Load Modeling Assumptions: What Is Accurate Enough?

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LOAD MODELING ASSUMPTIONS: WHAT IS ACCURATE ENOUGH?

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Abstract**—**This paper presents an elegant method for determining the simplest model of a power system electrical/mechanical load that will suffice for dynamic frequency power system studies and closed-loop simulation work. The strategy behind this technique is to supply the simplest load model possible that gives sufficiently accurate results for the goals of each unique modeling effort.

The paper identifies the frequency characteristics of several different load types. It also identifies the level of load model detail required for testing typical power management systems, contingency-based load-shedding systems, frequency-based load-shedding systems, governor control systems, island/grid/unit autosynchronization systems, and exciter control systems.

The paper describes how to lump loads without loss of fidelity, when an induction motor needs to be modeled as a single-cage or double-cage motor model, what sort of mechanical load model is appropriate, when we can assume zero inertia for a direct-on-line type of load, and how to verify the turbine/generator inertia and load inertia from field tests.

This paper concludes with a simple reference that engineers can use to specify the level of detail required when modeling industrial power system loads.

Index Terms—Frequency stability, inertia, load modeling, microgrid, induction machine, synchronous machine.

I. INTRODUCTION

All electric power systems have control and protection schemes that maintain parameters such as frequency, voltage, rotor angles, active and reactive power flow, and more. Engineers create software and hardware simulations to predict how these system parameters will change and how the protection and control systems will interact when influenced by some form of disturbance, such as a breaker opening, short circuit, control system failure, and more.

This paper identifies how accurately loads must be modeled, specifically for frequency stability studies and the associated controllers that preserve system frequency. To accomplish this, the paper discusses the following:

1. Inertia, its effect on stability, and how to measure it.
2. Induction machine (IM) (refer to [1]) and synchronous machine (SM) characteristics and their effects on frequency stability.
3. Load characteristics and their effects on frequency stability.

This paper concludes with a summary of load modeling simplifications that are acceptable for several common frequency stability studies and control systems.

II. MICROGRID MODELING REQUIREMENTS

Industrial power systems often run separated, or islanded, from utility connections. These islanded power systems are commonly referred to as microgrids. During islanded operation, these microgrids are autonomous power grids that often have frequency, rotor angle, or voltage stability problems. Modeling these power systems is therefore essential in determining the efficacy of running these power systems islanded.

Dynamic studies of islanded power grids are typically categorized into several types of stability studies, including the following:

1. Rotor angle studies explore rotor out-of-step phenomena associated with various faults. These results are used to select circuit breakers and protection schemes.
2. Frequency studies explore the interactions between turbines, governors, and loads. These results are used to coordinate load-shedding systems and validate automatic generation control (AGC) systems.
3. Voltage studies explore the effects of voltage amplitudes, VAR consumption and production, and volt/VAR control systems. Results from these studies are used to identify motor starting and system collapse phenomena.
4. Resonance studies, such as subsynchronous torsional interaction (SSTI) studies, identify oscillations between mechanical and electrical equipment at frequencies below the synchronous frequency (50 or 60 Hz).
5. Harmonic studies identify voltage energy content above the synchronous frequency that can damage equipment.

Understanding the difference between these dynamic studies is required to follow the assumptions made in this paper, which primarily focuses on frequency studies and stability analysis. The other stability study categories are outside the scope of this paper.

Studies of electric power systems in many cases depend on the assumptions made about equipment inertia. Inertia has an enormous impact on the rate of change of rotor angles and thus the frequency of an electric power system.

Electromagnetic torques in the air gaps of motors and generators act as a virtual gearbox between an electric power system and the associated mechanical systems. These electromagnetic torques allow for the calculation of the total inertia of all electrical and mechanical equipment connected to an electric power system.

It is the goal of every engineer modeling a power system to develop the simplest model possible to accurately depict system behavior. The level of modeling simplification should be conservative but not come at the expense of oversizing power system components or designing unnecessarily complicated control systems.

Finally, the ultimate task of modeling a microgrid control system is testing the protection and control scheme against a real-time model that is operating on a hardware device. This type of modeling provides the certainty that the control schemes will operate properly under all site conditions.

III. INERTIA BACKGROUND

Power system inertia is the ability of a power system to oppose changes in frequency. During a power unbalance scenario, frequency changes faster in a system with low inertia and vice versa.

Accelerating torque of all electric machines is the product of the moment of inertia (J) and its angular acceleration, as defined in (1).

$$J\left(\frac{d^2\delta_m}{dt^2}\right) = T_m - T_e = T_a \tag{1}$$

where:

- J is the total angular moment of inertia (kg-m^2).
- T_m is the shaft torque supplied by the prime mover (N-m).
- T_e is the net electrical/electromagnetic torque (N-m).
- T_a is the net accelerating torque (N-m).
- δ_m is the angular displacement (in radians) of the rotor with respect to a reference axis that rotates at synchronous speed.

Note that J is composed of all rotating bodies synchronously connected to the electric power system. This includes brushless exciters, shaft couplers, toothed wheels, generator rotors, turbine assemblies, motor rotors, and the mechanical loads attached to motors.

Because turbines produce power, (1) is most commonly multiplied by the angular speed of the rotor in radians per second (ω_m) to come up with the terms of electrical and mechanical power, as shown in (2).

$$J\omega_m\left(\frac{d^2\delta_m}{dt^2}\right) = P_m - P_e = P_a \tag{2}$$

where:

- P_m is the mechanical power input to the turbine.
- P_e is the electrical power crossing the generator air gap.
- P_a is the power that goes into accelerating the machine.

Under steady-state conditions, the machine is operating at synchronous speed, where P_m and P_e are equal, and therefore frequency is constant.

J is normally referred to as the inertia constant (H), which is defined as the ratio of stored kinetic energy in megajoules at synchronous speed to the machine rating ($S_{machine}$) in megavolt amperes (MVA). The resulting term is in units of seconds. H can also be hypothetically calculated as the time (in seconds) that a turbine/generator pair takes to accelerate from zero to rated speed under rated turbine torque conditions.

The calculation for H of a turbine/generator pair is shown in (3) and (4). Accelerating power can be expressed as shown in (5) and (6).

$$H = \frac{\omega_{sm}^2}{2S_{machine}}\left(J_r + \frac{J_t}{GB^2}\right) \tag{3}$$

$$\omega_{sm} = \omega_s\left(\frac{2}{p}\right) \tag{4}$$

$$\frac{2H}{\omega_{sm}}\left(\frac{d^2\delta_m}{dt^2}\right) = \frac{P_a}{S_{machine}} \tag{5}$$

$$\omega_m = \omega_{sm} + \frac{d\delta_m}{dt} \tag{6}$$

where:

- GB is the gearbox ratio between the turbine and rotor.
- ω_s is the speed of the electrical power system in electrical radians per second.
- ω_{sm} is the rated synchronous mechanical angular speed of the rotor in mechanical radians per second.
- J_r is the synchronous rotor inertia.
- J_t is the turbine inertia.
- p is the synchronous generator pole count.

It is noteworthy that the synchronous generator pole count dramatically affects H calculations. For example, large inertia hydroelectric turbines have significantly reduced H due to large pole counts. Gearbox ratios of high-speed turbines also tend to reduce H calculations.

It is more convenient to write (5) in terms of the synchronous mechanical angular velocity (ω_s), synchronous frequency (f_o), and electrical power angle (δ).

$$\frac{2H}{\omega_s}\left(\frac{d^2\delta}{dt^2}\right) = \frac{P_a}{S_{machine}} \tag{7}$$

$$\frac{2H}{f_o}\left(\frac{df}{dt}\right) = \frac{P_a}{S_{machine}} = P_{apu} \tag{8}$$

where P_{apu} is the accelerating power in per unit.

The inertia can be calculated using (9), where $(df/dt)_{pu}$ is the per-unit rate-of-change of frequency.

$$H = \frac{P_{apu}}{2(df/dt)_{pu}} \tag{9}$$

For a system with several generators and loads, system inertia (H_{System}) is the collective inertia of all of the generators (H_{Gen_i}) and loads [2]. Here, the inertia of all of the machines should be converted from the machine base (S_{Gen_i}) in MVA into a common system base (S_{System}) in MVA.

$$H_{System} = \sum_{i=1}^{N} \left(H_{Gen_i}\right) \frac{S_{Gen_i}}{S_{System}} \tag{10}$$

A. Generator Inertia and Frequency Response

System inertia can impact frequency response, and it increases with more interconnected rotating machinery. Therefore, a generator governor system has more time to respond for a system contingency if the whole system is interconnected.

The combined system rotational inertia of all of the loads and generators dramatically affects the frequency response of the system when there is a loss of generation. It primarily affects the initial rate-of-change of frequency (df/dt) and the frequency trend to the next steady-state value. The higher the inertia, the slower the frequency changes. System inertia increases the system margin and gives the governor time to respond and stabilize the system. However, inertia does not play a role in the final steady-state frequency settling point.

Fig. 1 shows the frequency response for a refinery system exposed to load acceptance for different generator inertias. In this case, the tuning constants of the governor were not changed as the inertia was increased. The frequency response was tested with different turbine/generator inertias at 1.65 seconds, 2.04 seconds, and 6 seconds. As shown in Fig. 1, when the inertia is equal to 2.04 seconds, the system swings to a minimum frequency of 57 Hz. When the inertia increases to 6 seconds, the swing reduces to 58.3 Hz and the frequency stabilizes much faster.

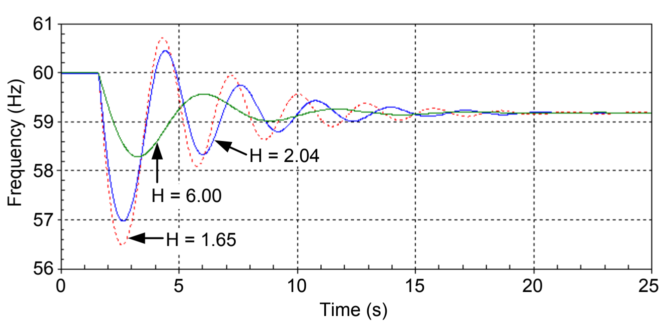

Fig. 1 Load Acceptance for Different Generator Inertias

B. Load Inertia and Frequency Response

Fig. 2 shows a 10 MW load acceptance test for the same generator shown in Fig. 1 with an inertia of 2.04 seconds. The ZIP-MVA load line indicated in Fig. 2 shows the frequency response for a ZIP-MVA load (this concept is explained in detail in Section VIII). ZIP-MVA is a constant MVA load; one example is a variable speed drive (VSD). The motor load line indicated in Fig. 2 shows the frequency response for a motor load with an inertia of 3.3 seconds for a 10 MVA base. It is clear that the motor load dampens the frequency response more when compared with the ZIP-MVA load. For frequency stability analysis, modeling the load as a ZIP-MVA load (with zero load inertia) is a more conservative approach and is acceptable if there is not much information available for motor inertia or if the motor load is not significant when compared with the generator inertia.

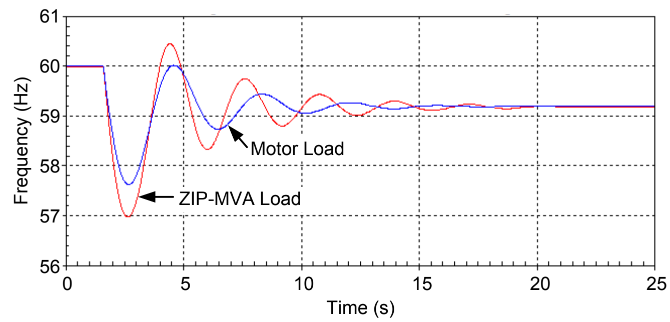

Fig. 2 Load Acceptance for Motor and ZIP-MVA Loads

IV. FIELD TESTING FOR INERTIA

One of the challenges of performing a frequency stability study is finding the inertia of a turbine/generator pair. This is challenging because either there are no data available from the field or the data are not accurate enough and need to be verified. A generator load rejection test is an ideal test to measure the inertia of a turbine/generator pair. A load acceptance test can also be used to measure the inertia, especially if the load used in the test is a ZIP-MVA load (with no inertia).

A partial load rejection test is typically performed by tripping (stopping) a load on an islanded bus running a single generator. When a generator breaker is opened under load, the test is commonly called a load rejection.

A load acceptance test is when a load is suddenly energized (started) on an islanded bus running a single generator.

A. Load Rejection Test

This section describes how to calculate the inertia of a turbine/generator pair using power system frequency measurements from a protective relay. Fig. 3 shows a curve from a field test that indicates the frequency response of a 30 MVA generator for a 10.0 MW to 0 MW load rejection. The frequency almost reaches 65 Hz and then settles at 61.2 Hz according to the droop characteristic of the machine.

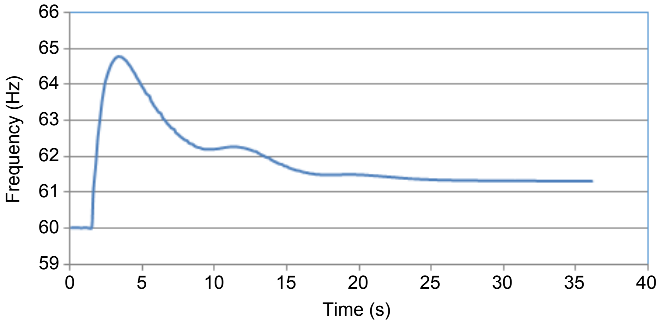

Fig. 3 Field Test Frequency Response for Load Rejection of 10.0 MW to 0 MW

Calculating the inertia is performed using direct substitution with (9). P_{apu} is determined for this case by measuring the electric power production before and after the event. For this test, 9.77 MW was produced by the generator before the electrical load was tripped offline, causing a load rejection to 0 MW. The power base of the test generator is 29.375 MVA, and the nominal frequency is 60 Hz.

Calculating the inertia from the plot in Fig. 3 is performed using the initial slope during the first half-second from the load rejection test. The first half-second of data from Fig. 3 is shown in Fig. 4. This slope should be the initial slope before the governor takes any action. This half-second assumption is accurate because this particular governor cannot change valve positions in the first half-second after a disturbance. Time-synchronized measurements of valve position are commonly used to determine the allowable time window that can be used for load rejection testing.

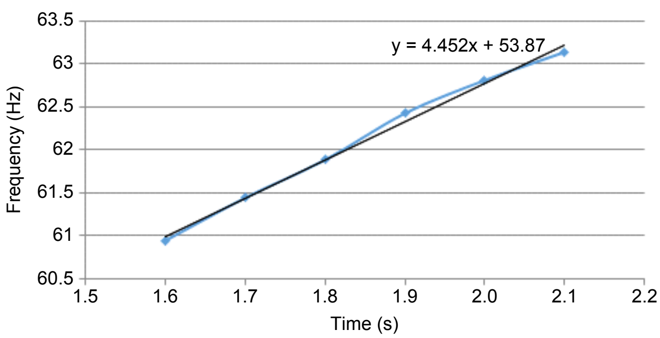

Fig. 4 Frequency Response in First Half-Second

The load rejection curve shown in Fig. 4 uses ten samples per second, so the first half-second has six samples. These six points are not exactly along a straight line because of slight governor and valve movements and imperfections in the frequency estimation methods within the measuring device.

The authors use a technique referred to as a median calculation to calculate the rate-of-change of frequency over several different sets of data samples. The median calculation has proven to be a reliable method of extracting inertial information from electronic devices (such as protective relays) when compared with the information from average calculations. This technique measures the slope for several different time periods (windows) and then calculates the median values. Each slope measurement is based upon a curve fit, as shown in Fig. 4. For the data in Fig. 4, the windows are varied from two to six samples, as shown in Table I. The median rejects any outlier data points when calculating the slope, as opposed to the average calculation, which might be biased by the outliers.

The inertia calculated for these different numbers of sampling points is shown in Table I.

TABLE I
INERTIA CALCULATED FOR DIFFERENT NUMBERS OF SAMPLING POINTS

Samples Per Window	Slope (Hz/s)	H (s)
6	4.452	2.25
5	4.705	2.13
4	4.873	2.05
3	4.684	2.13
2	4.968	2.01

The average slope and inertia are 4.737 Hz/s and 2.11 seconds, respectively. The median slope and inertia are 4.705 Hz/s and 2.13 seconds, respectively. The median inertia calculation is shown in (11).

$$H = \frac{(9.77\text{ MW} / 29.375\text{ MVA})}{2 \bullet \left(\frac{4.705}{60} \right)} = 2.13\text{ seconds} \quad (11)$$

The same procedure was repeated to determine the load rejection for 6.0 MW to 0 MW and for 4.0 MW to 0 MW. The total inertia calculated from the three load rejection tests is tabulated in Table II. The combined inertia median and the average of the turbine/generator pair are both equal to 2.04 seconds on the generator-rated base (29.375 MVA), which indicates that there are no outliers in the measurement data.

TABLE II
INERTIA CALCULATED FOR DIFFERENT LOAD REJECTIONS

Load Rejection (MW)	H (s)
4.0 – 0	2.04
6.0 – 0	1.95
10.0 – 0	2.13

B. Load Acceptance Test

This section explains how to calculate the load inertia from a load acceptance test. Fig. 5 shows a load acceptance test for the same 30 MVA generator from 4.7 MW to 6.9 MW. The same median calculation procedure as that used in the load rejection tests was used to calculate the inertia, with the results of the load acceptance tests shown in Table III. The average and median inertias for the load acceptance tests are 2.77 seconds.

The difference between the load acceptance inertia and the load rejection inertia is attributed to the load (motor) inertia, which is 2.77 – 2.04 = 0.73 seconds on the generator-rated base (29.375 MVA). This is equivalent to an inertia of 3.13 seconds on the load MVA base (6.85 MVA). Load acceptance tests are commonly used to provide an approximation of the total load inertia in a system.

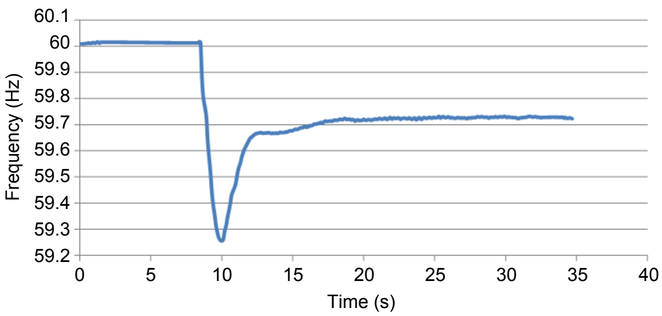

Fig. 5 Real Power Response for Load Acceptance Test From 4.7 MW to 6.9 MW

TABLE III
INERTIA CALCULATED FOR DIFFERENT LOAD ACCEPTANCE TESTS

Load Acceptance (MW)	H (s)
2.7 – 6.8	2.57
4.7 – 6.9	2.96

C. Application of Inertia

The typical load and source inertias (100 MVA base) for five different refineries are shown in Table IV. It also shows how the load inertia compares with the turbine/generator inertia within the refineries. These are real data from five operational refineries.

TABLE IV
LOAD AND GENERATOR INERTIAS FOR DIFFERENT REFINERIES

Refinery	System Power (MW)	Number of Generators	H (s)	Generator H (%)	Load H (%)
1	600	9 at 100 MW	58	80	20
2	400	6 at 100 MW	50	70	30
3	250	4 at 100 MW	29	85	15
4	100	4 at 45 MW	5	83	17
5	220	5 at 50 MW	15	67	33

Within the refineries, the generator inertia is about 70 to 80 percent of the total system inertia. Once a refinery is electrically connected to a large electric utility, the total generation and load inertias are substantially larger than those for islanded microgrids. These simplified measurement techniques and the composition of load and source inertias are essential for the application of frequency-based microgrid blackout protection schemes [2].

To avoid unnecessary complexity, modeling all of the load inertias in a system (including every small motor) is not recommended. However, modeling the loads without inertia reduces the overall system inertia accuracy by 20 to 30 percent, as shown in Table IV. Underestimating system inertia is sometimes acceptable in models because it makes estimated frequency swings larger than reality.

Load lumping of high-inertia loads, as described in [3] and [4], is an important technique that causes a model to more accurately depict real field conditions with limited model complexity. The authors recommend modeling approximately 90 percent of the system inertia or above for frequency stability analysis.

D. Toothed Wheel Inertial Measurements

The median calculation technique is typically not required if using toothed wheel measurements of actual generator rotor speed. These data give a more accurate estimation of inertia with less measurement error because the toothed wheel is physically mounted on the rotor. This allows the electronics to directly measure rotor speed, whereas a device monitoring the voltage and current can only infer speed from a frequency measurement.

Electronic devices can add error to frequency or speed measurements. For example, the filtering, latency, and data processing algorithms within electronic devices can affect frequency (or speed) measurements, especially under high rates-of-change of frequency.

V. IM FREQUENCY CHARACTERISTICS

Many loads in the refinery and petrochemical industries are direct-on-line IMs. Modeling all of the IMs in an actual system may be a very difficult process, especially if the motor data sheets are not available. This section explains critical background information necessary to approximate IMs for different types of studies.

It is important to characterize IMs and understand how the active power of IMs changes as the system frequency changes. In doing so, simplification requirements can be identified for each type of study. The torque versus frequency characteristics of both the load and IM are especially important to model when the frequency of a microgrid runs off-nominal.

Accurate frequency modeling of the loads can in some cases be critical. During frequency stability analysis, as the frequency increases in the system (due to excessive generation), the IMs increase their loads to help absorb some of the excessive generation and to move toward system stability. Similar trends are shown when the system frequency is decreased; the IMs reduce their loads to balance the system as well.

A. Variations in Frequency

Understanding the behavior of an IM helps determine the best approximate model to use if the actual IM cannot be modeled because of a missing data sheet or because of a limitation in the modeling software. A software limitation can be a result of a limited number of buses or a result of a hardware process limitation due to the small time step required for solving the system [5] [6]. The load for all of the tests discussed in this section is assumed to be constant torque load and not a function of frequency. Different load types are explained in Section VI.

Four different IM models were tested for the purposes of this paper. These IMs were selected for their different characteristics, which are shown in Fig. 6 and Table V. The data sheets had no information about the class type, so the IMs were classified based on their parameters.

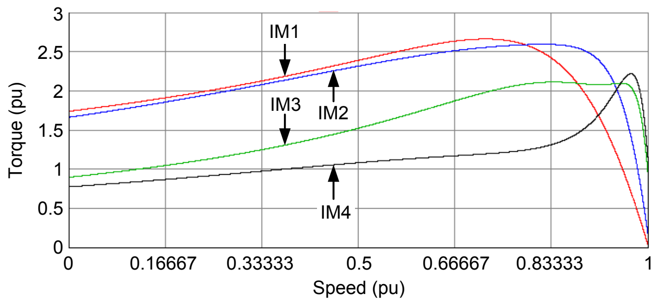

Fig. 6 IM Torque Versus Speed Characteristics

TABLE V
IM MOTOR DATA

Parameter at Full Load	IM1	IM2	IM3	IM4
Slip (%)	1.66	2.0	0.6	0.5
Mechanical power (MW)	0.112	3.0	0.90	1.05
Power factor (pu)	0.89	0.83	0.86	0.91
Efficiency (%)	91.5	92.3	96.1	96.4
Starting torque (pu)	1.745	1.668	0.903	0.78
Maximum torque (pu)	2.668	2.599	2.118	2.224
Starting current (pu)	6.493	6.234	6.684	6.501
Rated voltage (kV)	0.4	6.6	6.6	11
NEMA design	C	C	A	A

Fig. 7 shows a simulation where the active power of the four different IMs is compared as the frequency is changed by 20 percent. It is important to note that the four different IMs have identical power versus frequency curves because the same load model was used on all four simulations. Because this was a constant torque load model, the active power changed by approximately 20 percent for a 20 percent frequency change. In the authors' experience, a linear relation between the frequency and active power consumption of an IM for operating frequency ranges (±3 Hz) is a good assumption for most load types.

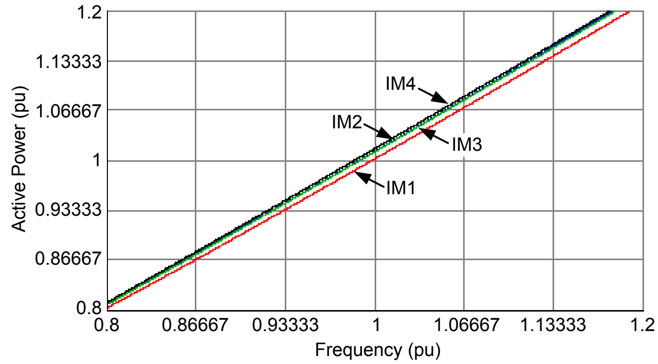

Fig. 7 Active Power Versus Frequency for Different IMs

B. Single-Cage Versus Double-Cage Motor Model

An IM can be modeled as a single-cage or double-cage motor. However, the model may not reflect the actual design of the motor. An actual double-cage IM can be modeled as a single-cage IM if a frequency stability study does not require the starting characteristics of the motor. A double-cage model is required when a study focuses on the motor starting.

Fig. 8 shows a comparison of the torque versus speed characteristics for two different IMs. Both IMs have the same nameplate ratings (output power, maximum torque, and full load speed), but they have significantly different starting torques. One of the IMs can be modeled as a single-cage IM, and the other IM must be modeled as a double-cage IM.

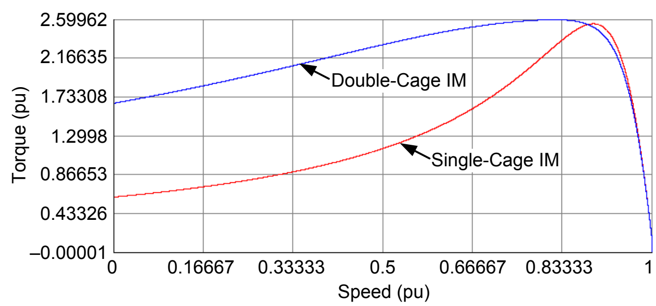

Fig. 8 Comparison of Single-Cage IM and Double-Cage IM Torque Versus Speed

A single-cage IM rotor creates a low starting torque due to the low rotor resistance of the cage. The resistance of the rotor must be increased to make a single-cage IM rotor model approach the starting torque of a double-cage IM model. However, using a larger fixed resistance on a single-cage model is not possible because it degrades the efficiency of the IM. To achieve accurate starting torques and losses, many IMs are therefore best modeled as double-cage IMs [7].

In most IMs, the first (outer) cage has a dominant resistance under high slip conditions that helps generate the higher starting torque. This, coupled with a second (inner) cage that has low resistance under low slip conditions, helps generate an accurate torque versus frequency profile [8]. The double-cage IM model therefore produces a high starting torque, proper efficiency performance, and realistic full load torque conditions. Transient stability modeling is also highly improved with a double-cage IM model [9].

VI. SM FREQUENCY CHARACTERISTICS

Modeling SMs can be important to system stability studies because SMs can run out of step with respect to the generator. Large SMs have a significant impact on frequency stability studies because they can significantly contribute to the total system inertia.

For a microgrid or refinery, the authors recommend detailed modeling of all SMs that are 10 percent or greater of the average generator size. Detailed SM models commonly include models of the inertia and the field excitation control system. SM characterization is used for understanding how the active power of the SM changes with the change in frequency of the system.

Fig. 9 shows the active power of two SMs of significantly different ratings as the frequency is changed by 5 percent (3 Hz) under constant torque load conditions. As expected, the constant torque load creates a linear correlation between frequency and active power, with the slope of this line nearly one to one. Fig. 9 shows that the SM construction has little effect on the active power versus frequency characteristic of an SM.

During frequency stability studies, as the frequency increases in the system (due to excessive generation), the mechanical equipment driven by the SMs increases its load to help to absorb some of the excessive generation and thereby improve system frequency stability. There is a similar trend when the system frequency is decreased; the mechanical equipment driven by the SMs reduces its load.

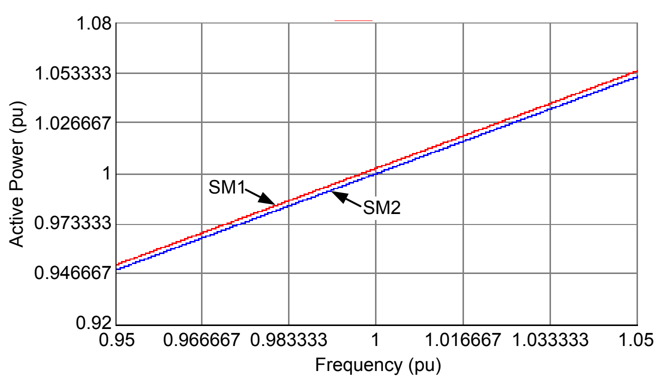

Fig. 9 Active Power Versus Frequency for SMs

VII. LOAD TORQUE FREQUENCY CHARACTERISTICS

For most frequency stability studies, the modeling of the mechanical load attached to an SM or IM is more critical than accurate modeling of the SM or IM (not including starting studies).

The main correlation between frequency and active power for three different load torque types is shown in Fig. 10. The line shown for constant power load is a purely hypothetical line; the authors know of no real IM load that has that characteristic. The constant torque load is typically used for crushers, conveyors, or loads with large gearbox ratios. The fan-type load is typically modeled for devices such as compressors, separators, fans, and fluid pumps.

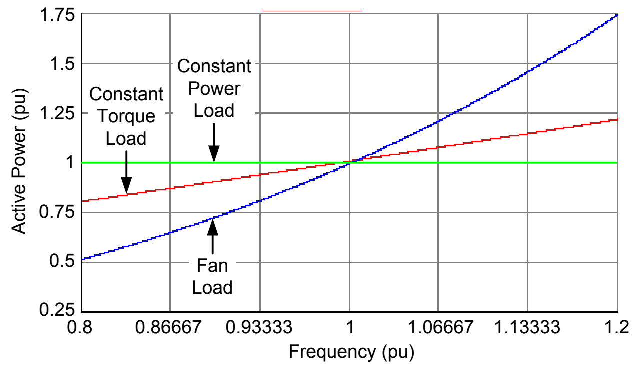

Fig. 10 Active Power Versus Frequency for Different Load Types

A modeling engineer is commonly faced with determining what type of load needs to be modeled if the load characteristics are not available. Because the fan load model may produce overly stable results, the authors recommend using the constant torque load model in cases of uncertainty. For extremely conservative results, such as for governor tuning studies, power system stabilizer tuning studies, and SSTI studies, the constant power load is used (even though it is not a viable load type).

VIII. ZIP LOAD MODELS

A static load is a composite load model that can maintain constant impedance, constant current, and/or constant power or a combination of the three, which is known as a ZIP load. A ZIP load model is a static load with no inertia. For some types of frequency studies, it is acceptable to model IMs and SMs as simplified ZIP loads. Before doing so, it is important to understand ZIP load characteristics.

Fig. 11 shows the characteristics of a ZIP load with constant MVA (ZIP-MVA) as well as the SM and IM driving a constant torque load. Modeling the IM or the SM as ZIP-MVA is not the best representation of either machine. However, the ZIP load is considered to be a conservative representation of IMs in dynamic stability analysis for two reasons. First, no inertia is associated with the ZIP-MVA load, and second, it does not adapt its active power during off-nominal frequency like the IM and SM do. This means that if the simulated power system survives with loads modeled as ZIP-MVA, then the system will certainly survive with real IM and SM loads. Refer to Fig. 2 to see the response for an IM compared with a ZIP-MVA load.

The most common use of ZIP loads is to represent a lumping of many small, rated IMs and SMs. This simplification is acceptable for the modeling of slow response control systems, as described in Section IX.

Most VSDs are modeled as ZIP loads for frequency stability studies. Because the motor loads driven by a VSD are decoupled from the power system, VSDs contribute no inertia to the power system. Active power consumption of VSDs is dominated by process control systems; therefore, the interaction of VSDs with electric power systems is minimal.

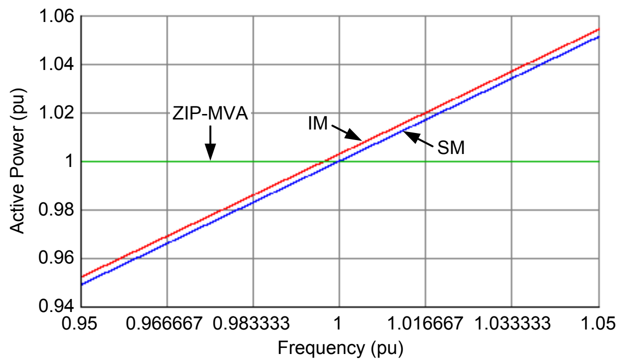

Fig. 11 Active Power Versus Frequency for SM, IM, and ZIP-MVA Loads

IX. LOAD MODELING SIMPLIFICATION

Load modeling simplification can be justified for two categories of electrical microgrid control systems: slow and fast response control systems. Slow response control systems must react in times of a few seconds or slower. Fast response control systems must react in times of a few power system cycles to avoid instabilities.

A. Slow Response Control

The following are generalizations about the rationale for simplifying load models for slow response control systems:

1. These systems are slower than the transient and subtransient time constants. Therefore, detailed rotor movements are unnecessary to model.
2. These systems have filters that remove fast data, so fast sampling is unnecessary.
3. Modeling only time constants of ≥5 seconds is required.
4. Inertia does not matter.
5. Governor droop lines matter.
6. Exciter reactive compensation matters.
7. Exciter dynamics do not matter.
8. Governor dynamics do not matter.
9. Power flow solutions matter.
10. Accurate voltage and frequency characteristics matter.
11. Load volt/VAR characteristics matter.
12. Load frequency and watt characteristics matter.
13. On-load tap changer (OLTC) and capacitor control characteristics must be modeled accurately.

B. Fast Response Control

The following are generalizations about the rationale for simplifying load models for fast response control systems:

1. These systems are similar in time constant to the transient and subtransient time constants. Therefore, detailed rotor movements must be considered.
2. These systems have filters that remove fast metering data, so fast sampling is unnecessary. However, digital data must be subcycle and must not be delayed.
3. Modeling time constants of ≤0.005 seconds is required.
4. Inertia matters. For a power system with low load inertia as compared with turbine/generator inertia, load inertia can be conservatively assumed to be zero. Generator prime mover inertia must always be accurately modeled.
5. Governor droop lines matter for multiple, consecutive, closely timed events, but they do not matter for a single event. Accurate steady-state parameters for second and third contingencies are needed.
6. Exciter reactive compensation matters for closely timed events.
7. Exciter dynamics are critical. Power system stability must be modeled.
8. Governor dynamics matter a lot.
9. Power flow solutions matter.
10. Accurate voltage and frequency characteristics matter in a steady state.
11. Load volt/VAR characteristics matter.
12. Load frequency and watt characteristics matter.
13. A simplified first-order governor model is acceptable for contingency-based load shedding.
14. A detailed, custom-built governor model is required for frequency-based load-shedding or generation-shedding control systems.

X. CONCLUSIONS

This paper presents a simplified method for modeling IMs and SMs, with the ZIP load being the determining factor in frequency power system studies and closed-loop simulation work. Modeling an IM as a ZIP-MVA load is considered to be a conservative representation for IMs during dynamic stability analysis from an inertia and power consumption perspective. If a system frequency study is stable when modeling ZIP-MVA loads, the loads are more stable for the actual IM models. While VSDs have no inertia reflected to the power system, they are always modeled as ZIP-MVA loads in frequency stability studies. Other types of studies may require a more sophisticated model for VSDs, especially harmonic and resonance studies. The paper also presents the frequency characteristics of IMs and SMs for different load types.

This paper primarily focuses on frequency stability-related studies. Rotor angle stability, voltage stability, harmonic stability, and resonance stability studies require a different analysis of load simplification. Table VI summarizes the load modeling simplifications for frequency stability studies and different control systems, as described in this paper.

TABLE VI
LOAD MODELING SIMPLIFICATIONS FOR DIFFERENT CONTROL SYSTEMS

Control System	Load Modeling Assumption	Governor and Exciter
Contingency-based load shedding	All loads ZIP-MVA	Simplified
Generation dispatch (AGC)	All loads ZIP-MVA	Simplified
Tie flow dispatch	All loads ZIP-MVA	Simplified
VAR dispatch (voltage control system)	All loads ZIP-MVA	Simplified
Automatic synchronization	All loads ZIP-MVA	Simplified
Decoupling and islanding systems	All loads ZIP-MVA	Detailed
Generation runback and frequency-based load shedding	IM – detailed, SM – detailed, VSD – ZIP-MVA	Detailed
Governor tuning, power system stabilizer, SSTI, and motor starting studies	IM – detailed, SM – detailed, VSD – ZIP-MVA	Detailed

XI. REFERENCES

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XII. VITAE

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