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RESEARCH ARTICLE

A Novel Approach to Extended System Frequency Response Model for Complex Power Systems (ESFR)

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ABSTRACT This paper presents a practical medium-order multi-machine Extended System Frequency Response (ESFR) model that is applicable for the frequency study of large, complex power systems or an island portion due to sudden load disturbances or generator outages. The ESFR model is a simplification of the real system and can be used to capture the essential system dynamics behaviour, commonly associated with high-capacity hydro generation and thermal generating units. Classification of power system generations and developing an equivalent unit for each class is proposed by the first step of this two-step method. The above components are put together in a composite frame, which takes into consideration all significant characteristics and factors related to the frequency response of the system. The IEEE standard model with the best performance for each element has been selected via a comparative analysis in single-machine and multi-machine environments. The second step aims to equalize the effective parameters numerically and comprises two sub-steps. The first sub-step identifies the parameters with considerable impacts on the frequency response of the components via sensitivity analysis. The second sub-step involves extensive comparative studies to find the best formulas for determining the equivalent value of the effective parameters. The graphical interface of an advanced power system software with a user-friendly simulation environment was used for the analysis. The results show that the current approach is capable in terms of accuracy and practicality to capture the diversity of the generating resources in modern power systems.

INDEX TERMS Frequency response, hybrid power systems, power system modeling.

I. INTRODUCTION

Stability of power systems is closely tied to system frequency. Risk of low frequency operation of power system can deteriorate the life of steam turbines and in the extreme conditions, the frequency collapse could occur [1], [2], [3].

To perform any dynamic study of electric power systems, a proper mathematical model is needed. The selection of a power system model cannot be dissociated from the problem itself, nor the unavailability of the fast-computing facilities. It is neither adequate, nor practical to apply a ''universal model'' for all power system dynamic problems [1], [4].

There are various types of power system dynamic problems, but there are only a limited number of system components which are significant to the dynamic study. For each of these components, several basic models are recommended by the professional societies, and can be adapted for the studies of specific problems [1], [4].

Frequency response model of the system is one of the vital requirements, not only for the operation of power systems, but also in the design and optimization of frequency base controllers and protection systems. This modelling system has

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received limited and separate measures in the literature. However, in many studies, researchers have faced this problem, but they preferred to use conventional models [5], detailed model [6] or personal methods [7], [8]. A discussion of the conventional SFR models, first introduced by Anderson and Mirheydar and subsequent developments facilitated by other researches, and their limitations are provided in section II of this paper.

Adaptive [9] and semi-adaptive [10] Under Frequency Load Shedding (UFLS) are common protections to maintain power system stability by removing the overload in some part of the system and prevent system collapse and its catastrophic consequences. The successful design of these protection systems and the related system reliability impacts are closely dependent on the availability and accuracy of the system frequency response model [1], [2], [11], [12], [13], [14], [15]. However, a review of the literature on SFR model used in UFLS designs did not result of any finding of new idea for SFR model, as they employed the conventional approach or detailed models.

The increasing penetration of renewable energy in nowadays power systems and the development of hydropower plants, wind farms and solar power could significantly impact the frequency response of the systems and need to be addressed. In such circumstances, as discussed in section II of this paper, the conventional SFR model which was principally developed to model the classic thermal units would not be able to adequately capture the effects of these types of generation.

On the other hand, concurrent with the development of digital simulation in power systems, new opportunities have been arisen that should be used in this field.

This paper explores these opportunities to develop and validate the Extended System Frequency Response (ESFR) model in order to cover the requirements of complex power systems in the area of design and operation.

II. CONVENTIONAL SYSTEM FREQUENCY RESPONSE (SFR) MODEL

On frequency modelling of power systems, Anderson and Mirheydar [16] had proposed a comprehensive model based on the mean of uniform or average frequency; where synchronizing oscillations between generators are filtered out, but the frequency behaviour is retained.

The first concept of this model is performed to describe a large system by minimum number of equations that will compute only the average frequency behaviour. They assumed most of generating units of the above large system are reheat steam turbine units and the model examines the midrange frequencies associated with changes in shaft speed. For this purpose, the thermal system dynamics of the boiler are ignored as being too slow and also the generator response is omitted as being too fast. Based on these, the reduced system only includes servo motors, steam turbine and generating unit inertia.

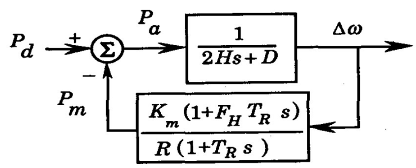

FIGURE 1. Simplified SFR model with disturbance input.

Considering the high correlation between active power balance and the frequency of the system, the contribution of transmission network is omitted in all previous studies. In view of Anderson [16], the negligibility of these networks was so granted that didn't need any discussion. Daniel and Ofer [17] mentioned that the thermal units are strongly connected to each other by the transmission network.

Expression of all parameters in per unit, on a common system base, which is equal to the total rating of all generating units in the system or the island, makes it possible to combine all generation units into a single large unit. The reduced order and the simplified SFR models are given in [16] and [18] as illustrated in Figure 1.

In this model six factors are employed, viz, Average Reheat Time Constant (T_R), Inertia Constant of the System or Island (H), Governor Regulation (R), Damping Factor (D), High Pressure Power Fraction of Reheat Turbine (F_H) and Gain (K_m).

It should be noted that T_R is the most significant time constant of the system from this point of view. It tends to dominate the largest fraction of the turbine power output. H and $1/R$ are the second and the third dominated constants respectively [16]. K_m expresses the total mechanical power in terms of governing valve area. Spinning Reserve (SR) and system power factor have contributions on this gain [18]. The comparison with real system performances and the detailed stability simulations are encouraging for this model.

Later Daniel and Ofer [17] developed a simplified model to simulate the frequency response and the load shedding system operation for the Israel electric power system. The installed capacity of the system at the time of the research included more diversified generation types (as compared to Anderson test system). The system consisting of 22 thermal units along with several industrial and jet type gas turbines. All the thermal units are simplified to a single equivalent unit and an equivalent gas turbine model represents all the gas turbines.

The parameters of the above equivalent units are the weighted values of the actual units which are operating during the time of analysis. But, the equivalent inertia constant is the sum of inertia constants of the operating units [17].

Recently Denis Lee, during his work on the design of an adaptive Under Frequency Load Shedding system [19], has also elaborated on system frequency response models. The author recommended that for power system consisting of several characteristic types of generation with the distinct dynamic response, it is essential to model these separately by the means of SFR model.

In [20], the authors believed the base SFR work does not provide an in-depth explanation of the methodology for obtaining the SFR model parameters when the system contains multiple generators with heterogeneous parameters. The authors tried to address this problem by proposing an aggregation method built on the foundation of conventional SFR called as Aggregated System Frequency Response (ASFR) model. They claimed the SFR is an over simplification of the detailed power system model that considers synchronous generator, network topology, and ZIP loads; therefore, it is reasonable that the frequency output of the SFR has some error.

In other words, they believe the SFR model can be used to analyse the dynamic behaviour of multi-machine systems; However, it is important to note that there are some inherent limitations to the SFR model due to neglecting of several factors such as the turbine governor non-linearity, the inter-machine oscillations, the impact of the voltage-dependent load, and the impact of the network loss variations. Considering these limitations, it is expected that the dynamic frequency response obtained by the SFR model may include some error compared to frequency response obtained from the detailed dynamic and steady states system models.

Different SFR-based models were developed in [20] to assess the robustness of the proposed method concerning multi-machine system aggregation. The findings indicate that while full-order SFR and ASFR equivalents display negligible errors, low-order SFR and ASFR equivalents have significant errors.

The objective of [21] is to reduce the order of multi-machine systems using the conventional SFR model through a transfer function equivalency method. The model attempted to apply the transfer function first developed by Anderson for hydro turbines, by replacing the specific parameters of the thermal units using the four parameters that serve similar functions for hydro generators. The authors highlight the dearth of research addressing simplifying the hydro turbines.

The findings of this research show the proposed model can simulate the frequency response of the multi-machine system accurately just when the installed capacity of the thermal unit is higher than hydro units. The intrinsic limitations described earlier, referring to [20], for the application of conventional SFR to simulate multi-machine systems are similarly valid for this model too.

The review of the literature clearly shows there is a significant research opportunity to develop a new aggregated modelling approach, which should be capable of simulating the frequency performance of multi-machine complex power systems simply and accurately, while eliminating the limitations of conventional SFR model, considering the hydro generations sufficiently, and also being capable to smoothly extend for other modern power systems' components such as wind farms and neighbour system HVDC connections.

Finally, recent advances in power system software and computer systems provided new opportunities such as using composite frame, rich library of the standard models and graphical editors. These can be used in dynamic studies, especially in the frequency response modelling of advanced power systems. The new frequency response model is performed to fulfil the requirements of this field.

III. EXTENDED SYSTEM FREQUENCY RESPONSE (ESFR) MODEL

A. GENERAL OVERVIEW OF THE PROPOSED APPROACH

It is evident that within the realm of renewable energy, hydroelectric power generation plays a significant role in modern power systems and their overall dynamic performance. Based on this issue and earlier discussion on existing frequency response models, the key goals of this research can be summarized as follows:

1- To develop a new Extended System Frequency Response (ESFR) model for complex power systems, which involves a considerable hydro generations portion.

2- To utilize the IEEE standard and reliable models for influential components of the power plants in achieving the comprehensive frequency modelling system.

In pursuing these goals, first, a classification of generation types, namely steam and hydro units, is required. Then each category is aggregated into an equivalent unit.

The approach begins first with distinguishing between significant and insignificant power system components that impact the frequency response of the power system; reminding that the system frequency dynamics is a function of the active power balance in the network. The next step is to identify and validate the most suitable standard models for the power generation components that play a vital role in the frequency performance of the system.

Then, the parameters employed by the selected standard models and which have considerable impacts on the frequency dynamics of the components should be identified. After that, the best approaches and formulations for determining the parameters of the equal units using the individuals should be defined and validated.

In addition, the current approach employs the graphical editor and rich model library of the advanced power system software, particularly DIgSILENT PowerFactory, to create a user-friendly environment for simulating complex power systems. A sample of the detailed grid and equivalent (aggregated) ESFR model, which is simulated using the DIgSILENT, are presented in Figure 2.

Table 1 provides a summary of the key distinctions between the proposed ESFR model, conventional SFR, and ASFR model.

B. TURBINE-GENERATOR MODEL

A high-order turbine-generator model includes two rotor circuits in each axis, considering Park's transform as a base; it

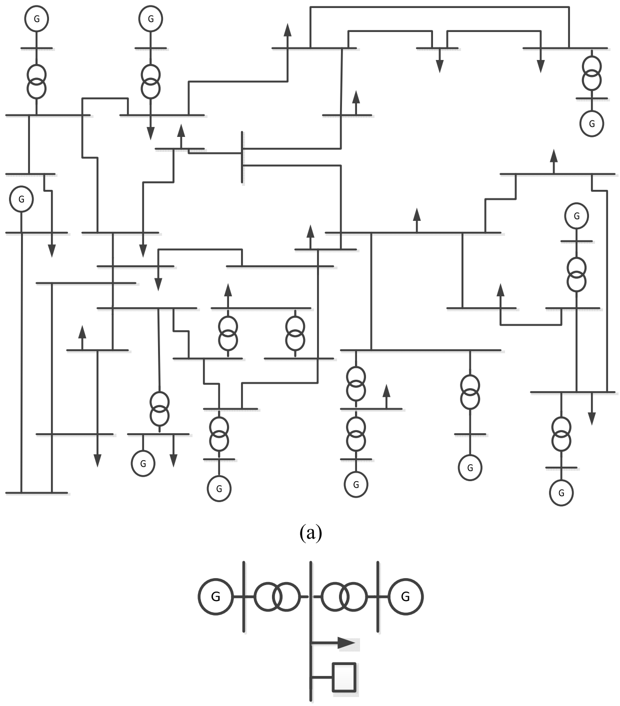

FIGURE 2. IEEE 39-Bus system: (a) Detailed grid, (b) ESFR model are simulated using DIgSILENT graphical interface.

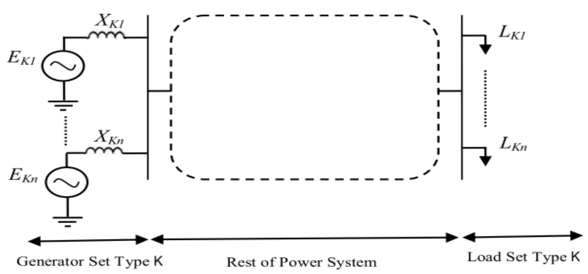

FIGURE 3. Schematic view of classified power system.

is the most complex model currently available in large-scale stability programs. It consists of the field circuit plus one armature on the d-axis and two armature circuits on the q-axis. The foundation of the third-order model is accepted by IEEE standards as a base for the turbine generator modelling within the dynamic studies [22] while consistent with that of the leading power system simulators, e.g. DIgSILENT and PSCAD. The dynamic parameters set used in the model are given in Table 2.

Considering the assumptions outlined in section II of this paper, from the frequency perspective, the contribution of the transmission networks is negligible. In such circumstances, there are parallel sets of generators (similar to what commonly exists in power plants) on one side connected strongly to parallel loads via short electrical distances, as shown in Figure 3. The dynamic parameters of generating units over the aggregation process can be determined based on the extensive experience that operators and engineers have in

TABLE 1. A comparison between SFR, ASFR and new ESFR models.

Item	SFR	ASFR	ESFR
Model base	Uses a specific transfer function	Uses a specific transfer function	Using the (IEEE) standard models
Aggregation method	Based on identifying predominant factors	Uses Transfer function reduce order method	Uses Influential parameters equity method
Developing method	Codding specific transfer function	Codding reduced order transfer function	Using advanced simulator graphical interface and their library
Capacity to consider turbine-governor nonlinearity	---	---	✓
Capacity to consider inter-machine oscillations	---	limited	✓
Capacity to consider a voltage dependent load	---	---	✓
Capacity to consider network loss variation	---	---	✓
Capacity to consider renewable resources	---	limited	✓

TABLE 2. Parameters of IEEE turbine-generator model [22].

Basic Data	Nominal Apparent Power	S_n
	Nominal Voltage	V_n
	Power Factor	PF
RMS Data	Turbine Inertia Constant	H
	Mechanical Damping	D
	Stator Resistance	R_{str}
	Stator Leakage/Potier Reactance	X_l
	Rotor Leakage Reactance	X_{rl}
	d-axis Synchronous Reactance	X_d
	q-axis Synchronous Reactance	X_q
	d-axis Transient Reactance	X'_d
	q-axis Transient Reactance	X'_q
	d-axis Sub-Transient Reactance	X''_d
	q-axis Sub-Transient Reactance	X''_q
	d-axis Transient Time Constant	T'_d
	q-axis Transient Time Constant	T'_q
	d-axis Sub-Transient Time Constant	T''_d
	q-axis Sub-Transient Time Constant	T''_q

modelling parallel units of power plants, and it inspired the proposed approach of this research.

In this approach, each class of generation - such as salient-pole or solid-rotor, hydro or thermal - is combined into a single, equivalent large unit. The "nominal apparent power" of the aggregated units is calculated by summing the "nominal apparent powers" of all generators involved in the classes, as given follows:

$$S_{K_{eq}} = \sum\nolimits_{i=1}^{n} S_{K_i} \tag{1}$$

where $S_{K_{eq}}$ is the equivalent apparent power of type K and S_{K_i} is the apparent power of unit i of type K while n is the number of generators in the class.

The Power Factor (PF) of each equivalent generator is dependent on the PF of individuals of the above set of generators considering the proportion of its generation of the total generation of the set which is formulated as follows:

$$PF_{K_{eq}} = \frac{\sum_{i=1}^{n} S_{K_i} \times PF_{K_i}}{\sum_{i=1}^{n} S_{K_i}} \tag{2}$$

where $PF_{K_{eq}}$ is the equivalent power factor of set K and PF_{K_i} is the power factor of the generation unit i of set K.

Inertia Constant (H) has a significant role between the mid-term and long-term stability model (RMS) parameters set of turbine-generator, as this mean is proven by the literature. Conceptually, the inertia constant quantifies the kinetic energy of the rotor at synchronous speed, in terms of the number of seconds it would take the generator to provide an equivalent amount of electrical energy when operating at a power output equal to its rating MVA. In continental Europe, the symbol T_m is used for the mechanical time constant [23], which is a new expression of H, as given follows:

$$T_m = \frac{J\omega_{sm}^2}{S_n} 2H \tag{3}$$

where ω_{sm} is the synchronous speed of the rotor, J is the total moment of inertia of the turbine and generator rotor and the coefficient $J\omega_{sm}$ is the angular momentum of the rotor at synchronous speed. S_n is the machine rating power in megavolt-amperes.

There are two approaches, outlined in the [1], [16], [17], [18], [19], and [23], to determine the equivalent accelerating time constant ($T_{m_{eq}}$) of each class of generation. The first approach involves summing the individual inertia time constants of the operating unit (T_{m_i}) within the class to calculate the inertia time constant of the aggregated unit. Considering the second scenario, the equivalent time constant is equal to the mean value of the accelerating time constant of the related operating units, considering their proportions in the total power generation. This mean is formulated as follows:

$$T_{m_{eq}} = \frac{\sum_{i=1}^{n} T_{mi} S_i}{\sum_{i=1}^{n} S_i} \tag{4}$$

where S_i is the nominal apparent power of generation unit i.

Due to significant differences between the determined values using these methods, a comparative analysis has been performed for this research, and a sample of results is presented in Figure 4. The findings reveal a high similarity between the second strategy and the frequency response of the actual grid.

Machowski et al. [23] have indicated that the differential equations describing the dynamic performance of the machine consider the influence of the damper windings. Based on this observation, the damping coefficient in the swing equation needs only to quantify the mechanical damping due to windage and friction, and as this is usually small, it may be neglected (D ≈ 0).

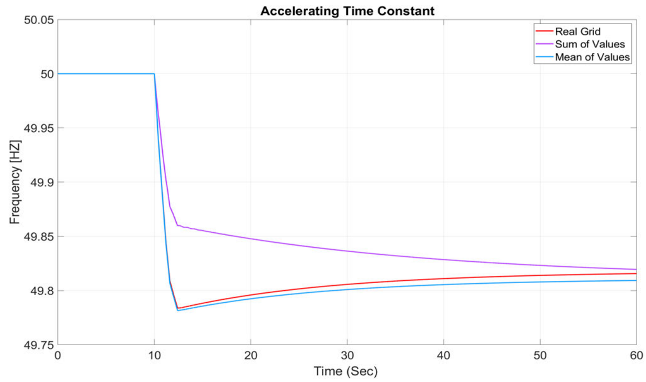

FIGURE 4. **Comparison between acceleration time constant equivalent approaches.**

The analysis conducted within this research shows that considering X_d alone, among other generator parameters (i.e., reactances and time constants), is sufficient for a frequency modelling system. The equivalent reactances (or resistances) of the parallel generators of a class, can be determined, in a similar manner, as follows:

$$X_{K_{eq}} = \frac{\sum_{i=1}^{n} S_{K_i} \times X_{K_i}}{\sum_{i=1}^{n} S_{K_i}} \tag{5}$$

where X_{Keq} is the equivalent synchronous reactance of generator set type K and X_{K_i} is the synchronous reactance generator number i of type K.

As an applied and handy tip, the authors remind that this approach uses the graphical editor of the advanced simulators, and the user may receive a "missing necessary objects" alarm to force assigning values to all generator parameters. In such circumstances, typical data can be used in the model for these non-influential parameters. Samples of these parameters' values are available in [24] and [25] as well as presented in Appendix (Table 8 -11).

C. GOVERNOR MODELLING

The action of turbine governors due to frequency changes, while reference values of regulators are kept constant, is referred to as primary frequency control, and it has a significant impact on the frequency performance of the system. Governors of generators that do not participate in the primary frequency control also form an additional primary reserve that activates only by large disturbances; This is necessary to avoid system blackouts [23].

Various standard models of "Governor" have been presented by leading professional societies such as IEEE and IET are commonly available in the model library of the advanced power system simulators. The governor systems and parameters differ from unit to unit based on the generators facilitated by these governors. The most notable difference

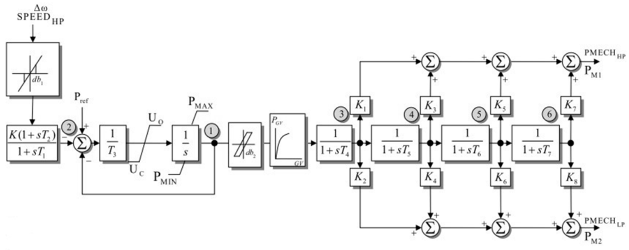

FIGURE 5. Steam units governor single Line Diagram-IEEE G1 type.

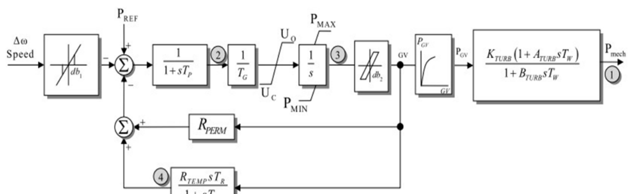

FIGURE 6. Hydro units governor single line Diagram-IEEE G3 type.

TABLE 3. Steam units governor parameters-IEEEG1 model.

Parameters	Symbol	Unit
Controller Gain	K	p.u.
High Pressure Turbine Factor	K_1	p.u.
High Pressure Turbine Factor	K_2	p.u.
Intermediate Pressure Turbine Factor	K_3	p.u.
Intermediate Pressure Turbine Factor	K_4	p.u.
Medium Pressure Turbine Factor	K_5	p.u.
Medium Pressure Turbine Factor	K_6	p.u.
Low Pressure Turbine Factor	K_7	p.u.
Low Pressure Turbine Factor	K_8	p.u.
Governor Time Constant	T_1	s
Governor Derivative Time Constant	T_2	s
Servo Time Constant	T_3	s
High Pressure Turbine Time Constant	T_4	s
Intermediate Pressure Turbine Time Constant	T_5	s
Medium Pressure Turbine Time Constant	T_6	s
Low Pressure Turbine Time Constant	T_7	s
Participation Factor	delta	p.u.
Valve Closing Time	U_C	p.u./s
Valve Opening Time	U_O	p.u./s
Minimum Gate Limit	P_{min}	p.u.
Maximum Gate Limit	P_{max}	p.u.

is between the hydro unit and steam unit Governors. Based on the comparative analyses done between 33 well-known models for different types of governors in single-machine and multi-machine systems, IEEE G1 and IEEE G3 have been identified as the best fits for steam units and hydro units for this application [26], [27], [28].

The block diagrams of these models are presented in Figure 5 and Figure 6, respectively. Parameters, which are required in using IEEEG1 and IEEEG3 standard models, are also respectively presented in Tables 3 & 4.

In this research, the IEEE Standard Frame of signal interconnections is selected as a base for simulating different types of synchronous generators [29].

TABLE 4. Hydro units governor parameters-IEEEG3 model.

Parameters	Symbol	Unit
Gate Servomotor Time Constant	T_g	s
Pilot Vale Time Constant	T_P	s
Governor Time Constant	T_r	s
Water Starting Time Constant	T_W	s
Participate Factor	delta	p.u.
Permanent Droop	Sigma	p.u.
Temporary Droop	Delta	p.u.
Water-hammer 1th Factor	a_{11}	p.u.
Water-hammer 2th Factor	a_{13}	p.u.
Water-hammer 3th Factor	a_{21}	p.u.
Water-hammer 4th Factor	a_{23}	p.u.
Turbine Rated Power	P_{turb}	MW
Valve Closing Time	U_C	p.u./s
Valve Opening Time	U_O	p.u./s
Minimum Gate Limit	P_{min}	p.u.
Maximum Gate Limit	P_{max}	p.u.

The six parameters of the thermal units, which are known as the main effective factors that predominate the frequency performance of the systems, only involve Governors between power plant controllers. Among the governor parameters, the Reheat time constant (T_R) and Droop (R) are the two parameters known as the most influential in terms of their impact on system frequency performance. The reheat time constant tends to dominate the response of the largest fraction of the turbine power output [16], [18].

It is worth mentioning that often power systems include a group of generators with similar dynamic parameters; practically, these power plants are commonly built under a single contract. The analysis shows if the total generation of such a group of generators reaches the largest fraction of system generation, the typical time constant of this group is the time constant of the equivalent unit for this type of generation and this equivalent unit will be functioning as the largest fraction of turbine power output in the system.

It is evident that the steam reheat time constant (T_R) of a steam unit is equivalent to 1/2 of water starting time constant (T_W) for hydro units [27]. Among the aggregation process, the above parameter of the unit with the largest fraction in each type should be considered for the equivalent unit of the above class. This principle is in line with the results of the present study.

In the conventional SFR model, *Km* expresses the total mechanical power in terms of governing valve area. Spinning Reserve (SR) and system power factor affect this gain [18]. But in the new model, the power factor and governing valve area are directly defined in the model; The advanced software determines the SR based on the rating and scheduled powers of the system within each operating scenario.

The common idea found in references, which are cited in this research, is that the gain of the feedback loop or droop has a significant impact on the frequency response of the system. The equivalent droop, when several generators are connected to a system or an island, can be determined as given below [30]:

$$\frac{1}{\mathrm{R_{eq}}} = \sum\nolimits_{\mathrm{i}=1}^{\mathrm{n}} \frac{1}{\mathrm{R_i}} \tag{6}$$

where R_i is the droop of generator number i and n is the total number of generators in a class. Sometimes the speed-droop coefficient or simply droop is referred to in a ratio form as:

$$\rho = \frac{R}{\omega_n} \tag{7}$$

where ω_n is the rated rotational speed.

In such an approach, the reciprocal of droop:

$$K = \frac{1}{\rho} \tag{8}$$

is the effective gain of the governing system.

Using the formula above, the governor controller gain for a system or an island can be determined. The recent expression of the droop, as Controller Gain, is used by the IEEEG1 steam turbine model to simulate the steam unit governor system; Therefore, the feedback gain is equal to 1.

As the contribution of control gain on the frequency response of the system is confirmed, particular simulations which are developed within this research on the equivalent control gain of the steam units (Keq), this gain can be determined as follows:

$$K_{eq} = \frac{\sum_{i=1}^{n} K_i P_i}{\sum_{i=1}^{n} P_i} \tag{9}$$

where K_i is the controller gain of unit i and P_i is the nominal active power generation of unit i.

The effective governor time constant (nominated T_G or T_1), which is called governor time constant or governor response time, in short, has also a significant role in the performance of the governors and is defined as:

$$T_G = \frac{1}{K_A R} \tag{10}$$

where R is speed-droop, and K_A is the amplification gain of the servomotor.

For a class or group of generators, R_{eq} can be determined using equation (6), and the equivalent amplification gain of the servo-motors is equal to the average of the individual amplification gains considering the proportion of each generation unit of the total generation of the group, which is formulated as follows:

$$K_{A_{total}} = \frac{\sum_{i=1}^{n} K_{A_i} P_i}{P_L} \tag{11}$$

where K_{A_i} is the amplification gain of unit i and P_i is the generation output of unit i. P_L is also equal to the total system load, including the transmission loss, and can be determined by:

$$P_l = \sum\nolimits_{i=1}^{n} P_{mi} \tag{12}$$

where P_{mi} is the turbine power output of unit i, and n is the number of generating units in the group. The above formula is calculated concerning the total demand rather than the sum of power ratings; as a result, the local "speed droop" of the generation characteristic depends on the spinning reserve and its allocation in the system. Considering the structure of the IEEEG3 governor model, the determination of the equivalent Droop of the hydro governors is not as easy as steam governors. Three dynamic parameters, which include Temporary Droop (*Delta*), Permanent Droop (*Sigma*) and Governor Time Constant (T_r), have significant contributions to the feedback loop of hydro governors while there are interactions between them. Further evaluation of the permanent droops of the hydro governors also shows this parameter, in an opposite axis with temporary droop, is effective on the post-fault steady-state frequency value, not on the overshoot/undershoot of the system. Principally, there are two ways to determine the three interactive equivalent parameters. The first method is by forming the transfer function of each hydro governor for the feedback pathways, as the polynomials have similar input/output and structure. Then, summing these transfer functions of the parallel feedback paths is feasible. Finally, the degree of the resulting polynomial must reduce to suit the standard form of a hydro governor feedback loop. The second method of equivalent parameter identification is built on numerical iterative methods. Within this work, the equivalents for the rest of the hydro-governors' parameters, except the governor time constant, temporary, and permanent droops, are obtained using the presenting formulas; Then, these three parameters, which have a limited range of variation, are identified using an exhaustive search as it is recommended to be used depending on the expected degree of accuracy. Further studies, as illustrated in Figure 7, have been done to formulate the determination of the equivalent Governor Time Constant (T_r) of hydro units with an acceptable approximation led to:

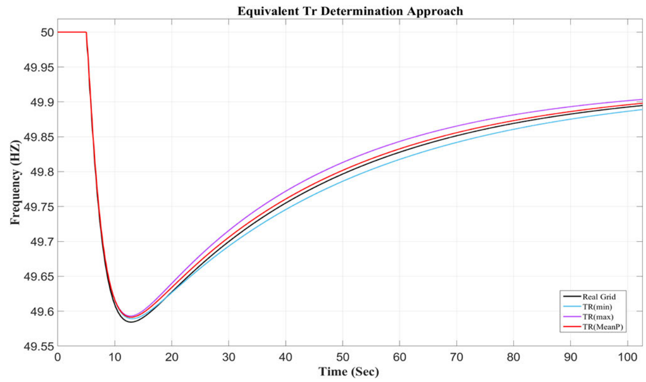

FIGURE 7. **Comparison of analysis of various governor time constant equivalent methods.**

$$T_{r_{eq}} = \frac{\sum_{i=1}^{n} T_{r_i} P_i}{\sum_{i=1}^{n} P_i} \tag{13}$$

where Tr_i is the governor time constant of unit i, and P_i is the nominal active power generation unit i.

The analysis of the equivalent methods of various temporary droop for hydro governors (see Figure. 8) indicates that

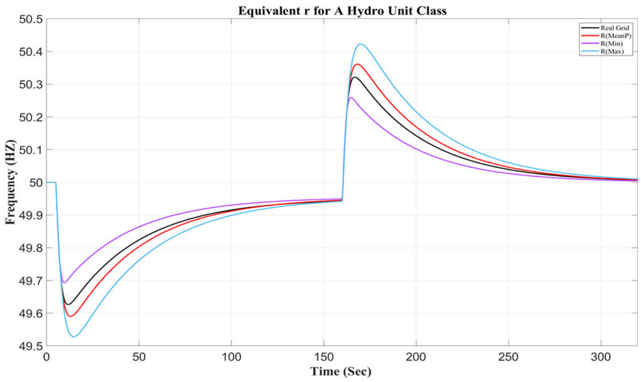

FIGURE 8. Comparison of analysis of the equivalent methods of various temporary droop for hydro governors.

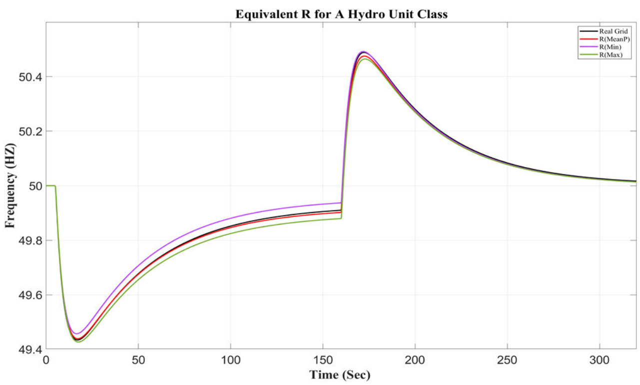

FIGURE 9. Comparison of analysis of the equivalent methods of various permanent droop for hydro governors.

the best formula to give a reasonable approximation of the equivalent Hydro Governor Temporary Droop (*Delta*) is as follows:

$$Delta_{eq} = \frac{\sum_{i=1}^{n} Delta_i P_i}{\sum_{i=1}^{n} P_i} \tag{14}$$

where $Delta_i$ is the temporary droop of hydro governor i, and P_i is the nominal active power generation unit i.

Considering the analysis and the results (as presented in Figure 9), in a similar manner, the best formula to determine the equivalent Hydro Governor Permanent Droop (*Sigma*) with acceptable accuracy is as follows:

$$Sigma_{eq} = \frac{\sum_{i=1}^{n} Sigma_i P_i}{\sum_{i=1}^{n} P_i} \tag{15}$$

where $Sigma_i$ is the permanent droop of hydro governor i, and P_i is the nominal active power generation unit i.

The formulas obtained above make it possible to determine the three interconnected factors (Tr, Delta & Sigma) with minimum effort and sufficient accuracy. While the comparative analysis shows the proposed iterative method provides more accurate results, but is rather tough to apply. The results for all these three parameters show the exact values are limited between the following constraints:

$$X_{min} < X_{eq_{Real}} < X_{eq_{Determined}} \tag{16}$$

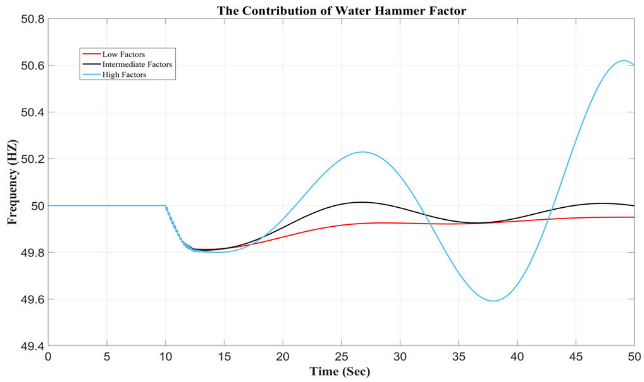

FIGURE 10. The contribution of water hammer factors on frequency response of generator.

where X_{min} is the minimum value of the parameter in the related class, and $X_{eqDetermined}$ is the determined value for the parameters using the related formula (14-16).

Based on [27], the Governor Derivative Time Constant (T_2) of the steam governor is equal to Pilot Valve Time Constant (T_P) for the hydro unit governor, and it tends to dominate the response of the largest fraction. However, the analyses show that Pilot Valve Time Constant (T_P) does not have massive impacts on the frequency response of hydro units.

The Hydro Gate Time Constant or Gate Servo Time Constant (T_g) for hydro governors performs the function of the Servo Time Constant (T_3) of the steam governor and tends to dominate the response of the largest fraction.

The valve closing/opening time of an aggregated unit is equal to the average opening/closing times of the individual generators in a class, considering their portion of the total generation of that class or group, as given follows:

$$U_{c/o_{eq}} = \frac{\sum_{i=1}^{n} U_{c/o_i} P_i}{\sum_{i=1}^{n} P_i} \tag{17}$$

where U_{c/o_i} is the valve closing/opening time of unit i and P_i is the nominal active power generation unit i.

Similarly, this approach is valid in determining the Maximum/Minimum gate limit that leads to:

$$P_{Max/Min_{eq}} = \frac{\sum_{i=1}^{n} P_{Max/Min_i} P_i}{\sum_{i=1}^{n} P_i} \tag{18}$$

where P_{Max/Min_i} is the Maximum/Minimum gate limit of unit i and P_i is the nominal generation unit i.

There are four parameters of the hydro-governors related to the Water Hammer Factor. Related to these factors, there are no issues reported in the literature besides limited lines in [21] and [26]. So, one question that arises is whether or not the Water Hammer Factors have remarkable impacts on the dynamic performance of the generator.

The analysis carried out in this research has confirmed that the factors mentioned above have significant impacts on the generator's dynamic performance. Figure 10 presents a sample of results for three generators with consistent characteristics and identical parameters but different Water Hammer Factors. The results indicate that parallel to increasing the

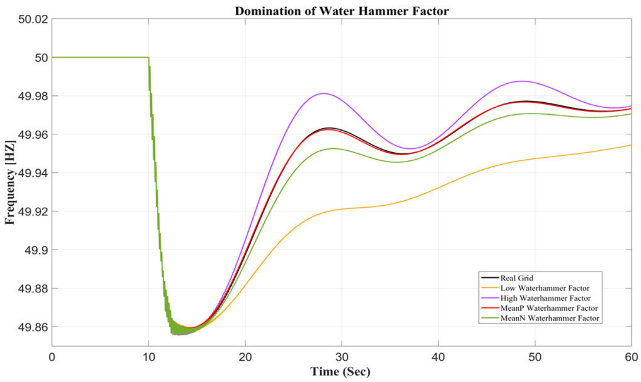

FIGURE 11. Comparison of analysis of various Water hammer equivalent methods.

values of these factors, the governor's reaction becomes faster but more oscillatory. Further, if these factors reach critical values, they lead to instability in the system.

Following the above and related to the ESFR modelling system, it is crucial to find the best way of determining equivalent Water Hammer Factors for a hydro-generator group. In the course of identifying the just mentioned equivalents, four different assumptions have been considered:

- The lowest factors predominate the frequency response of the class,
- The unit with the highest fraction predominates the frequency response of the class,
- The equivalent factor is the mean of individual generation units' Water Hammers considering the proportion of each generator to total generation,
- The equivalent factor is the mean value of the individual values of the group.

All four hypotheses mentioned above have been tested, and the corresponding frequency responses of the equalization methods are compared with the detailed grid performance. A sample of this comparison is illustrated in Figure 11. The analysis clearly indicates that the equivalent values of the Water Hammer Factors for a group of hydro-generators are in line with the third assumption formulated as follows:

$$a_{K_{eq}} = \frac{\sum_{i=1}^{n} a_{k_i} P_i}{\sum_{i=1}^{n} P_i} \tag{19}$$

where a_{K_i} is K^{th} Water Hammer Factor of generator i, and P_i is the active power generation of the generator i.

In a similar fashion for steam unit governors, different turbine factors have been utilized by the standard model (IEEEG1). These parameters are named as K_1 to K_8 (Table 3). Associated with the mentioned eight Turbine Factors, four Turbine Time Constants (T_4 to T_7) are also used by the IEEE model to simulate the steam unit governors (Table 3).

The other question is whether there is a significant relationship between the Turbine Factors and the frequency response of the units. Related to this issue, no remarkable data have been found in the literature that could adequately answer this question. Therefore, the required comparative simulations were conducted by defining three

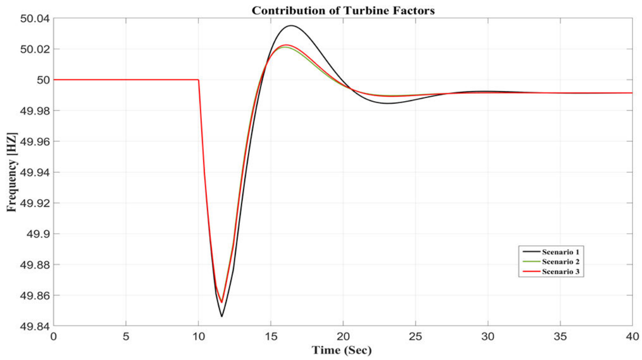

FIGURE 12. The contribution of turbine factors on frequency response of generator.

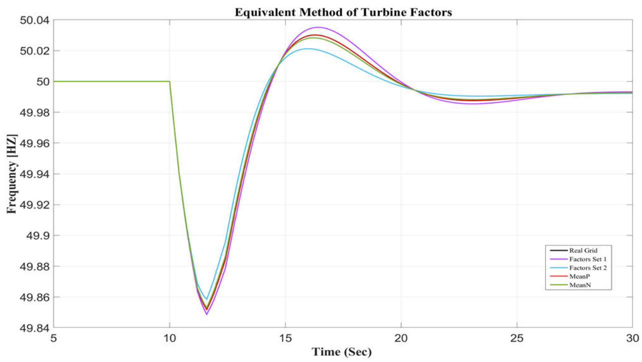

FIGURE 13. Comparison of analysis of various Turbine Factors equivalent methods.

scenarios using different distributions of the turbine factor values. Scenarios 1 and 2 used different values for high and intermediate-pressure turbine factors but similar medium and low-pressures. Scenarios 2 and 3 have the same high and intermediate-pressure turbine factors, while different values for medium and low-pressures. The corresponding frequency responses are presented comparatively in Figure 12.

Based on the analysis (see Figure 12), it can be concluded that there is a relative ranking among the turbine factors. Therefore, the high-pressure turbine factor has the maximum impact on the frequency response of the generators, while the low-pressure turbine factor has the minimum influence.

Therefore, in the next step, it is essential to find the best approach to determine equivalent turbine factors for a specific group of steam generators. Following this, the four hypotheses assumed for determining equivalent Water Hammer Factors have also been evaluated for the turbine factors, and the results are compared with the detailed grid performance (see Figure 13).

The comparative analysis indicates that the third assumption would result in the closest response to actual grid performance. Therefore, an equivalent turbine factor for a group of steam generators can be determined by follows:

$$K_{j_{eq}} = \frac{\sum_{i=1}^{n} K_{j_i} P_i}{\sum_{i=1}^{n} P_i} \tag{20}$$

where K_{j_i} is j^{th} Turbine Factor and P_i is the active power generation of the generator i.

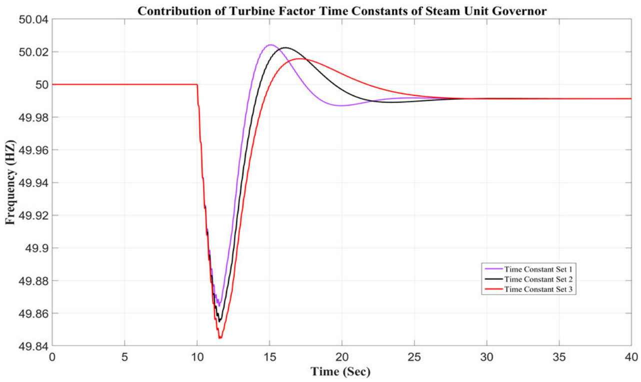

FIGURE 14. The contribution of turbine time constants on frequency response of generator.

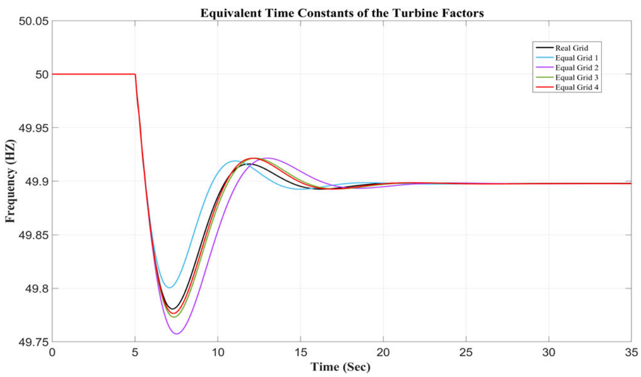

FIGURE 15. Comparison of analysis of various turbine time constant equivalent methods.

The question in this case is whether the variations of turbine time constants within normal ranges of these factors also influence the frequency response of the systems. To address this issue, comparative analyses have been performed under various scenarios. The results confirm that these time constants have a noticeable impact from this perspective. A sample of the results is presented in Figure 14.

Following this, finding the best approach to the determination of equivalent turbine time constants is required to identify. The four hypotheses that were considered as possible approaches in determining the equivalent Water Hammers were also evaluated for the current case, and a sample of the results is illustrated in Figure 15.

Based on these, the best formula to determine equivalent turbine factors for a group of steam generations is as follows:

$$T_{j_{eq}} = \frac{\sum_{i=1}^{n} T_{j_i} S_i}{\sum_{i=1}^{n} S_i} \tag{21}$$

where T_{j_i} is the j^{th} Turbine Time Constant of generator i, n is the total number of generators in the group/class and S_i is the rated apparent power of generator i.

D. CONSIDERATION OF FREQUENCY CONTROL UNITS

It is a common practice in the operation of power systems to assign at least one of the fast response generators in the system as a swing generator to maintain the generation-consumption balances confronting load variations. This unit is known as the frequency control unit(s). Thus, it is essential to consider within ESFR modelling whether developing a separate equivalent for the frequency control units is required or not. In other words, the issue of frequency response units equivalency can be assumed to be addressed in two ways.

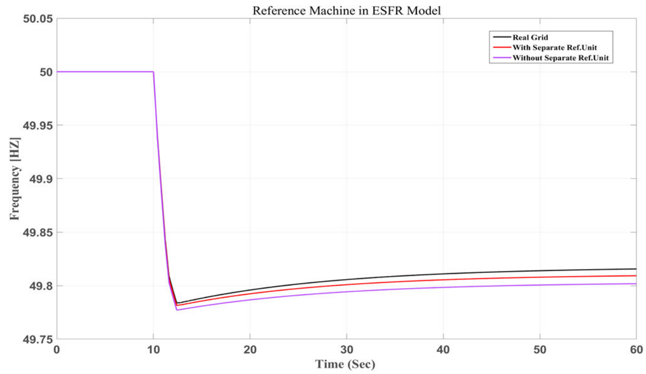

FIGURE 16. The contribution of frequency control units modelling in frequency response of the system.

Considering the first approach, frequency control units can be aggregated with the generation type or class that involves the maximum capacity assigned to this task. But the next allocates a particular equivalent generator to the frequency control units. To evaluate the advantage of defining a separate equivalent over merging with the same generation type, the required comparative analysis has been performed, and a sample of the results is visualised in Figure 16.

The results depicted in Figure 16 indicate that the second strategy lightly improves the accuracy level of the model. However, the improvement is not significant. Therefore, depending on the desired level of accuracy expected within a study, a separate frequency control class can be recommended.

E. TECHNICAL IMPLEMENTATION

As mentioned before, the basic idea is to assume that the system frequency is a function of the overall balance between active power generation and consumption in the grid. In conventional SFR models, this function is restored independently using transfer functions defined between the desired input (i.e. sudden change of active power in the system) and output (i.e. frequency response of the system). In the new approach, it is essential to find out how to model active power balance by eliminating the reactive local voltage effects using the graphical editor of advanced power system software.

One way to achieve this is to use the capacity of the external grid element, which is available in all nowadays advanced power system simulators when adjusted for a constant voltage of *1 p.u.*, no active power transfer and negligible inertia time constant; Thus, the voltage of main bus (see Figure 2, b) would be fixed without intervention to the active power balance and total system inertia. From this perspective, an advantage of this approach over the conventional SFR is the capacity to consider load voltage dependency and a part of inter-machine oscillations, both identified as the

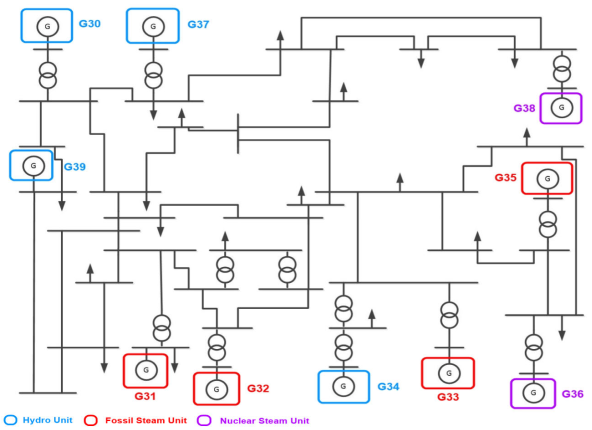

FIGURE 17. The test case configuration (IEEE 39Bus), generation types and placement.

TABLE 5. Definition of generation units.

Plant Code	Machine Type	Mover Type	Parameters Set
G30	Salient Pole	Hydro	H17
G31	Solid Rotor	Fossil Steam	F18
G32	Solid Rotor	Fossil Steam	F19
G33	Solid Rotor	Fossil Steam	F19
G34	Salient Pole	Hydro	H18
G35	Solid Rotor	Fossil Steam	F19
G36	Solid Rotor	Nuclear Steam	N3
G37	Salient Pole	Hydro	H18
G38	Solid Rotor	Nuclear Steam	N4
G39**	Salient Pole	Hydro	H18
**Frequency Control Unit (Slack bus)			

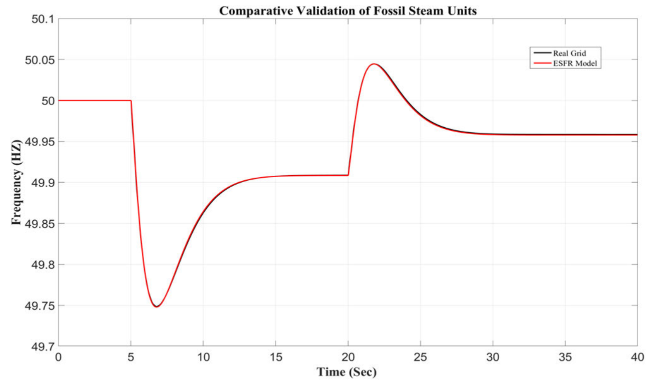

FIGURE 18. Comparative analysis of the ESFR model performance for fossil steam class.

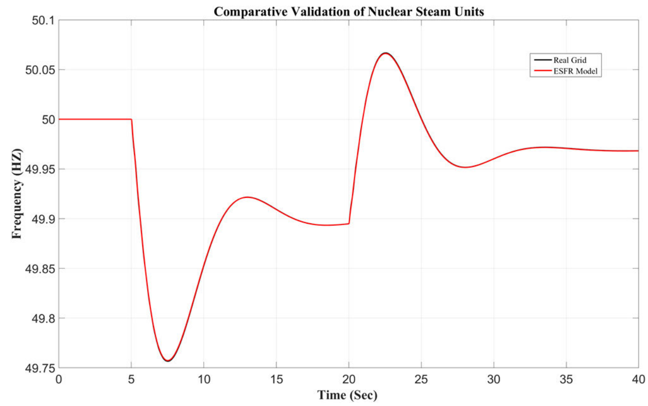

FIGURE 19. Comparative analysis of the ESFR model performance for nuclear steam class.

disadvantages of the SFR model in [20]. The analysis performed within this research certainly confirms the necessity and effectiveness of this suggestion.

IV. CASE STUDY

The new simplified model is developed and validated using the IEEE 39-Bus (New England) test system. Regarding the purpose of this study and considering the general characteristics of the test case, various types of salient-pole and solid-rotor synchronous generators are supposed to operate in the system. This set includes Hydro Units, Fossil Steam Units and Nuclear Steam Units.

The configuration of the test system and subsequent generation types are depicted in Figure 17. The generation types and capacities are specified based on the test system database and real network characteristics. More details about the system can be found in the related references [31], [32], [33].

With due attention to the characteristics of the test system and the dynamic parameters used for the generators, the system generation units are divided into four sub-classes that include Hydro Units, Fossil Steam Units, Nuclear Steam Units, and Frequency control unit, as details are given in Table 5.

The generation nomination and categorisation, which have been used in this work, are representatives of the practical data provided by the leading references [24] and are commonly used by researchers. Further details about the parameter values and the conventional controller settings related to these generator types are available in Appendix and also can be found in [24].

V. MODEL VALIDATION

A comparative analysis between detailed dynamic simulation (10-machine test grid), conventional SFR and the proposed ESFR model is used not only to validate the new frequency modelling system under various operating scenarios but to evaluate the robustness of the new approach over earlier efforts. The operational scenarios and the related events have been selected consistent with the actual grid frequency deviation records [34].

In a hierarchical validation approach, first, the performance of each equivalent unit is evaluated in comparison with the actual generators in the group for each type of generation separately, within load injection and load rejection events. The results for the fossil steam, nuclear steam and hydro units have been presented respectively in Figure 18, Figure 19 and Figure 20.

The validation results during the hierarchy scenarios are evaluated graphically and also numerically. Mean Squared

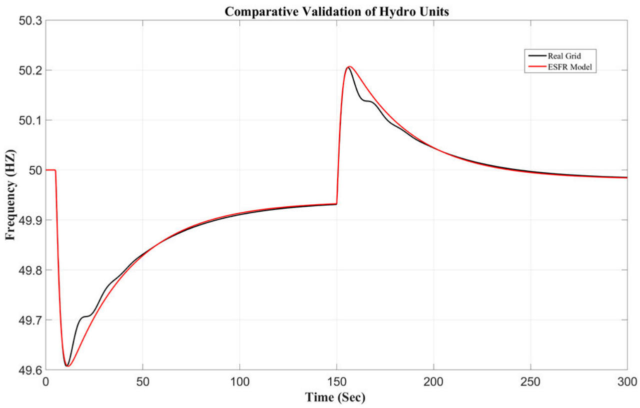

FIGURE 20. **Comparative analysis of the ESFR model performance for hydro generation class.**

TABLE 6. **ESFR model, generation type equivalent validation results.**

Test Case	MSE	MAPE	Min/Max Error
Fossil Steam Units	0.0000	0.0012	0.00% 0.00%
Nuclear Steam Units	0.0000	0.0005	0.00% 0.00%
Hydro Units	0.0001	0.0108	0.33% 0.09%

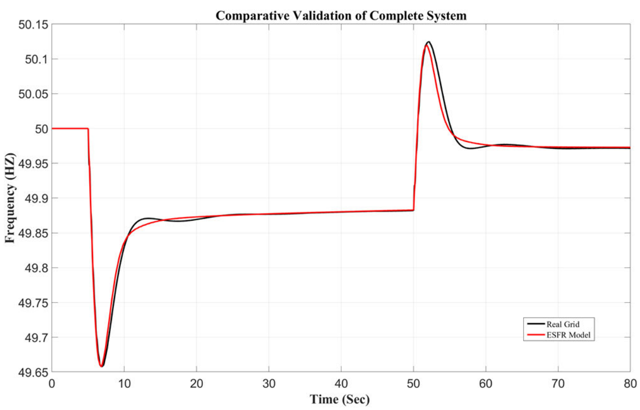

FIGURE 21. **Comparative analysis of the ESFR model performance for IEEE-39 Bus test case.**

Error (MSE) and Mean Absolute Percentage Error (MAPE) are two well-known indices of the performance compatibility evaluation [35], [36], in addition to the percentage of error in simulating max/min (overshoot/undershoot) frequency deviation [37], which have been applied in numerical validation. The numerical results for this step are presented in Table 6. The results clearly confirm high consistency between model outputs and the detailed grid performance in all cases for the single-generation type at this stage.

Considering the satisfactory results that have been achieved during the first step of the validation process, it is time to test the performance of the whole grid, which is a complex system integrating all Hydro, Fossil Steam and Nuclear Steam Units, for the appropriate events involving load injection and load rejection. The results are illustrated in Figure 21.

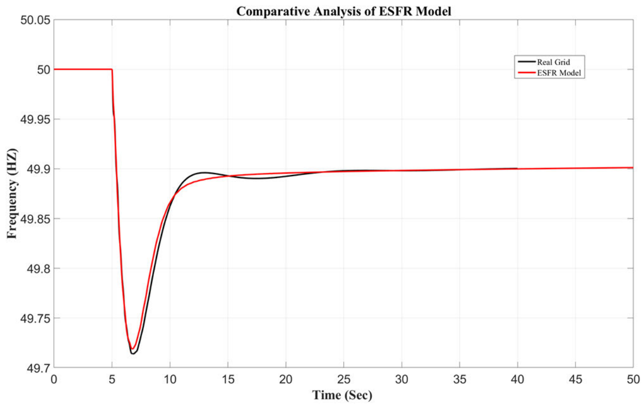

FIGURE 22. **Comparative analysis of the ESFR model performance for IEEE-39 Bus test case.**

TABLE 7. **ESFR model, whole system validation results.**

Test Case	MSE	MAPE	Min/Max Error
Whole System-Load Injection/Rejection Test	0.0000	0.0065	0.00% 3.61%
Whole System-Generator Outage Test	0.0000	0.0047	1.00%

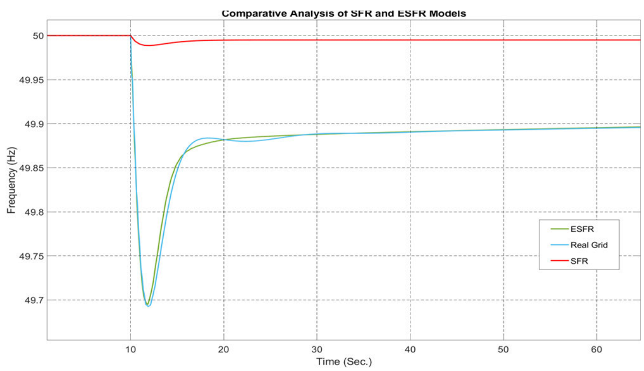

FIGURE 23. **Comparative analysis of the ESFR and SFR models.**

Although both load injection and generator outage events face the power systems a shortage of generation into consumption, the generator outage changes the system inertia constant and, subsequently, the accelerating time constant. Therefore, for achieving a high confidence level, this event, together with the previous test scenarios, has provided a complete validity of the model. Then, the performance of the modelling system is evaluated due to a generator outage event, and a sample of results is depicted in Figure 22.

The validation results for the recent step (i.e., whole complex system scenarios) are analysed graphically and numerically. The three indices introduced earlier, including MSE, MAPE, overshoot/undershoot error, are employed in this step to evaluate the compatibility of the ESFR outputs with the actual grid performance. The numerical results for this step are presented in Table 7. The results not only clearly confirm the high capability of the model but also reveal the new model outputs are highly reliable for all events (load injection, load rejection and generator output).

TABLE 8. Typical values for the dynamic parameters of hydro turbine-generator.

Parameter			Hydro Unit	
Unit No.		Arbitrary Ref. Number	H17	H18
Rated MVA		Machine-Rated MVA: base MVA for impedances	250.00	615.00
Rated kV		Machine-Rated terminal in kV: base kV for impedances	18.00	15.00
Rated PF		Machine-Rated power factor	0.85	0.975
SCR	(1)	Machine short circuit ratio	1.05	…
x_d''	pu	Unsaturated d axis subtransient reactance	0.155	0.230
x_d'	pu	Unsaturated d axis transient reactance	0.195	0.2995
x_d	pu	Unsaturated d axis synchronous reactance	0.995	0.8979
x_q''	pu	Unsaturated q axis subtransient reactance	0.143	0.2857
x_q'	pu	Unsaturated q axis transient reactance	0.568	0.646
x_q	pu	Unsaturated q axis synchronous reactance	0.568	0.646
r_a	pu	Armature resistance	0.0014	0.001
x_l or x_p	pu	Leakage or Potier reactance	0.160	0.2396
r_2	pu	Negative-sequence resistance	0.00	0.00
x_2	pu	Negative-sequence reactance	0.2	0.2
x_0	pu	Zero-sequence reactance	0.1	0.1
T_d''	s	d axis subtransient short circuit time constant	…	…
T_d'	s	d axis transient short circuit time constant	…	…
T_{do}''	s	d axis subtransient open circuit time constant	0.03	0.03
T_{do}'	s	d axis transient open circuit time constant	9.200	7.400
T_q''	s	q axis subtransient short circuit time constant	…	…
T_q'	s	q axis transient short circuit time constant	…	…
T_{qo}''	s	q axis subtransient open circuit time constant	…	…
T_{qo}'	s	q axis transient open circuit time constant	0.06	0.06
T_a	s	Armature time constant	…	…
W_R	MW.s	Kinetic energy of turbine-generator at rated speed in MJ or MW.s	1603.00	3166.00
r_F	Ω	Machine field resistance in Ω	…	…
$S_{G1.0}$	(2)	Machine saturation at 1.0 pu voltage in pu	0.0769	0.180
$S_{G1.2}$	(2)	Machine saturation at 1.2 pu voltage in pu	0.282	0.330
E_{FDFL}	(2)	Machine full load excitation in pu	1.88	…
D	(3)	Machine load damping coefficient	2.00	2.00

Another question that must be answered is the capacity of the ESFR model beyond the conventional SFR-based models. It would also be a clear answer to the question about the necessity of introducing the new frequency response model. In pursuit of this purpose, the behaviour of the conventional SFR model, ASFR model [21] and the proposed ESFR model are compared with the detailed complex network performance for the same operating scenarios. The complex power system used in model validation is the IEEE-39 Bus test system facilitated with six steam generators (fossil steam and nuclear steam) and four hydropower plants, as shown in Figure 17. The ASFR model outputs were out of form, which is consistent with the authors' honest statement that the application of this model is restricted to power systems with dominant thermal generation. A sample of comparative validation for the conventional SFR, new ESFR and detailed models are illustrated in Figure 23. The result clearly shows the necessity of innovating and the high level of accuracy presented by this new model.

TABLE 9. Typical values for the dynamic parameters of hydro governor.

Parameter			Hydro Governor	
Unit No.		Arbitrary Ref. Number	H17	H18
Gov.	(6)	Governor type: G=general, C=cross-compound, H=hydraulic	G	G
R	(6)	Turbine steady-state regulation setting of droop	0.050	0.050
P_{max}	MW	Maximum turbine output in MW	250.00	603.30
T_1	s	Control time constant (governor delay) or governor response time (type H)	30.000	36.000
T_2	s	Hydro reset time constant (type G)or pilot valve time (type H)	3.500	6.000
T_3	s	Servo time constant (type G or C) or Hydro gate time constant (type G) or dashpot time constant (type H)	0.520	0.000
T_4	s	Steam valve bowl time constant (zero for type G hydro-governor) or ($T_w/2$ for type H)	0.000	0.000
T_5	s	Steam reheat time constant or $1/2$ hydro water starting time constant (Type C or G) or minimum gate velocity in MW/s (Type H)	0.415	0.900
F	(6)	Pu shaft output ahead of reheater or -2.0 for hydro units (types C or G), or maximum gate velocity in MW/s (type H)	-2.000	-2.000

TABLE 10. Typical values for the dynamic parameters of steam turbine-generator.

Parameter	Fossil Steam		Nuclear Steam	
Unit No.	F18	F19	N3	N4
Rated MVA	590.00	835.00	500.00	920.35
Rated kW	22.00	20.00	18.00	18.00
Rated PF	0.95	0.90	0.90	0.90
SCR	0.500	0.500	0.580	0.607
x_d''	0.215	0.339	0.283	0.275
x_d'	0.280	0.413	0.444	0.355
x_d	2.110	2.183	1.782	1.790
x_q''	0.215	0.332	0.277	0.275
x_q'	0.490	1.285	1.201	0.570
x_q	2.020	2.157	1.739	1.660
r_a	0.0046	0.0019	0.0041	0.0048
x_l or x_p	0.155	0.246	0.275	0.215
r_2	0.026	0.022	0.029	0.028
x_2	0.215	0.309	0.280	0.230
x_0	0.150	0.174	0.152	0.195
T_d''	0.0225	…	0.035	…
T_d'	…	…	1.512	…
T_{do}''	0.032	0.041	0.055	0.032
T_{do}'	4.200	5.690	6.070	7.900
T_q''	0.0225	…	0.035	…
T_q'	…	…	0.756	…
T_{qo}''	0.062	0.144	0.152	0.055
T_{qo}'	0.565	1.500	1.500	0.410
T_a	0.140	…	0.310	0.190
W_R	1368.00	2206.40	1990.00	3464.00
r_F	0.1094	…	…	0.0901
$S_{G1.0}$	0.079	0.134	0.0900	0.0816
$S_{G1.0}$	0.349	0.617	0.3520	0.3933
E_{FDFL}	2.980	3.670	2.710	2.870
D	2.00	2.00	2.00	…

TABLE 11. Typical values for the dynamic parameters of steam governor.

Parameter	Fossil Steam Governor		Nuclear Steam Governor	
Gov.	G	G	G	G
R	0.050	0.050	0.050	0.050
P_{max}	553.00	766.29	450.00	790.18
T_1	0.080	0.180	0.250	0.215
T_2	0.000	0.030	0.000	0.015
T_3	0.150	0.200	0.000	0.050
T_4	0.050	0.000	0.300	0.250
T_5	10.000	8.000	5.000	5.640
F	0.280	0.300	0.320	0.325

VI. CONCLUSION

This paper describes a new Extended System Frequency Response (ESFR) model of an electric power system, which is performed via a greatly simplified and high-capability frequency modelling approach to address the requirements of complex power systems.

The proposed parameter equivalency, classified, aggregated model uses the well-known and standard IEEE submodels as a platform and also employs the high capabilities of the advanced power system software in an effort to provide a new simplified modelling approach to simulate the frequency response of complex power systems which include hydro generations considering the potential to be adapted for complex loads, other renewable generations (particularly wind and solar generation) and neighbour system connections.

The analysis and validation are performed by comparing the model outputs with detailed dynamic simulations, partly depending on the generation type, and the whole complex system. The results confirm not only the necessity of introducing this model beyond the conventional approach but its high capability in simulating the frequency performance of modern power systems with a high confidence level close to 100% (mean absolute percentage error in the worth condition is less than 0.007% and maximum error in estimating frequency overshoot/undershoot is constrained to 3.61%), which it is encouraging certainly.

This validated modelling system can be a practical and beneficial approach to study and address the impact of renewable energy resources with increasing penetration in modern power systems. The satisfactory results achieved at this stage of the research provides a compelling motivation for further development of the ESFR model to consider the complex loads, wind generation, solar generation and neighbour system connections.

APPENDIX

See Tables 8–11.

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