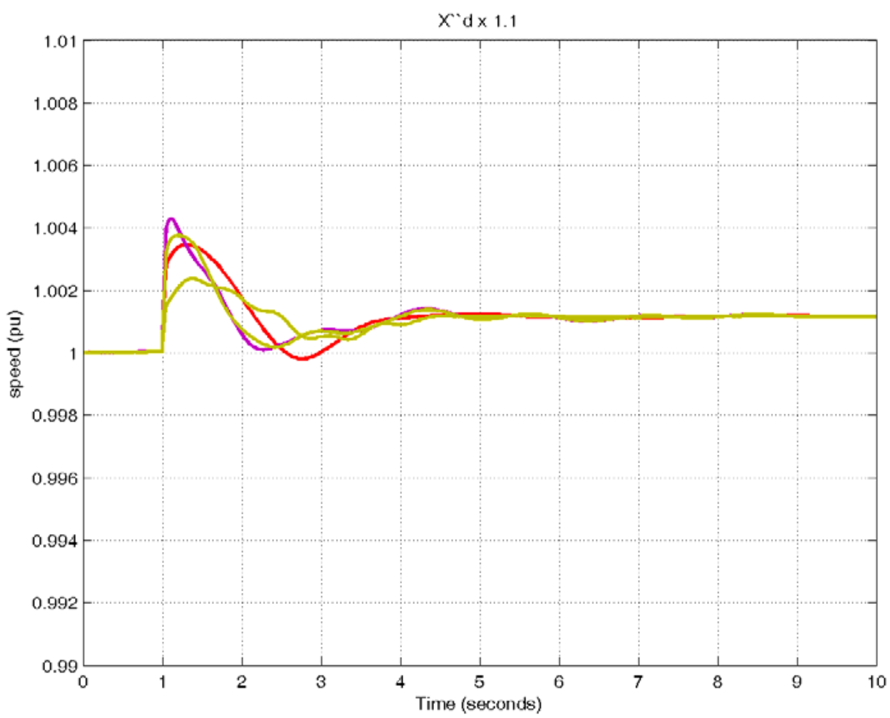


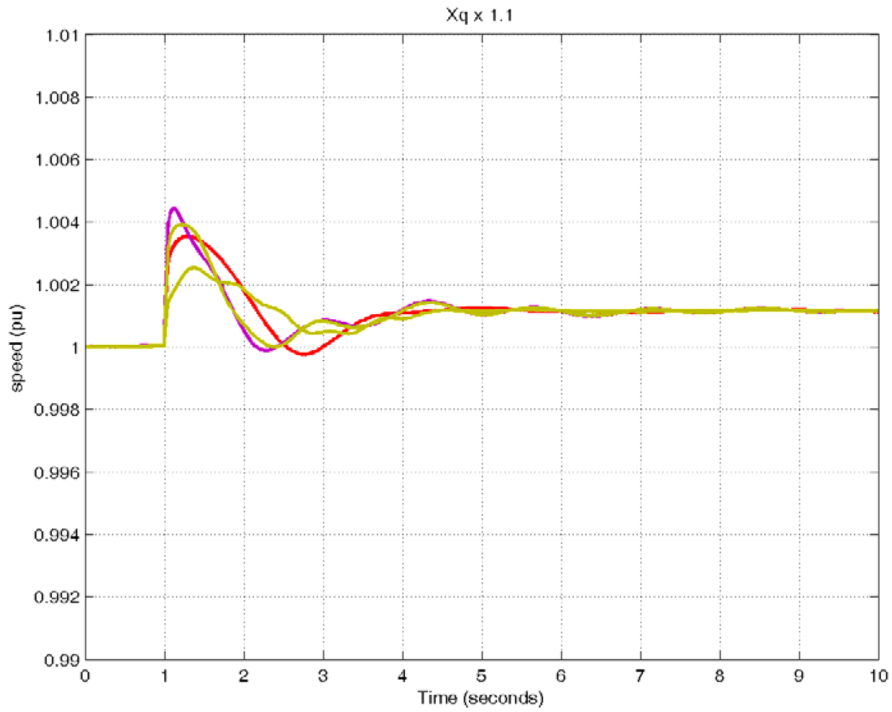
Base Case
1.01
1.008
1.006
1.004
1.002
1
0.998
0.996
0.994
0.992
0.99
speed (pu)
0
1
2
3
4
5
6
7
8
9
10
Time (seconds)

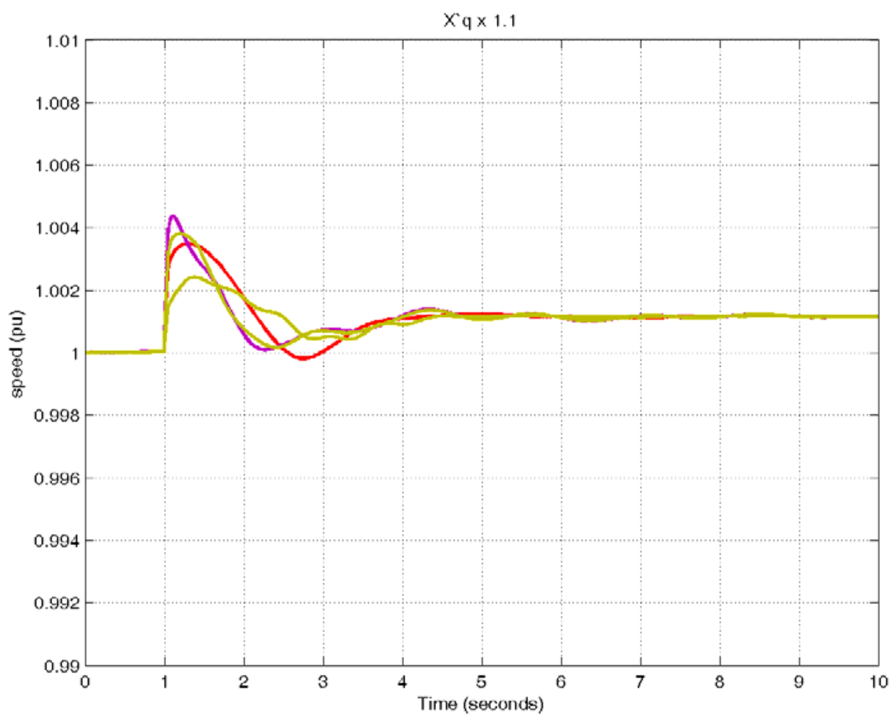


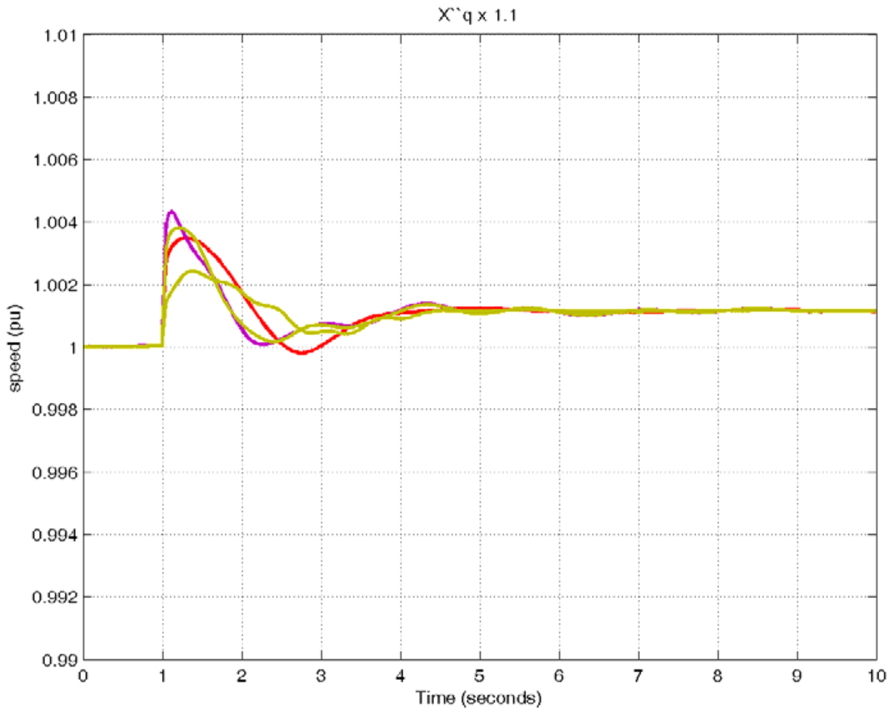
Xd x 1.1
1.01
1.008
1.006
1.004
1.002
1
0.998
0.996
0.994
0.992
0.99
speed (pu)
0
1
2
3
4
5
6
7
8
9
10
Time (seconds)

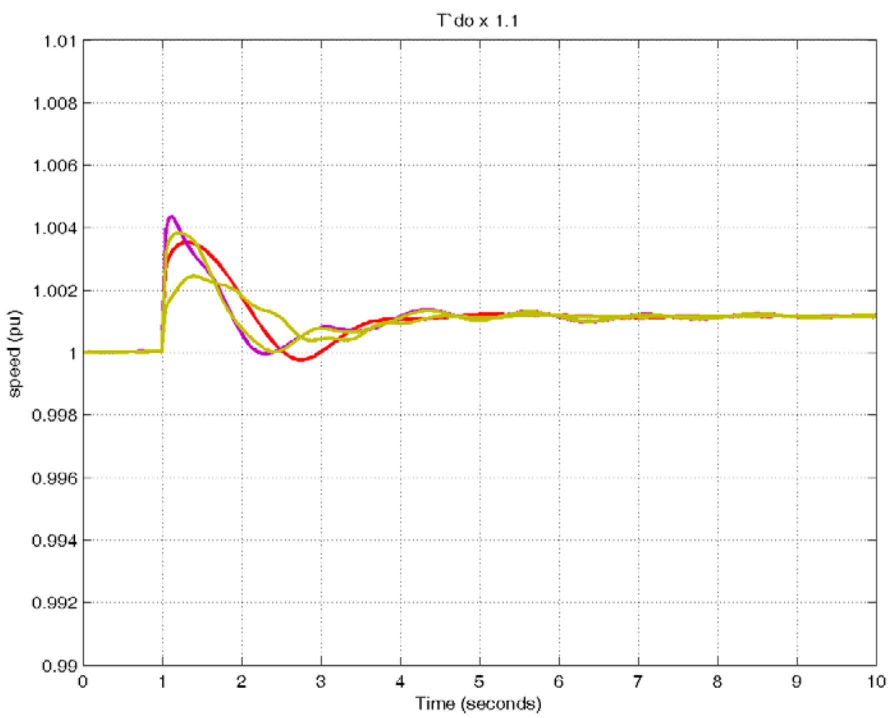

X`d x 1.1
speed (pu)
Time (seconds)
1.01
1.008
1.006
1.004
1.002
1
0.998
0.996
0.994
0.992
0.99
0
1
2
3
4
5
6
7
8
9
10

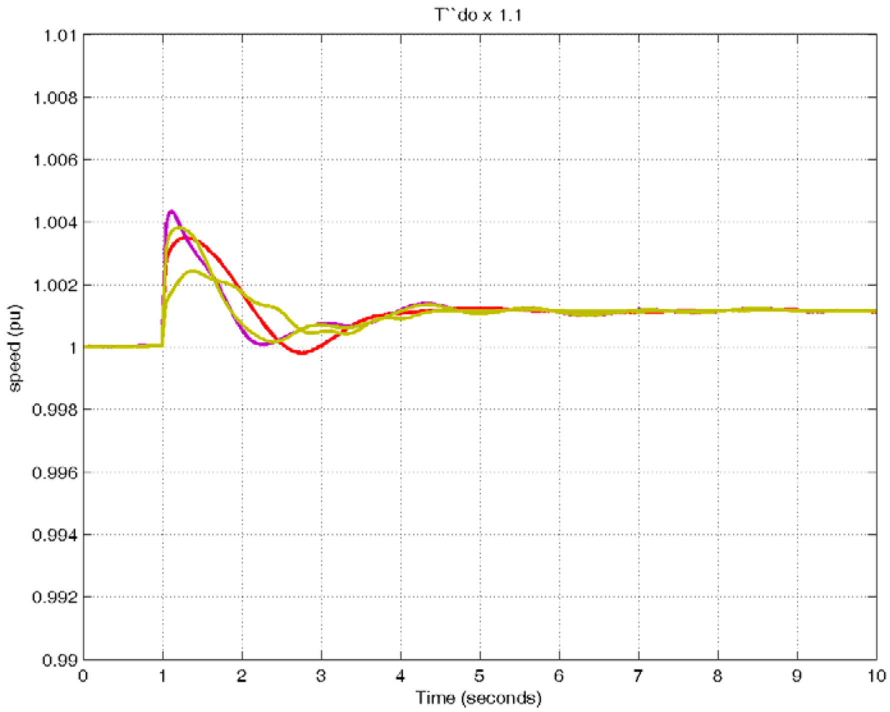

X``d x 1.1
speed (pu)
Time (seconds)
1.01
1.008
1.006
1.004
1.002
1
0.998
0.996
0.994
0.992
0.99
0
1
2
3
4
5
6
7
8
9
10

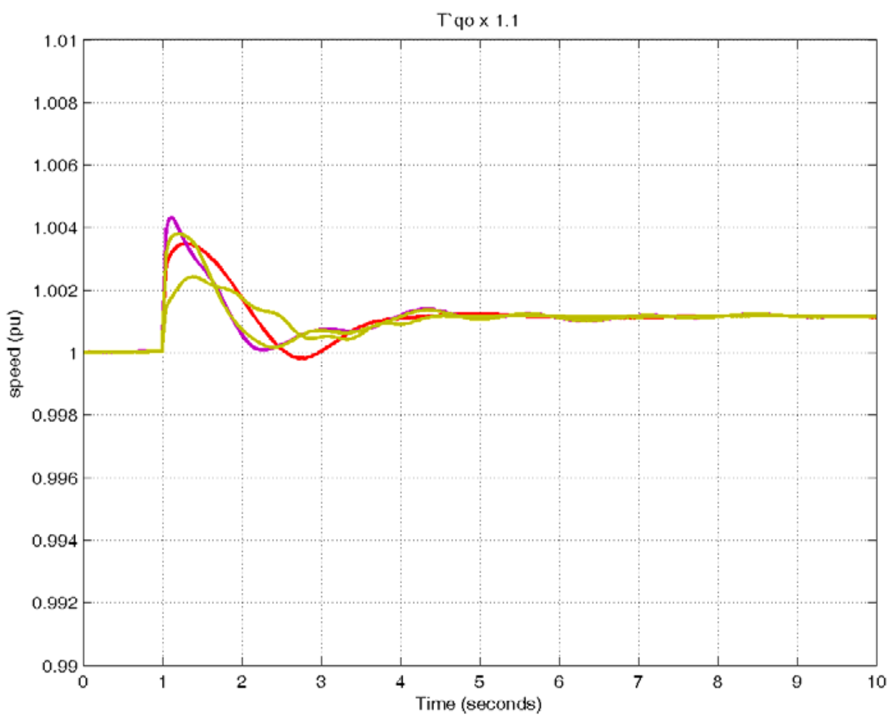

Xq x 1.1
1.01
1.008
1.006
1.004
1.002
1
0.998
0.996
0.994
0.992
0.99
speed (pu)
0
1
2
3
4
5
6
7
8
9
10
Time (seconds)

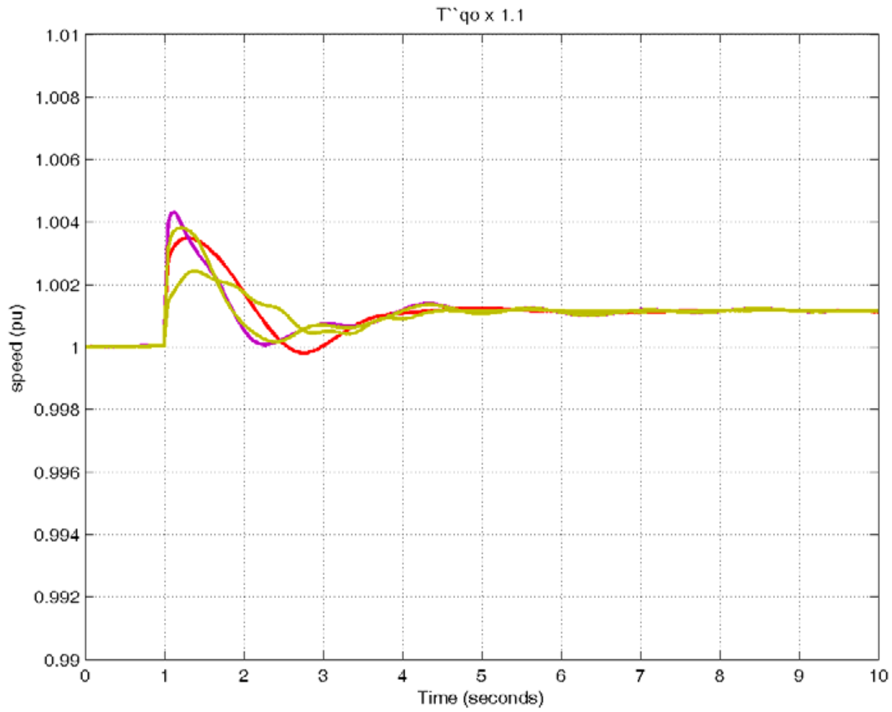

X`q x 1.1
1.01
1.008
1.006
1.004
1.002
1
0.998
0.996
0.994
0.992
0.99
speed (pu)
0
1
2
3
4
5
6
7
8
9
10
Time (seconds)

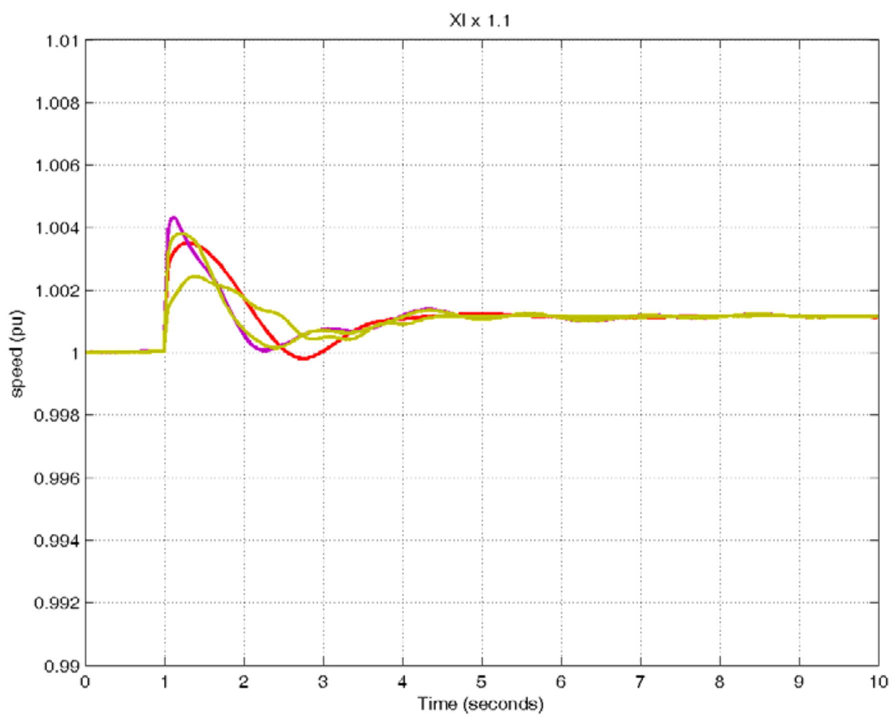

X``q x 1.1
speed (pu)
Time (seconds)
1.01
1.008
1.006
1.004
1.002
1
0.998
0.996
0.994
0.992
0.99
0
1
2
3
4
5
6
7
8
9
10

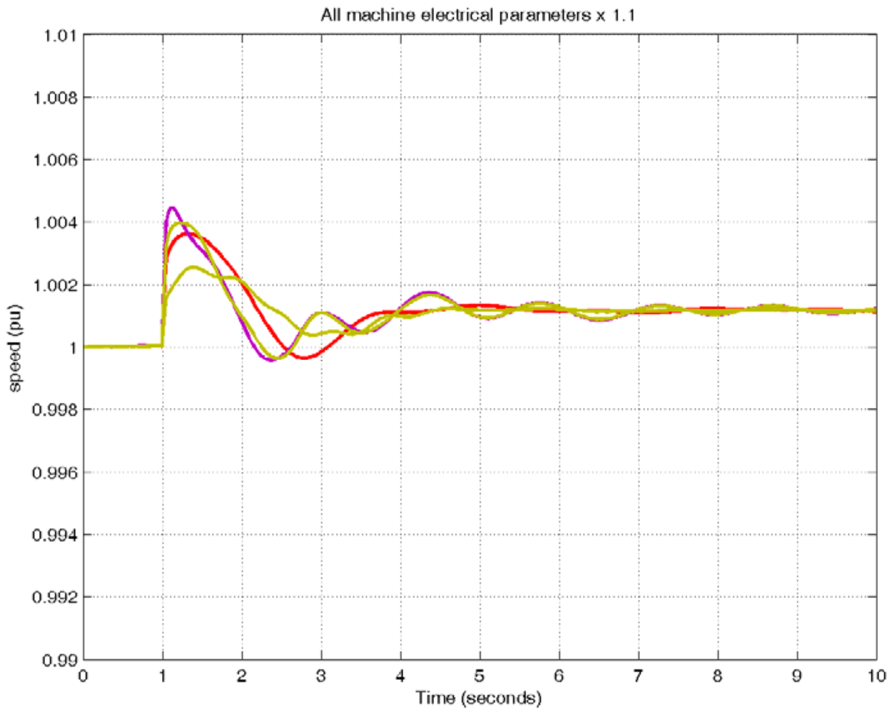

T`do x 1.1
speed (pu)
Time (seconds)
1.01
1.008
1.006
1.004
1.002
1
0.998
0.996
0.994
0.992
0.99
0
1
2
3
4
5
6
7
8
9
10

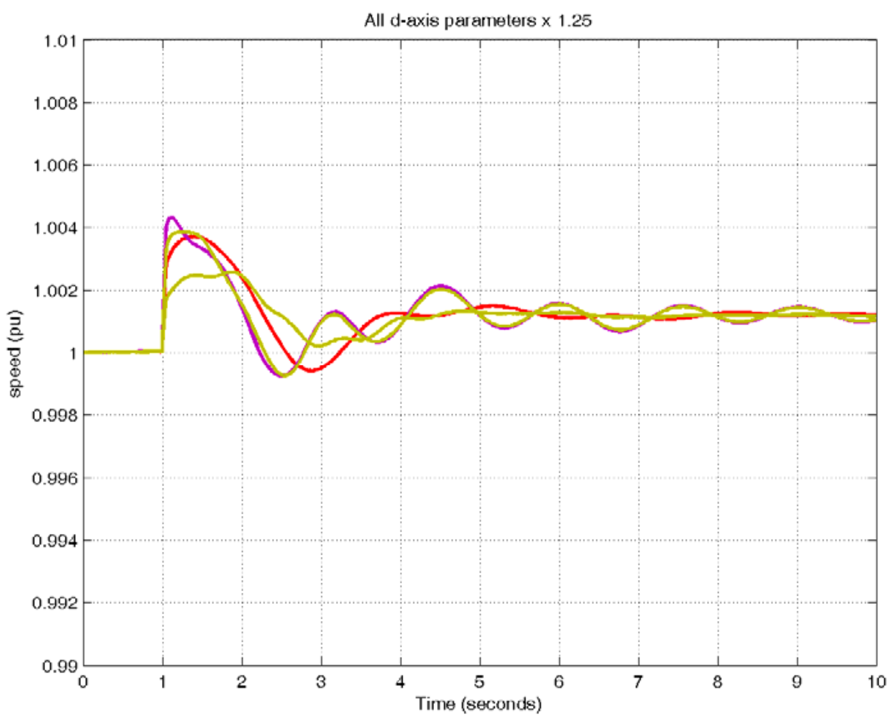

T``do x 1.1
speed (pu)
Time (seconds)

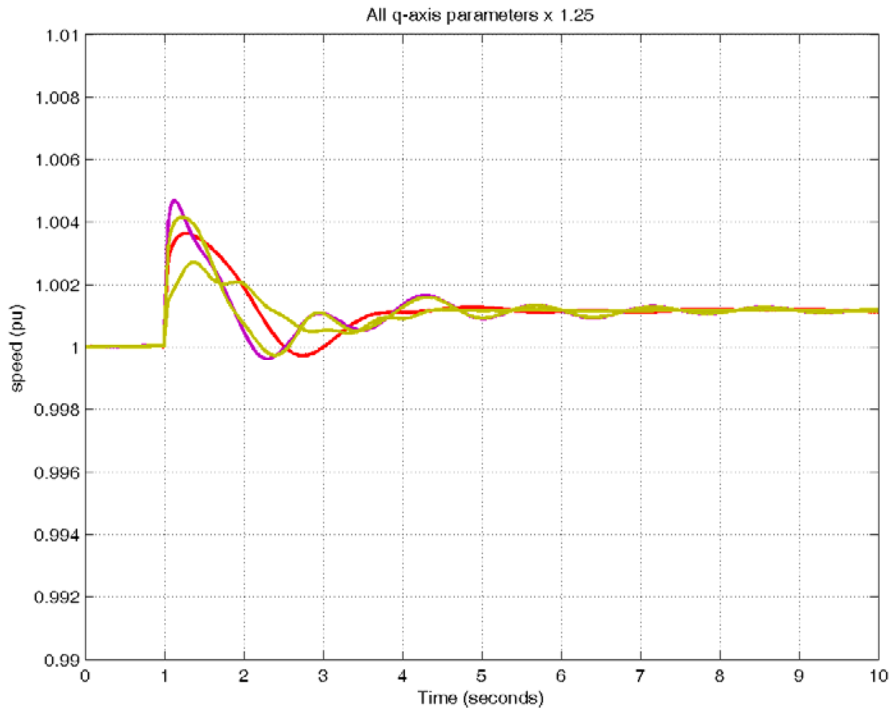

T`qo x 1.1
speed (pu)
Time (seconds)

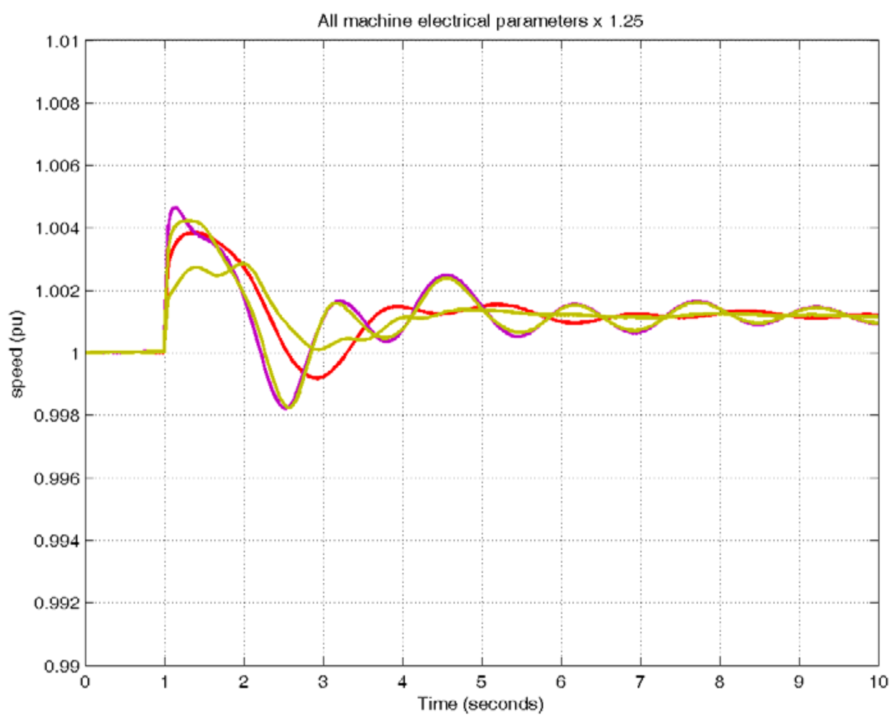

T``qo x 1.1
1.01
1.008
1.006
1.004
1.002
1
0.998
0.996
0.994
0.992
0.99
speed (pu)
0
1
2
3
4
5
6
7
8
9
10
Time (seconds)

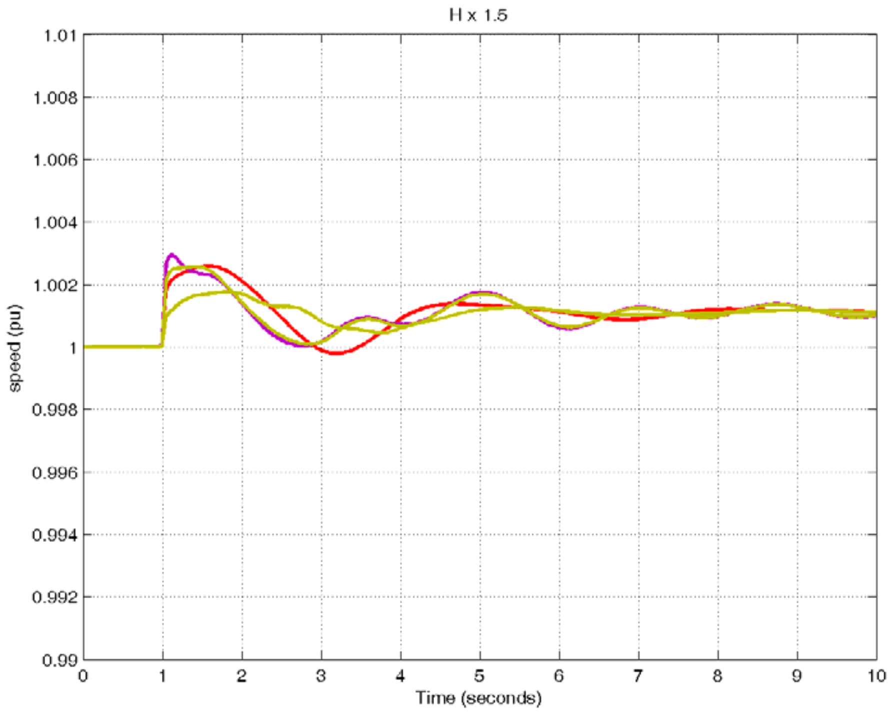

Xl x 1.1
1.01
1.008
1.006
1.004
1.002
1
0.998
0.996
0.994
0.992
0.99
speed (pu)
0
1
2
3
4
5
6
7
8
9
10
Time (seconds)


All machine electrical parameters x 1.1
speed (pu)
Time (seconds)
1.01
1.008
1.006
1.004
1.002
1
0.998
0.996
0.994
0.992
0.99
0
1
2
3
4
5
6
7
8
9
10

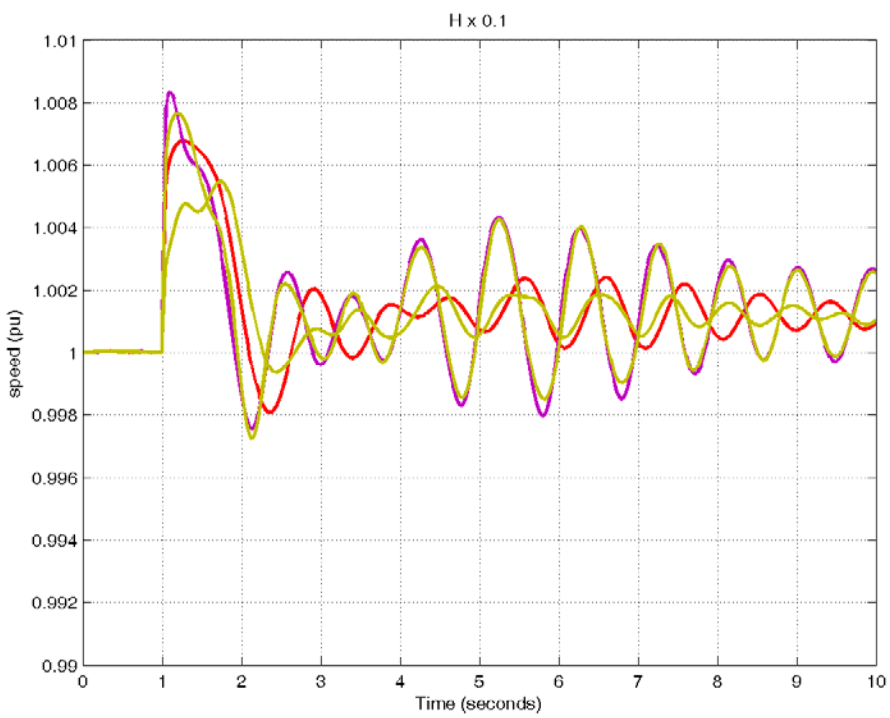

All d-axis parameters x 1.25
speed (pu)
Time (seconds)
1.01
1.008
1.006
1.004
1.002
1
0.998
0.996
0.994
0.992
0.99
0
1
2
3
4
5
6
7
8
9
10


All q-axis parameters x 1.25
1.01
1.008
1.006
1.004
1.002
1
0.998
0.996
0.994
0.992
0.99
speed (pu)
0
1
2
3
4
5
6
7
8
9
10
Time (seconds)

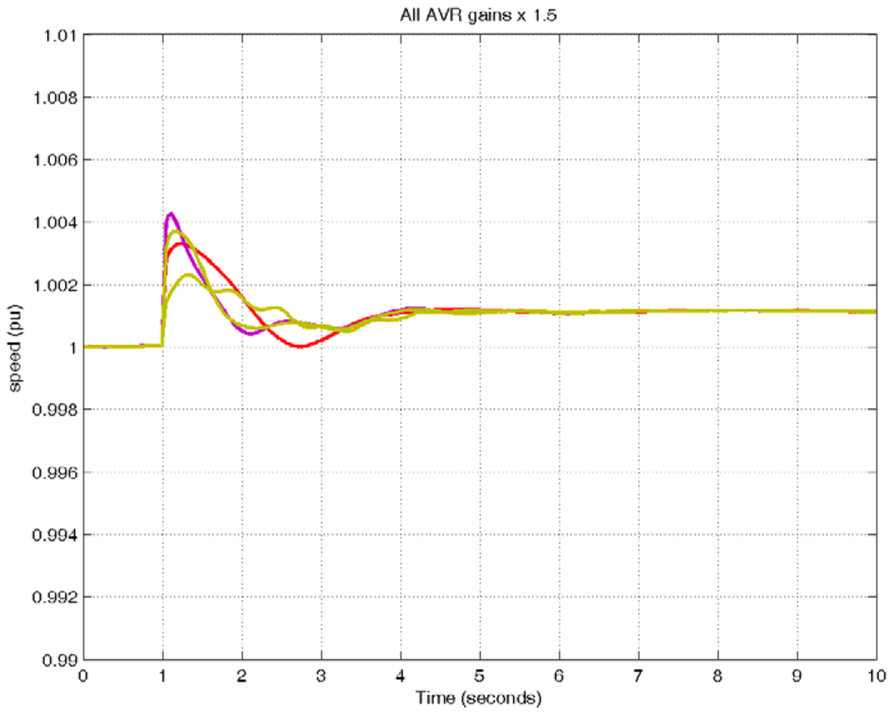

All machine electrical parameters x 1.25
1.01
1.008
1.006
1.004
1.002
1
0.998
0.996
0.994
0.992
0.99
speed (pu)
0
1
2
3
4
5
6
7
8
9
10
Time (seconds)

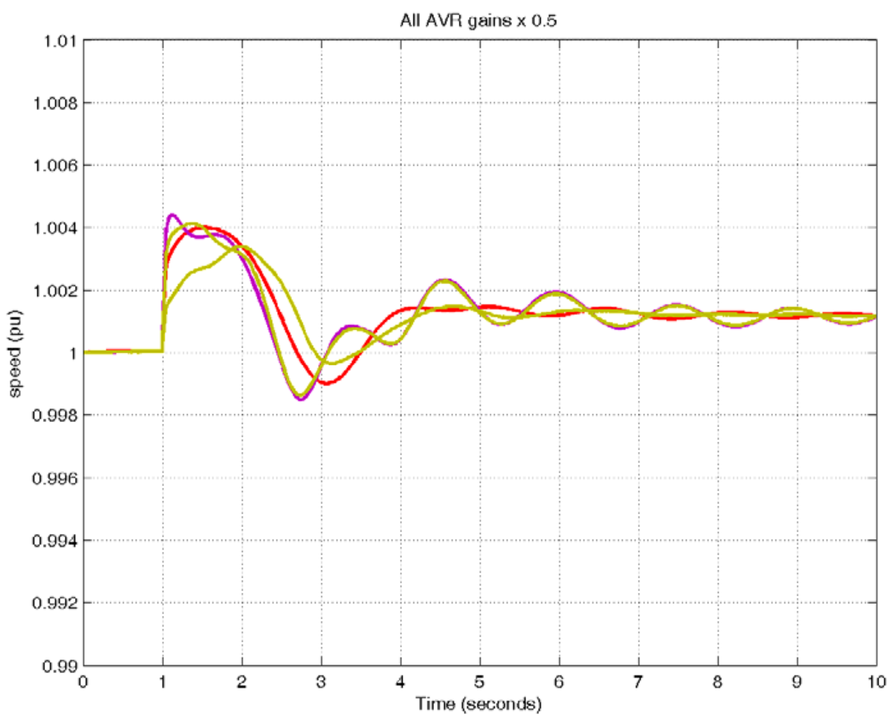


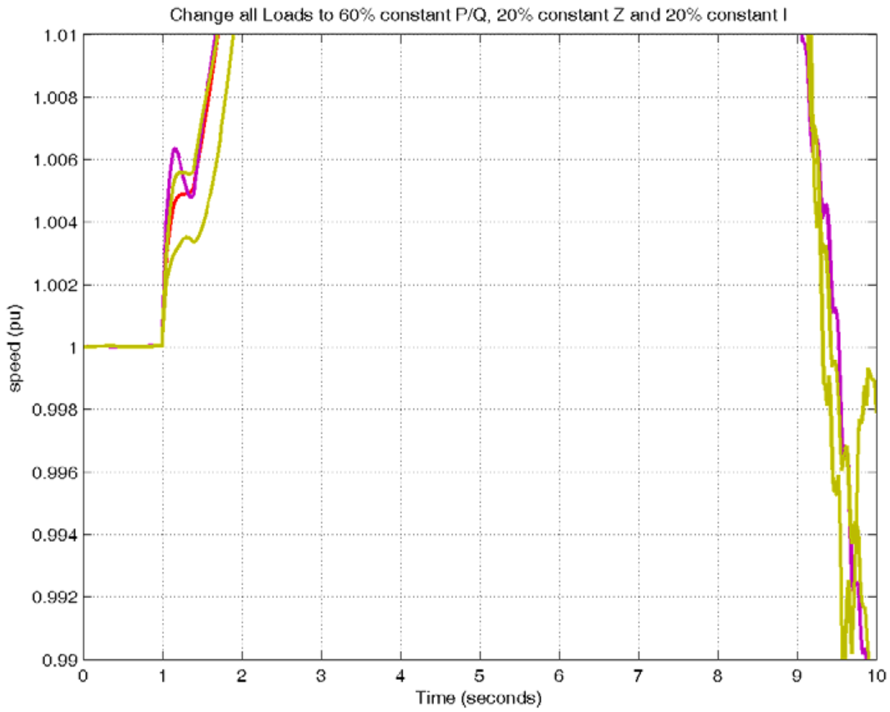
H x 1.5
speed (pu)
Time (seconds)

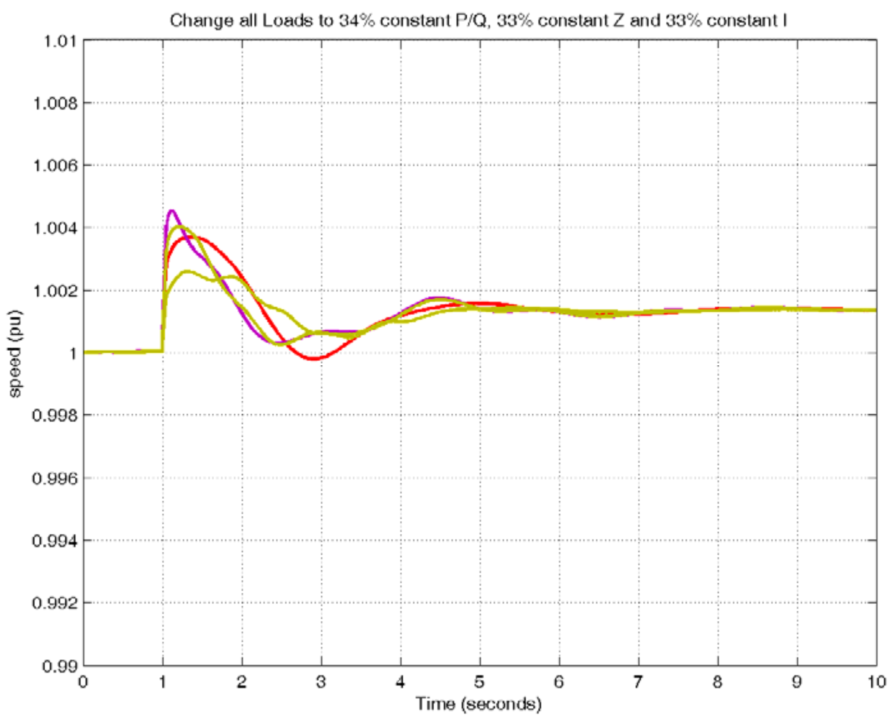


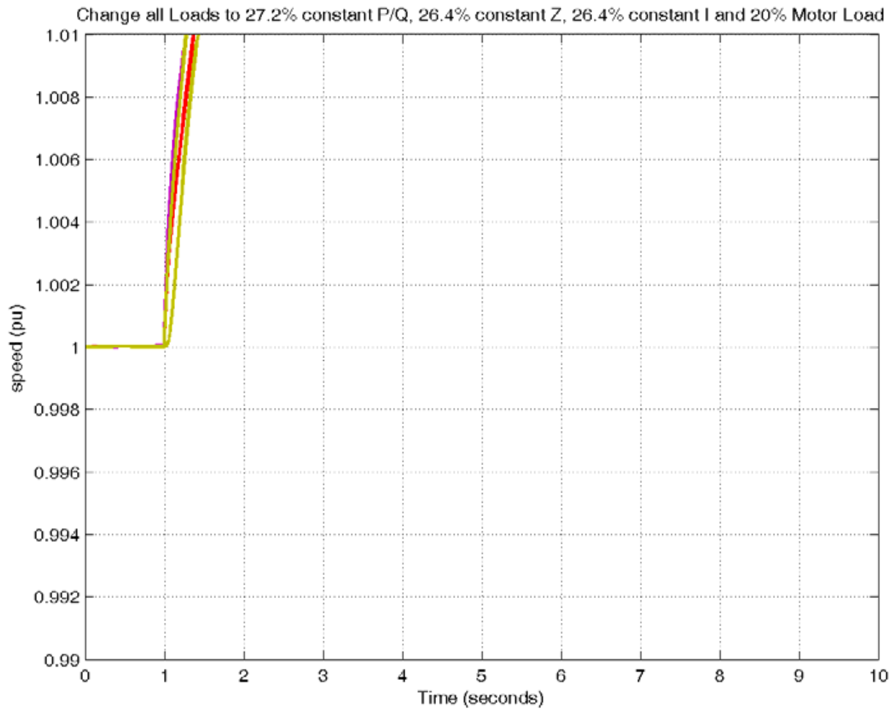
H x 0.1
speed (pu)
Time (seconds)

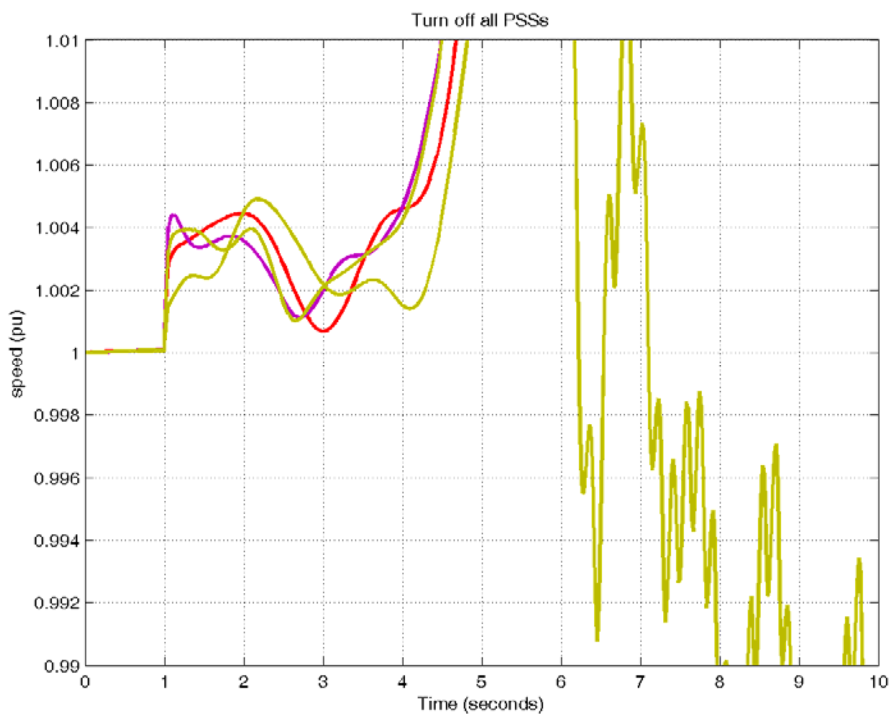

All AVR gains x 1.5
1.01
1.008
1.006
1.004
1.002
1
0.998
0.996
0.994
0.992
0.99
speed (pu)
0
1
2
3
4
5
6
7
8
9
10
Time (seconds)

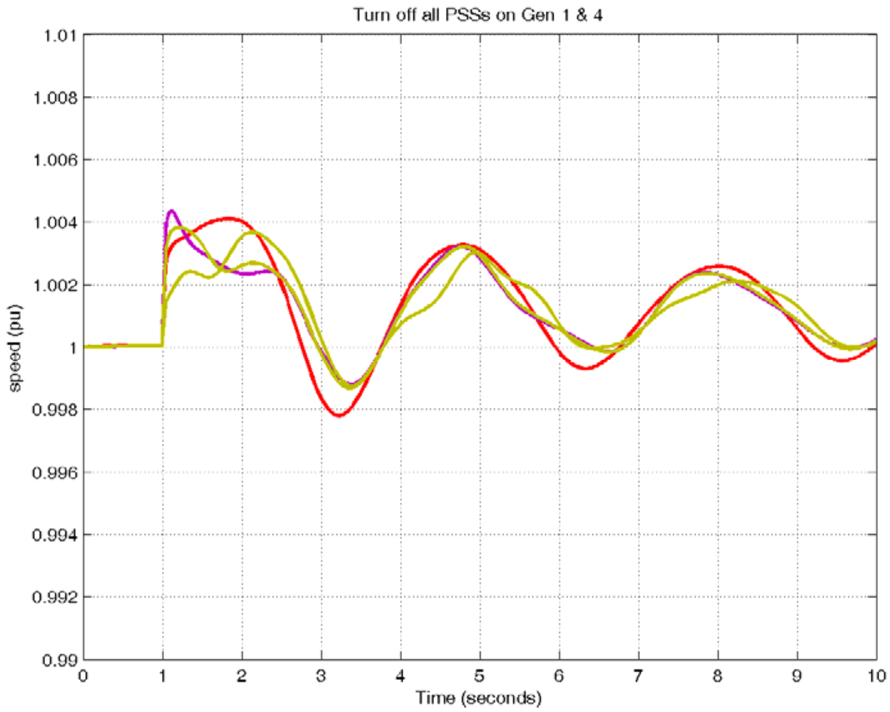

All AVR gains x 0.5
1.01
1.008
1.006
1.004
1.002
1
0.998
0.996
0.994
0.992
0.99
speed (pu)
0
1
2
3
4
5
6
7
8
9
10
Time (seconds)

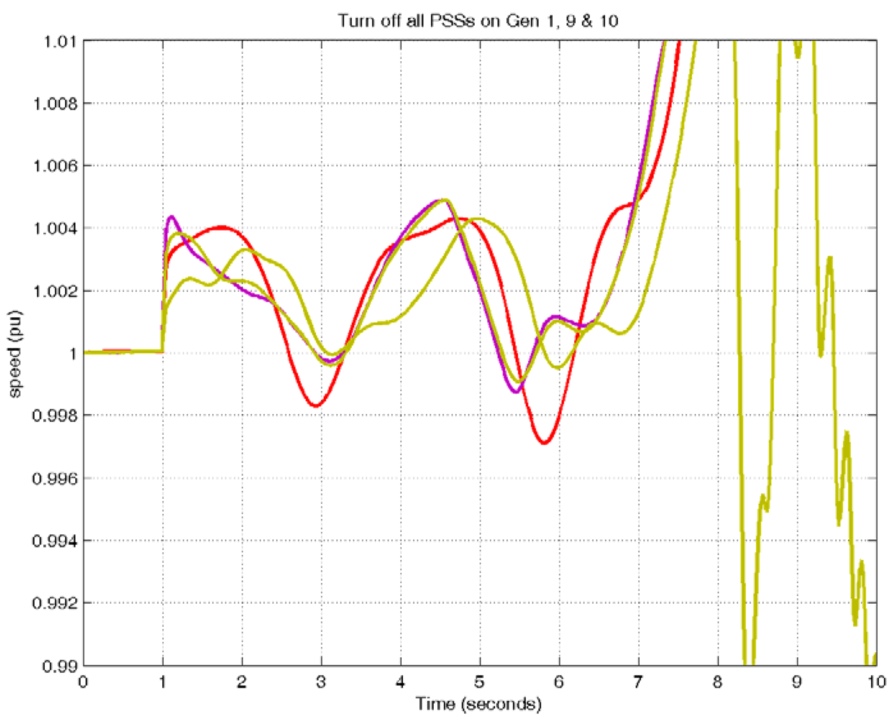

Change all Loads to 60% constant P/Q, 20% constant Z and 20% constant I
1.01
1.008
1.006
1.004
1.002
1
0.998
0.996
0.994
0.992
0.99
speed (pu)
0
1
2
3
4
5
6
7
8
9
10
Time (seconds)


Change all Loads to 34% constant P/Q, 33% constant Z and 33% constant I
1.01
1.008
1.006
1.004
1.002
1
0.998
0.996
0.994
0.992
0.99
speed (pu)
0
1
2
3
4
5
6
7
8
9
10
Time (seconds)


Change all Loads to 27.2% constant P/Q, 26.4% constant Z, 26.4% constant I and 20% Motor Load
speed (pu)
Time (seconds)
1.01
1.008
1.006
1.004
1.002
1
0.998
0.996
0.994
0.992
0.99
0
1
2
3
4
5
6
7
8
9
10


Turn off all PSSs
speed (pu)
Time (seconds)
1.01
1.008
1.006
1.004
1.002
1
0.998
0.996
0.994
0.992
0.99
0
1
2
3
4
5
6
7
8
9
10


Turn off all PSSs on Gen 1 & 4
speed (pu)
Time (seconds)
1.01
1.008
1.006
1.004
1.002
1
0.998
0.996
0.994
0.992
0.99
0
1
2
3
4
5
6
7
8
9
10


Turn off all PSSs on Gen 1, 9 & 10
speed (pu)
Time (seconds)
1.01
1.008
1.006
1.004
1.002
1
0.998
0.996
0.994
0.992
0.99
0
1
2
3
4
5
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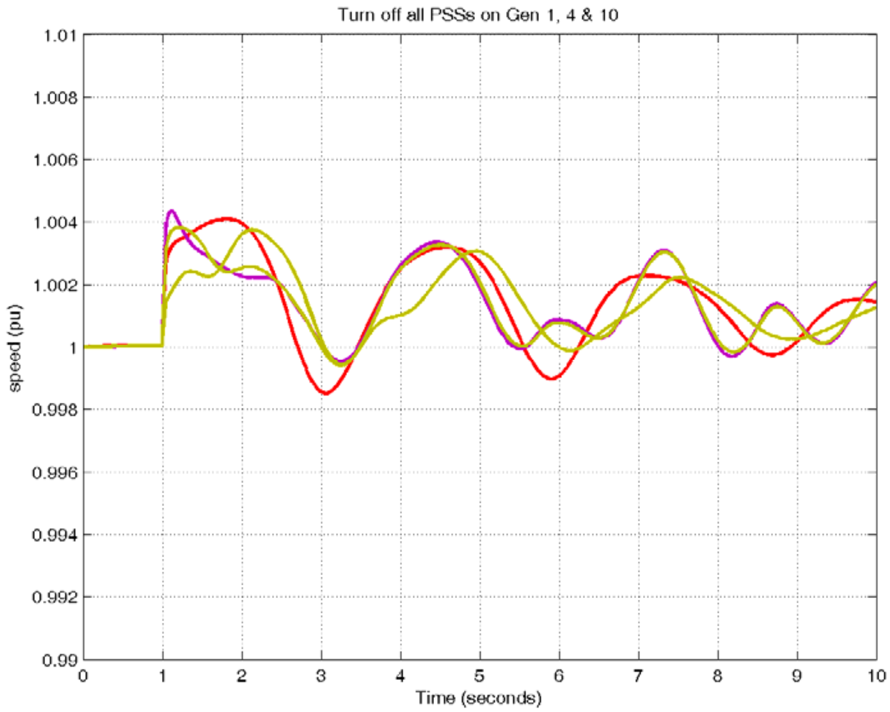
8
9
10


Turn off all PSSs on Gen 1, 4 & 10
speed (pu)
Time (seconds)
1.01
1.008
1.006
1.004
1.002
1
0.998
0.996
0.994
0.992
0.99
0
1
2
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4
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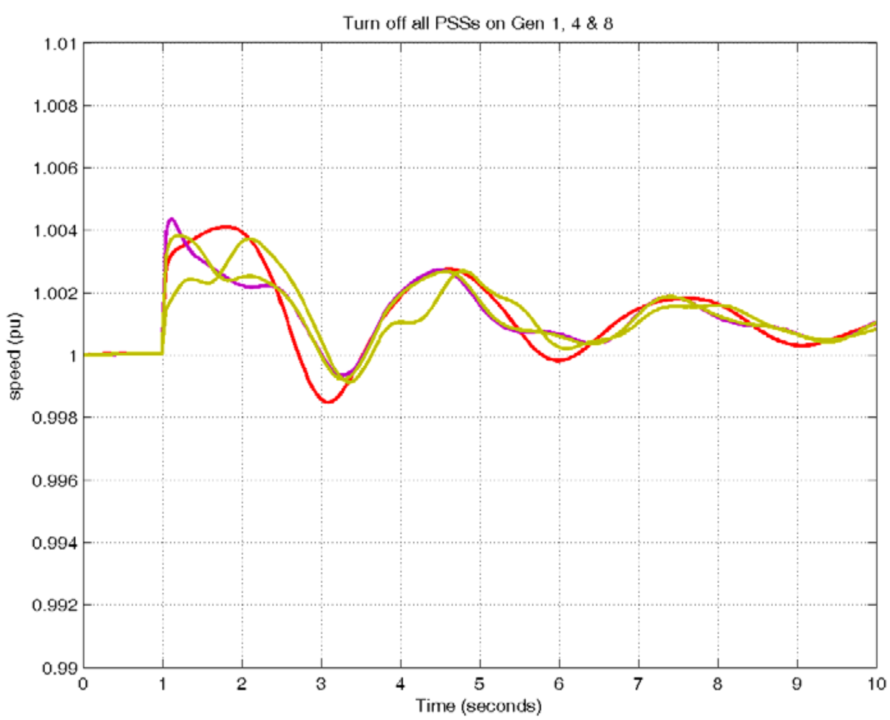
Turn off all PSSs on Gen 1, 4 & 8
speed (pu)
Time (seconds)
1.01
1.008
1.006
1.004
1.002
1
0.998
0.996
0.994
0.992
0.99
0
1
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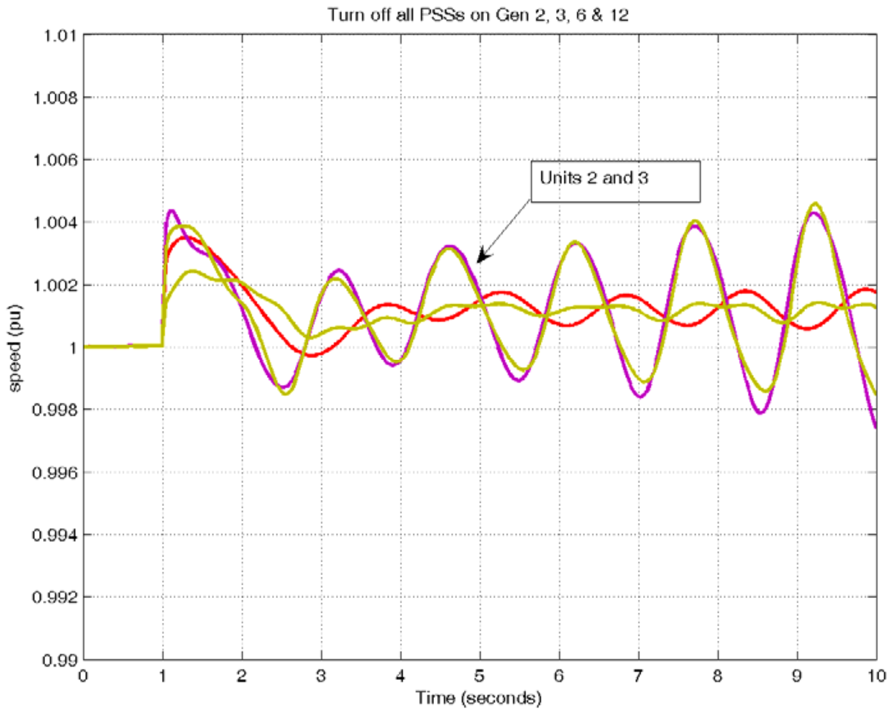
Turn off all PSSs on Gen 2, 3, 6 & 12
Units 2 and 3
speed (pu)
Time (seconds)
1.01
1.008
1.006
1.004
1.002
1
0.998
0.996
0.994
0.992
0.99
0
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