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An Approach to Modeling and Simulating Dynamic Interactions and Interdependencies Between the Electric Power Grid and Natural Gas System

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Technical Report 0000

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EXECUTIVE SUMMARY

System operations need to evolve to account for the changes on interdependancies. The steady shift to low cost natural gas as fuel source in the United States electricity portfolio combined with the growing number of electric motor-driven compressor stations emphasize concerns about energy security and interdependence between the electrical and natural gas infrastructure [19]. The most concerning regions are the Northeast and South, where electricity generated from natural gas surpasses the generation from other energy sources (see Figure 7). Effective management of the nation's infrastructure during extreme failures will require that the natural gas and the electric power industries jointly cultivate communication, operating procedures, and operator training exercises for emergency event response. Electrical utilities are engaging with interstate pipelines and local distribution companies to harmonize operations [1] [2] [3]. However, it is uncertain whether these utilities have effective telemetry, communications, and procedures for operators to jointly respond and prioritize actions during black sky events or orchestrated adversary attacks.

This report will describe the use of real-time simulation technologies to develop a training architecture that could help address technical gaps in operation and coordination of regional interdependent critical infrastructures during large-scale incidents or black sky events severely affecting the existing energy posture. The development leverages the real-time power system Hardware-in-the-Loop Laboratory Testbed and Open Platform (HILLTOP) to prototype a notional system reflecting the interactions between the electrical and natural gas systems. The main contributions of this work are the technical approach, modeling technique, and component models to assemble realistic simulations of coupled natural gas and electric power systems that could support joint operator training and decision making in response to contingencies in either infrastructure.

Potential Benefits

1. Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs) could use this initiative to simulate *what-if* scenarios and augment existing operator training routines. Results could improve power grid resiliency by helping inform system planning with the aim of securing critical generation assets that depend on natural gas as fuel. Another use may be for utility companies, in preparation for the NERC's GridEx, to co-simulate an area that is highly dependent on natural gas resources for electric power generation and execute the outcomes from tabletop exercises [4] [5]. To some degree, this could help evaluate the practicality of planned emergency response capabilities and well as information-sharing requirements. Also, the approach may help develop response plans to N-k contingencies and simulate system dynamics for the loss of multiple components, where power system operators could observe the impact of their actions to the natural gas system. Furthermore, operators would gain insight about the natural gas system and its dependency on the power systems, and therefore understand the level of situational awareness required to prevent failures from cascading between systems.

2. Natural gas utilities may use this work to emulate their delivery system and its dependencies on electric power to help practice and improve daily operations. The exercise may provide awareness of the measurements and communication needed to estimate the effects of prioritiz-

ing selected natural gas loads as part of an incident response plan. For example, maintaining natural gas supply to selected critical generation plants during extreme periods in order to elongate the fuel oil inventory and prevent cascading outages.

3. Government offices could further evolve this approach to help inform policy and influence contracting requirements between natural gas-fired power generation plants and the natural gas providers. Also, it could help device guidance to foster communication between the generation and pipeline companies based on information about the power system conditions monitored from the control rooms of the ISOs/RTOs or the natural gas providers [6]. For example, selected natural gas-fired power plants that are considered critical assets to the energy infrastructure could be required to hold contracts for continuous fuel supply in the event of extreme weather. Finally, one of the key concerns with co-simulation of interdependent infrastructures is the lack of harmonized databases and information related to the coupling between systems. This work could serve as a pilot to create momentum for compiling such a database in order to better understand vulnerabilities in the electric power grid.

Key take-away of our co-simulation: **Power system operators need situational awareness about the natural gas system, specially information about the loss of key natural gas compression stations or pipeline failures well in advance. This information would help power system operators to execute efficient load-shedding schemes and avoid cascading failures. However, without this information grid operators may be caught off-guard during a gas contingency event which could result in cascading power failures.**

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1. INTRODUCTION

The infrastructure for transporting liquids and gases in the United States encompasses nearly a half a million miles of pipelines that move natural gas, oil, ammonia and many other hazardous liquids (Parfomak, 2013). The scope of such a system is unparalleled in history and brings with it many benefits and associated hazards. Among the hazards are sabotage, vandalism, equipment failure caused by aging or environmental factors, and accidents, including dig-ins. Of the half-million miles of chemical pipelines, about three hundred thousand miles are specifically for conveying natural gas from production basins to customers. The pipeline network for the United States and southern Canada is shown in Figure 1. These natural gas pipelines can be further divided into interstate pipes – those that cross state boundaries – and intrastate pipes that only operate in a single state without crossing boundaries. The gas transmission lines typically terminate at a “city gate” station wherein the distribution companies assume operation.

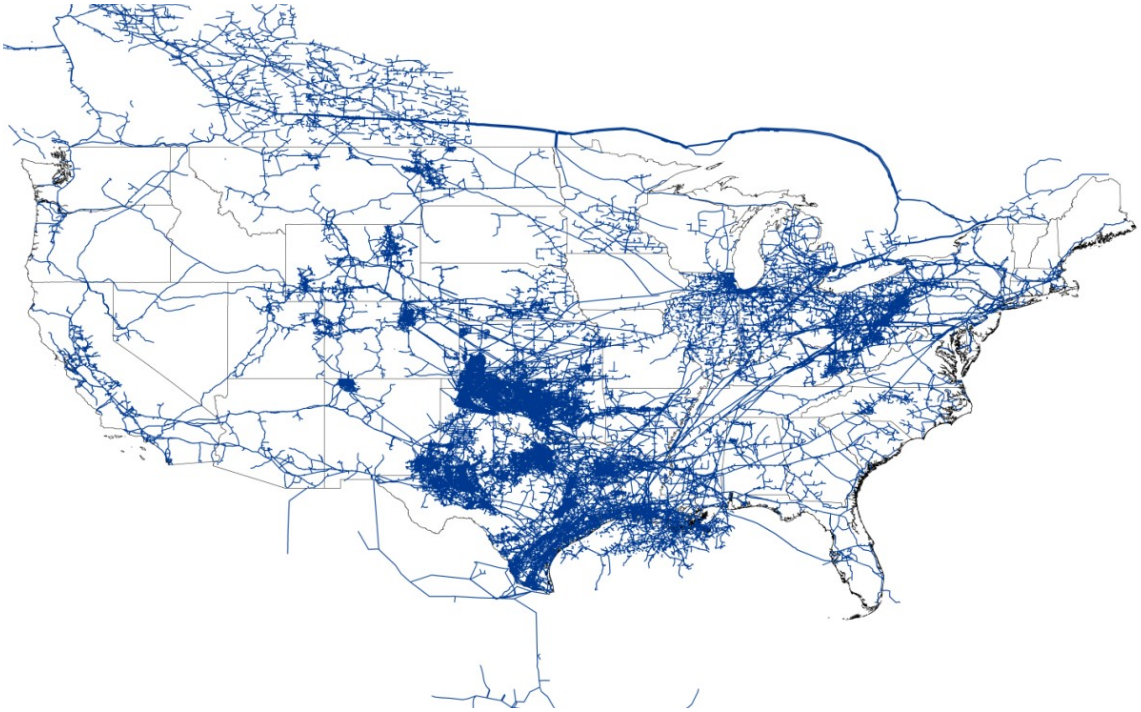


Figure 1. The natural gas transmission network in North America [7].

The natural gas network consists of three major elements: gathering, compressing, treating, and dehydrating the off gas from oil wells; transportation of the gas via pipelines; and distribution of the gas to end users. These three elements are depicted in Figure 2 and Figure 3 illustrates the major corridors for natural gas transmission.

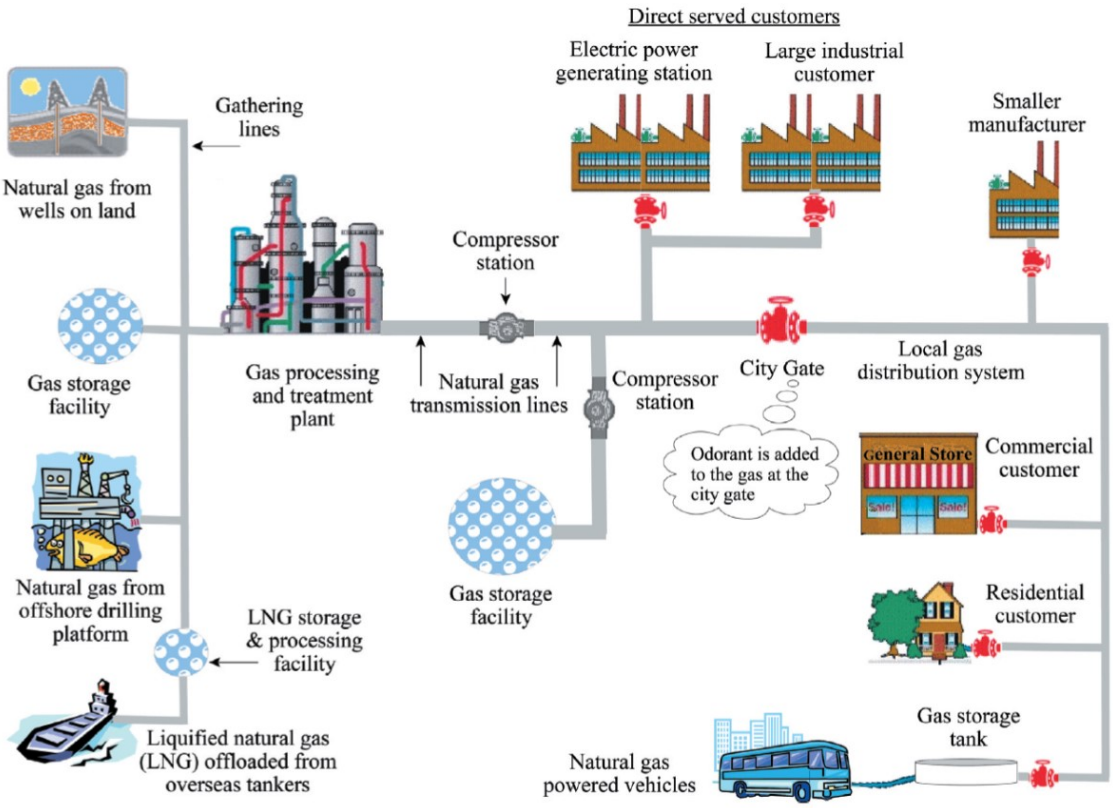


Figure 2. The natural gas system [8].

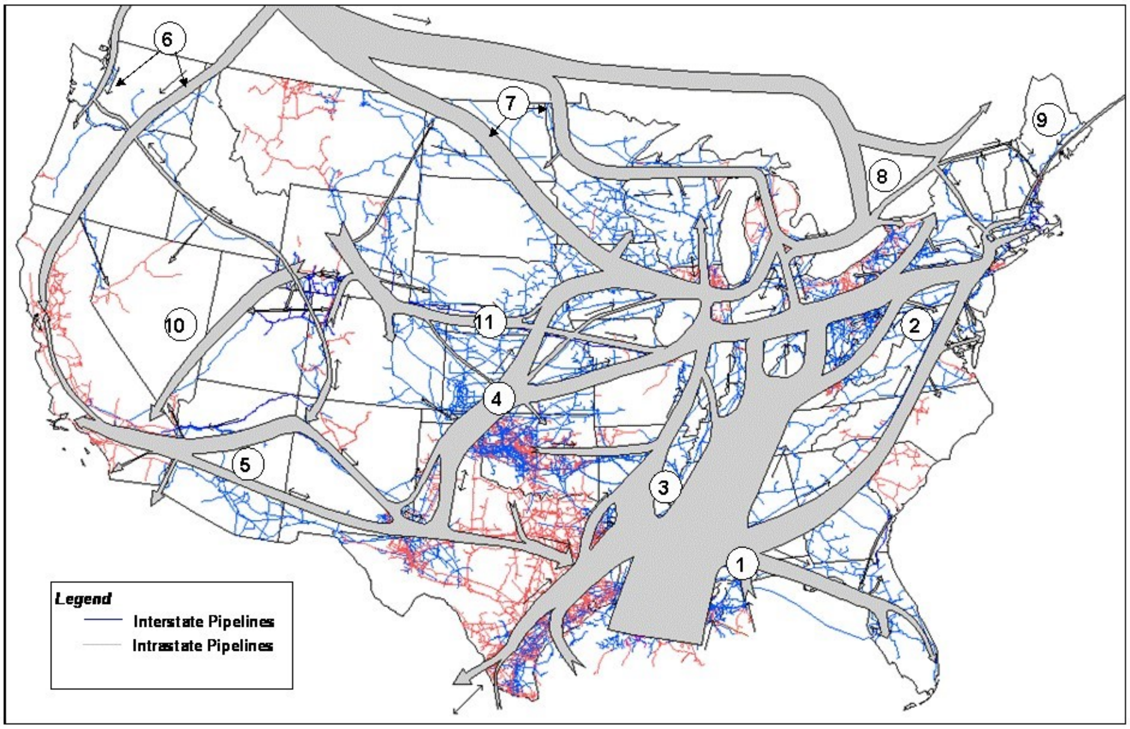


Figure 3. Natural gas transportation corridors [7].

The pipes themselves consist of high-strength steel 30 to 36 inches in diameter [15], which are placed a distance of 30 to 36 inches beneath the surface [16] and operate at a pressure of between 500 and 1,400 *psig* [17] [15]. Several billion cubic feet of natural gas flow through some of the larger pipelines at velocities of 30 ft/s or more. This high flow rate incurs frictional energy losses both between the gas and the pipe and within the gas itself. These energy losses are manifested as pressure drops that must be balanced using compressor stations, typically spaced about every 40 to 100 miles, depending on the terrain [18]. The compressors are typically driven by turbines that burn siphoned natural gas from the pipelines, though some compressors are driven by electricity [19]. At present, the United States employs more than 1,400 compressor stations that push natural gas through a pipeline network that contains more than 11,000 delivery points and 5,000 injection points [18]. Valves are spaced from between 5 miles to 20 miles, and are normally open until maintenance is required [18].

The natural gas industry has seasonal peaks for both electricity and for heating, as shown in Figure 4. Natural gas is consumed primarily for heating homes in the winter, where the peak occurs in early January and is about 50% higher than the summer peak. The seasonal demand peaks are mitigated using storage in underground caverns located throughout the United States. Figure 4 shows that during the summer and fall months, the caverns are filled in anticipation of the winter peak. The caverns are discharged throughout the winter as demand outstrips supply.

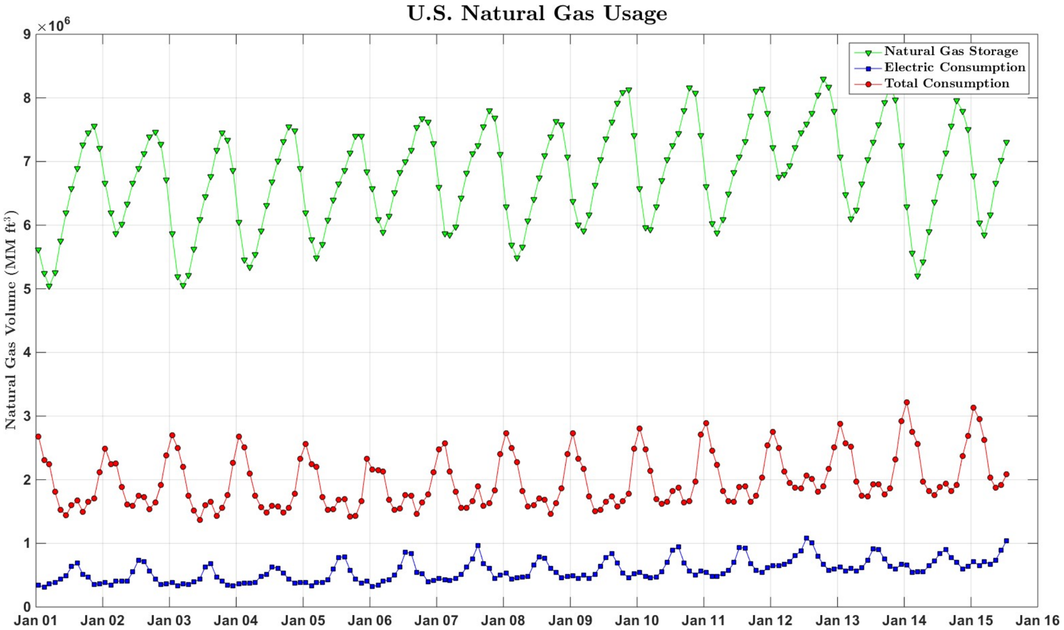


Figure 4. Seasonality of natural gas for the electric sector [9].

Natural gas has become an important part of the electricity generation portfolio in many areas of the United States. There are now more than 2,000 generator stations that comprise more than 475 *GW* of generation and account for nearly 40% of all installed summer generation nationwide. Low prices have been a major factor favoring the use of natural gas as primary fuel source for electricity generation. Figure 5 shows the electricity net generation in the United States with natural gas having an progressive increase since 1990. For example, in 2015, natural gas surpassed coal-fired generation for the first time in history [9]. Furthermore, the Energy Information Administration's Annual Energy Outlook 2020 predict that electricity generation from natural gas will remain above 35% (see Figure 6) and highlights that future generation mix will be sensitive to the price of natural gas and growth in electricity demand [11].

The steady shift to low cost natural gas as fuel source in the electricity portfolio combined with the growing number of electric motor-driven compressor stations emphasize concerns about energy security and interdependence between the electrical and natural gas infrastructure [19]. This may cause operational conflicts during large scale incidents in the event that proper guidelines are not available and/or contract between electric power producers and natural gas suppliers are not in place. The most concerning regions are the Northeast and South, where electricity generated from natural gas surpasses the generation from other energy sources (see Figure 7).

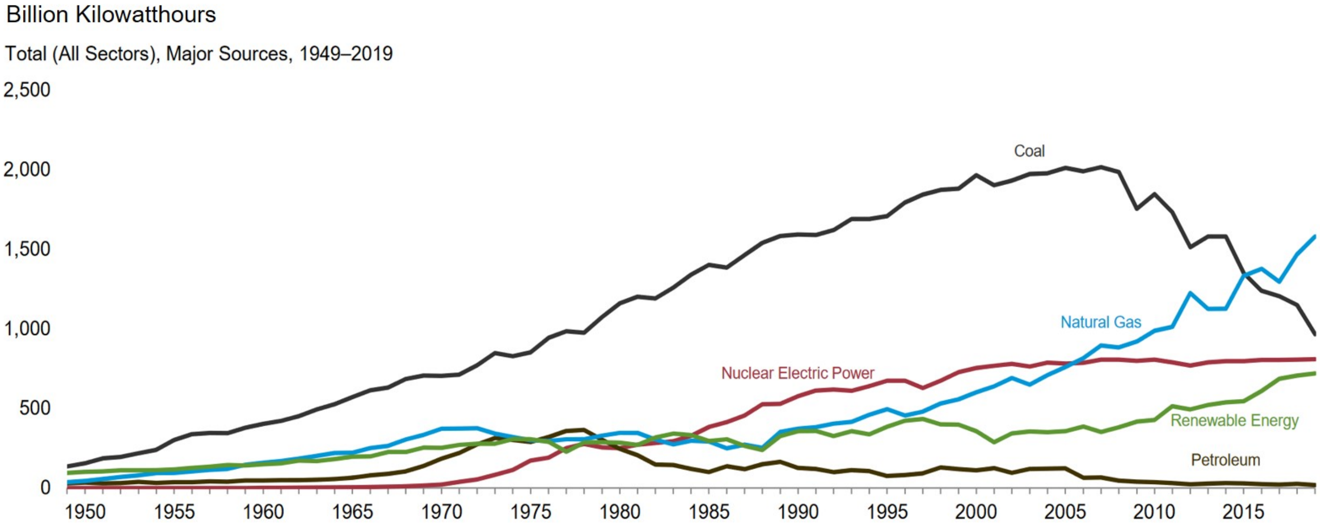


Figure 5. Electricity net generation in the United States from major sources – history [10].

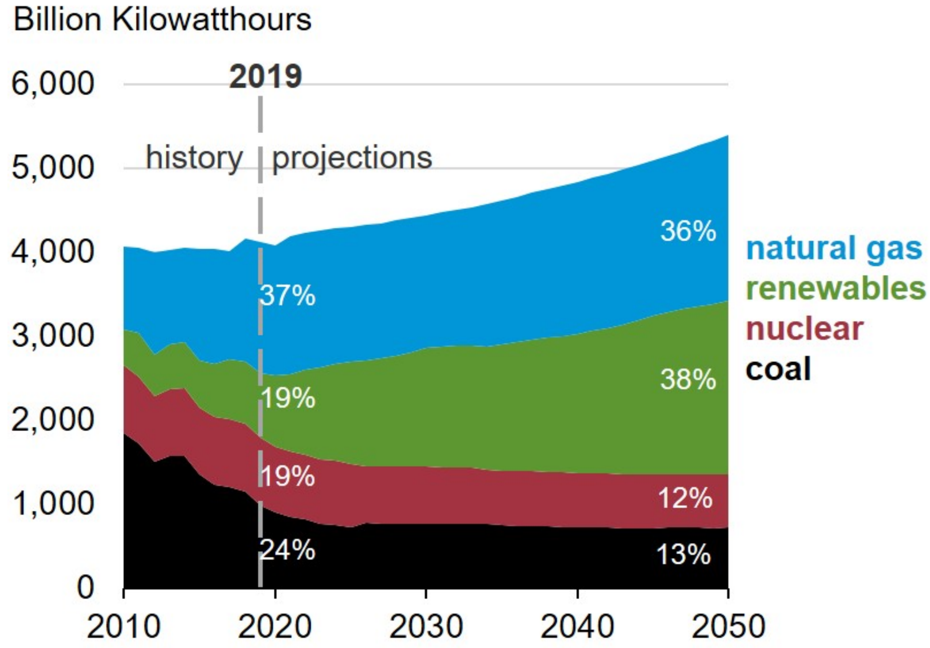


Figure 6. Electricity generation in the United States from selected fuels – history and projection [11].

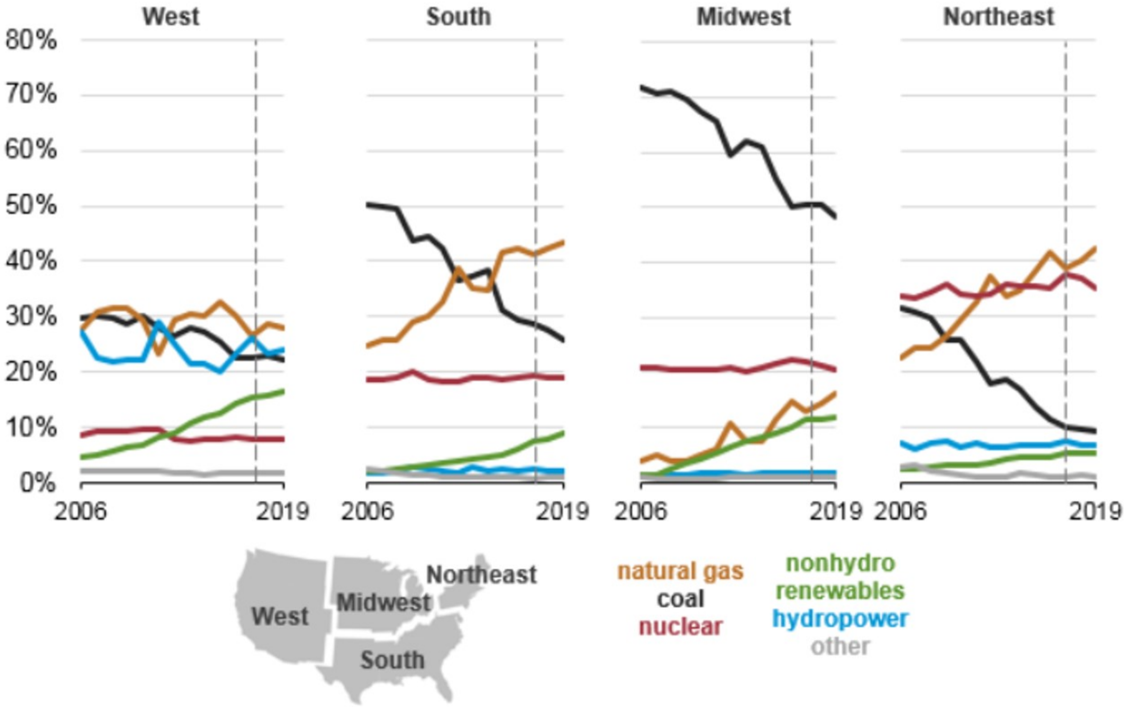


Figure 7. Regional share of total electricity generation by energy source 2006-2019 [12].

The natural gas industry varies significantly across the country, as there are few gathering areas and many areas with high demand. Texas and Oklahoma, for example, have significant natural gas pipeline infrastructure, and high population areas such as New England and California have relatively few total inbound pipelines. Because both New England and California rely heavily on natural gas, any disruption can cascade into the electrical system, causing blackouts or other infrastructure failures. Figure 8 shows some interdependencies of critical infrastructures. This figure illustrates the complex and multifaceted nature of interdependencies between critical infrastructure and highlight two direct interdependencies between natural gas and electric power system.

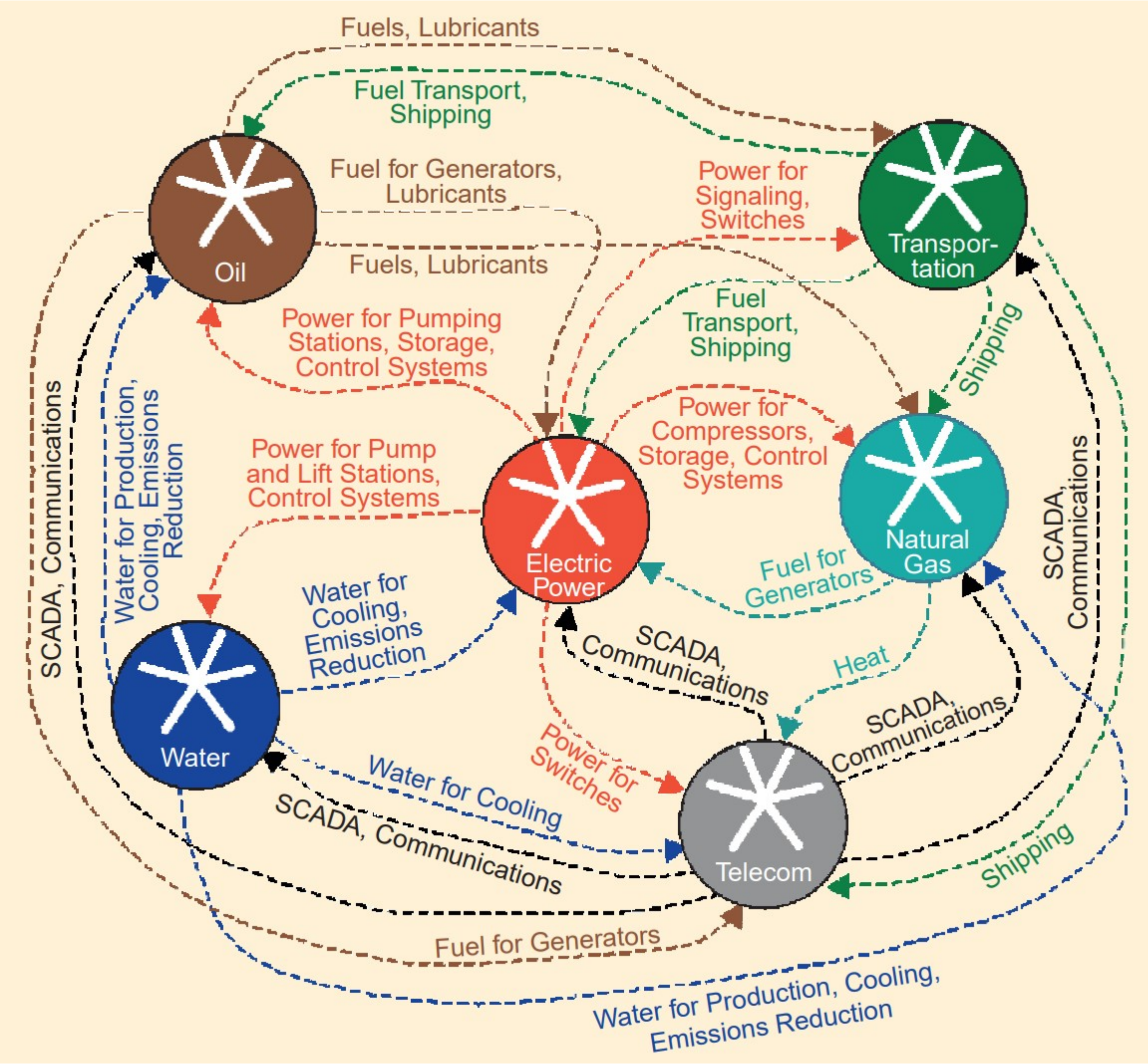


Figure 8. Interdependencies of critical infrastructure. Adapted from identifying, understanding, and analyzing critical infrastructure interdependencies [13].

Effective management of the nation's infrastructure during extreme failures will require that the natural gas and the electric power industries jointly cultivate communication, operating procedures, and operator training exercises for emergency event response. Electrical utilities are engaging with interstate pipelines and local distribution companies (LDC) to harmonize operations [1] [2] [3]. However, it is uncertain whether these utilities have efficient awareness mechanism or procedures for operators to jointly respond and prioritize actions during black sky events or orchestrated adversary attacks.

Today, operators of these organizations mostly train independently. The North American Electric Reliability Corporation (NERC)'s Grid Security Exercise (GridEx) is initiative to address this issues, where utility companies, infrastructure cross-sector partners, and supply chain stakeholder organizations are provided an opportunity to demonstrate how they would respond to and recover from coordinated cyber and physical security threats and incidents [4].

This report will describe the use of real-time simulation technologies to develop a training architecture that could help address technical gaps in operation and coordination of regional interdependent critical infrastructures during large-scale incidents or black sky events severely affecting the existing energy posture. The development leverages the real-time power system Hardware-in-the-Loop Laboratory Testbed and Open Platform (HILLTOP) to prototype a notional system reflecting the interactions between the electrical and natural gas systems. The main contributions of this work are the technical approach, modeling technique, and component models to assemble realistic simulations of coupled natural gas and electric power systems that could support joint operator training and decision making in response to contingencies in either infrastructure.

2. CONCEPT AND ARCHITECTURE

For decades, the electric power transmission utilities have used real-time simulation technologies to test protection schemes and control algorithms [20]. However, the typical use of these tools is mostly restricted to electrical simulations without including other interdependencies, with the exception of communication networks. The proposed tool leverages HILLTOP to simulate in real-time a notional system reflecting interactions between electrical and natural gas assets [21]. HILLTOP helps expand the simulations to include the effect of other infrastructures, and at the same time facilitates the integration of hardware controllers and field remote metering systems. Furthermore, HILLTOP could provide a virtual training ground for operators to exercise new policy and to assess their response *what-if* scenarios across multiple infrastructures.

The electric power system has substantially faster dynamics than the natural gas systems. Thus, contingencies in the power system will immediately affect the electricity-dependent components of the natural gas system [22]. However, issues in the natural gas infrastructure may not immediately influence the state of the power system, and depending on the damage, it may take days or weeks to resolve [23]. Therefore, if prolonged loss of natural gas service is predictable by the power system operator, remedial action such as generation dispatch, service reroute, and optimized load shedding can be implemented to prevent cascading failures in the power system [24].

2.1 ARCHITECTURE

The analysis of system dynamics can provide realistic and interactive insight about the overall system behavior and operator actions in response to incidents or man-made events. HILLTOP simulates the electrical network and natural gas system using two separate, yet synchronized solvers, facilitating the emulation of dynamics following generator dispatch orders, load changes, equipment malfunction, or faults originating from either of the simulated systems. The electrical network simulates using Opal-RT's ePHASORSim, a commercially available offline and real-time transient stability solver based on phasor domain techniques with millisecond time step resolution and capable of simulating large-scale power systems (up to hundred of thousands of nodes) [25]. The natural gas system is simulated using MathWorks Simulink, a versatile engineering tool commonly used to model and analyze multidomain dynamics [26]. The models are coupled at the natural gas-fired generators and the electrically driven compressor stations [22]. Alternatively, other simulation tools that emulate the natural gas system can be integrated with the electrical network over an application programming interface (API). Figure 9 shows the notional setup integrating the simulation models, interactions with the operators, and visualization.

User interaction with the models occurs over Restful-API, facilitating simultaneous actions from multiple operators for a simulated scenario. Similarly, this approach enables the implementation of system profiles, scripted contingency scenarios, and impromptu threats to the simulation. For example, it is possible to introduce commands emulating the effect of physical damage, equipment malfunction, and system faults.

Another important aspect of the architecture is the users' display and control interface to the simulation. These should be flexible to changes and reflect the tools currently available to system operators whose actions will depend on training, emergency guidelines, policy, and their perception of the system state. The display and control interface were developed using Ignition HMI by Inductive Automation, a software for developing flexible and scalable Supervisory Control and Data Acquisition (SCADA) [27]. Ignition HMI communicates with the simulation via Modbus TCP and the Restful-API. For the proof-of-concept, the electrical system display shows the diagram and common parameters such as bus voltages, power flowing through lines, status of components, frequency, and machine output power (see 10). Similarly, the natural gas display shows system topology, gas flow of compressors and pipes, and the inlet and outlet pressure of each compressor (see 11). Additionally, the electrical display shows the gas pressures of the compressor stations to provide the power system operator situational awareness about the natural gas system.

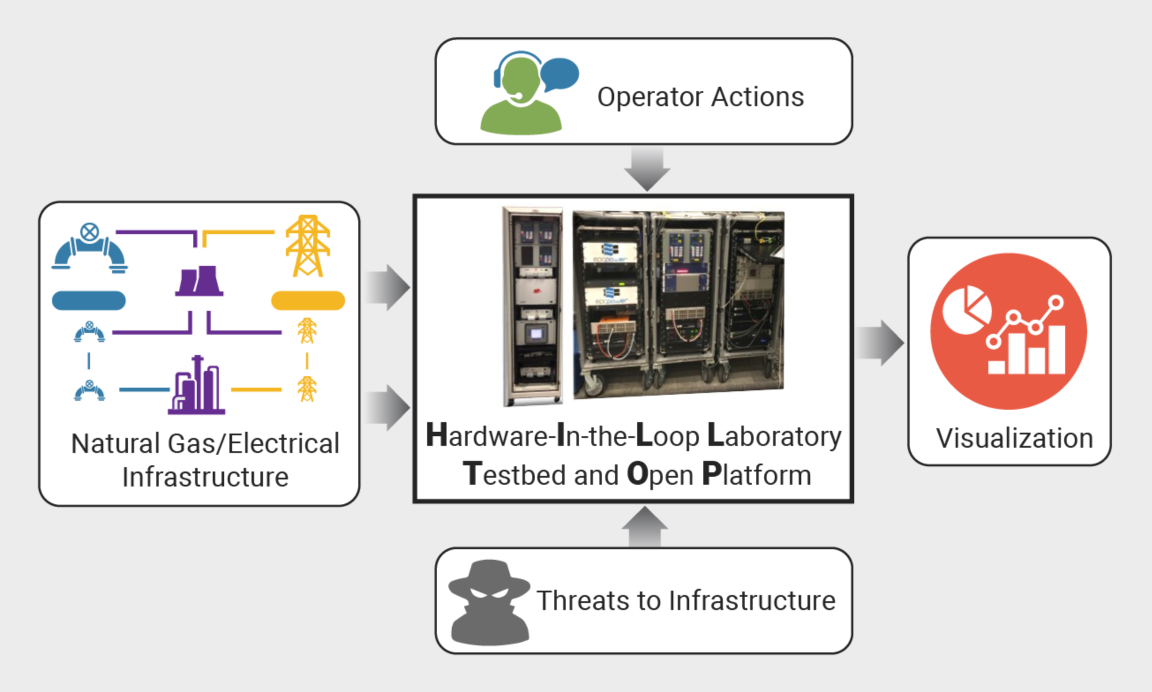


Figure 9. Conceptual setup for the simulation environment.

2.2 SCOPE AND LIMITATIONS

One of the major limitations for co-simulating electrical and natural gas systems is insufficient and/or unreliable information about where the two systems interface and their operating contract restrictions. This issue may be mitigated with collaboration between the representative utilities of interest, or using data services such as S&P Global Platts [28]. However, due to lack of access to real-life data, this study was limited to simulating notional architectures for the electric power and natural gas topologies; see details in Section 3.

Ideally, this work would present models of real-life infrastructure, where failures have been logged or observed, to help verify results and demonstrate the usefulness of the proposed approach. For example, the New England infrastructure, where ISO New England experienced a substantial consumption of their fuel oil inventory during a two week outbreak of Arctic cold. In this case, the natural gas-fired generation dropped from 46% to 24% [29]. Note that an additional week of cold outbreak could have dramatically affected the region's electric service [1] [3] [2].

The approach considers the following assumptions:

1. The power system must be represented as positive sequence models. This does not present an issue with adoptability because digital models of the electric transmission systems are commonly available to ISOs and transmission utilities in positive sequence modeling.
2. The power system dynamics should initialize from a valid power flow solution. Otherwise, a brief transient period will occur until the system reaches steady-state. Note that a prolonged initialization transient could affect the response of the natural gas system because electrically driven compressors may shut down on undervoltage protection.
3. The dynamic response of electric system is solved using phasor domain. Although phasor solutions do not provide as detailed results as time-domain methods, the phasor approach is less computationally intensive and still allows for steps in load demand, faults, generator ramping, and switching operations.
4. The natural gas system includes first-order models for upstream supply, compressor stations, header pipe sections, lateral pipes, natural gas-fired turbine generators, and local distribution systems. These components are modeled in MathWorks Simulink, which at the moment requires graphical interaction rather than netlist programming. This, possibly imposes a limit in model scalability versus ease of use.
5. Modeling of the natural gas systems is limited to represent the bulk gas transport because of the lumped architecture. The proposed approach should be suitable to model regional natural gas systems at the transmission level and without detailing the local distribution systems.
6. The components of the natural gas system are dimensionally scalable such that gas dynamics can be simulated with smaller time constant and reduced total execution time.
7. Low-pressure equipment shut down is limited to compressor stations and turbine generators.
8. The natural gas turbine governor dynamics only include power rate limits, rather than the saturation limits and nonlinearities associated with a mechanical governor.
9. The natural gas compressor dynamics represent the output flow rate limits.
10. The natural gas flow model is based on the Weymouth equation, which is a combination of theoretical relationships as well as empirical data. The Weymouth equation relates pressure and flow in a pipe for laminar flow, similar to a nonlinear resistor relating current to voltage.

2.3 POTENTIAL BENEFITS

2.3.1 Electric Power Industry

Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs) could use this initiative to simulate *what-if* scenarios and augment existing operator training routines. Results could improve power grid resiliency by helping inform system planning with the aim of securing critical generation assets that depend on natural gas as fuel. Another use may be for utility companies, in preparation for the NERC's GridEx, to co-simulate an area that is highly dependent on natural gas resources for electric power generation and execute the outcomes from tabletop exercises [4] [5]. To some degree, this could help evaluate the practicality of planned emergency response capabilities and well as information-sharing requirements. Also, the approach may help develop response plans to N-k contingencies and simulate system dynamics for the loss of multiple components, where power system operators could observe the impact of their actions to the natural gas system. Furthermore, operators would gain insight about the natural gas system and its dependency on the power systems, and therefore understand the level of situational awareness required to prevent failures from cascading between systems.

2.3.2 Natural Gas Industry

Natural gas utilities may use this work to emulate their delivery system and its dependencies on electric power to help practice and improve daily operations. The exercise may provide awareness of the measurements and communication needed to estimate the effects of prioritizing selected natural gas loads as part of an incident response plan. For example, maintaining natural gas supply to selected critical generation plants during extreme periods in order to elongate the fuel oil inventory and prevent cascading outages.

2.3.3 Government

Government offices could further evolve this approach to help inform policy and influence contracting requirements between natural gas-fired power generation plants and the natural gas providers. Also, it could help device guidance to foster communication between the generation and pipeline companies based on information about the power system conditions monitored from the control rooms of the ISOs/RTOs or the natural gas providers [6]. For example, selected natural gas-fired power plants that are considered critical assets to the energy infrastructure could be required to hold contracts for continuous fuel supply in the event of extreme weather. Finally, one of the key concerns with co-simulation of interdependent infrastructures is the lack of harmonized databases and information related to the coupling between systems. This work could serve as a pilot to create momentum for compiling such a database in order to better understand vulnerabilities in the electric power grid.

3. MODELING AND SIMULATION APPROACH

An important aspect of the study is to observe the electric system stability and dynamics in response to operator actions that aim to mitigate contingencies, including unexpected loss of prime generation due to equipment failures or operations in the natural gas infrastructure. To achieve this goal, the modeling and simulation must represent the coupling between the electrical network and natural gas system. This section describes the characteristics of both systems, and the selected approach to emulate dynamics that couple the response of these two systems acting under different time constants.

3.1 ELECTRICAL SYSTEM

This work implements the publicly available and well-known IEEE 39-bus system, also known as the 10-Machine New England Power System (see Figure 10) [14] [30]. The IEEE 39-bus system is widely used to develop, test, and demonstrate control algorithms [31], dispatch strategies [32] [33], restoration schemes [34] [35], and load-shedding techniques [36] [37] [38] [39]. The architecture consists of 10 generators interconnected through 34 transmission lines and 12 transformers supplying electric power to 19 aggregated loads. The total system load is 6,150 MW with 610 MW of emergency generation and reserve margin, adding up to 6,760 MW of available generation.

The system data consists of electrical demand, positive sequence parameters, and generator controls settings. Network components such as transmission lines and loads use PI-sections and constant impedance model representations, respectively. Transformers models use per-unit circuit equivalent of two-winding transformers without on-load tap changers. Machines are sixth order models without saturation effect and dynamic response described through transient and sub-transient reactance as well as damper windings on the d-axis and q-axis. Other components influencing machine response include a high-pressure turbine along with re-heater and governor, a simplified exciter model based on IEEE Type AC4 excitation system, and a speed-sensitive power system stabilizer.

This study assumes that bulk delivery of natural gas to the three natural gas-fired power plants and district heating loads depend on two electrically driven compressor stations connected at buses 12 and 28 (see Figure 10). These compressor stations consume 18 MW (compressor station #1) and 35 MW (compressor station #2) during normal operating conditions to maintain pipe pressure at approximately 1,500 psi (see Figure 11) [40]. However, in emergency conditions when inlet natural gas pressure drops, the electrical consumption of the compressor stations may even double in attempts to maintain assigned set-point pipe pressure. In this case, protective equipment will restrict the compressor station from exceeding operational limits by shutting down and disconnecting the unit. Note that compressor station #2 has greater electrical demand than compressor station #1 because it has larger pressure drop in the pipes caused by the attached natural gas loads.

The integration of the electric and natural gas systems is such that electrical demand changes from these two compressor stations will reflect on the dynamics of the power system. Natural gas compressor stations are often unmanned and operated via SCADA systems [40]. Ideally, in case of an electric outage, automatic transfer switches (ATS) connect backup generation to supply critical pumps and equipment ensuring continued operation. Once the electric power is restored, the ATS transfers the load to utility service and operation resumes as normal. To emulate a worst-case scenario, we assume backup power to the compressor stations is not available or failed to operate.

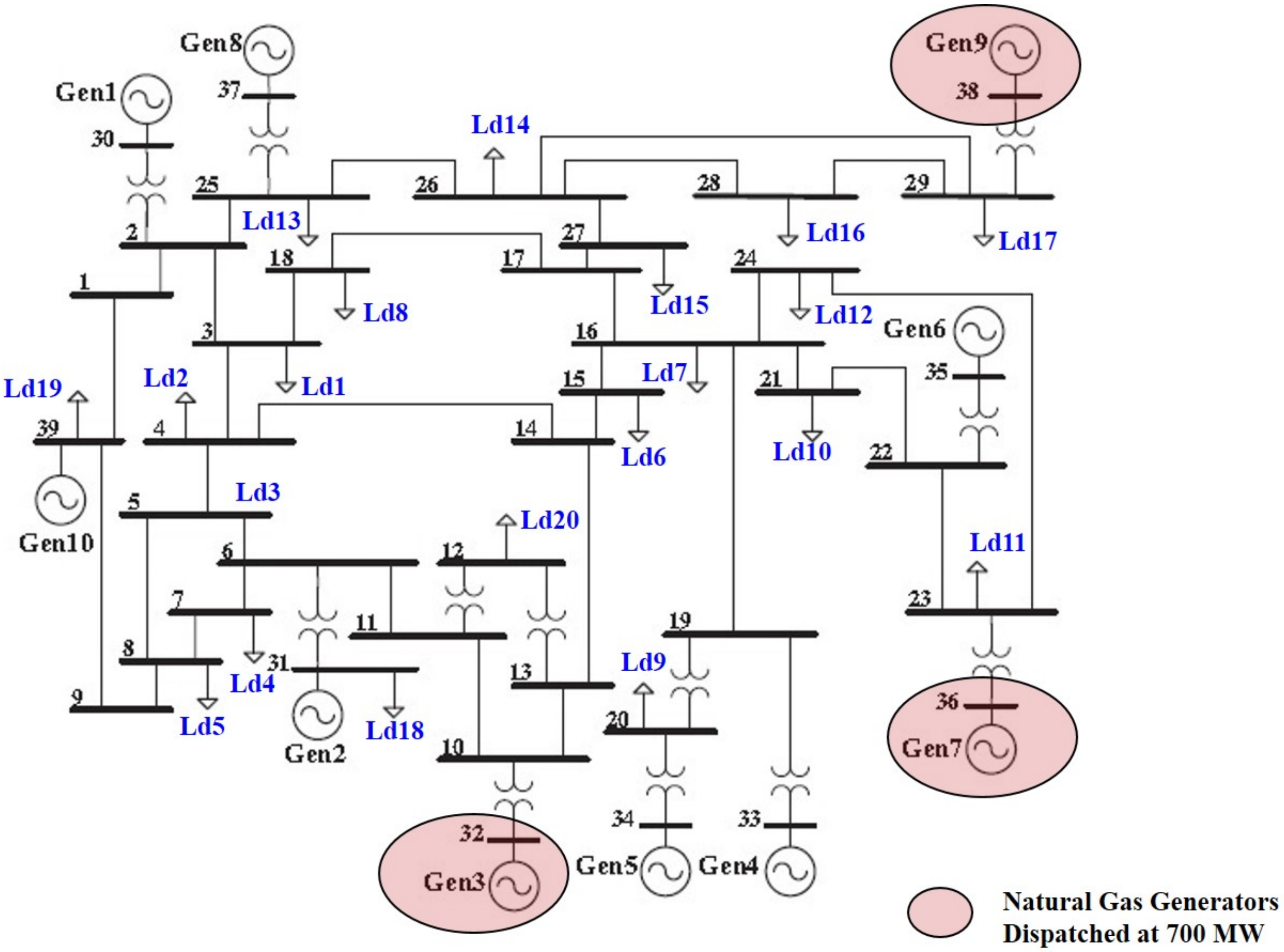


Figure 10. Electric diagram of the IEEE 39-bus system [14].

3.1.1 Assigning Limits to Generation Capacity

The original dataset for the 39-bus system does not specify generator types or maximum generation capacity. For this study, three (3) natural gas-fired generators are arbitrarily selected considering the scenario narrative and contingency events described in Section 4. These generators are units 3 (bus #32), 7 (bus #36), and 9 (bus #38). The maximum generating capacity of each natural gas-fired unit is 700 MW. When available, the total natural gas generation consists of 31% of the overall system capacity. This percentage of natural gas generation correlates to numbers presented by U.S. Energy Information Administration indicating, *"In 2016, natural gas-fired generators accounted for 42% of the operating electricity generating capacity in the United States. Natural gas provided 34% of total electricity generation in 2016"* [41].

The maximum generation capacity and operational set-points of the remaining seven (7) generators were defined using economic dispatch simulated with NETSSWorks, an AC optimal power flow simulation software that facilitates optimal management of loads and electrical resources under user-defined constrains [42]. The assignment of generation capacity was subject to the following constrains: 1) cost of dispatching natural gas-fired power generators is relatively lower than the cost of other generation resources; 2) Area 2 should lack generation capacity upon loss of natural gas assets in order to require load-shedding actions from the power system operators (see Figure 14); and 3) the seven generators that are not natural gas-fired should always be available for dispatch with unlimited fuel capacity. Table 1 summarizes the generator sizes and assigned cost.

TABLE 1

List of Generator Maximum Capacity

Bus #	Generator ID	Initial Setpoint MW	Generation Capacity, MW	Cost %
30	1	1100.0	1100.0	90
31	2	300.0	300.0	30
32	3	700.0	700.0	60
33	4	346.0	400.0	90
34	5	660.0	660.0	80
35	6	707.8	1000.0	90
36	7	700.0	700.0	60
37	8	427.0	550.0	90
38	9	700.0	700.0	60
39	10	426.7	650.0	95

3.2 NATURAL GAS SYSTEM

The natural gas infrastructure implements a notional layout consisting of an upstream wellhead and pipeline supply (interstate service), three electrically driven compressor stations, nine pipes with coupling junctions (intrastate and laterals), two heat loads modeled as controlled sources of flow representing a LDC and an intrastate downstream service, and three natural gas-fired turbine governors with regulators that provide shaft power to the electrical machines (see Figure 11). The topology shows five 30 inch inner diameter header pipe sections in series, coupled with four lateral pipes ranging from 12 to 15 inch inner diameter. Three of these lateral pipes supply the turbine governors and one feeds the LDC. Although the system is simple, it is sufficient to exercise the goals of the project, demonstrate the need for cooperative operator training, and promote the much needed situational awareness across both infrastructure. Furthermore, maneuvering this simple system may prove challenging depending on initial conditions and simulated scenario.

Obtaining publicly available field parameters for NG equipment proved challenging. Therefore, the simulated system uses values presented in literature, engineering assumptions, or technical papers published by equipment manufacturers. For example, the turbine governor is implemented as a first order model based on the Alstom GT24/GT26 gas-fired combustion turbine [43]. Component models used adjustable parameters to facilitate customization to specific regions when system data are accessible, e.g, pipe diameters and lengths, compressor station sizes and efficiencies, turbine governor ramp rate, among others. A key development assumption is that the compressor stations are based on single- or dual-stage centrifugal compressors driven by induction motors, introducing major gas–electricity interdependence.

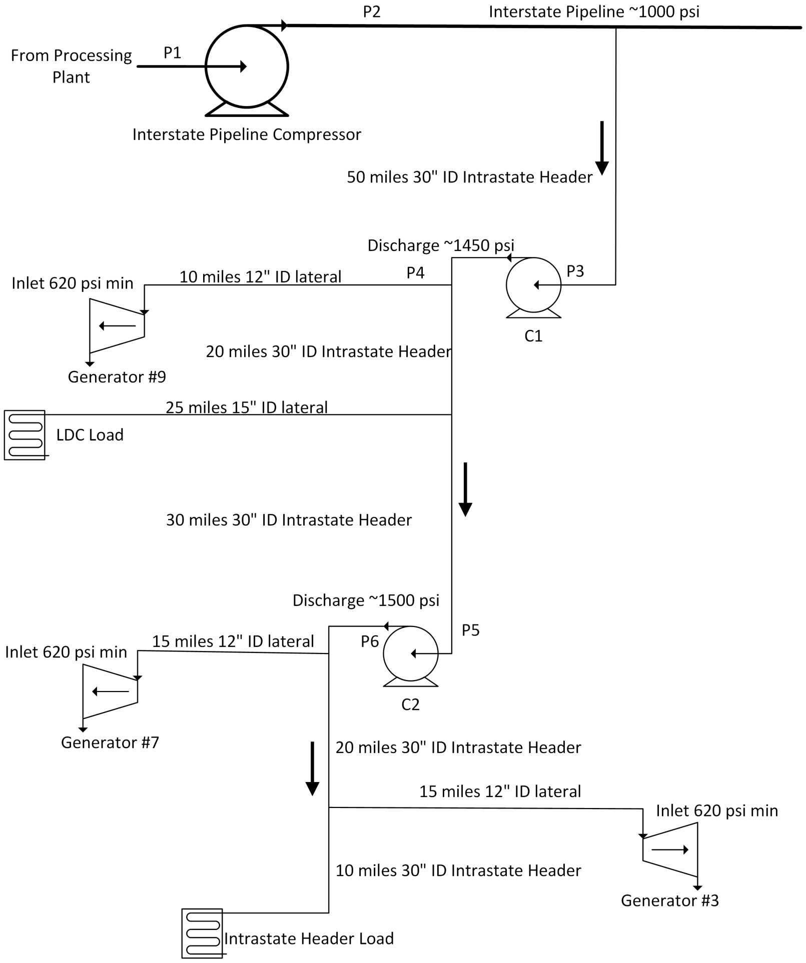


Figure 11. Notional natural gas systems.

3.2.1 Electrical Equivalent Circuit of the Gas System Dynamics

Figure 12 shows the electrical equivalent circuit of the simulated natural gas system, where pipe pressure or "linepack" (in psi) corresponds to voltage, gas flow rate (Nm^3/sec) corresponds to current, and mass corresponds to charge. This equivalent circuit helps clarify the modeling approach and makes the natural gas topology more accessible to those with electrical background. Note that imperial and metric units are mixed because most natural gas systems are commonly represented using imperial units, but metric units are easier to manipulate when transitioning between mechanical and electrical power quantities.

Instead of pure resistances, pipe sections are modeled with the nonlinear Weymouth equation [44]. The linepack, or entrained pressure stored in the pipe, is modeled with the ideal gas law modified to account for gas compressibility [45]; in the electrical model, this is represented by a capacitor. The compressors are modeled as variable flow sources, regulating pressure boosters; this corresponds to voltage sources in the electrical analog. For contingencies such as loss of electric power to the compressor station, the compressor flow is set to zero to represent the function of blocking valves, which isolate the compressor on both the inlet and discharge sides. Gas flow loads such as the turbine governors and LDC are represented as independent current sources.

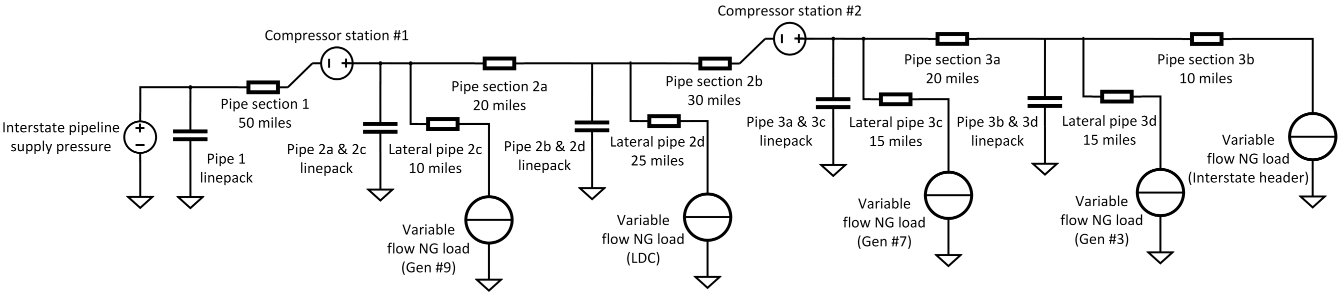


Figure 12. Electrical equivalent of the natural gas system.

3.2.2 Simulation Model of the Natural Gas System

The natural gas system is implemented in Simulink, which facilitates coupling with the electrical system. Key parameters for the co-simulation include generator start up and shut down commands, bus voltages for the electric service of the compressor stations, electrical demand of the compressor stations, and the shaft power output of the natural gas prime movers. The generators provide a constant electrical output power and the operator only has access to the start up and shut down commands. The bus voltages at the compressor stations are used to establish a shut down mechanism based on undervoltage protection in case of electrical faults or service failure. Ideally, backup generation would maintain electric service; however, to emulate worst-case scenario, it is assumed that backup assets are not available or failed to operate. The electrical demand of the compressor stations reflects directly in the power system response and the need for reliable electric service adds a layer of complexity if the operators do not know what substations to prioritize.

The natural gas system can initialize using different conditions. For example, 1) zero pressure or flow in the pipes indicating need for black starting the natural gas system; 2) nominal pressure in the pipes and zero flow showing that natural gas resources are available but the valves controlling service to heating loads and power plants are closed; and 3) nominal pressure and flow in the pipes with all heating loads and power plants being supplied representing normal operating conditions. These initial conditions allow the emulation of multiple scenarios that will heavily influence the actions of system operators at various levels of difficulty.

The gas flow settings of the LDC and turbine governors, pressure and gas flow settings for compressor stations, and model topology parameters are selected arbitrarily and based on available literature [46]. The amount of gas flow through the turbine governor determines the shaft mechanical output power set-points. During normal conditions, the model assumes that natural gas-fired generators receive sufficient gas flow to maintain constant shaft output power such that the machines generate 700 MW of electric power. The user can adjust these values at any point throughout the simulation or even provide a custom profile.

3.2.3 Components of the Natural Gas System

Compressor station The compressor station model assumes an electric motor as prime mover to the compressor stage and therefore provides an input to shut down the station due to undervoltage conditions in the electric system. The motor is not explicitly modeled; however, the overall effect to the electric and natural gas system is simulated. The electric system perceives the compressor stations as a slow-changing load that may suddenly disconnect and the natural gas system sees the compressor as a path for pressurize gas flow. Thus, when the motor stops, the electrical demand and compressor gas flow equal to zero. The inlet pressure of the compressor is defined independently and a PID loop controls the discharge pressure. The main outputs of the compressor station are flow (Nm^3/sec) and electrical demand (kW). The compressor shaft power is calculated per eq. 1, [47].

$$Power = \left(\frac{n}{n-1}\right)\left(\frac{Z_a}{\eta_{poly}}\right) T_1 \cdot q_s \left(\frac{P_s}{Ts}\right) \cdot \left[\left(\frac{P_2}{P_1}\right)^{\left(\frac{n}{n-1}\right)} - 1\right] \cdot \eta_{motor} \tag{1}$$

$Power$	Shaft power into compressor, *kW*
n	Polytropic index, *unitless*
Z_a	Average gas compressibility factor, *unitless*
η_{poly}	Polytropic efficiency, %
η_{motor}	Compressor motor efficiency, %
T_1	Suction side temperature, K
T_s	Standard condition temperature, K
q_s	Gas flow rate at standard condition, (Nm^3/sec)
P_s	Standard condition pressure, kPa
P_1	Suction side pressure, kPa
P_2	Discharge side pressure, kPa

The model can be representative of multiple multi-stage compressors operating in parallel depending on the nominal pressures and flows. In cases where the inlet pressure exceeds the discharge pressure, e.g, when filling a section of pipe with gas, the compressor electrical demand is practically negligible because compression is not required. However, once gas is available in the pipe, the compressor station electrical demand will increase as it is pressurized. A major function of the gas flow through the compressors is to maintain pipe pressure, or linepack, after disturbances in the natural gas system. Testing showed that maintaining the balance of gas flows is not enough to hold constant pressure across the delivery systems. Therefore, the compressors need to maintain discharge (e.g, linepack) pressure independent of flow in order to hold desired pressure. If flow demand increases, the compressor has to overcome any discharge pressure drop while also meeting the new flow demand. Additional actions such as charge and discharge of the linepack associated with each pipe are necessary to hold steady state pressures within bounds.

The loss of a compressor station will cause a reduction in gas flow to the downstream laterals feeding the turbine governors. The turbines shut down when the gas inlet pressure drops below the outlet pressure of the compressor stage, where gas is mixed with air from a turbocharger. In the model, the compressor stage pressure threshold is set at 620 psi, approximating the outlet pressure of a turbocharger for the Alstom GT24/GT26 [43]. In the event of an outage in the NG system, the governor will draw gas flow from the lateral pipe until the pressure drops below this threshold. At this point, the pressure regulator will not be able to maintain 620 psi and the governor will disable.

Header Pipe The header pipe provides a generic model of a pipe that includes an inlet, an outlet, and a lateral tap at the inlet end to connect lateral pipes that supply the heating loads, for example, an LDC or natural gas-fired power plants. The linepack of the header pipes is lumped at the inlet end. This accumulated pressure includes the linepack in the lateral pipe connected at the tap. To account for the lateral pipe pressure, the model of the header pipe considers the dimensions of the lateral pipe. The pressure drop of a pipe section is represented as a function of flow and pipe dimensions based on the Weymouth equation. The upstream pressure and the flow are treated as the independent variables and the downstream pressure is treated as the dependent variable. The linepack pressure is modeled using the ideal gas law with pipe dimensions and net gas flow. The Weymouth equation is implemented as eq. 2 and the ideal gas equation is implemented as eq. 3.

$$Q = 1.41 \cdot 10^{-4} \left(\frac{T_b}{P_b} \right) D^{8/3} \left[\frac{P_1^2 - P_2^2}{LGT_a Z_a} \right]^{0.5} \tag{2}$$

Q	Flow through pipe, ft^3/sec
Tb	Base temperature, $^\circ R$
Pb	Base pressure, psi
D	Pipe diameter, $inches$
P_1	Upstream end pressure, psi
P_2	Downstream end pressure, psi
L	Pipe length, $miles$
G	Gas specific gravity, $unitless$
Ta	Gas temperature, $^\circ R$
Za	Gas compressibility factor, $unitless$

$$\dot{P}V = Z\dot{n}RT \tag{3}$$

$\dot{P}$	Rate of change of pipe pressure, psi/sec
V	Pipe volume, ft^3
Z	Gas compressibility factor, $unitless$
$\dot{n}$	Mass flow rate into pipe, lbm/sec
R	Ideal gas constant, $ft-lbf\cdot lb^{-1}\ ^\circ R^{-1}$
T	Gas temperature, $^\circ R$

Header Pipe Coupling The coupling model cascades two natural gas header pipes in series. The pipes are coupled such that continuity of gas flow between sections is maintained by forcing flow out of the upstream pipe and relating it to the linepack pressure differential of the two coupled pipe sections by Weymouth equation. The coupling includes the saturation behavior introduced by check valves and relief valves preventing flow or pressure from potentially exceeding physical limits or becoming negative during transients. The resulting system consists of one long header pipe with multiple laterals taps, one for each header pipe that is connected, and independently defined gas flow rates into the upstream pipe and out of the downstream pipe. The gas flows out of the laterals are also independent and may vary depending on the usage of the pipe. The header pipe coupling is represented as a manipulated version of Weymouth equation, where pressures are treated as independent variables and flow as the dependent.

Lateral Pipe The lateral pipe provides a generic model of a pipe feeding a natural gas load such as an LDC or electric power plant. Using our modeling approach, lateral pipes must be realized as a tap off a header pipe. The pressure drop of a pipe section is represented as a function of flow and pipe dimensions based on the Weymouth equation. The stored pressure of a lateral pipe is lumped at the inlet end and aggregated with the linepack of the header pipe that feeds this particular lateral pipe. The laterals include the saturation behavior introduced by check valves and relief valves preventing flow or pressure from potentially exceeding physical limits or becoming negative during transients.

Turbine Governor The turbine governor is represented as a simplified and generic model of a natural gas prime mover/governor. The basic path through the model is from gas flow at the prime mover inlet to shaft mechanical output power and from shaft output to the electric power generator. Gas flow is given as a constant (58.33 Nm^3/sec) fed through a simple control loop when the machine operates to regulate power or frequency. However, for prime power operations, the control loop is bypassed and the generator provides constant power output. The prime mover ramp rate and governor slew rate are represented using a rate-limiting mechanism. The prime mover is modeled as 40% efficient with a conversion factor of 31 MW per Nm^3/sec, where Nm^3 denotes standard cubic meter. The shaft power is normalized such that 1.0 p.u. corresponds to 1000 MW. There is a protection mechanism based on under-pressure conditions that will shut down the prime mover if the inlet pressure drops below 620 psi. This pressure threshold is 150 psi higher than the discharge air pressure from a turbine inlet compressor stage, as required for operating a gas turbine prime mover. Other actions include emergency stop and manual restart of the prime mover.

TABLE 2

Summary of Input Parameters to Define Component Models of the Natural Gas System

Component	Parameters
Wellhead	- Inlet pressure to the compressor station - Open/closed condition of the inlet valve to the compressor station
Compressor Station	- Maximum electrical demand - Compressor motor efficiency - Minimum inlet pressure for operations - Discharge pressure setpoint - Polytropic index - Polytropic efficiency - Standard condition temperature - Inlet/suction temperature - Standard condition pressure - Gas compressibility factor
Header Pipeline	- Inside diameter - Length - Diameter scale factor - Length scale factor - Base temperature - Gas temperature - Base pressure - Ideal gas constant - Gas specific gravity - Gas compressibility - Initial linepack pressure
Lateral Pipeline	- Inside diameter - Length - Base temperature - Gas temperature - Base pressure - Gas specific gravity - Gas compressibility
Gas Turbine	- Machine base power - Rated output power - Power production rate - Electrical efficiency - Gas flow rate - Flow rising ramp rate - Flow falling ramp rate - Minimum inlet pressure for operations - Turbine initial state
Heating Load	- Gas flow rate

4. TEST SCENARIO

This section provides one example of the scenarios that could be studied using the proposed co-simulation approach. The case uses the system topologies described in Section 3 to demonstrate the interactions between the electric power and natural gas infrastructure during what could be the result of a natural incident and/or man-made event. The narrative highlights the need for communication and coordination between operators of both systems to maintain service continuity during emergency events. Furthermore, the narrative emphasizes the importance of overlapping or combined training for operators while also considering their system interdependencies.

Key take-away of our co-simulation: **Power system operators need situational awareness about the natural gas system, specially information about the loss of key natural gas compression stations or pipeline failures well in advance. This information would help power system operators to execute efficient load-shedding schemes and avoid cascading failures. However, without this information grid operators may be caught off-guard during a gas contingency event which could result in cascading power failures.**

4.1 SYSTEM INITIALIZATION

The model initialize and reaches to steady state within 200 seconds. The power system operates in normal conditions; where generators, transformers, lines, and loads are energized and system voltages are within acceptable bounds. Similarly, the natural gas system is pressurized and flow is available in the pipes. During initialization, the turbine governors of the natural gas generators draw gas flow from the pipes, causing pressure drops in the lateral pipes and producing dynamics, both in the electrical and natural gas systems. After the pressure in the pipes serving the natural gas generators regulates to 620 psi, the generators start up and independently produce 700 MW of output power each. Figure 13 shows an estimated timeline of events for the scenario and highlighting actions in the electrical and natural gas systems. Note the response of the natural gas components was accelerated 10x by applying a scale factor to the physical dimensions of the pipes resulting in faster flow velocities.

4.2 SEQUENCE OF CONTINGENCY EVENTS

The sequence of events begins at 600 seconds, well after the system initializes. The exercise segments the power system into two sections, e.g, Area 1 and Area 2, by simultaneously disconnecting three critical transmission lines in ways that prevent the immediate reconnection of the corresponding circuits (see Figure 14). The operators' display and control interfaces developed for the electrical and natural gas system are shown in Figure 15 and Figure 16, respectively.

Although the simulated power system is robust, once segmented, available generation resources become limited and asset management complexity increases. Area 1 stabilizes to 3,069 MW with 220 MW of generation reserve and Area 2 stabilizes to 3,080 MW with 391 MW of generation reserve; neither of the two areas disconnect load. Figure 17 and Figure 18 show the response

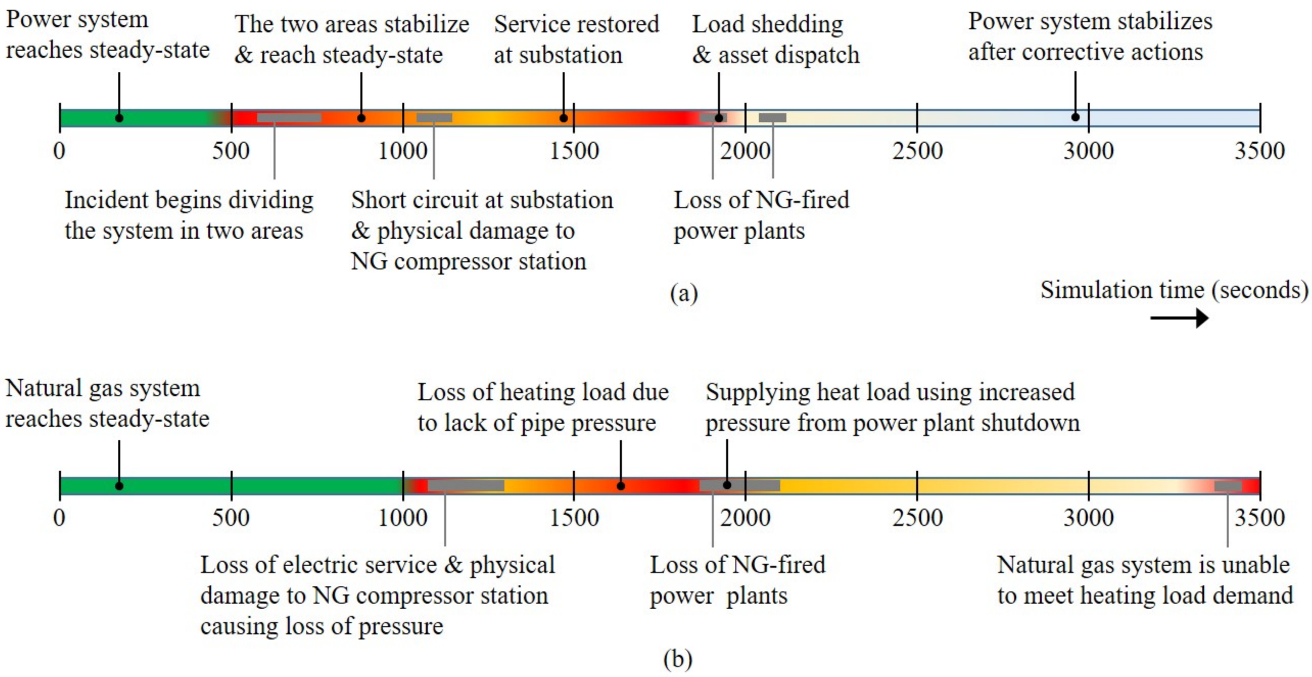


Figure 13. Summary of the major events in the scenario under accelerated timeline: (a) power system and (b) natural gas systems.

of the electrical and natural gas systems to the contingency events. For easier understanding of the simulated case, the time axis of these figures are aligned, e.g, colors and annotations, with the notes from Figure 13.

At 1,100 seconds, a short circuit occurs at the electric service of compressor station #1, which uses the power grid as primary source of electricity (see Figure 11 - component C1). Natural gas compressor stations are often unmanned, monitored and controlled via SCADA from remote locations [40]. Consequently, the scenario assumes that the backup generators of the compressor station failed to operate, forcing the station out of service until the power grid is restored.

Although compressor station C1 is not in service and the pipe pressure steadily drops, the existing linepack could continue supplying natural gas loads between 48–72 hours of service without accelerating the simulation [19], which could provide enough time until the electric service is restored to compressor station C1. Therefore, to emulate a worst case, the sequence considers physical damage to the pipes entering the compression station isolation valve. This damage would prolong the time out of service for this compressor station from several days to weeks, a timeline exceeding expectancy of the available linepack. To aggravate the situation, following the loss of compressor station C1, the downstream compressor station C2 also shut down because the pressure at inlet valve drops below the pressure at its outlet valve by a substantial margin. Generator outage may arise due to equipment failures, lack of natural gas fuel supply resulting from gas transportation restrictions, limited obligation contracts with the natural gas providers, and interruptions of fuel

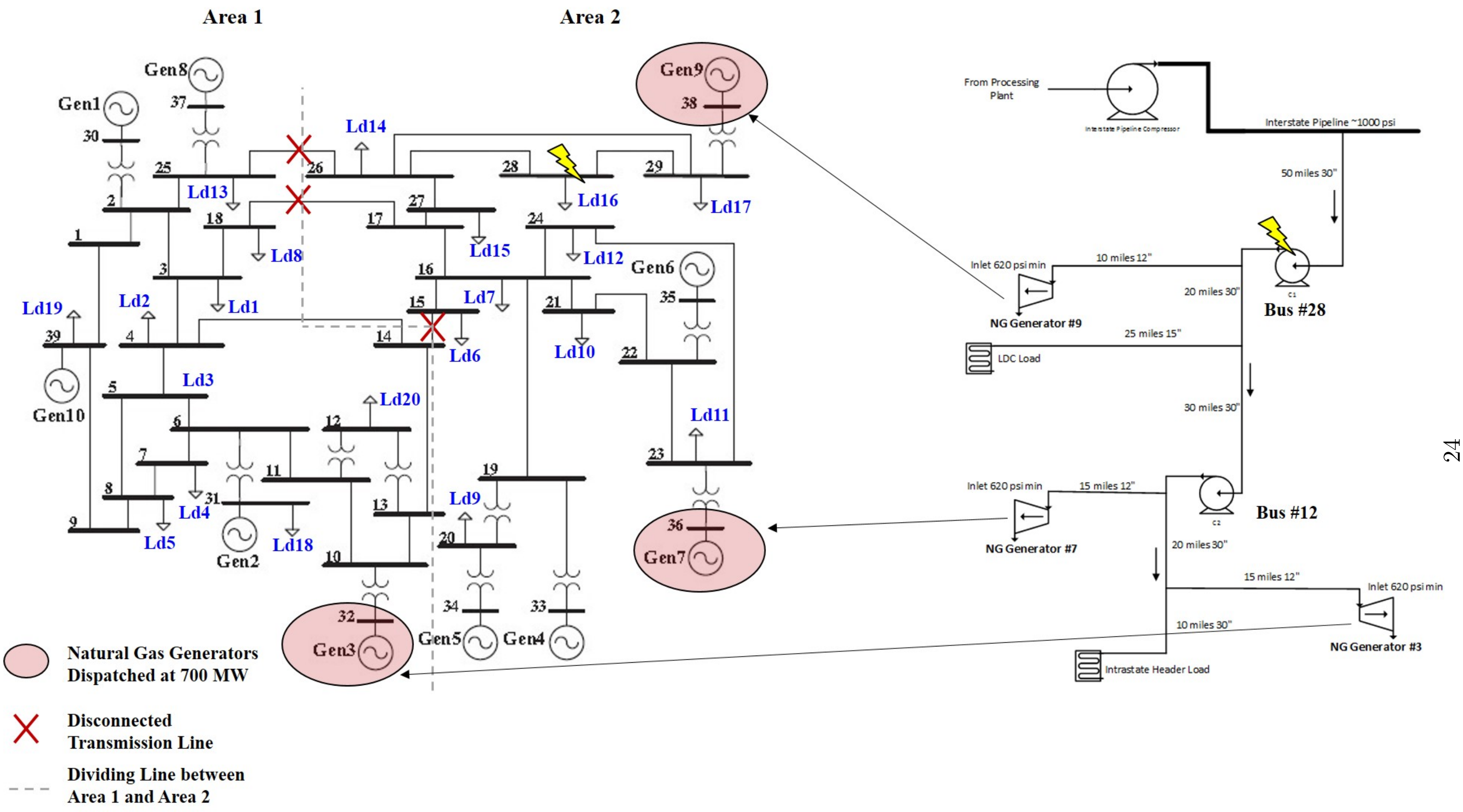
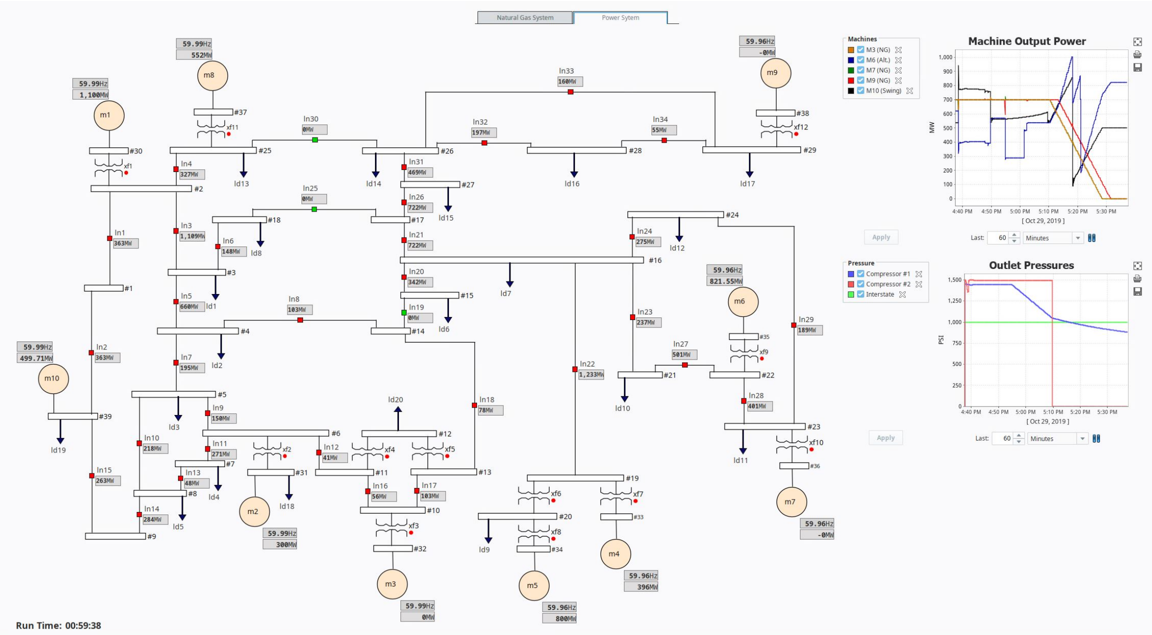
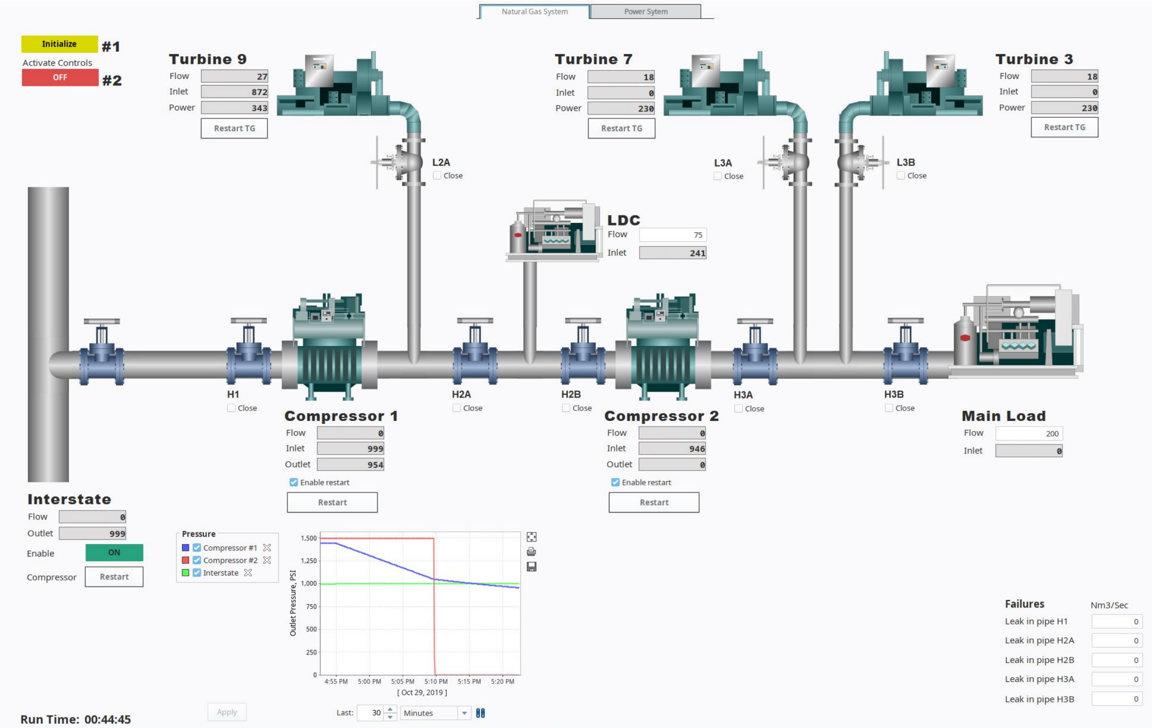


Figure 14. Power system divided into two islands, with Area 2 allocating the largest portion of natural gas generation. The right side of the figure denotes the simulated notional natural gas system and interdependencies with the electrical system.



Run Time: 00:59:38

Figure 15. Operator display and control interface for the electrical system.



Turbine 9
Flow 27
Inlet 872
Power 343

Turbine 7
Flow 18
Inlet 0
Power 230

Turbine 3
Flow 18
Inlet 0
Power 230

L2A ☐ Close
L3A ☐ Close
L3B ☐ Close

LDC
Flow 75
Inlet 241

H1 ☐ Close
H2A ☐ Close
H2B ☐ Close
H3A ☐ Close
H3B ☐ Close

Compressor 1
Flow 0
Inlet 999
Outlet 954
☑ Enable restart

Compressor 2
Flow 0
Inlet 946
Outlet 0
☑ Enable restart

Main Load
Flow 200
Inlet 0

Interstate
Flow 0
Outlet 999
Enable ON
Compressor Restart

Failures	Nm3/Sec
Leak in pipe H1	0
Leak in pipe H2A	0
Leak in pipe H2B	0
Leak in pipe H3A	0
Leak in pipe H3B	0

Run Time: 00:44:45

Figure 16. Operator display and control interface for the natural gas system.

supply in preference to gas heating commodity during winter periods. The goal of this scenario is to extend the generator outage by preventing fuel service to the three natural gas-fired generation plants. Ideally, during this type of situations the utility operators of the electrical and natural gas systems would establish communication and coordinate action to minimized loss of service in both infrastructures.

After the interruptions in the natural gas service, the survivability of the electric power system will solely depend on operator actions, situational awareness, and resources management strategies. Through disabling the main compressor station, the sequence ensures steady loss of natural gas generation because the operation of gas-fired power plants will be limited to the available linepack in the pipelines. The generators will gradually shut down as the lateral pipeline pressure falls below 620 psi. After the inlet gas valves to the generators close and stop gas flow, some pressure will build up in the pipes allowing the natural gas operators to momentarily supply commodity heating loads until pipe pressure drops below a workable range.

To maintain generation-to-load balance and stability in the electric system, the operator must dispatch available generation and execute suitable load-shedding schemes, which may not be possible ad-hoc. Even for a simple test system as the one used in this scenario (Figure 14), the coordination between load shedding and generation dispatch is not straightforward and requires smart algorithms to optimally manage the available assets. In this example, the NETSSWorks software was leveraged to compute adequate load shedding and dispatch actions to maintain the power system stable and within acceptable operating regions. At the loss of generator #3, Area 1 disconnects 17% (519 MW) of the load as well as dispatch available generation to maintain stability. Simultaneously, Area 2 losses generator #7 and disconnects 6.4% (197 MW) of the available load. At this point, natural gas-fired generator #9 still remains in service within Area 2. After the linepack feeding generator #9 depletes below underpressure threshold, the generator shuts down and Area 2 disconnects extra 23.7% (731 MW) of demand, resulting in a 30.1% (928 MW) of load not served.

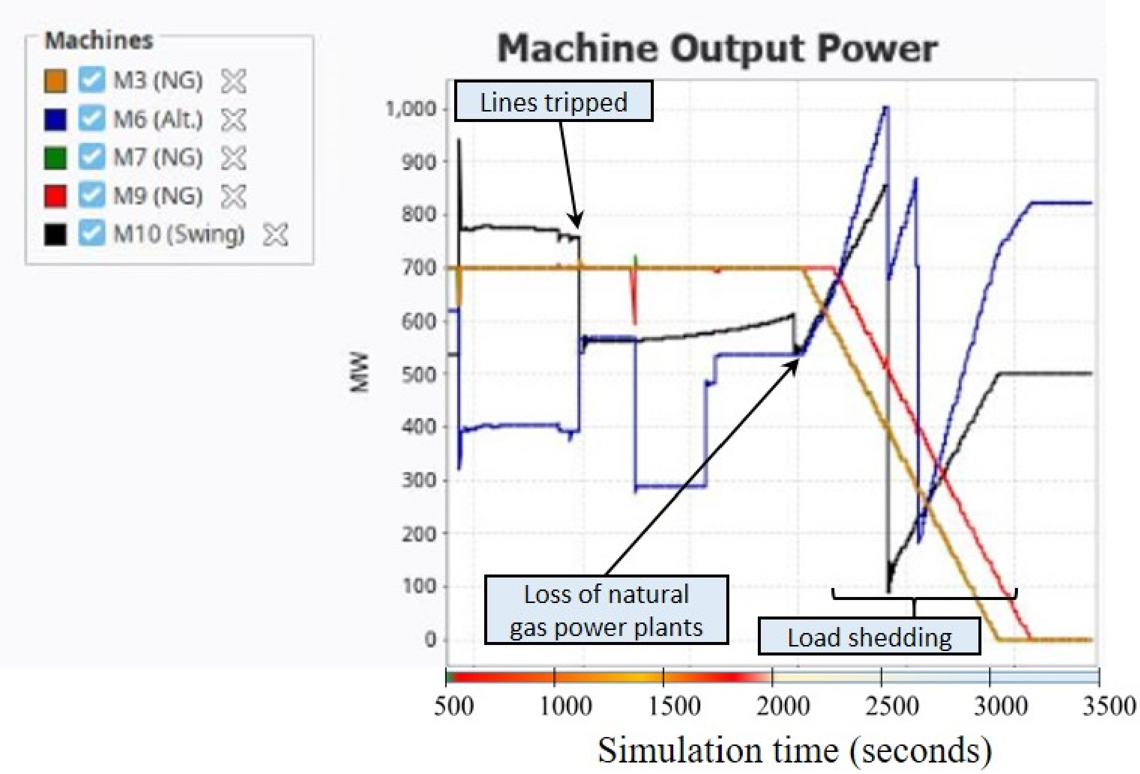


Figure 17. Selected generator megawatt output power in response to the simulated scenario. See Figure 13 for sequence details.

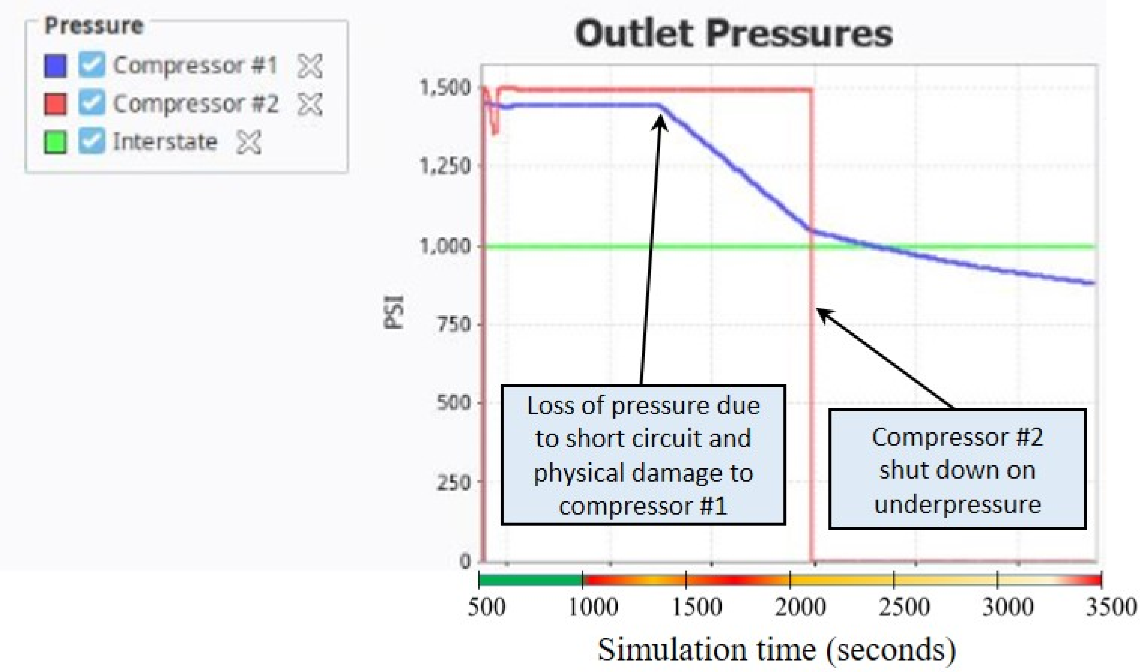


Figure 18. Selected natural gas system pressures in response to the simulated scenario. See Figure 13 for sequence details.

5. CHALLENGES AND LESSONS LEARNED

This section discusses the challenges encountered during model development and the key observations to be considered for studies and demonstrations.

5.1 INTEGRATION BETWEEN THE NATURAL GAS SYSTEM AND ELECTRIC POWER GRID

At a high level, the challenges of integrating electric power grid with natural gas infrastructure appear to be largely cultural, organizational, and logistical. Both systems have co-existed for many years, but the relatively recent shift to natural gas as a preferred fuel for the generation of electricity has increased the interdependence of the two systems [9]. The increased use of electric motors for driving centrifugal compressors increases this interdependence further still [13] [19]. Although there are many conceivable advantages to integrating the control infrastructure for the electrical power grid with that of the natural gas system, the long history of separate operating procedures and organization business models and goals present obstacles to overcome.

Simulations and tabletop exercises can demonstrate the needs for coordinated black start capabilities and emergency operations of the two systems. Engagement between respective organizations could address appropriate restoration sequences to re-energize load and compressors stations associated with critical natural gas distribution facilities that provide service to residential and commercial heating as well as electric power generation [1] [2] [3].

Furthermore, electric grid operator would benefit from having real-time situational awareness of linepack available to natural gas-fired generators, especially during emergency conditions. This would provide information concerning how long the natural gas-fired power plants could operate following loss of a compressor station or upstream pipeline, which could then be used to plan load-shedding strategies. Similarly, information about day-ahead dispatch strategies used by electric utilities could potentially provide useful planning data for natural gas operators who plan compressor operations and gas flow schedules.

5.2 MODELING AND DEVELOPMENT CONSTRAINTS

The following list summarizes the major modeling and development constraints and observations encountered during this work. Note the list is not comprehensive, but summarizes the high-impact items.

- Lack of access to real-life system data. This limits model realism and forces simulation studies to use notional architectures and educated assumptions about the infrastructure that may not entirely represent existing topologies or operating conditions.
- Adequately characterizing network topology, generator and load characteristics, and protection device functionality without overly taxing simulation platform capabilities.

- Adequately estimating system parameters when publicly available information is sparse, e.g, performance characteristics and operating procedures for generators, compressors, and protection equipment.
- Selecting suitable time steps to solve the coupled electrical and natural gas models may prove challenging, as electrical response is orders of magnitude faster than the natural systems. This limitation can be easily observed during live and interactive demonstrations where the natural gas system needs to be simulated at faster rates than real-time, e.g, 10x or more, to avoid days- or week-long simulations.

5.3 CONSTRAINTS DURING BLACK START SCENARIOS

- The location of black start capable power plants dictates which region can be re-energized first. This may be problematic if the region with black start capable units does not have critical loads or if the transmission lines reconnecting to the rest of the system are not available.
- Operators must execute timely and coordinated control of the generators to achieve a smooth black start without significant oscillations in the system, especially when synchronizing and interconnecting two energized regions with significant difference in available inertia.
- Restoration sequence should not overload individual generation assets, transmission lines, or transformers. Otherwise, equipment could malfunction or damage increasing restoration delays.
- Depending on the location, electrically driven natural gas compressor stations may require to be treated as high-priority loads during system pickup because the operational status of compressor stations may be a decisive factor to the availability of natural gas-fired power plants.
- If the natural gas system also requires black start, e.g, zero pressure or flow in the pipes, power grid operators should expect larger power demands from the electrically driven compressor stations as these need to compress gas into the empty pipes. This process may take hours or even days to complete unless properly coordinated.

5.4 EXPANDING THE TOOL TO SIMULATE REGION-WIDE SYSTEMS

The modeling approach is intended to be flexible enough to support a large spectrum of network types and sizes. The electrical model is implemented using Opal-RT's ePHASORSim, a tool capable of simulating large-scale power systems, up to hundreds of thousands of nodes, with sufficient fidelity to analyze transient stability and other electrical phenomena. This software accepts data inputs as manageable text using the well-known formats such as Siemens PSS/e, Microsoft Excel, and others. To simulate large electrical systems, computing resources are acknowledged as key limitation. However, the natural gas system is modeled in MathWorks Simulink using building-block subsystem components that at the moment requires user's manual interaction with every component for connectivity as well as parameter definition. This user dependency limits the scalability of the natural gas system model. As a mitigation, the electrical simulations could be integrated with software that is specific for modeling and simulating the dynamics of natural gas systems via Restful API.

5.5 DATA REQUIREMENTS FOR MODELING

The minimum data required to model the electrical system should contain transmission line information (connectivity, lengths, and impedance), transformer ratings, generator information (fuel type, capacity, and parameters for dynamic studies), information about electrical loads, and power flow solutions to support system verification. Note this information is readily available to power system operators in Siemens PSS/e format.

For the natural gas system, the minimum data include pipeline information (e.g, linepack, lengths, inner diameters, elevation data), details about the compressor stations, LDC gas flows, locations of major valves, operating pressure, and bus voltage thresholds for compressor station or generator automatic shut down. Finally, information about natural gas-fired turbine generator governor models or gas-fired boiler pressure regulator characteristics.

6. FUTURE WORK

The team actively seeks to implement the developed components and scripts to simulate a real-life network with sufficient interaction between the electric grid and the natural gas system where their interdependency is known to cause planning and operational issues. For example, a region of interest is New England which has a track record of near 40% in daily use of natural gas-fired generation [48] [49]. A possible venue for demonstration is NERC's GridEx, where utility companies, infrastructure cross-sector partners, and supply chain stakeholder organizations are provided an opportunity to demonstrate how they would respond to and recover from coordinated cyber and physical security threats and incidents.

7. ACKNOWLEDGMENTS

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