STANDARD APPROACH TO PERFORM POWER SYSTEM STABILITY STUDIES IN OIL AND GAS PLANTS

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Abstract – Many large Oil and Gas plants have installed cogeneration or gas and steam generators to increase efficiency, reduce electricity cost, and improve system reliability. Adding synchronous generators to a power system tremendously increases system complexity and brings in stability concerns. Power system stability requires all synchronous machines in an interconnected electrical system to remain in synchronism; otherwise the generators will become unstable or lose stability, which can quickly propagate across the entire network to cause system-wide shut down. Following IEEE recommended practice and authors' extensive experience in modeling power system dynamics and conducting studies, this paper addresses approaches and procedures to perform transient stability study and helps engineers to understand required protections and operations to ensure stable operation of the system. Relevant IEEE standards and task force reports and important literatures in the area are referenced in the paper.

Index Terms — Industrial power systems, Power system analysis and computing, Power system control, Power system dynamics, Power system protection, Power system stability.

I. INTRODUCTION

Increasing numbers of industrial and commercial facilities have installed local generation, large synchronous motors, or both. The role of maintaining system stability with co-generation and other on-site generation is an area of interest and challenge in a power system. When a cogeneration plant or a system with on-site generation is connected to the grid, it changes the system configuration and operating conditions are fundamentally changed. This situation may result instability problems both in the plant and the connected utility. Computer modeling and systematic studies thus are required to identify the source of the problems and develop possible mitigation measures.

This paper discusses fundamentals to transient stability issues in industrial systems, reviews relevant IEEE standards for power system dynamic modeling involving synchronous generators and controls, and provides standard procedure to model and perform transient stability studies in oil and gas plants. A system modeling and study example using an industry accepted computer software is presented to illustrate the described procedures.

A. Cogeneration

Many large industrial plants install cogeneration (combined heat and power (CHP)), or gas and steam generators to increase efficiency, reduce electricity cost, and improve system reliability. The extra heat and steam from the processes are moved to a cogeneration facility, where the heat and steam are used to generate electricity. The electricity generated by cogeneration can be supplied to the facility or is exported to the electric grid. The process is depicted in Fig. 1.

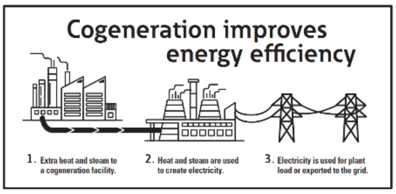


Fig. 1 Co-generation

B. On-site Generation

To increase plant electrical system reliability, generators can be installed onsite to protect islanding operation in case of a grid outage. In that case, onsite generators can continue to provide power to the plant loads to maintain the operation. The configuration of an onsite generation in parallel with electric grid is shown in Fig. 2.

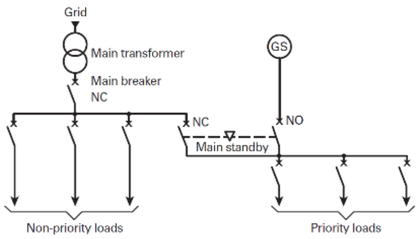


Fig. 2 Onsite generation

C. Stability Issues

Adding synchronous generators to a power system tremendously increases system complexity and brings in synchronous generator stability concerns.

The power system requires all synchronous machines (including generators, motors, and condensers) in an interconnected electrical system to remain in synchronism; otherwise the system will become unstable, or lose stability -continuous synchronous machine rotor angle acceleration or deceleration causing electrical quantities such as voltage and current, active and reactive power continuous or magnified oscillations. Loss of synchronism can occur between one machine and the rest of the system, or between groups of machines, possibly with synchronism maintained within each group after separating from each other. The unstable phenomena can propagate quickly to across the entire electrical network and trigger similar oscillations to other synchronous machines.

The consequences of losing system stability are very severe including forcing tripping of unstable generators, disconnecting tie lines and transmission/distribution lines, making the entire system to shutdown, which results in substantial losses to customers and operations. Due to the importance, transient stability studies are mandatorily required for electrical systems containing synchronous machines.

Power system stability studies focus on modeling the entire electrical system, in particular synchronous machines with their dynamic models including excitation and speed governor systems, simulating and studying various normal and abnormal operating and fault conditions, analyzing machine rotor angle oscillations, system frequency and voltage variations, and other responses, identify unstable scenarios, and recommending remedy or solutions. The overall objective of power system stability studies are to ensure electrical system under study will be able to maintain stable operation following severe disturbances.

II. SCOPE OF WORK

There are several types of stability issues in power systems. IEEE/CIGRE Joint Task Force on Stability Terms and Definitions [1] has given a chart to define different stability phenomena existing in power systems. The major power system stability concerns are synchronous generator rotor angle stability, system frequency stability, and system voltage stability. Rotor angle stability is generally a short-term phenomena, whereas frequency and voltage stabilities can exhibit both short term and long term behaviors. The main concern in rotor angle stability during transient which is specifically associated with large disturbances in the system. In other words, transient stability is related to generator rotor angle stability subsequent to large disturbance in the system in a short time frame. Definitions and relationships of various power system stability categories are illustrated in Fig. 3.

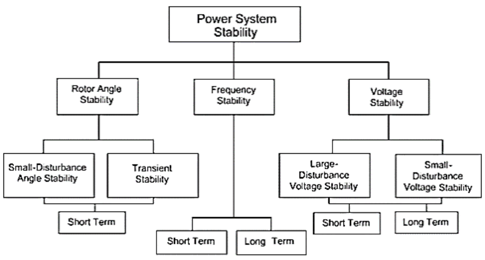


Fig. 3 Power system stability category

Terminology of stability in the short term or long term is associated with the development and duration of transients. From the fastest transient such as lightening and switching transients, to a slower rotor angle transient stability, to even slower generation unit commitment, the processes are ranging from 10-7 second to 105 second. In the book of Power System Stability and Control by Dr. Prabha Kundur [2], typical time frame for each power system transients are provided in Fig. 4.

Understanding the transient stability time frame is also very important because it provides a guideline as to when system dynamic models are constructed. Those models have to be detailed enough to include time constants in the same range as the time frames suggested by Fig. 4 in order to be able to simulate and represent sufficient dynamics of the real world. From transient the stability study point of view, models and dynamics should cover time frames of Transient Stability and Governor and Load Frequency Control which are in the range of milliseconds to a few seconds.

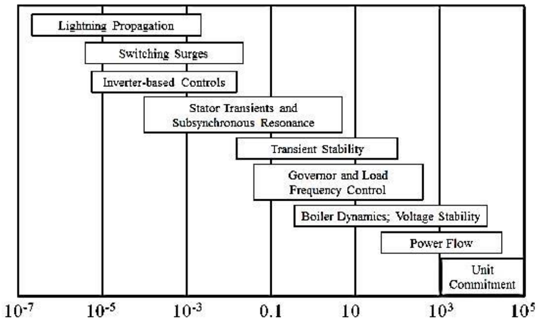


Fig. 4 Time frame

Rotor-angle stability (or angle stability) being focused on in this paper is concerned with the ability of interconnected synchronous machines of a power system to remain in synchronism under normal operating conditions and after being subjected to a disturbance. The mechanism by which synchronous machines maintain synchronism with one another is through the development of restoring torques whenever there are forces tending to accelerate or decelerate the machines with respect to each other.

III. TRANSIENT STABILITY FUNDAMENTALS

Fig. 5 shows the schematic of the cross section of a three-phase synchronous machine with one pair of field poles. The machine consists of two essential elements: the field and the armature. The field winding carries direct current and produces a magnetic field which induces alternating voltages in the armature windings.

For the purpose of identifying synchronous machine characteristics two axes are defined as:

1) The direct (*d*) axis centered magnetically in the center of the north pole of rotor magnetic field

2) The quadrature (*q*) axis electrically 90 degrees ahead of the *d*-axis

The position of the rotor relative to the armature (stator) is measured by the angle θ between the d-axis and the magnetic axis of phase a winding. The selection of the *q*-axis as leading the *d*-axis is purely arbitrary. This convention is based on ANSI/IEEE Standard 100-1977, IEEE Standard Dictionary of Electrical and Electronics Terms [3].

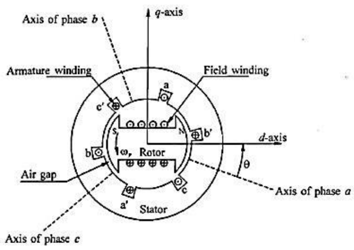


Fig. 5 Synchronous machine structure

The Torque Equation describes interaction between synchronous machine rotor magnetic field and stator magnetic field in Eq. (1):

$$T_s = K\varphi_f \varphi_r \sin\theta \quad (1)$$

Where

T_s = Shaft mechanical torque
K = Constant
φ_f = Air-gap magneto motive force (armature MMF)
φ_r = Rotor magneto motive force (rotor MMF)
θ = Relative angle between φ_f and φ_r

When a mechanical torque is applied to the shaft for a generator case, through interaction of Eq. (1), an electrical power P_e will be produced at the generator terminal if it is connected to an electrical network as illustrated in Fig. 6.

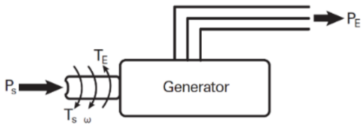


Fig. 6 Generator input and output power balance

In per unit system, a synchronous generator rotor motion equation can be written in the format of Swing Equation in Eq. (2):

$$M\frac{d^2\delta}{dt^2} + \frac{d\delta}{dt} = P_m - P_e \quad (2)$$

Where

δ = Angular potion of the rotor *w.r.t.* synchronous rotating reference
M = Inertia constant (= 2*H*)
D = Mechanical damping constant
P_m = Shaft input mechanical power
P_e = Output electrical power
P_m - P_e = Acceleration power

Under steady state $P_m = P_e$, rotor angle ***δ*** is a constant. If either P_m or P_e changes due either to disturbances or system operations, a net acceleration power will be applied to the rotor, and the result of the Swing Equation will show oscillations of rotor angle. ***δ*** then becomes a prime indicator of synchronous machine stability.

It can be proven that electrically, rotor angle is equivalent to phase angle of an internal voltage representing a synchronous machine. Fig. 7 shows an equivalent presentation for a generator with internal voltage magnitude E' and angle δ connected through a network impedance X_T to a reference bus with voltage magnitude E_B and angle 0°:

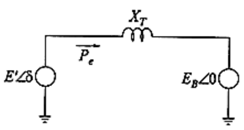


Fig. 7 Two-machine system illustration

It is realized that the electrical power P_e transferred from the generator to the network is a function of rotor angle as in Eq. (3) which is plotted as the Power Transfer Capability Curve in Fig. 8.

$$P_e = \frac{E'E_B}{X_T}\sin\delta = P_{max}\sin\delta \quad (3)$$

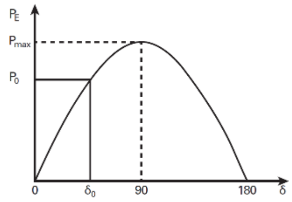


Fig. 8 Power transfer capability curve

P_e consists of two power components:

$$\Delta P_e = K_s\Delta\delta + K_d\Delta\omega \quad (4)$$

The synchronizing power (or torque) component is in phase with the rotor-angle deviation, and the damping power (or torque) component is in phase with the speed deviation. Lack of sufficient synchronizing torque results in aperiodic instability, whereas lack of damping torque results in oscillatory instability.

The synchronizing power coefficient K_s is found form Eq. (5):

$$K_s = \frac{E'E_B}{X_T}\cos\delta \quad (5)$$

and damping power coefficient K_s is the machine damping constant *D*:

$$K_d = D\ (= 0\ if\ D = 0) \quad (6)$$

Thus, the steady state stability requirement for a synchronous machine is defined by a region [0, 90°] for rotor angle δ to ensure a positive synchronizing power, i.e.:

$$0 < \delta < 90° \quad (7)$$

The transient stability limit for rotor angle δ is defined in the range of [-180°, 180°]:

$$-180° < \delta < 180° \quad (8)$$

This is due to the fact that at $\delta = \mp 180°$, the synchronous machine internal voltage angle will be out of phase with respect to the reference voltage, thus a large current will be created in the generator loop. Generator current and voltage will oscillate along rotor angle variances between $-180°$ and $180°$; with current maxima and minima corresponding to voltage maxima and minima as shown in Fig 9. Such voltage and current in oscillatory mode with excessive magnitude can damage equipment or trip the generator.

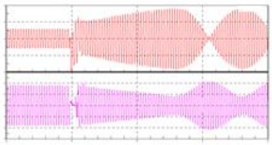


Fig. 9 Voltage and current during loss of synchronism

To prevent the synchronous generator rotor angle going out of step (or slipping the pole) at $\mp 180°$, actions must be taken to clear disturbances within the allowable time. In the case of a generator terminal three-phase fault, the concept can be demonstrated using Equal Area Criteria in Fig. 10.

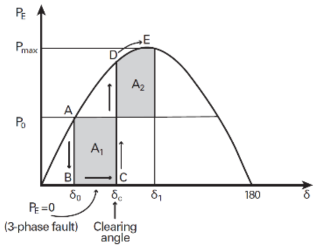
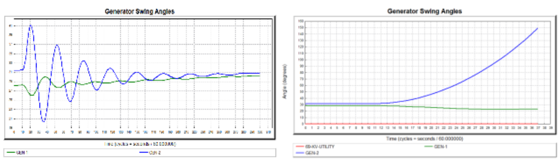


Fig. 10. Equal Area Criteria – acceleration torque and decelerate torque

During the fault, P_e drops to 0 thus acceleration power $P_m - P_e > 0$ so the generator will continue to accelerate from δ_0 to a point when the fault is cleared when $\delta = \delta_c$. During the acceleration, generator rotor acquires kinetic energy which is area A_1:

$$E_K = \int_{\delta_0}^{\delta_c} [P_m - P_e] d\delta \tag{9}$$

After the fault is cleared and P_e is assumed, acceleration power $P_m - P_e < 0$ to decelerate the rotor and δ continues to increase. If an equal area A_2 can be achieved before δ reaches to $180°$, the generator will eventually return to stable operation with rotor angle swing gradually diminished as depicted in Fig. 11 (a); otherwise the first rotor unstable swing occurs and the generator will slip the pole as in Fig. 10 (b).



(a) Stable swing (b) First swing unstable (blue)
Fig. 11. Generator rotor angle swing

IV. SYSTEM MODELING

A computer model needs to be built in order to simulate power system dynamics and conduct transient stability study. The model shall include system configuration, utility connection, generator, loads and protections. A complete one-line diagram as illustrated in Fig. 12 will be used to represent all information mentioned above.

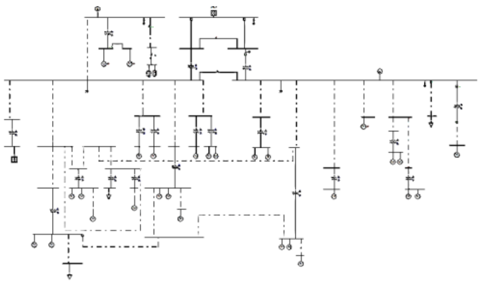


Fig. 12. One-line diagram of an industrial network

A. Grid and Utility

Power grid or utility system to which the study system is connected to can be modeled based on assessment for the system capacity or rigidness compared to the study system.

In most cases the power grid or utility system is considerably larger than the study system in terms of voltage, frequency regulation and MVA capacity, thus conventionally the power grid or utility system is simply represented by a constant voltage and frequency source, or infinite bus.

There are cases in which the power grid or utility system cannot be assumed as a constant voltage and frequency source, then proper dynamic models for the power grid or utility system has to be derived. These models can range from a simple Thevinin equivalent to more complicated dynamic circuits as suggested IEEE Std 1110-2002 Guide for Synchronous Generator Modeling Practices and Applications in Power System Stability Analyses [4].

B. Network

Network refers to the study system configured and interconnected by buses, switchgears, transformers, cables, lines, current limiting reactors, and other network equipment and components.

Normally a positive sequence impedance model for the network is sufficient for transient stability study. However, if the studies touch on unbalanced system operating conditions, such as single-phase or other unbalanced fault studies, then all three sequence models for network equipment and components will be needed in order to form proper sequence networks for unbalanced calculations.

C. Generator

The most important and key component in power systems contributing to system transient stability is the generator.

A synchronous generator in full operation has to include a rotor and stator for power conversion, an excitation system and automatic voltage regulator (AVR) for providing excitation to rotor winding and regulating voltage, and a prime mover and speed governor system to provide shaft mechanical power and control generator speed and electrical output frequency. Excitation and AVR, speed governor are also called controls to a synchronous generator.

A synchronous condenser is a synchronous generator configured in special operation mode. It consists of rotor and stator, an excitation and AVR system, but its shaft is not connected to anything thus no prime mover nor speed governor is included in its model.

Fig. 13 depicts a synchronous generator and the associated controls.

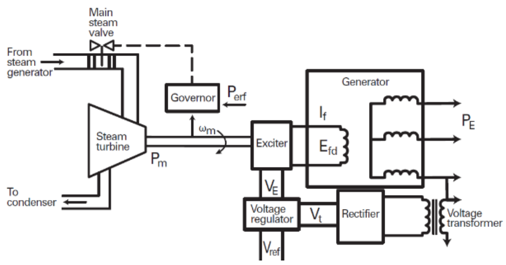


Fig. 13. Generator and controls

1) Rotor and stator

Generator rotor and stator should be modeled per IEEE Std 1110-2002 [4]. Applicable models are given in Fig. 14.

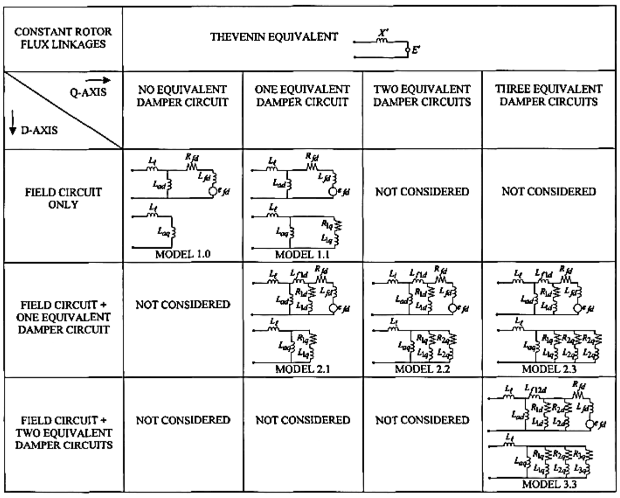


Fig. 14. Generator rotor and stator model

Generator models defined by IEEE are commonly used d-q models, consisting of impedance in direct-axis and quadrature-axis with different values at sub-transient, transient, and steady states. Time constants which define transient time from one state to another state are also part of the model parameters. These models should be adapted by generator manufactures worldwide and normally they are found from the standard generator datasheet.

These models not only represent generator stator and rotor winding dynamics, but also properly account for air gap flux between stator and rotor with saturation effect included, which is very important to overall generator dynamic responses under different operating conditions.

Typical generator impedance model data are provided in Table I per IEEE standard [4].

TABLE I
TYPICAL GENERATOR IMPEDANCE MODEL DATA

	Machine 1 310 MVA/13.8 kV/ 60 Hz/128.6 rpm		Machine 2 202 MVA/13.8 kV/ 60Hz/112.5 rpm		Machine 3 187 MVA/13.8 kV/ 60 Hz/180 rpm	
	Measured (1986)	Manufacturer	Measured (1985)	Manufacturer	Measured (1992)	Manufacturer
T'_{do}	7.36	6.6	5.62	5.7	6.22	6.5
T'_d	1.92	2.2	1.419	1.5	1.01	1.12
T''_{do}	undefined	0.05	undefined	0.09	undefined	0.06
T''_d	0.068	0.046	0.0669	0.03	0.053	0.04
T_a	0.289	0.26	0.186	0.15	0.23	0.22
T''_{qo} (b)	undefined	0.10	undefined	0.09	undefined	0.10
X'_d	0.386	0.33	0.323	0.28	0.296	0.35
X''_d	0.307	0.25	0.229	0.22	0.252	0.23
X'''_q (c)	0.302	0.33	0.212	0.29	0.243	0.31
X_d	1.021	1.14	1.104	1.0	1.305	1.32
X_q	0.541	0.63	0.416	0.62	0.474	0.80

2) Excitation and AVR system

Standard generator excitation and AVR system models are provided in IEEE Std 421.5-2016 Recommended Practice for Excitation System Models for Power System Stability Studies [5]. The standard covers three major excitation types from major excitation system manufacturers. The three types of excitation systems are:

1. Type DC – Direct current commutator rotating exciter
2. Type AC – Alternator supplied rectifier excitation system
3. Type ST– Static excitation system

The models include excitation function, voltage regulation function, and important excitation/AVR limiters and supplementary controls. They are valid for frequency deviations of ±5% from rated frequency and oscillation frequencies up to 3 Hz. And model structures are intended to facilitate the use of field test data as a means of obtaining model parameters.

Type DC2C excitation system model and sample model data are shown in Fig. 15 and Table II.

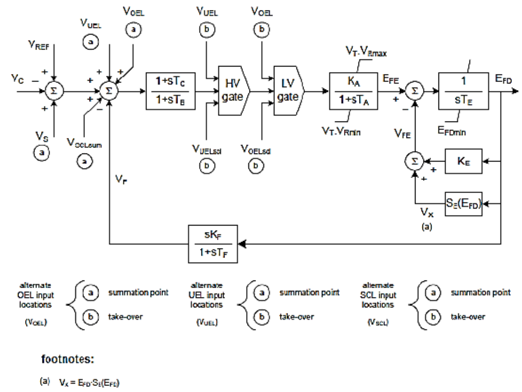


Fig. 15. Type DC2C excitation system model

TABLE II
SAMPLE DATA FOR TYPE DC2C EXCITATION SYSTEM MODEL

Description	Symbol	Type	Value	Units
Resistive component of load compensation	R_C	A	0	pu
Reactance component of load compensation	X_C	A	0	pu
Regulator input filter time constant	T_R	E	0	s
Regulator output gain	K_A	A	300	pu
Regulator time constant	T_A	E	0.01	s
Regulator denominator (lag) time constant	T_E	A	0	s
Regulator numerator (lead) time constant	T_C	A	0	s
Exciter field proportional constant	K_E	A	0	pu
Exciter field time constant	T_E	E	1.33	s
Maximum controller output	V_{Rmax}	E	4.95	pu
Minimum controller output	V_{Rmin}	E	-4.95	pu
Rate feedback gain	K_F	A	0.02	pu
Rate feedback time constant	T_F	A	0.675	s
Exciter output voltage for saturation factor SE(E1)	E_1	E	3.05	pu
Exciter saturation factor at exciter output voltage E1	S_{E1}	E	0.279	
Exciter output voltage for saturation factor SE(E2)	E_2	E	2.29	pu
Exciter saturation factor at exciter output voltage E2	S_{E2}	E	0.117	

If the particular excitation and AVR system installed is not included in IEEE model list, then the model needs to be constructed and implanted in the computer software which is employed to perform transient stability study. Essential information and data for the user defined model are model transfer function and associated parameters as shown in Fig. 6 and Table II.

Power system stabilizer (PSS) if installed and active should also be included in generator dynamic model for transient stability study.

3) Speed governor and prime mover system

For transient rotor angle stability the turbine governor model is of key importance Popular speed governor and prime mover system models are listed in IEEE Task Force on Turbine-Governor Modeling Dynamic Models for Turbine-Governors in Power System Studies [6]. The models are developed power system simulations.

Fig. 16 and Table III show IEEEG1 steam turbine governor system model and parameters.

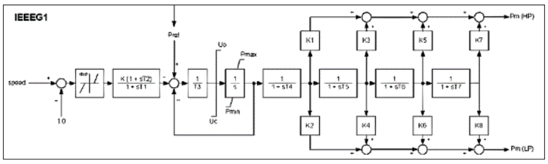


Fig. 16. Type IEEEG1 steam turbine governor system model

TABLE III
PARAMETERS FOR IEEEG1 STEAM TURBINE GOVERNOR SYSTEM MODEL

Parameters	Description
K	Governor gain (1/droop) [pu]
T1	Lag time constant [s]
T2	Lead time constant [s]
T3	Valve position time constant [s]
Uo	Maximum valve opening rate [pu/s]
Uc	Maximum valve closing rate [pu/s]
Pmax	Maximum valve opening, on MW capability [pu]
Pmin	Minimum valve opening, on MW capability [pu]
T4	Time constant for steam inlet [s]
K1	HP fraction
K2	LP fraction
T5	Time constant for second boiler pass [s]
K3	HP fraction
K4	LP fraction
T6	Time constant for third boiler pass [s]
K5	HP fraction
K6	LP fraction
T7	Time constant for fourth boiler pass [s]
K7	HP fraction
K8	LP fraction
db1	Deadband

D. Motors

Synchronous motors are modeled the same way as synchronous generators; except motors do not have a speed governor and prime mover system. Instead, they have load on shaft which produces mechanical torque based on load type and shaft speed. A load vs. torque curve needs to be provided to describe P_m in the Swing Equation. A sample load vs. torque curve is shown in Fig. 17 [7].

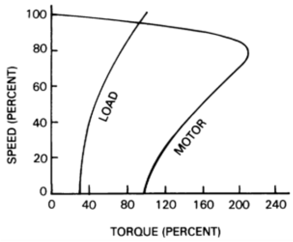
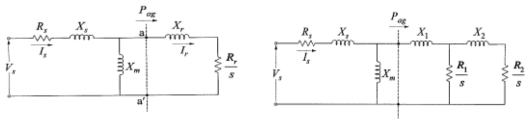


Fig. 17. Sample motor load vs. torque curve

Induction motors are modeled in equivalent circuit model. Both single cable and single cage equivalent circuit models are shown in Fig. 18 [2].



(a) Single cage (b) Double cage

Fig. 18. Induction machine equivalent circuit models

The induction generator shares the same models as an induction motor on the machine side. The difference between induction generator and induction motor is that induction generator has mechanical power applied to the shaft from a prime mover.

It is pointed out that induction machine equivalent circuit models are a simplified representation of machine rotor and stator dynamics and interactions by assuming air gap flux is constant. If a more accurate dynamic model for induction machine is required, a full d-q modeling of the induction machine including air gap flux effect can be used [2].

E. Other Loads

Other system loads should be modeled based on their dynamic characteristics, such as input-output characteristic, transfer function, voltage-current curve, etc. Among the various models, those commonly used for general power system loads are constant impedance, constant power, constant current source, and constant voltage source models. Cautions must be given to the load model selection, as sometimes they can cause calculation instability during simulations. For example, if a constant power model is selected for a load in a study, and the study scenario is to place a short circuit fault near this load, then the model will tend to behave as a current source with very high even infinite magnitude in current which will result in numerical calculation error and interrupt the computer simulation process.

F. Protections

Some protection schemes should be considered and properly included in transient stability study. Some examples are voltage relays, frequency relays, differential relays, over-current relays, load protections relays, fuses, etc. Protection zones, settings and time delays, as wells as tripping controls and interlocks should also be modeled. During disturbances, if simulation results trigger protection settings, corresponding tripping or other actions should be taken in accordance with to defined and programmed logic and sequences. These actions will then be included in the simulation going forward.

V. MODEL VALIDATION

NERC (North American Electric Reliability Corporation) pointed out: “Model construction and validation are important tasks that form the foundation of all power system studies.” [8] The network and equipment models, in particular generator and control system models, should be properly validated before being applied to a transient stability study. NERC MOD standard series specify modeling, data, collection, and analysis of generators. Among MOD standards, MOD-026-1 and MOD-027-1 are particularly important for generator dynamic development and validation [9, 10].

Examples of model parameters to be validated are shown in Table IV [11].

TABLE IV
MODEL PARAMETERS

Conditions	Generator	Exciter	Governor
Set by design	Reactances Time constants Inertia Saturation	Limits Exciter time constants Voltage sensing time constants Saturation	Water starting time No load gate Full load gate Turbine power fractions Maximum power Dead band Turbine damping
Tunable		Voltage regulator gains Time constants Reactive compensation Limit levels	Droop Time constants Gains Rate limits

Model validation should be based on benchmark results, which are typically provided by one of the following two means:

A. Vendor provided benchmark results

If generator, exciter, and turbine-governor vendors can provide factory testing data, either the lab testing, simulation results, or both, that will be the preferred solution. Those resources are reliable and testing conditions are easy to understand by communicating with the vendors in order to set up model validation configuration in computer simulation. For this purpose, it is recommended the customers who will go through the generator model validation process request relative benchmark testing results with testing conditions and model/parameter data in order specifications.

B. Benchmark from field testing

It is possible to arrange field testing for generators including exciters and turbine/governors and generator data to perform model validations. Some of the suggested field tests are shown in Table V [12].

TABLE V
GENERATOR BENCHMARK FIELD TESTING

Components	Testing
Generator	Open circuit saturation tests Inertia tests Impedances and time constants verification tests
Excitation Systems	Var rejection tests Open circuit or on-line AVR step tests Frequency response tests
Turbine Controls	Speed reference step tests

WECC (West Electricity Coordinating Council) suggested acceptable validation methods for generator excitation and turbine models are given in Table VI and Table VII [13]:

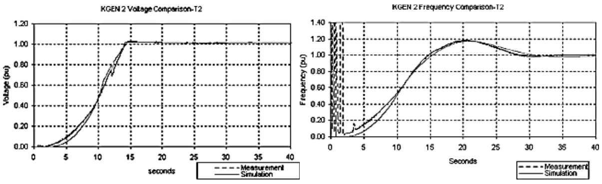
TABLE VI
ACCEPTABLE EXCITATION MODEL VALIDATION METHODS

Event	Input to Model	Validation Signal
Voltage reference step (on-line)	Voltage reference step Generator real power Generator reactive power	Stator voltage Field voltage (or exciter field current)
Voltage reference step (off-line)	Voltage reference step	Stator voltage Field voltage (or exciter field current) Generator reactive power
Sudden change in generator reactive power	Generator real power Generator reactive power	Stator voltage Field voltage (or exciter field current)
Reactive load rejection	Generator reactive power	Stator voltage Filed voltage (or exciter field current)
Frequency response of Vt/Vref	Voltage reference swept sine	Stator voltage

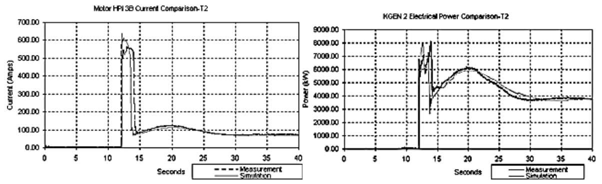
TABLE VII
ACCEPTABLE TURBINE-GOVERNOR MODEL VALIDATION METHODS

Event	Input to Model	Validation Signal
Speed reference steps with generator online	Speed reference Frequency	Generator real power
Sudden frequency changes due to disturbance with generator online	Frequency	Generator real power
Low Load rejection	Initial MW prior to load rejection	Generator speed response

Example of model validation is given in [14] where a generator exciter and governor models are validated against field testing data. Fig. 19 shows comparison of model simulations vs. field testing results after the models were validated.



(a) Generator frequency (b) Generator voltage



(c) Generator active power (d) Large motor current

Fig. 19. Model validation example

VI. STUDY SCENARIOS

Transient stability study scenarios should include both normal and abnormal operating conditions as well as fault conditions. System initial operating conditions in terms of total generation, gird power import/export, loads, and system configurations will also play important roles in study results. Some most common disturbances that potentially produce instability in industrial power systems are listed in Table VIII which are combined recommendations from [8] and authors past experience.

TABLE VIII
TRANSIENT STABILITY STUDY SCENARIOS

Category	Scenarios
Generator parameters	Generator damping
	Generator inertia
	Generator synchronous impedance
	Initial electrical power setting
Generator settings	Mechanical power setting and reserve
	Control modes and settings
	Initial operating generator(s) and generation
	Voltage regulation
Generator control and dynamics	Excitation force
	Excitation control / AVR control
	Speed-governor control
	Prime mover dynamics
Disturbances	Short circuits
	Loss of tie circuit(s) to gird
	Loss of a portion of on-site generation
	Switching operation
	Disturbance type
	Disturbance location
	Other generators and large machines in the system
System load and change/impact	Dynamic motor starting / restarting
	Bus transferring
	Initial load and load impact
Utility ties	Utility tie and short-circuit capacity
Network configuration	Network configuration
	Intentional / unintentional islanding

VII.

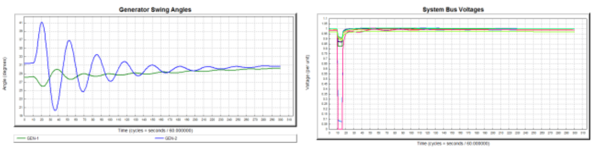
VIII. STUDY RESULTS AND FINDINGS

The primary goal for performing transient stability study is to check stable operation of generator rotor angle. The study results also provide useful information on system frequency and voltage variation, generator active and reactive power variation, motor dynamic response, and other important results. The information and results can help in identifying system stability and other issues, validate operation procedures, and design proper protections. Some typical transient stability study results and analysis focuses are listed in Table IX.

TABLE IX
TRANSIENT STABILITY STUDY RESULTS

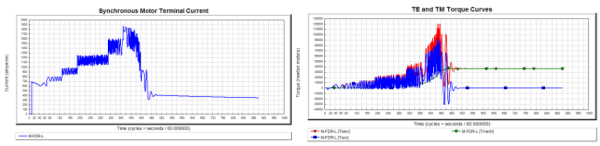
Category	Results
Oscillations and variations	Synchronous machine rotor angle stability
	Frequency variations
	Voltage variations
	Generator stability margin
Control dynamics and models	Excitation / AVR dynamic responses
	Prime mover / governor dynamic responses
	Excitation / AVR system parameter tuning
	Governor system parameter tuning
Fault clearing	Critical fault clearing time
	Critical system separation time
Load shedding	Generator load-frequency characteristics
	Load shedding schedule
Motor dynamics and generator support	Motor dynamic start / acceleration
	Motor dynamic restart / acceleration
	Generator voltage and var support
Bus transfer	Bus and load transferring schedule

Transient stability study is a time domain simulation. Study results are best presented by plotting the curves to illustrate system responses after disturbances and operations. Fig. 20 to Fig. 22 are sample plots corresponding to three different study scenarios, *i.e.*, Temporary three-phase fault, Synchronous motor starting, and Utility outage followed by disconnecting. Selected generator, motor and system curves are plotted against time.



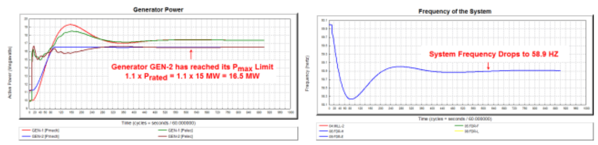
(a) Generator rotor angle (b) System bus voltages

Fig. 20. Temporary three-phase fault



(a) Motor current (b) Motor torques

Fig. 21. Synchronous motor starting



(a) Generator power (b) System frequency

Fig. 22. Utility outage followed by disconnecting

IX. POSSIBLE RECOMMENDATIONS AND MITIGATIONS

The goal of performing a transient stability study is to identify if there any unstable operation scenarios and provide recommendations to mitigate problems either from the system design improvement point of view, or through specifically designed protections, or by implementing operation controls. It is necessary to distinguish the causes before trying to solve the problem. In time domain analysis, the potential oscillation phenomena are clearly presented by plots and other warning signals discussed in the previous section thus they can be further investigated. Steps in Table X can be considered as a suggested procedure to identify and mitigate the possible causes of the low-frequency oscillation [7], and protections in Table XI are some commonly used schemes to protect system from sustained voltage and frequency oscillations, loss of excitation to generators, fast fault clearing and generator tripping to prevent rotor angle out of step.

TABLE X
COMMON STABILITY IMPROVEMENT PROCEDURES

Procedure	Description
Adjust generation and/or line flow	Investigate possible solution(s) by adjusting the power flow of the interconnecting equipment for high generator rotor angle stability margin
Reduce interconnected impedance	Lower system impedances will reduce the electrical distance of the generation units and establish a stronger tie between co-gen and utility systems
Reduce fault clearing time	Use high-speed relays and breakers to clear the fault within a few cycles
System separation	Separate system if instability is due to connection of multiple subsystems
Installing power system stabilizer (PSS)	Extend stability limits by modulating generator excitation to provide damping to the oscillation of a synchronous machine rotor

TABLE IX
TRANSIENT STABILITY PROTECTIONS

Category	Protections
Protections	Out-of-step relay protection (78) Loss of excitation protection (40) Reverse power protection (32R) Frequency relay protection (81) Voltage relay protection (59) Differential relay protection (87)

A couple of selected protection schemes and operation controls are explained below as an illustration.

A. Reduce Fault Clearing Time

For a given system configuration, equipment data, and a fault scenario, there is a corresponding critical fault clearing angle shown as δ_{cc} in Fig. 23. Definition of the critical clearing angle is the maximum rotor angle at which the fault must be cleared in order to achieve an equal area between accelerating power and decelerating power for the generator under concern. If the fault is cleared after this angle, then the generator won't be able to restore rotor angle stability; on the other hand, for any fault clear angle that is smaller the δ_{cc}, the generator states (rotor angle, frequency, voltage and current, as well as active and reactive power) shall return to stable operation after temporary oscillations.

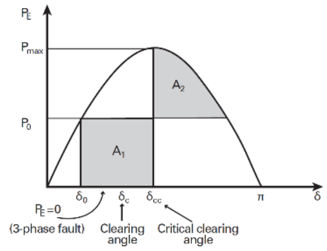


Fig. 23. Critical fault clearing time

The actual critical fault clearing time t_{cc} which corresponds to δ_{cc} for a generator terminal fault condition can be derived from swing equation Eq. (2). Considering electrical power P_e during the fault remaining as zero, and ignoring damping, Eq. (2) is reduced to:

$$M\frac{d^2\delta}{dt^2} = P_m \tag{10}$$

Assuming the initial rotor angle δ0, critical fault clearing angle δ_{cc} and realizing the above equation Eq. (10), t_{cc} can be computed as:

$$t_{cc} = \sqrt{\frac{2M(\delta_{cc}-\delta_0)}{P_m}} \tag{11}$$

Eq. (11) shows several important factors affecting t_{cc}:

If initial rotor angle δ_0 is large, required critical fault clearing time will be shorter.

If generator mechanical power P_m is large, required critical fault clearing time will also be shorter.

If generator inertia constant M is larger, required critical fault clearing time will be longer.

These observations can help to understand the relationship between other parameters in the system and are useful for system stability improvement.

B. Adjust Generation

As suggested in Table X, adjusting power generation of generating units can help to improve transient stability. The essence of doing this is to increase a generator Transient Stability Margin (TSM). There are several definitions of TSM.

1) Based on rotor kinetic energy

As proven in Eq. (9), the area encompassed by generator acceleration power and rotor angle is equivalent to the generator kinetic energy. Referencing to Fig. 24, TSM can be expressed in Eq. (12) by the ratio between available regions for kinetic energy to release to the region of gaining kinetic energy during the fault.

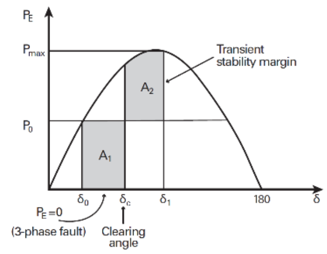


Fig. 24. TSM based on kinetic energy

$$TSM = \frac{A_{dec} - A_{acc}}{A_{dec}} \quad (12)$$

where

$$A_{acc} = A_1, \qquad A_{dec} = A_2 + A_3$$

It is noted for two special cases when TSM = 0% which indicates $A_{acc} = A_{dec}$, or $\delta_c = \delta_{cc}$; and when TSM = 100% which represents $A_{acc} = 0$, or $\delta_c = \delta_0$, meaning the fault is cleared instantaneously. When $A_{dec} < A_{acc}$, then TSM becomes negative which means there is not a sufficient deceleration region for the generator to become stable.

2) Based on critical clearing angle

TSM can also be expressed by the ratio of additional available fault clearing angle to the critical fault clearing angle. This is illustrated in Fig. 25 and Eq. (13).

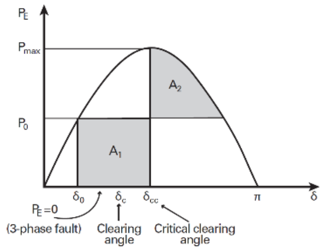


Fig. 25. TSM based on kinetic energy

$$TSM = \frac{\delta_{cc} - \delta_c}{\delta_{cc} - \delta_0} \quad (13)$$

For two special cases when TSM = 0% which indicates $\delta_c = \delta_{cc}$; and when TSM = 100% which represents $\delta_c = \delta_0$, meaning the fault is cleared right after the fault. In the case of $\delta_c > \delta_{cc}$, it will result in a negative TSM which means an unstable rotor swing will result.

3) Based on mechanical power

Since acceleration region and deceleration region in transfer capability curve depend on generator mechanical power P_m, P_m can also be used to calculate TSM.

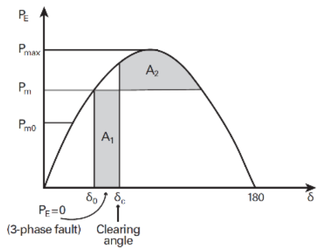


Fig. 26. TSM based on mechanical power

In Fig. 26, assuming fault clearing angle $\delta_c$is fixed, changing P_m against the reference P_{m0} varies acceleration region A_1 and deceleration region A_2, thus stability margin also varies. TSM is defined as a function of P_m and P_{m0} in Eq. (14) [15]:

$$TSM = \frac{P_m - P_{m0}}{P_{m0}} \quad (14)$$

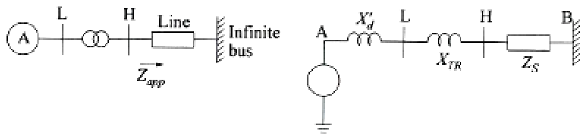
For $P_m = P_{m0}$, TSM = 0% which means no stability margin improvement. With increasing P_m, acceleration region will get smaller thus the stability margin is improved.

C. Out of Step Relay Protection

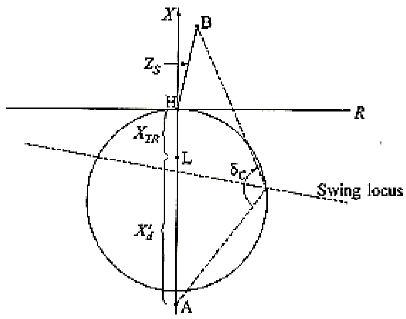
Various protections and relays can be configured to protect generator stability. Some of these protections are listed in Table IX.

One of the effective protections is an out-of-step relay which specifically prevents generator rotor angle running out of step. The operating principle of out-of-step relay is the Mho element scheme as demonstrated in Fig. 27 [2].

An Mho relay monitors the apparent impedance (looking into the network) at the HT terminal (H) of the unit transformer and is set to reach into the local generator. the relay will immediately trip the generator when the apparent impedance measured at the HT bus enters the offset Mho characteristic. The setting objective is to allow tripping only for unstable swings. Typical, the angle δ_c at the point where the swing impedance enters the relay characteristic is set to about 120º, the maximum angular separation of the machine from the system which may occur without loss of synchronism.



(a) System schematic (b) System equivalent circuit



(c) Relay characteristic and swing locus as measured at HV bus

Fig. 27. Generator out-of-step protection using an Mho element scheme

X. ILLUSTRATION CASE

This case study will illustrate the standard procedure of executing a transient stability study to evaluate the response of a typical industrial system under various disturbances.

A. System description and model

The system model shown in Fig. 28 must first be developed for the normal operating conditions of the plant where all voltages and power flows are within the equipment rating.

A 25 km 69 kV double circuit transmission line feeds into a substation and two outgoing 3 km transmission lines provide power to the industrial plant via two step down 69 / 13.8 kV, 15 MVA transformers.

Two main 13.8 kV generator switchgears distribute power to loads and motors at varying voltages of 4.16 , 2.4 and 0.48 kV.

The Generation schedule of the plant is Gen 1 = 11.25MW, Gen 2 = 10 MW while importing 17.33 MW from the Utility.

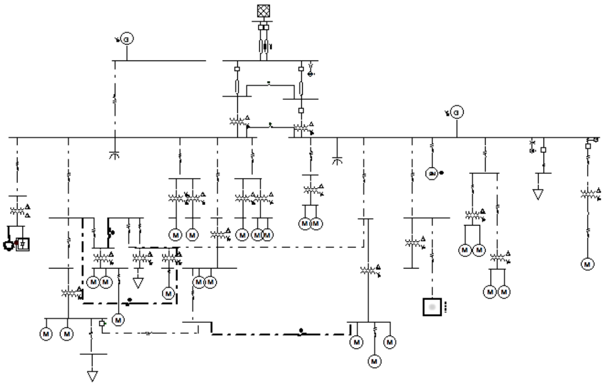
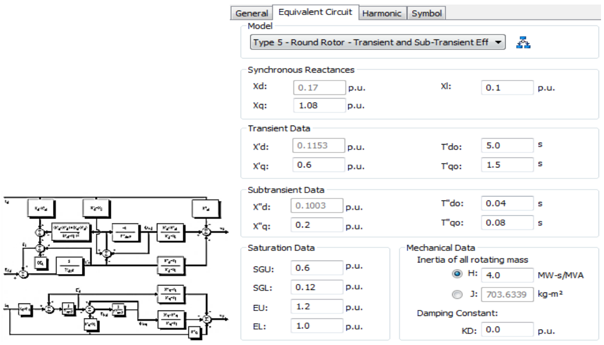


Fig. 28. Plant One Line Diagram

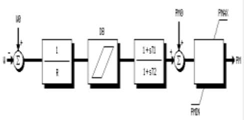
B. *Dynamic components*

Dynamic models of synchronous generators (Fig. 29a), prime movers (Fig. 29b) , and excitation systems (Fig. 29c) can then be specified using the manufacturer data or as per IEEE recommendations.

This will include data such as generator prime mover power rating, droop, exciter gains and all the time constants required for the complete modeling of the control system.

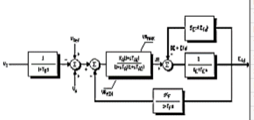


(a) Synchronous generator model and data



Parameter	Description	Value	Unit
TBMW	Turbine Rated Power	15.0	MW
R	Speed Regulation Droop	0.05	p.u.
T1	Controller Lag Time Constant	0.0	s
T2	Controller Lead Time Constant	1.0	s
PMAX	Upper Power Limit	1.1	p.u.
PMIN	Lower Power Limit	0.0	p.u.
DB	Dead Band	0.01	p.u.

(b) Speed governor system model and data



Parameter	Description	Value	Unit
TR	Regulator Input Filter Time Constant	0.0	s
KA	Voltage Regulator Gain	65.2	p.u.
TA	Voltage Regulator Time Constant	0.2	s
VRMAX	Voltage Regulator Output Upper Limit	2.607	p.u.
VRMIN	Voltage Regulator Output Lower Limit	2.607	p.u.
KF	Excitation Control Stabilizer Gain	0.12	p.u.
TF	Excitation Control Stabilizer Time Constant	1.0	s
KE	Self Excited Field Constant	0.111	p.u.
TE	Exciter Time Constant (Integration Rate)	1.93	s
SEMAX	Exciter Saturation at EEFDMAX	0.61	p.u.
SE0.75	Exciter Saturation at 0.75*EFDMAX	0.176	p.u.
EFDFL	Full Load Excitation Voltage	2.03	p.u.
TA1	Voltage Regulator Time Constant	0.0	s
TA2	Voltage Regulator Time Constant	0.0	s

a)

(c) Excitation system model and data

Fig. 29. Typical generator and control models

Typically, all running motors above 50 hp will be dynamically modeled in Fig. 30 as they represent the largest number of loads in an oil and gas facility and their inertia will contribute to the system stability.

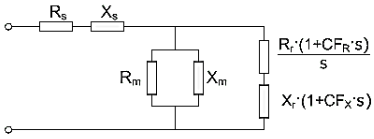


Fig. 30. Induction Motor Equivalent Circuit

Static loads are also modeled dynamically to represent any load variations as a function of voltage and frequency Eq. (15):

$$P(t) = P_0 \times (V_{pu}(t))^{np} \times \left[1 + P_{freq}\left(F_{pu}(t) - 1\right)\right]$$
$$Q(t) = Q_0 \times (V_{pu}(t))^{np} \times \left[1 + Q_{freq}\left(F_{pu}(t) - 1\right)\right] \qquad (15)$$

Where

$P(t), Q(t)$	= Active and reactive power at time (t)
V_{pu}	= Per unit load bus voltage at time (t)
$F_{pu}(t)$	= Per unit system frequency at time (t)
P_0, Q_0	= Initial active and reactive power of the Load
nP, nQ	= Active and reactive power voltage exponent
P_{freq}, Q_{freq}	= Active and reactive frequency factors

C. *Initial condition*

The initial condition is defined as the state of the system at time t = 0.0 and includes bus voltages, generation, motor and static loads, branch active and reactive power as computed by the power flow program.

If all control variables are initialized correctly then they should not exhibit any noticeable oscillations as compared to their initial value up to the time of the application of the disturbance.

D. *Transient stability study parameters*

The integration time step is defined as the time between successive calculations.

It is recommended that it is set to less than the numerical value of the smallest time constant entered in the control parameters of the system. Typically when modeling running or starting motors the integration time step is in the order of 0.2 cycles.

Another critical parameter is the maximum angular separation beyond which loss of synchronism between generators is declared and the simulation can no longer proceed. This parameter is typically in the range of 120º to 140º.

Finally the total simulation time in the order of a few seconds a typical time span for a transient stability study.

E. *Disturbances*

Transient Stability Simulations can involve multiple disturbances that if not cleared within a critical period of time can cause loss of synchronism, voltage collapse or a system frequency drop that would trigger protective relays to trip and shut down the system.

These disturbances include but are not limited to:

1) Tripping overhead lines and cables with or without automatic re-closure
2) Single pole switching
3) Tripping of synchronous machines
4) Adding and removing shunts
5) Load shedding and addition
6) Applying and clearing faults with / without a fault impedance (LLL, LL, LLG, LG)
7) Starting and stopping of single or multiple motors
8) Automatic switching by protective relays

F. Monitoring of variables and alarms

The equipment control variables that are to be monitored in order to evaluate the system response to a disturbance can now be specified and displayed as graphical output charts versus time.

These include generator swing angle which is a measure for system stability, active and reactive power flows, bus voltages and system frequency.

In addition, system wide alerts can be set up to monitor any generator or load bus voltage and frequency variations that exceed a user defined threshold and duration.

G. Study Scenarios and Simulation Results

The following scenario will combine the time based approach and the monitoring of critical variables such as voltage and frequency to initiate preventive measures to insure system stability.

A three phase fault 15 km away from the plant on the 69 kV transmission lines is simulated. It was observed that the critical clearing time before the loss of synchronism of the plant generators was 10 Cycles from the inception of the fault as shown in Fig. 31.

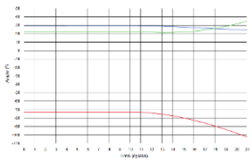


Fig. 31 Synchronous machine rotor angles swings during fault

At this point system separation from the utility occurs and the simulation results of different components of the plant where monitored. It was noticed that the frequency of the system dropped below the critical threshold of $\pm$ 0.5 Hz and did not recover (red curve in Fig. 32).

The frequency relay on the main 13.8 KV bus 04:MILL-2 is set to trip both breakers CB-7 and CB-8 that are supplying a 10 MW, 4 Mvar load and an 8 MVA synchronous motor respectively. The under frequency set point is at 0.5 Hz below system frequency with a total activation time including breaker speed is 4 cycles. An observation delay of 6 cycles was introduced to monitor if the system frequency will recover before initiating any selective load shedding.

The simulation was run for 900 cycles and the response of the variables of interest was monitored.

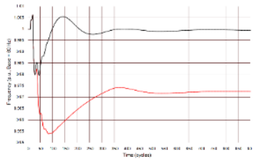


Fig. 32 Frequency response without load shedding (red line) and with load shedding (blue line)

The relative swing angle of GEN 2 with respect to GEN 1 is plotted as a measure of system stability after the islanding of the system has occurred. As can be noticed the angular separation will stabilize at the new operating conditions of the plant. (Fig. 33)

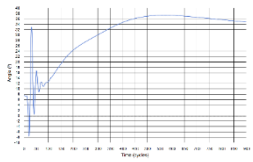


Fig. 33 Synchronous machine relative rotor angle swings after system islanding.

After the selective load shedding the power output of both plant synchronous generators stabilize within their pre-disturbance generation schedules (Fig. 34).

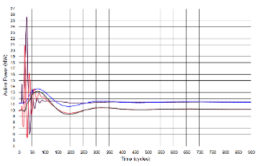
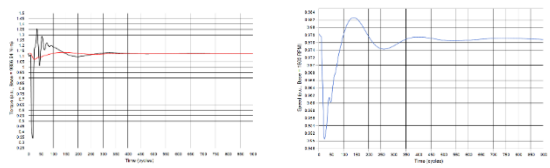


Fig. 34 Plant generator electrical and mechanical power

The majority of loads in an industrial system are induction motors and it is important to monitor their dynamic response to determine if they can ride through the disturbance and resume normal plant operations. The current contributions during fault conditions are fairly large and their combined inertia will have an impact on the system response time.

The torque and speed of a large 2500 HP, 2.4 kV induction motor are monitored during the transient (Fig. 35).



(a) Electrical (dark) and mechanical torques (red)

(b) Speed

Fig. 35 The largest induction motor torques and speed

Finally the voltage profile of the main buses in the system are evaluated for nominal operating conditions within the ± 5% acceptable limits (Fig. 36).

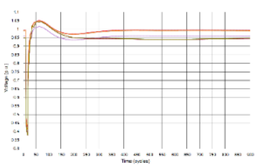


Fig. 36 Bus voltage profile

It is validated that after sufficient loads are shed, system can return to a new steady state operating condition, *i.e.*:

1) System frequency recovers (blue line in Fig. 32)
2) Generator mechanical power and electrical power rebalanced (Fig. 34)
3) Induction motor torque and speed after reacceleration stabilized (Fig. 35)
4) System voltage dipped during the fault but quickly recovered after the fault is separated (Fig. 36)

XI. CONCLUSIONS

Due to the importance of electric power supply and system stability, generator rotor angle stability during transient under various normal and abnormal operating conditions in oil and gas plants must be thoroughly studied. However, understanding transient stability issues, properly modeling different system components, defining study scenarios, conducting computer simulation studies and fully understanding results are always a challenge to power system engineers and managers who are responsible for their system safety, reliability, and stability. This paper systematically introduces and explains procedures to perform stability studies in oil and gas plants. It provides a rich resource to major IEEE standards and references for generator and control modeling, model verification, and studies. Some commonly used generator stability protection schemes are also discussed. The illustration example using an industry accepted software tool further demonstrates the standard study procedure described. Materials developed in this paper can be used as a guideline for industrial power system stability modeling and studies.

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XIII. VITA

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