Considerations for Interconnection of Large Power Grid Networks

Komal S. Shetye, Thomas J. Overbye,
Hanyue Li, and Julian Thekkemathiote
Texas A&M University
College Station, TX, USA
{shetye, overbye, hanyueli, julianp}@tamu.edu

Harvey Scribner
Southwest Power Pool
Little Rock, AR, USA
hscribner@spp.com

***Abstract*—Interconnection i.e. the wide-area synchronous operation of large power systems using ac interties has provided opportunities to improve system reliability and better connect the ever-increasing renewable generation locations to load centers. While some of these goals are achievable with dc ties, ac connections and synchronous operation have unique advantages as well as certain challenges that need to be carefully studied. This paper aims to highlight the key issues that need to be considered in assessing the feasibility of the synchronous interconnection of large power grids, with a focus on dynamics. To provide realistic results without revealing confidential information about the actual grid, the paper makes use of synthetic grid models for the US Eastern and Western Interconnect footprints.**

***Index Terms*—interconnection, synchronous, ties, feasibility, large-scale systems, synthetic grids**

I. INTRODUCTION

Interconnection i.e. the wide-area synchronous operation of large power systems using ac interties has been an area of active interest and development. The synchronous grid of continental Europe is the largest interconnection in the world, serving over 400 million customers in 24 countries with an average yearly generation of 2500 TWh. In North America (NA), there are four major interconnected systems, the Eastern (EI), Western (WI), Texas, and the Quebec Interconnection. All of these ac networks are internally synchronized and are linked to each other only through dc ties. However, for eight years between 1967 and 1975, a single synchronous system (excluding Texas and Quebec) was operating [1], which included 94% of the US generating capacity [2]. This first major interconnection was motivated by the November 1965 Northeast Blackout, which left 30 million people without power across 11 US states, and Canada. The interties functioned well at first but soon became unstable due to oscillations on the western side and large inadvertent exchanges. This led to overloading of transmission facilities, major system breakups, and reduced transmission capacity. Interconnecting large grids especially with ac ties is a big challenge that needs rigorous assessment and planning.

There have been several studies and implementations around the world of joining large grids with dc ties, and some examples with ac ties. In 1991, the continental Europe grid was broken into two synchronous grids separating western and central Europe due to political issues, and re-connected in 2000 with the emergence of favorable conditions [3]. This was done after extensive steady-state and dynamics studies [4]. For further expansion, [5] studied the feasibility of connecting this synchronous grid with the Baltic States. This involved creating a merged static and dynamics model of the two grids. Some of the issues found in this process were the emergence of very low frequency ($\sim$ 0.07 Hz) oscillations, as well as transfer capability limitations due to local congestion.

Reference [6] considered possible scenarios for interconnecting North and South Korea using a 765 kV HVAC interconnection, with power flow studies for load increase scenarios for the ac ties. The need for, political issues with, and advantages of different schemes were discussed. In [7], two candidates were evaluated for the future Chinese "super grid", to enable bulk capacity long distance power transmission, i.e. 1) the ultra-high-voltage ac (UHVAC) synchronous power grid, 2) the extra high-voltage ac (EHVAC) asynchronous super power grid. This paper provided qualitative assessments of both schemes considering security, economic, and environmental factors based on which the EHVAC method was found to be superior, with a caveat that better studies are needed to verify the results. The benefits of the ac connections were lower short circuit currents, with the main disadvantage being the susceptibility to cascading failures.

In NA, the more recent as well as previous interconnection studies have mainly focused on the economic or resource planning aspects [8], [9] or the use of HVDC for transmission expansion and design [10]. These works are part of a larger effort comprising of research and industry members that proposed four different high-capacity wide-area transmission infrastructure designs to expand the US grid [11]. This study was focused on leveraging dc systems i.e. upgrading the existing back-to-back (B2B) dc ties and/or building long HVDC lines or overlays. While this included rigorous analyses considering future capacity, carbon policies, etc., a key area of improvement mentioned in [11] is performing contingency and stability analyses. The feasibility of ac tie connection has been seldom studied [12], with the need for more up-to-date assessments with improved models such as automatic generation control (AGC) modeling in long-term dynamics, etc. identified in both [12], [13]. System dynamics is a key concern while considering operating two large grids synchronously.

The goal of this paper is to highlight the key considerations of studies involving interconnection of large-scale grids, with a focus on dynamics. To provide realistic results without revealing confidential information about the grid, the paper makes use of synthetic grid models covering, approximately, the US portions of footprints of the existing EI and WI. The paper discusses issues such as modeling two different interconnections that use different software packages and hence contain different dynamic models, actual ac connection of the grids at different locations, long term dynamics and AGC modeling, and visualization.

The paper is structured as follows. Section II describes the synthetic east and west networks of the US grid, and the process of connecting them with ac connections (also referred to as "ties"). Section III describes the dynamics i.e. transient stability considerations such as frequency response, and long term AGC modeling with examples of visualization of large-system results. Section IV summarizes the paper and its key outcomes.

II. Network and Steady State Considerations

A. Synthetic East (SE) and West (SW) Grids

As mentioned earlier, using realistic synthetic grids allows us to test new methods and present research results without revealing critical energy infrastructure information (CEII). Accordingly, the paper uses two synthetic grids [14], [15] available at [16], geographically sited over the EI and WI footprints. The 10,000-bus western synthetic grid (Figure 1) and the 70,000-bus eastern case (Figure 2) bear no relation to the actual grids except that generation and load profiles are similar, based on public data. The transmission lines are entirely fictitious. These test systems are meant to reflect heavy load, i.e. peak summer conditions. Table I enumerates some of the key system parameters of each synthetic grid.

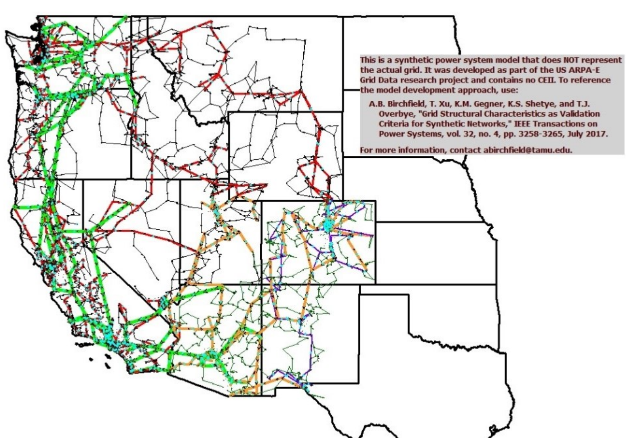

Fig. 1. Synthetic Western US grid

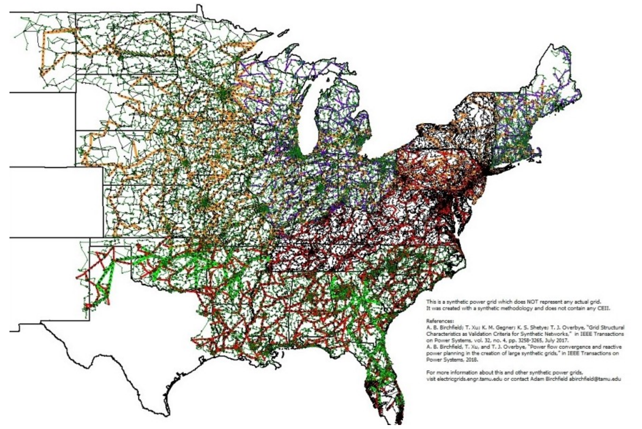

Fig. 2. Synthetic Eastern US grid

TABLE I
Synthetic Networks Summary

Property	Synthetic East (SE)	Synthetic West (SW)
# of Buses	70,000	10,000
# of Gens	10,390	2,485
# of Loads	38,180	4900
# of Lines	71,353	9726
Total Gen (MW)	613,000	15,400
Total Load (MW)	594,700	151,000
# of Areas	52	16
Voltage Levels (kV)	13-24, 69, 100, 115, 138, 161, 230, 345, 500, 765	13-24, 115, 138, 161, 230, 345, 500, 765

B. Interconnection of SE and SW Systems

Consideration 1: Number and location of ties

Naturally, geographic proximity of two buses/substations, one in either system, is one of the main factors in deciding the points of interconnection. If they are at the same nominal voltage level, they can be connected by jumpers or what are also called zero impedance branches. Otherwise, connections can be made with transformers, which would be a more expensive option. Another important aspect of choosing the connection points and locations is the adjoining transmission infrastructure. Assuming that these ac ties are meant to support sizeable transactions, the lines immediately connecting these ties to the rest of the grid on each side should be able to handle the flows. This would be the minimum cost approach. Otherwise, the interconnection plan needs to include rating upgrades and construction plans of lines/transformers/substations near the ac ties.

The number of connection points depends on factors such as the desired MW transfer capacity. Having too few lines would restrict this value, potentially causing congestion, in addition to weakening the connection between two large systems, from both a steady state and dynamics perspective. A major motivation, especially relevant in NA is to assess the potential for improved generation (mostly renewable) resource utilization across the systems, e.g. the benefits of trying to

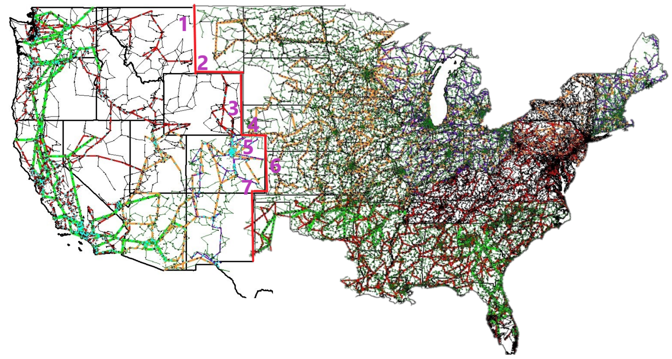

Fig. 3. Synthetic Eastern and Western US grids with the Onelines meeting at the Red Boundary and the 7 Transmission Lines and Transformers in the Interface shown in Magenta

connect the wind centers in the middle of the US to the load centers in the West.

Considering these factors, the SE and SW grids were connected at seven locations, as numbered in Figure 3:

1) Glasgow (Montana) to Fort Peck (Montana)
2) Hardin (Montana) to Colstrip (Montana)
3) Wheatland (Wyoming) to Scottbluff (Nebraska)
4) Peetz (Colorado) to Sidney (Nebraska)
5) New Raymer (Colorado) to Kimball (Nebraska)
6) Burlington (Colorado) to Goodland (Kansas)
7) Lamar (Colorado) to Johnson (Kansas)

These seven connections collectively are referred to as "the Interface" in the rest of the paper.

Consideration 2: Setting parameters for the ac ties

A key task then is to assign appropriate impedance values and MVA ratings (i.e. limits) to these newly created ties. Zero impedance branches are commonly modeled in the power flow as very low reactance branches; this approach was followed here where values around $0.02-0.03$ pu were used for the reactance of a tie line. In case of transformers, larger values were used, ranging from $0.04-0.07$ pu. These were determined by, 1) reactances of neighboring branches, and 2) series ac reactances of transformers in the case with similar voltage levels. The MVA ratings of the ties were assigned close to those of the connecting branches, choosing the lower end in case of a large difference for a transformer. Table II shows the impedance and ratings assigned to the ac ties.

TABLE II
SEAMS SUMMARY

No.	From Bus (kV)	To Bus (kV)	X (p.u.)	Lim (MVA)
1	Glasgow (138)	Fort Peck (500)	0.055	600
2	Hardin (345)	Colstrip (500)	0.06	1200
3	Wheatland (345)	Scottsbluff (500)	0.07	1400
4	Peetz (500)	Sidney (500)	0.03	2000
5	New Raymer (500)	Kimball (500)	0.02	2000
6	Burlington (500)	Goodland (500)	0.03	2000
7	Lamar (500)	Johnson (161)	0.04	800

Consideration 3: Initializing flows on the ties

It is expected that such interconnection models would be extensively used to assess the transfer capacity between existing systems. For such studies, it is important to initialize the flows on these newly created ac ties ideally or close to zero MW. Note that some flows may be unavoidable due to the difference in the power sharing among areas and generators on either side due to system-specific participation factors. Hence the focus can or should be on ensuring that the net MW flow across the Interface is close to zero. In this example, it involved changing the dispatch of certain generators on the SW side given that the slack bus generator was in the SE. Table III shows the initialized individual and net flows across the Interface.

TABLE III
AC TIES INITIAL FLOWS

From Bus	To Bus	Branch Device Type	MW From
Glasgow (138)	Fort Peck (500)	Transformer	57
Hardin (345)	Colstrip (500)	Transformer	-196.4
Wheatland (345)	Scottsbluff (500)	Transformer	273.6
Peetz (500)	Sidney (500)	Line	41.4
New Raymer (500)	Kimball (500)	Line	36.1
Burlington (500)	Goodland (500)	Line	-119.2
Lamar (500)	Johnson (161)	Transformer	-100.5
		Total MW	**-8.0**

Consideration 4: Expected flow through each tie

Sensitivity analyses such as power transfer distribution factors (PTDFs) can help determine the expected percentage of a power transfer across the Interface, on each ac tie. In the previous part, the tie ratings were determined just based on the neighboring lines. The PTDF analysis yields a better estimate of the capacity needed for different values and directions of transfers, so that capital resources for potential upgrades may be prioritized for the more sensitive ties.

PTDFs show the percentage of the transfer that will flow on each element (i.e. a transmission line or a transformer branch) for a transaction between a defined source (buyer) and sink (seller). Here, the buyers and sellers are on opposite sides of the Interface, so 100% of the transfer goes through the Interface. For six transfer scenarios, PTDFs were calculated for the whole system including the ac ties using a linearized lossless dc power flow solution. Table IV shows the PTDFs on the ties for the six transfer scenarios that are between either 1) two subsystems such as the whole of the Synthetic East and West grids, or 2) Areas in each grid. The Areas are defined by geographic states. Here NE: Nebraska, CO: Colorado, MT: Montana, MN: Minnesota, NM: New Mexico, OK: Oklahoma, SD: South Dakota, ID: Idaho, AZ: Arizona, and IL: Illinois.

Table IV shows that for a given transfer across the Interface, one can expect a flow of at most 25% through any one of the ties, with around 5% on the lower side. In most transfer scenarios, a major portion of the flows would occur through the Hardin-Colstrip and the Burlington-Goodland ties, i.e. around

TABLE IV
PTDFs

From Bus	To Bus	Buyer to Seller, PTDF (%) SE to SW	NE to CO	MT to MN North	NM to OK	SD to ID	AZ to IL North	Avg.
Glasgow	Fort Peck	5.88	3.16	8.41	4.56	7.19	5.42	**5.77**
Hardin	Colstrip	20.95	12.78	38.3	17.07	25.03	19.93	**22.34**
Wheatland	Scottsbluff	8.4	7.8	11.06	7.67	8.66	7.92	**8.58**
Peetz	Sidney	13.23	16.94	8.71	15.15	13.05	13.78	**13.47**
New Raymer	Kimball	17.04	21.5	11.61	18.16	17.77	17.81	**17.32**
Burlington	Goodland	22.87	26.03	14.89	25.17	19.2	23.35	**21.92**
Lamar	Johnson	11.63	11.79	7.03	13.22	9.1	11.79	**10.76**

a fifth to a quarter each, of the total MW transferred. These would be followed by the New Raymer-Kimball and the Peetz-Sidney ties. On the other hand, Fort Peck is expected to carry at most 6% of any transfer.

Consideration 5: Transfer limits

A key quantity to determine would be how much power transfer is possible across the Interface, in either direction (i.e. 1) West to East or the SW to SE grid, and 2) East to West or the SE to SW system). There are several methods available to determine this, such as finding the Available Transfer Capability (ATC). ATC analysis determines the maximum incremental MW transfer possible between two parts of a system without violating any specified limits. The Single Linear Step approach is a common method of solving ATCs. It uses sensitivities about the present system state, which are included in the PTDF and Line Outage Distribution Factor (LODF) calculations. For example, the estimated maximum transfer without overloading the line is,

Transfer Limit = (Limit – Present Loading) / PTDF

When including contingency (CTG) analysis, the OTDF (Outage Transfer Distribution Factor) and linearized estimates of post-CTG flows are used to determine the Transfer Limit,

Transfer Limit = (Limit – Post-CTG Loading) / OTDF

For the base case (i.e. with no contingencies), the first limiting element of the Interface is encountered at a transfer value of 4800 MW for the East to West direction, and at 6600 MW in the West to East direction. This happens to be the Hardin-Colstrip tie of the Interface, which corroborates the PTDF results. When non-Interface limiting elements are considered, these values are lower with 1800 MW for East to West and 2000 MW for West to East transfers, with the same few limiting elements resulting for multiple transfer scenarios. This is indicative of the potential for major improvements in transfer capacity, with a few rating upgrades. When N-1 contingencies are applied, the first limiting element of the Interface is Lamar-Johnson at a 5000 MW West-East transfer across the Interface. For East-West transfers, the transfer limit is around 3500 MW with Hardin-Colstrip and Lamar-Johnson reaching their limits.

Note that these results were for a dc analysis, which ignores reactive power. Next, we use a full ac power flow solution with different transfers across the interface and identify each transfer limit (i.e. transfer value until which a power flow solution is obtained). For simplicity, areas are chosen arbitrarily in the East and West to set up MW transactions. The transfer limit in this case is around 2300 MW East to West (OK to CO transfer) and 2500 MW West to East (Wyoming to NE transfer).

Consideration 6: Modeling extremely large networks in conventional software

In the SE and SW systems, as well as in the real EI and WI grid models used in industry, a minor but important issue is overlapping bus and area numbers across the two systems. This can cause complications while combining and simulating the two systems together (something which is rarely done in practice, and perhaps seldom in research). To the authors' knowledge, this issue has not been explicitly discussed or addressed in the literature so far. This was resolved by adding the number 2,000,000 to the bus numbers in the West, and 2000 to the area numbers. A key thing to note here is that the underlying simulation software should be able to model such large bus numbers, which is not the case in some of the very common and widely used packages. Other considerations with the use of commercial packages used for such large-system studies are mentioned in the dynamics discussion.

III. Dynamics

Consideration 7: Implementing dynamic models from different systems

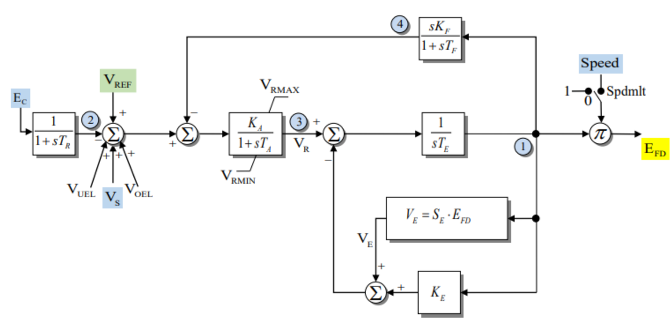

Fig. 4. IEEET1 Exciter Block Diagram [17]

The actual EI and WI cases both contain a variety of dynamic models of generators, their controls, loads, and relays, etc. These models have also been included in the SE and SW systems. Traditionally, one particular commercial software (referred to henceforth as Package A, (SP_A)) has been widely used to represent the EI steady state case and its dynamic models, while another commercial package B (SP_B) has been used for decades in the West. While they mostly use IEEE or industry standard dynamic models that are usually implemented exactly the same way in both SP_A and SP_B, there are several instances where the the same model is represented slightly or quite differently. This not only poses a problem to read the model data, but could also affect simulation results, as shown in [18]. Examples include generator speed multiplier blocks in exciters as seen in Figure 4, wherein SP_A has no speed multiplication for this model but SP_B does. For this task, we used a software package C (SP_C) that models all these variations from SP_A and SP_B.

Consideration 8: Frequency response and stability

In power system dynamics, frequency disturbances and response are known to be a wide-area (or global) phenomenon in a system. Hence such contingencies, of a magnitude large enough to cause wide-area impacts, would be appropriate in analyzing very large systems such as the interconnected SE-SW. A well-known, real-life benchmark event is the loss of two generating units in Arizona, totalling around 2800 MW. Since the synthetic systems contain real generator data, this event is applied in both the SW and the interconnected SE-SW system, with the average frequency of the buses in each substation shown in Figure 5 for the 10,000 bus SW system and in Figure 6 for the 80,000 bus combined SE-SW grid.

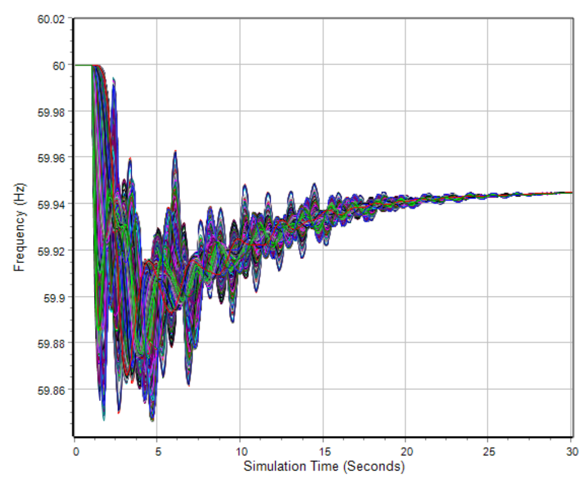

Fig. 5. Substation Average Bus Frequency for the 2800 MW Generation Drop Contingency in the SW System

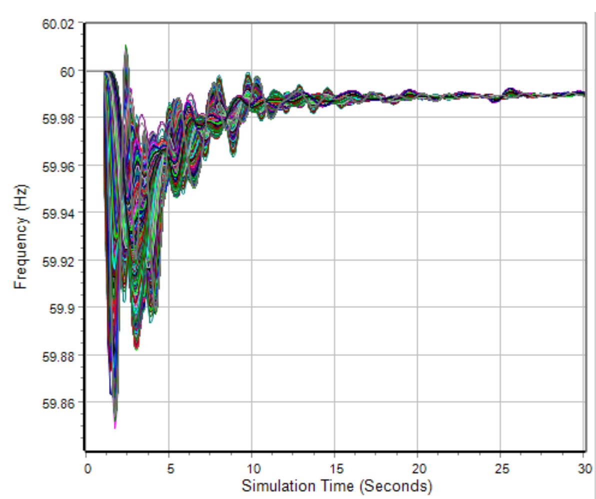

Fig. 6. Substation Average Bus Frequency for the 2800 MW Generation Drop Contingency in the Combined SE-SW System

A number of observations can be made. While the overall frequency nadir is about the same across the two simulations, the settling values are quite different (59.945 Hz vs 59.99 Hz). Also the combined SE-SW system has a faster rate of recovery, thus overall having a better frequency response than the SW only system. This is likely due to the MW support provided by the SE, as seen in Figure 7. Almost 2100 MW of the 2800 MW lost in the contingency comes from the East, which accounts for nearly 75% of the dropped generation. To see how this effects the SE system, Figure 8 shows Figure 6 again on the right, and compares it side-by-side with just the SE frequencies during the same simulation. The impact on the SE frequencies is marginal, as observed. Other simulations indicate a similar percentage of flow from the East to the West for such contingencies. Conversely, for a loss of generation in the East, around 25% flows from the West. In short, from a dynamics perspective, the SE system aids the SW significantly without affecting itself much.

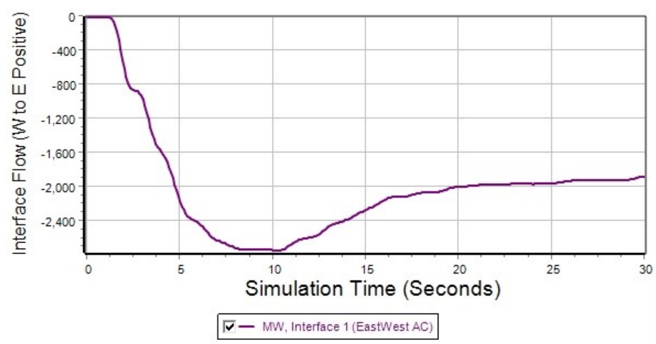

Fig. 7. Total MW Flow on the Interface from West to East

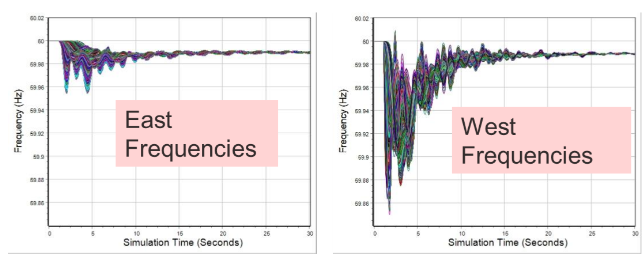

Fig. 8. Substation Average Bus Frequency in the Combined SE-SW System (SE Buses on the Left, SW on the Right)

Another important observation from Figure 7 is that the Interface flow does not return to zero/pre-disturbance value even after the frequency has settled. This is because the AGC response was not modeled (so far) in these dynamic simulations.

Consideration 9: Tie flows should be able to return to pre-contingency values

Transient stability or dynamic simulations have a time-frame of around msec-sec, with a typical large-system simulation being 30 seconds long. This is because this time frame is sufficient for the dynamics of key components such as exciters, governors, and stabilizers to respond and settle. However, at times longer duration simulations are needed to consider long-term or slower phenomena, a good example being the AGC response, which lies in the time frame of minutes. Continuing from the previous example of the loss of 2800 MW, about 75% to 80% of the governor response will occur in the east, with the flow increasing from east to west across the Interface if the contingency is generation loss in the west and the opposite direction for generation loss in the east. By themselves, the governors do not restore the system frequency to its setpoint value; rather this is done by the AGC utilizing the balancing authority area control error (ACE) signal. The ACE has a frequency component,

$$ACE = P_{actual} - P_{sched} - 10\beta(freq_{actual} - freq_{sched}) \quad (1)$$

where β is the frequency bias; it has a negative sign, units of MW/0.1 Hz and is about 1% of the peak load/generation.

This AGC response usually takes place on the order of minutes, so it has not traditionally been included in standard transient stability level dynamic simulations. This was modeled and studied specially to determine whether the Interface flows can return to pre-disturbance values for such an interconnected system. This was setup by defining all areas as being on AGC control, assigning to each a β value, a frequency measurement bus, an ACE MW deadband and a set of scheduled transactions. For each area, the unspecified transactions were modified so the starting ACE for each area is zero. In addition, each generator also needs an AGC controller. The AGC controller has a MW minimum and maximum value, and a participation factor. Given that this information is not available, defaults were used in the initial studies (min/max values from the power flow, and its participation factor proportional to is maximum MW value). Then during the simulation, the area ACE is calculated, with the ACE error sent to the generator AGC controllers, with the desired MW control change proportional to its participation factor. This error is then used to change the governor setpoint values.

For the simulation presented here, the contingency is again a loss of generation (2800 MW) in the SW. Initially, as before, the change in the generation is handled by the governor response. But then in these extended simulations bilateral transactions are implemented between the area that lost the generation and other nearby areas, with the transactions ramping up over a specified time period. For simulation and display convenience these transactions were setup to start faster than would actually occur (here at a simulation time of 30 seconds) and ramp faster (here with ramping between 30 and 90 seconds). The total simulation ran for 120 seconds. Figure 9 shows the response of the Interface MW over the whole two-minute simulation. With the AGC modeled and transactions setup, the Interface MW does indeed return to the pre-disturbance value.

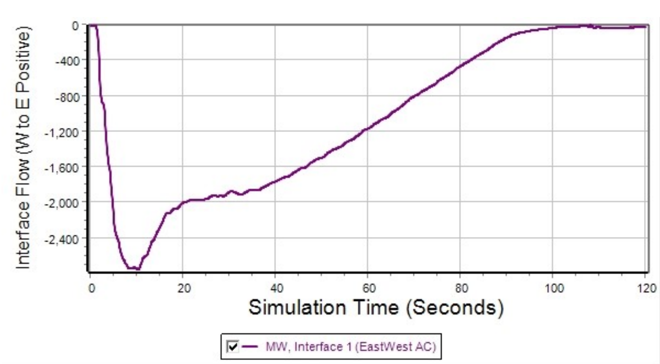

Fig. 9. Total MW Flow on the AC Ties from West to East

Consideration 10: Understanding large-scale results

A major challenge associated with these analyses is understanding what is occurring in the large-scale electric grids, particularly when they could be subject to unusual operating conditions such as those associated with a new ac interconnection. This in addition to the large quantity of simulation results, especially dynamics with hundreds of thousands of buses, models, states, etc. creates a unique challenge for interpreting and summarizing these results. For the earlier generation outage, graphing all of the 80,000 bus frequencies from the combined SE-SW system in Figure 10 and all of the voltage magnitudes in Figure 11 provides an understanding of the overall system response to the event.

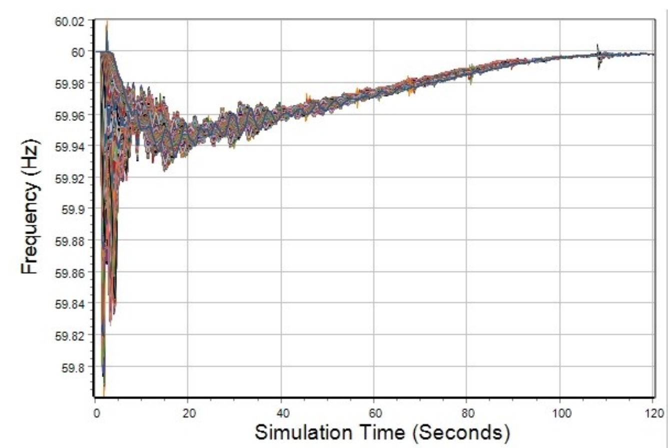

Fig. 10. Frequency Response at All 80,000 Buses

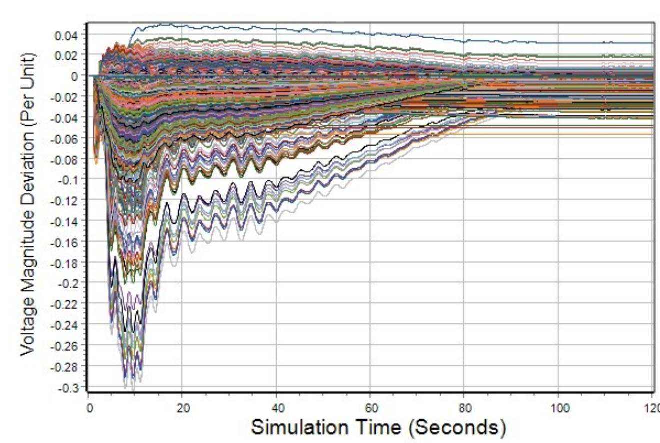

Fig. 11. Voltage Magnitude Deviation at All 80,000 Buses

While the individual signals cannot be determined from such figures they do provide the overall envelop of the response. This example demonstrates that 1) all frequencies settle back to 60 Hz with the AGC response, 2) the voltage magnitudes settle back close to their original values (for the generator contingency), and 3) there is a part of the system in which the voltage recovers slowly.

An approach to visualize the spatial variation in system quantities such as voltage magnitude deviation at a particular time would be to use a contour [19]. This is illustrated in Figure 12 in which a red/blue contour is used to show the voltage magnitude variation at ten seconds. The contour can be combined with other objects such as GDVs shown in the same figure. A GDV is an electric grid display object whose location is dynamically determined from geographic information embedded in an electric grid model [20]. Here the GDV summary objects [21] are super-imposed on the contour with the yellow/magenta rectangles showing the change in MW generation in different parts of the system in response to the contingency and the black GDV summary flow arrows showing the change in MW flow on the transmission grid.

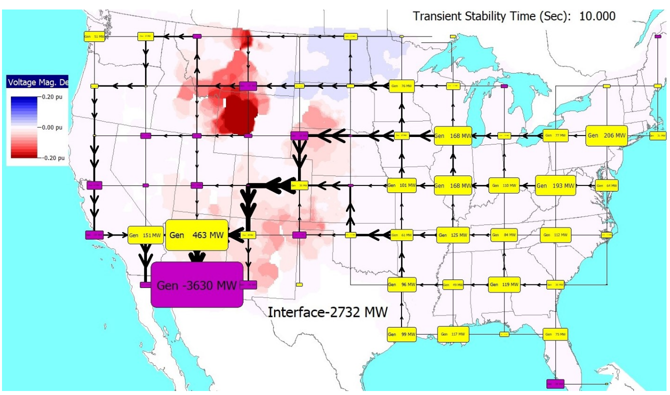

Fig. 12. Visualization at 10 Seconds using Voltage Contour and GDV Summary Objects

IV. Concluding Remarks

This paper aimed to highlight the key issues that may need to be considered in assessing the ac interconnection of large power grids with a focus on the dynamics aspects, using the US Eastern and Western grids as examples. To protect the confidentiality of the real grids, realistic but fictitious synthetic grids were used to demonstrate the methodology. The ten considerations discussed in the paper were as follows:

1) Number and location of ties
2) Setting parameters for the ties
3) Initializing flows on the ties
4) Expected flow through each tie
5) Transfer limits
6) Modeling large networks in conventional software
7) Implementing dynamic models from different systems
8) Frequency response and stability
9) Tie flows returning to pre-contingency values
10) Understanding large-scale results

From the dynamic studies, the key limiting characteristic on interconnecting the synthetic east and west systems (and most likely the actual EI and WI system due to the generator data across the real and synthetic grids being the same) was found to be that during generator loss contingencies in the west, approximately $75 - 80\%$ of the lost power will flow through the Interface from east to west. This is due to the governor response that takes place uniformly through the interconnect and most of the generation is east of the Interface. This issue is fundamental to interconnecting large grids and does require any interface joining two such larger grids be able to handle this flow (at least until AGC can respond). In particular for the SE and SW, there need to be more than just a few tielines. For the flow to return to pre-contingency values, AGC needs to be modeled in these simulations, which is not a common practice. To address this, AGC was implemented and included in our dynamic simulations run for several minutes. Considering the different scenarios run, the grid was found to be stable when AGC response was modeled.

Studies of such interconnections are expected to generate a large amount of results and data, especially when dynamics are considered. This needs advanced techniques of interpreting these results, one of being wide-area visualization as shown in this paper. The preliminary studies in this paper were performed to illustrate issues associated with the interconnection of large-scale grids, with an eye towards providing a test system for other researchers. These grids i.e. the individual synthetic east and west and their ac interconnected versions are available publicly [16] for researchers to access, modify if needed, and run their own scenarios in addition to those shown in this paper. This may include, 1) different ac tie connections, 2) static and dynamic contingency scenarios, 3) loading conditions, 4) renewable generation, 5) time series simulations such as those used in OPFs, and so on.

Acknowledgment

This work was funded by the Southwest Power Pool through the PSERC project S-92G, and also by the PSERC project S-91 and the NSF Award ECCS-1916142.

References

[1] J. Cohn, "When the grid was the grid: the history of North America's brief coast-to-coast interconnected machine [scanning our past]," *Proceedings of the IEEE*, vol. 107, no. 1, pp. 232–243, 2019.

[2] N. Cohn, S. B. Biddle, R. G. Lex, E. H. Preston, C. W. Ross, and D. R. Whitten, "On-line computer applications in the electric power industry," *Proceedings of the IEEE*, vol. 58, no. 1, pp. 78–87, 1970.

[3] I. Toljan, E. Banovac, and S. Tešnjak, "Development of UCTE and Reconnection of 1st and 2nd Pan-European Synchronous Zones," in *Proceedings of the 4th IASME/WSEAS international conference on Energy & environment*. World Scientific and Engineering Academy and Society (WSEAS), 2009, pp. 419–424.

[4] H. Breulmann, E. Grebe, M. Lösing *et al.*, "Analysis and damping of inter-area oscillations in the UCTE/CENTREL power system," *CIGRE Session*, no. 38-113, 2000.

[5] M. Luther, I. Biernacka, D. Preotescu *et al.*, "Feasibility Aspects of a Synchronous Coupling of the IPS/UPS with the UCTE," *CIGRE Session*, no. C1_204, 2010.

[6] S. S. Lee, J. K. Park, and S. I. Moon, “Power system interconnection scenario and analysis between Korean peninsula and Japan,” in *2003 IEEE Power Engineering Society General Meeting (IEEE Cat. No.03CH37491)*, vol. 3, 2003, pp. 1455–1460 Vol. 3.
[7] Z. Xu, H. Dong, and H. Huang, “Debates on ultra-high-voltage synchronous power grid: the future super grid in China?” *IET Generation, Transmission Distribution*, vol. 9, no. 8, pp. 740–747, 2015.
[8] A. L. Figueroa-Acevedo, “Opportunities and benefits for increasing transmission capacity between the US eastern and western interconnections,” *PhD Dissertation, Iowa State University*, 2017.
[9] Y. Li and J. D. McCalley, “Design of a High Capacity Inter-Regional Transmission Overlay for the U.S.” *IEEE Transactions on Power Systems*, vol. 30, no. 1, pp. 513–521, 2015.
[10] M. A. Elizondo, N. Mohan, J. O’Brien, Q. Huang, D. Orser, W. Hess, H. Brown, W. Zhu, D. Chandrashekhara, Y. V. Makarov, D. Osborn, J. Feltes, H. Kirkham, D. Duebner, and Z. Huang, “HVDC macrogrid modeling for power-flow and transient stability studies in North American continental-level interconnections,” *CSEE Journal of Power and Energy Systems*, vol. 3, no. 4, pp. 390–398, 2017.
[11] A. Bloom (National Renewable Energy Laboratory), “Interconnection Seams Study,” in *TransGrid-X 2030 Symposium, Ames, Iowa*, 2018.
[12] Western Area Power Administration, “East/West AC Intertie Feasibility Study,” *Tech. Report*, 1994.
[13] J. Caspary, J. McCalley, S. Sanders, and M. Stoltz, “Proposed Eastern Interconnection and Western Electricity Coordinating Council Seams Study,” in *CIGRE US National Committee 2015 Grid of the Future Symposium*, 2015, pp. 1–11.
[14] A. B. Birchfield, T. Xu, K. M. Gegner, K. S. Shetye, and T. J. Overbye, “Grid structural characteristics as validation criteria for synthetic networks,” *IEEE Transactions on Power Systems*, vol. 32, no. 4, pp. 3258–3265, July 2017.
[15] T. Xu, A. B. Birchfield, and T. J. Overbye, “Modeling, tuning, and validating system dynamics in synthetic electric grids,” *IEEE Transactions on Power Systems*, vol. 33, no. 6, pp. 6501–6509, 2018.
[16] “Electric Grid Test Case Repository - Synthetic Electric Grid Cases.” [Online]. Available: https://electricgrids.engr.tamu.edu/
[17] I. C. Report, “Computer representation of excitation systems,” *IEEE Transactions on Power Apparatus and Systems*, vol. PAS-87, no. 6, pp. 1460–1464, 1968.
[18] K. S. Shetye, T. J. Overbye, S. Mohapatra, R. Xu, J. F. Gronquist, and T. L. Doern, “Systematic determination of discrepancies across transient stability software packages,” *IEEE Transactions on Power Systems*, vol. 31, no. 1, pp. 432–441, 2016.
[19] J. D. Weber and T. J. Overbye, “Voltage contours for power system visualization,” *IEEE Transactions on Power Systems*, vol. 15, no. 1, pp. 404–409, 2000.
[20] T. J. Overbye, E. M. Rantanen, and S. Judd, “Electric power control center visualization using geographic data views,” in *2007 iREP Symposium - Bulk Power System Dynamics and Control - VII. Revitalizing Operational Reliability*, 2007, pp. 1–8.
[21] T. J. Overbye, J. L. Wert, K. S. Shetye, F. Safdarian, and A. B. Birchfield, “The use of geographic data views to help with wide-area electric grid situational awareness,” in *2021 IEEE Texas Power and Energy Conference (TPEC)*, 2021.