EISPC

EASTERN INTERCONNECTION STATES' PLANNING COUNCIL

White Paper:

Long-term Electric and Natural Gas Infrastructure Requirements

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Illinois Institute of Technology

For EISPC and NARUC

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As Project Manager for the DOE-funded cooperative agreement that supports the activities of the Eastern Interconnection States Planning Council (EISPC), I am proud to make available to public utility regulators, policymakers, utility industry leaders, and consumers, this landmark paper on a complex set of issues pertaining to the interdependencies between our nation's gas and electric infrastructure systems. This white paper examines the respective roles played by the electric and gas systems in assuring our country's affordable and reliable supply of energy.

This research, undertaken by the Illinois Institute of Technology, provides a detailed overview of the system basics, markets, operations, and planning of these two infrastructures. It explores the coordination between them and the points at which coordination gaps create uncertainties. It highlights challenges to improving the data exchange and planning coordination between these systems: data limitations, confidentiality and competitiveness concerns, critical infrastructure issues, systemic incompatibilities, and economic obstacles, among others. These sections of the paper represent an excellent primer for those exploring the issue with expertise in some elements and an interest in understanding the complete picture. The white paper turns to a series of recommendations for harmonizing these systems and optimizing their interactions by noting directions for future study and suggesting ideas for consideration. As a catalyst for discussion of these issues, the white paper provides an important milepost in describing one potential direction forward; it is however intended to be one inject into the marketplace of ideas on the subject and does not represent a consensus view of the EISPC members. I look forward to vigorous debate and the emergence of well-considered policy resulting from that debate.

The NARUC staff that supports this project appreciates and is grateful for the assistance in preparing this report by IIT and its team of researchers, as well as the EISPC Studies and Whitepapers workgroup, particularly Denis Bergeron from Maine, Bob Pauley from Indiana, Scott Morris from Alabama, and Al Freeman from Michigan. Our experts Doug Gotham from Purdue University and the National Regulatory Research Institute staff provided helpful context. I also acknowledge the support and funding provided by the U.S. Department of Energy and the National Energy Technology Lab.

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The National Association of Regulatory Utility Commissioners (NARUC)
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Preface

The 1987 repeal of the Power Plant and Industrial Fuel Use Act prohibiting the use of natural gas by new electric generating units led to a large increase in natural gas generating capacity through 2000. Additional factors contributing to this increase were low natural gas prices through the 1990s, the availability of increasingly efficient natural gas technology in the form of advanced combined cycle units, the short construction-to-operation time to build new combined cycle units, and the attractiveness of natural gas as a trace SO_2-emitting fuel source. Natural gas is now being obtained more efficiently, cheaply, and easily than ever before. The natural gas consumption by the power industry has exceeded those of residential and industry consumers. In the near future, the electricity sector will be responsible for most of the growth in natural gas demand. However, the existing supply of power generation is unlikely to meet the projected electrical demand as several large coal and nuclear generating units are subject to retirement in the near future.

The electricity sector's growing reliance on natural gas has raised major concerns among Independent System Operators (ISOs), electricity market participants, industrial consumers, national and regional regulatory bodies, and other stakeholders regarding the electricity infrastructure's ability to maintain the power system reliability when facing a constrained natural gas pipeline capacity. The extent of these concerns varies from region to region in the United States; however, they are most acute in areas where the reliance on uninterruptible natural gas supply for power generation grows rapidly. The 2013 extreme winter weather in the northeastern part of United States, where the percentage of natural gas consumption by power generators is among the highest in the nation, indicated that major changes ought to be introduced in the coordination of electricity and natural gas infrastructures before the overall system reliability is seriously jeopardized.

As a myriad of new natural gas-fired generating units are scheduled to be installed, the existing natural gas transportation infrastructure ought to be considered for expansion for lowering the chance of generator outages when supplying the peak demand in a market-based economy. The additional natural gas consumption by electricity industry has significantly increased the interdependency of the two systems and increased the focus on the necessary interface between the infrastructures. Even on non-peak flow days, natural gas-fired generation requires high-volume, high-pressure loads with large load swings that pipelines may not have been designed to accommodate. Pipelines need to align a slow-moving product (natural gas) with a fast- moving product (electricity) that is subject to large variations (natural gas-fired generators come on/off-line on short notices). The sudden demand swings from generators may cause pipeline pressure drops that could reduce the quality of service to all pipeline customers.

In the meantime, most power generating companies still have non-firm contract with pipeline companies while local distribution companies (LDCs) hold firm contracts with pipeline companies. So the main issues are whether natural gas availabilities are predictable within the natural gas pipeline nomination cycle, 1) if natural gas supplies are available and confirmed, 2) if the pipeline is sized to handle the load variations, 3) of storage is in the proximity of the power plant, and whether natural gas volumes are available in excess of confirmed nominations, including specified allowances for hourly load swings.

In this regard, two different outlooks for resource planning in natural gas and electricity industries have created concerns when it comes to aligning resource adequacy practices. In electricity sector, electric transmission system owners have almost no control over the size or the location of electric loads or the timing of electricity use by customers. Transmission systems are not planned using firm commitments from potential users, but on rather speculative estimates of anticipated electric load growth. Proposed transmission lines do require certain pledges from major electric users sought through simulated cases. These simulations are run in the course of acquiring regulatory approval for the electrical planning projects. However, simulated solicitations do not constitute a basis for committed electrical contracts. To balance out the lack of real commitments, the electricity grid is designed to be a very flexible system with multiple parallel paths for electricity flow capable of serving numerous buses, and where facilities are interconnected to withstand serious contingencies. Under such a design, electricity customers rarely lose power in bulk power systems.

The natural gas system planning procedure, on the other hand, is less flexible. The standard industry practice is to expand pipeline capacity based on firm contracts. FERC generally does not authorize new pipeline capacity unless customers have already committed to it (e.g., firm delivery contracts). Pipelines are prohibited from charging the cost of new capacity to their existing customer base. New customer requests for firm service are considered when pipelines add new facilities or improve existing facilities. NERC Reliability Standards require a layer of system backups to cover a scenario called a "single contingency situation." Such backups have to ensure that no failure of a single piece of electric equipment will cause a loss of power. Some planners introduce additional standards that require handling extra contingencies such as extreme weather conditions, the outage of the critical generators, and limitations on the use of peaking generation units, etc. As a result, pipeline capacity closely matches the requirements of the firm customers. Pipelines know the exact location of the customers who have firm rights, and have contracts in place that describe exactly how much firm capacity each customer may call upon. However, if all of the pipeline's firm customers use their full capability, little or no excess pipeline capacity is available. Unlike power transmission, pipelines do not have contingency planning standards. There is some redundancy in the pipeline system. Pipelines use side-by-side pipelines, or loops, that provide support in cases of maintenance or loss of integrity. However, these structures are not sufficient to increase natural gas flow in any dramatic volume.

If natural gas requirements are unknown within the natural gas pipeline nomination cycle and the available capacity for interruptible loads is factored into the pipeline operating plans, or if hourly swings are excessive, a pipeline would need to allocate, reserve, or build facilities on the pipeline to provide service for the intra-cycle requirements. This may involve the creation of pipeline services that do not exist. While pipelines are capable of adding capacity in the form of more pipe, compression, or market-area storage deliverability, they are unlikely to do so without a cost recovery mechanism, which is traditionally in the form of a contract for that service.

In regions with restructured (deregulated) electricity markets, natural gas-fired generators rely more heavily on pipeline capacity release and interruptible services. In fact, most natural gas-fired units have difficulty committing to firm services since the majority of them serve mid-range and peak electricity demands. While this trend is expected to change with the pending retirement of coal-fired units, thus forcing more natural gas units to serve base loads, current energy profiles make it difficult for natural gas-fired units to commit to firm pipeline capacity, and new power generators find it difficult to be integrated into natural gas pipeline expansion plans.

It is clear that natural gas market day and the electricity market day are not synchronized. Natural gas timely nominations are due approximately a full day before the natural gas flows, and energy market day-ahead generation scheduling is concluded in the afternoon just hours before the power day begins. This scheduling inconsistency implies that natural gas-fired generators either purchase and schedule fuel delivery without knowing their power market energy dispatch status, or they bid into the energy market without knowing whether they will be able to successfully purchase and schedule natural gas. The misalliance in scheduling is manageable most of the time, but the situation can become challenging with potential reliability implications during peak natural gas demand and during pipeline maintenance or emergencies. Power grid operators often provide extensive record of cases when natural gas-fired generators failed to respond to power dispatch instructions since they were unable to secure natural gas fuel.

While the lack of coordination remains to be a major concern, there is anxiety in both industries that the growing interdependency could heighten the potential impact of malicious cyber attacks. It is thus imperative to investigate cyber security issues through coordination and to detect and address any vulnerability that may result from integrating natural gas and electric systems.

States are taking an increasingly active interest in the implication of higher natural gas utilization for electric power generation, its effect on more traditional usages of natural gas by residential and commercial customers, and its impact on market operations including the potential impacts on natural gas and power distribution companies. From the perspective of EISPC, there seem to be several operational, contracting, planning, financial market, and regulatory differences that may impede the ability of natural gas and electricity industries to engage in comprehensively coordinated and long-term activities. Longer delays in modifying the power generating company's contract with pipeline companies may cause serious fuel supply issues due to the increment of natural gas consumptions by the electric power industry.

In a nutshell, there are several common concerns at the heart of regional and national efforts for the coordination of electricity and natural gas industries, including the sufficiency of natural gas infrastructure and pipeline capacity for natural gas delivery and storage, harmonizing the operation of the natural gas and electricity markets to allow for more precise and flexible scheduling of required amounts of natural gas for electric generators, allocation and recovery of costs associated with ensuring reliable electricity and natural gas resources, and increasing the communication between the industries to provide more seamless coordination, while observing applicable legal boundaries on such communication.

This white paper which includes 16 tasks is intended to be a catalyst that provides the necessary information for state regulators and government representatives, and those in natural gas and the electricity industries, who are interested in learning the fundamental details of the operation and the planning of the two industries. The white paper will assist stakeholders in fostering appropriate public policies and facilitating necessary coordination for the optimal operation and the investment planning of the two interdependent infrastructures.

Scope of the White Paper

This white paper discusses the following 16 tasks in detail:

- Task 1: Explain market structures for both the electric power system (such as RTOs and nonmarket regions) and each of the elements of the natural gas system.
- Task 2: Explain system operations for both electricity and natural gas. This should include the timely sharing of information to address the needs of both the natural gas and electricity industries; the electricity industry's intra-hour (as low as 5 minute intervals) compared to the intra-day nomination processes used by the natural gas industry; and contracting issues due to the different schedules, load shapes and load duration curves for both the natural gas and electricity industries with a discussion of the implications of the industry load characteristics.
- Task 3: Provide an explanation of the following electric issues: a. The ability to better integrate variable resources using natural gas facilities; b. The potential for substantial increases in natural gas-fired generation due to issues like rigorous carbon regulation and the associated effect on the nation's utilization of coal-fired power plants; c. The potential implications for electricity industry reliability with an expanded dependency on natural gas.
- Task 4: Detail the contracting procedures and issues for the natural gas and electricity industries. The Subcontractor shall provide a discussion of: (i) typical contract process that reflects the operational requirements of both industries; (ii) typical terms and conditions for power generators purchasing natural gas (the commodity, pipeline, storage); (iii) potential changes being considered by the natural gas industry in their contracting procedures to better accommodate the range of operating requirements of electric generators; (iv) potential changes being considered by the electricity industry in their contracting procedures to better accommodate the natural gas industry's operating requirements; (v) an independent assessment of what changes in the natural gas and electric contracting process, terms, and conditions that might better accommodate operational requirements in both industries; (vi) address if there is a role for RTOs/ISOs to facilitate contracting and construction of required facilities; (vii) address if there is a constructive role for states to facilitate contracting and construction of required facilities?
- Task 5: Address planning issues including the limitations imposed on integrated electric transmission and resource planning. This discussion should include FERC's, NERC's, and, where applicable, Market Monitor's perspectives.
- Task 6: Explain what the planning issues are in the natural gas industry including those of producers, pipelines, storage, and local distribution companies.
- Task 7: Provide a discussion on the coordinated planning issues concerning natural gas and electricity industries.
- Task 8: Explain what the planning implications are due to various regulatory regimes and the issues that result from those differences. This should be an assessment of both intra-industry (natural gas and electric) as well as inter-industry (natural gas and electricity).
- Task 9: Discuss the most often used planning tools available to the natural gas and the electricity industries.
- Task 10: Explain the issues regarding the capability of coordinating natural gas and electricity planning tools.
- Task 11: Address what the immediate and long-term data limitations and concerns are that may limit natural gas and electricity planning objectives- for each respective industry as well as for the

coordinated natural gas and electricity industries. By way of examples, are there load forecasting issues that need to be addressed? Are there equipment availability/capability concerns that are important for improved planning in both the natural gas and electricity industries?

- Task 12: Discuss the confidentiality and critical infrastructure concerns and potential solutions to overcome the concerns to allow natural gas and electricity industries, states, and other stakeholders to engage in operational and long-term planning.
- Task 13: Describe federal and state regulatory issues with natural gas and electricity industries, and make recommendations to overcome any perceived obstacles. What, if any, actions can states take to facilitate the timely construction of new natural gas infrastructure?
- Task 14: Provide an explanation of potential payment options to increase the deliverability and the efficiency in the natural gas industry and to meet the needs of the electricity industry.
- Task 15: Provide a set of recommendations on improving the coordination of natural gas and electricity industries.
- Task 16: Glossary of terms, bibliography, and a discussion of contracting concepts.

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List of Acronyms

AC	Alternating Current
AEO	Annual Energy Outlook
AMI	Advanced Metering Infrastructure
BCF, bcf	Billions Cubic Feet
BCFD, bcfd	Billion Cubic Feet per Day
BOE, boe	Barrel of Oil Equivalent
BTU, btu	British Thermal Unit
CA	Contingency Analysis
CAISO	California ISO
CAW	Customer Activity Website
CC	Combined Cycle
CCGT	Combined Cycle Gas Turbine
CCNG	Combined Cycle Natural Gas
CEA	Commodity Exchange Act
CHP	Combined Heat and Power
CNG	Compressed Natural Gas
CO2	Carbon Dioxide
CT	Combustion Turbine
DA	Day-ahead
DAM	Day-ahead Market
DC	Direct Current
DG	Distributed Generation
DISCO	Distribution Company
DoS	Denial of Service
DRA	Drag Reducing Agent
EDI	Electronic Data Interchange
EFP	Exchange for Physical
EIA	Energy Information Administration
EMS	Energy Management System
EPA	Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
EU	European Union
FERC	Federal Energy Regulatory Commission
FPA	Federal Power Act
FTR	Financial Transmission Right
GADS	Generating Availability Data System
GDP	Gross Domestic Product
GEITF	Gas Electricity Interdependency Task Force
GENCO	Generation Company
GEP	Generation Expansion Planning

GHG	Greenhouse Gas
GIRP	Gas Integrated Resource Plan
GIS	Geographical Information System
GNP	Gross National Product
GPD	Gas Planning and Design
GPS	Global Positioning System
GW	Gigawatt
HV	High Voltage
HVDC	High Voltage Direct Current
Hz	Hertz
ICE	Intercontinental Exchange
IEA	International Energy Agency
INGAA	Interstate Natural Gas Association of America
ISO	Independent System Operator
ISONE	ISO New England
kV	kilovolt
LDC	Local Distribution Company
LEL	Lower Explosive Limit
LMP	Locational Marginal Price
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
MCP	Market Clearing Price
MDCQ	Maximum Daily Contract Quantity
MER	Monthly Energy Review
MISO	Midwest ISO, Midcontinent ISO
MMBtu, MBtu	Million British Thermal Unit
MMcf	Million Cubic Feet
MMS	Market Management System
MW	Megawatt
MWh	Megawatt-hour
NEP	Network Expansion Planning
NEPOOL	New England Power Pool
NERC	North American Electric Reliability Corporation
NESCOE	New England States Committee on Electricity
NGA	Natural Gas Act
NGL	Natural Gas Liquid
NGSA	Natural Gas Supply Association
NGV	Natural Gas Vehicle
NOPR	Notice of Proposed Rulemaking
NPCC	Northeast Power Coordinating Council
NREL	National Renewable Energy Laboratory
NYISO	New York ISO

NYMEX	New York Mercantile Exchange
OASIS	Open Access Same-Time Information System
PSLF	Positive Sequence Load Flow
PSS/E	Power System Simulator for Engineering
PUC	Public Utilities Commission
PV	Photovoltaic
RAA	Reserve Adequacy Assessment
RETAILCO	Retail Company
RPM	Reliability Pricing Model
RPS	Renewable Portfolio Standard
RT	Real-time
RTM	Real-time Market
RTO	Regional Transmission Organization
RTU	Remote Terminal Unit
SCADA	Supervisory Control and Data Acquisition
SCOPF	Security-constrained Optimal Power Flow
SCUC	Security-constrained Unit Commitment
SE	State Estimation, State Estimator
SNG	Substitute Natural Gas, Synthetic Natural Gas
SPP	Southwest Power Pool
TAZ	Traffic Area Zone
TCF	Trillion Cubic Feet
TRANSCO	Transmission Company
UFLS	Under-frequency Load Shedding
UVLS	Under-voltage Load Shedding
V	Volt
VA	Volt Ampere
VER	Variable Energy Resource
W	Watt
WECC	Western Electricity Coordinating Council

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0. Introduction to Natural Gas-Electricity Interdependency Issues

0.1 Energy Industry Outlook

The United States has the world's second largest natural gas resource base, providing the potential for an abundant and low-priced natural gas supply for many years. The robust supply outlook is almost entirely dependent on the new and unconventional shale natural gas, which is made commercial by a combination of horizontal drilling and hydraulic fracturing technology. The shale natural gas production began to grow rapidly in 2003 and accounted for over 40% of the U.S. natural gas production in 2012; by 2025 it will likely account for over 60% of the U.S. natural gas production.

As a result of shale natural gas production growth, the geography of the U.S. natural gas production is changing rapidly. For example, in 2000, the Gulf of Mexico produced a quarter of all the U.S. natural gas; in 2012 it only produced 6%. This decline is offset by shale growth in the Gulf Coast, Rocky Mountains, and the Northeast. Three shale plays located at Marcellus (Northeast), Haynesville (Louisiana), and Barnett (Texas) have been dominant so far which accounted for 72% of the shale gas production in 2012. The continued improvement in efficiency has lowered breakeven natural gas supply costs to below \$4.00 per million British thermal unit (MMBtu) in the core of the best shale plays. However, the insufficient demand for natural gas lowered Henry Hub prices from \$8.86/MMBtu in 2008 to \$2.75/MMBtu in 2012. Producers responded by lowering the natural gas-directed rig count from 1,465 to 529 through the same period. As the demand for natural gas grows and prices recover, producers will increase the rig count to take advantage of large volumes of low-priced supply. New sources of demand for natural gas are also emerging. Electric power generation demand for natural gas has increased significantly, driven by lower natural gas prices, combined cycle natural gas turbine (CCGT) economics, and coal plant regulations (Figure 0-1). The natural gas use was increased from 18% of total power generation in 2002 to 34% in 2013 (Figure 0-2).

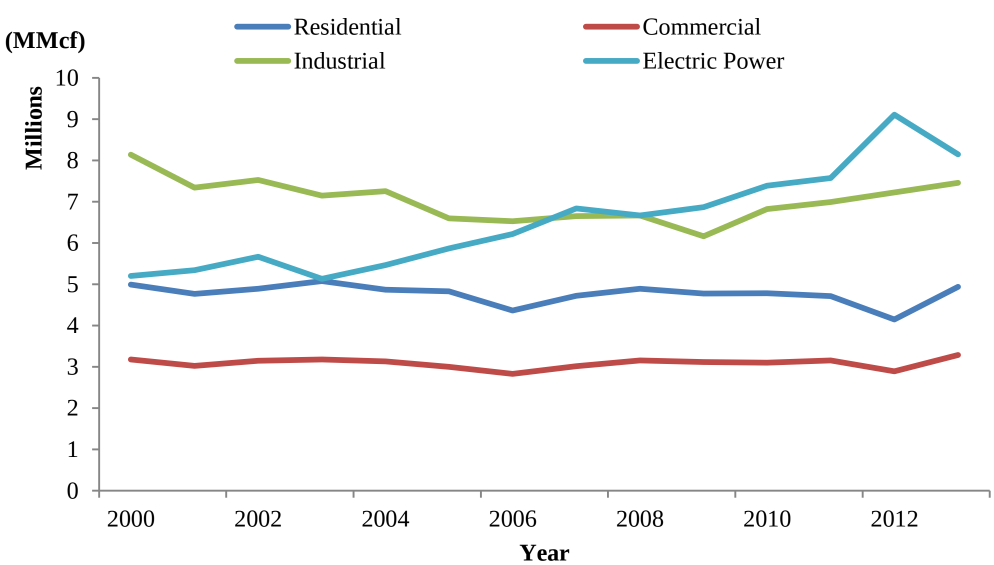


Figure 0-1: Natural gas consumption curve from 2000 to 2013

(Source: U.S. Energy Information Administration)

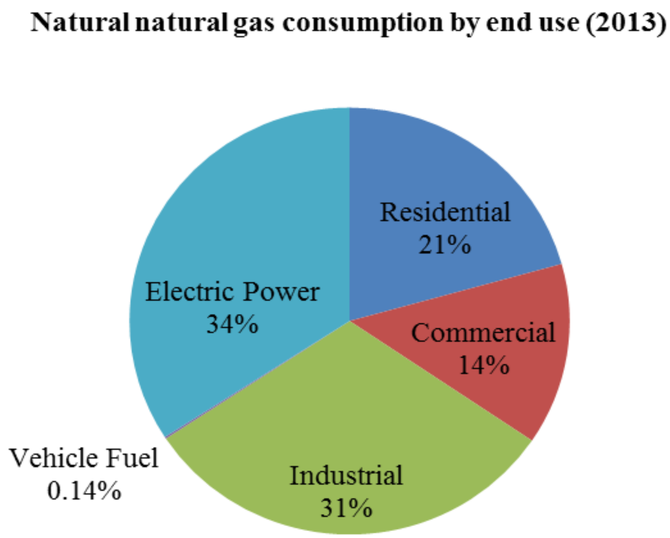


Figure 0-2: Natural gas consumption by end use

(Source: U.S. Energy Information Administration)

Continued low prices of natural gas will further encourage the use for power generation. Nearly 10 billion cubic feet per day (bcfd) of incremental power generation demand will be added between 2010 and 2025; around half from coal substitution and half from new electricity demand. The difference between average annual prices per MMBtu for natural gas and coal delivered to U.S. electric power plants narrowed substantially in 2012. In essence, the fuel costs for NGCC units and coal steam turbines per megawatt-hour (MWh) of generating power were equal on a national average basis (Figure 0-3), given that combined-cycle gas plants are much more efficient than coal-fired plants. When the ratio of natural gas prices to coal prices is approximately 1.5 or lower, a typical natural gas-fired combined-cycle plant has lower generating costs than a typical coal-fired plant.

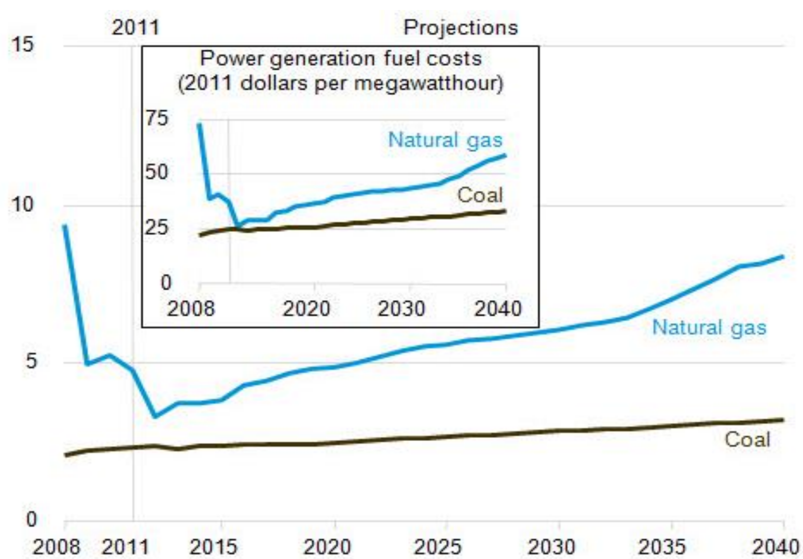


Figure 0-3: Average delivered fuel prices to electric power plants in the Reference case, 2008-2040

(Source: U.S. Energy Information Administration)

Subsidies and regulations have enabled variable renewable energy (excluding hydro) to grow rapidly from 2% of generation in 2003 to over 5% in 2012. A peak shaving natural gas unit and resilient grid infrastructure would be required to handle the higher short-duration voltage variations that come with increased renewable generation. Seasonal volatility in natural gas demand is also increasing as a result of the growth in natural gas power generation. Natural gas demand for power generation generally peaks in the summer while residential and commercial demand peaks in the winter. The gap between the seasonal peaks has widened by 50% from 470 bcfd to 700 bcfd over the last 10 years and some markets are now even experiencing dual seasonal spikes.

Low-priced natural gas will also support a resurgent industrial growth, with projections of over 5 bcfd of new demand from energy intensive industries by 2025. Several new large-scale petrochemical projects are already committed. In a longer term, with sustained arbitrage between U.S. natural gas prices and oil prices (arbitrage currently around $88/boe), it may be possible to displace oil with natural gas in certain transportation markets. The new sources of domestic demand are dependent on abundant low-priced natural gas. However, low-priced natural gas also makes LNG exports attractive to higher-priced international markets. The current policy challenge is to define the best short, medium and long term use of U.S. natural gas for balancing exports with new sources of domestic demand.

Largely due to the confluence of existing and emerging federal environmental regulations and low natural gas prices, the majority of new North American power generating capacity projected for the next 10 years will rely on natural gas as its primary fuel (Figure 0-4). Higher availability of unconventional natural gas production in North America makes natural gas-fired power generation a premier choice for new generating capacity (e.g., combined-cycle units), overtaking and replacing coal-fired capacity.

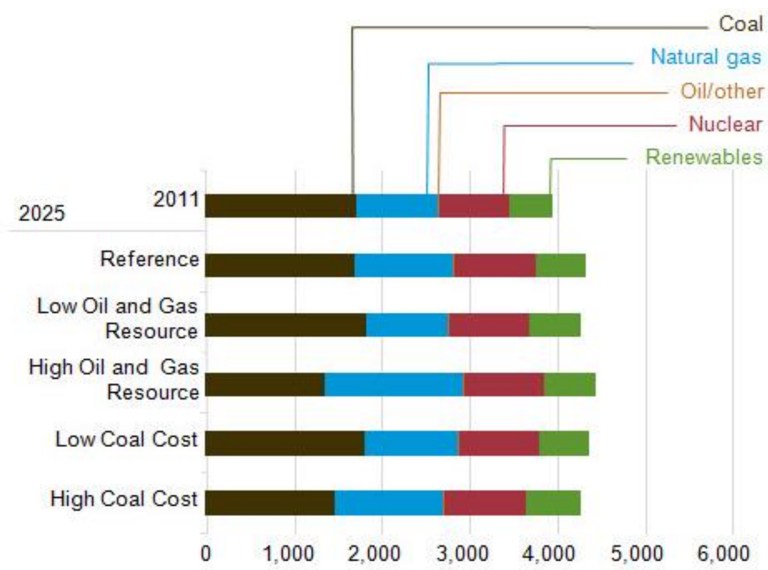


Figure 0-4: Power sector electricity generation by fuel

(Source: U.S. Energy Information Administration)

In retrospect, the natural gas infrastructure has not kept pace with the changing dynamics of supply, demand, and increased volatility, even though 23,000 miles of new pipeline were placed into service over the last 10 years. Traditional patterns of supply from the Gulf Coast to Northeast demand markets have been disrupted by new supply from the emerging shale plays. For example, just five years ago there was hardly any production from the Marcellus in the Northeast. Today the Marcellus produces over 7 bcfd and new infrastructure is needed. Infrastructure constraints have led to extreme price events. In 2007 and 2008, Rockies natural gas prices occasionally went to zero as takeaway capacity was insufficient to handle rising production. In winter 2013, Boston/New England prices spiked to over $25/MMBtu as natural gas power generation demand increased and generators struggled to secure supply.

0.2 Interdependency of Natural Gas and Electricity Infrastructures

The continuing and rapid growth in natural gas-fired power plants will consume a larger share of the forecasted increase in natural gas demand in the coming decades. The possibility of replacing coal and oil burning plants with natural gas plants could greatly improve the sustainability of forests, waters, and farmlands, which are negatively affected by acid deposition. However, increased dependence on natural gas for electric power generation can amplify the bulk power system's exposure to interruptions in natural gas fuel supply and delivery, which would further raise interdependency issues in the operation of the two industries.

The interdependency issues are itemized as follows:

- ***Market Operations***: In electricity markets, Independent System Operators (ISOs) execute security-constrained unit commitment (SCUC) to minimize the production cost by satisfying electricity network security constraints. Natural gas market prices will directly affect the operation cost of generating units. If the natural gas price is more expensive than alternative fossil fuels, such as coal and oil, the market could switch from natural gas to those with lower costs. Since 2000, the North American natural gas market has remained tight due to strong demand and lower supplies, which resulted in substantially higher prices for electricity generated with natural gas. Figure 0-5 shows the natural gas real prices by sector from 2001 to 2013. In addition, low natural gas prices before 2000 caused the industry to scale back natural gas exploration and production activity. Such incidents could yield major impacts on generation scheduling, production cost, electricity price, power transmission congestion management, and emission of the electric power system infrastructure.

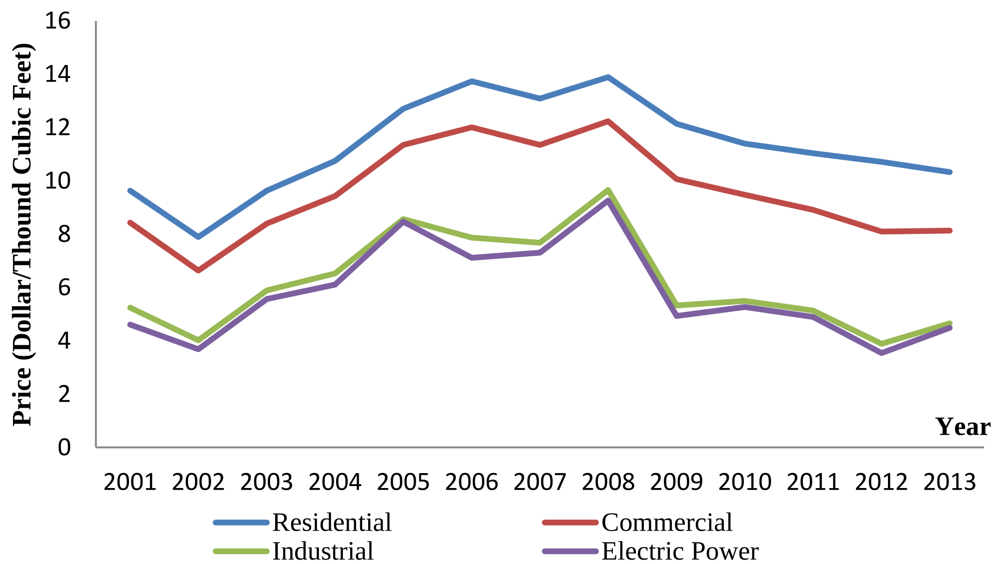


Figure 0-5: Natural gas price by sector

(Source: U.S. Energy Information Administration)

- ***Climate Factor***: In severe weather situations (e.g., hot summer or unusually cold winter days), the demand for electricity and natural gas may peak together, which could cause a spike in energy price. In such cases, natural gas price hikes could push up the marginal cost of natural gas-fired generating units, which would directly translate into higher market prices for electricity. For instance, average wholesale (spot) prices for natural gas increased significantly throughout the United States in 2013 compared to those in 2012. The average wholesale price for natural gas at Henry Hub in Erath, Louisiana, the key benchmark location for pricing throughout the United States, rose 35% to $3.73 per MMBtu in 2013. Figure 0-6 shows the daily spot prices at Henry Hub and Northeastern point through 2013. Prices at the Algonquin City gate hub serving New England and the Transco Zone 6-NY serving the New York City metropolitan area were affected by demand spikes driven by cold weather in January and December of 2013. These cold snaps pushed New England and New York spot prices well above the national average because of northeastern pipeline constraints that prevented the natural gas supply from increasing to meet higher demand.

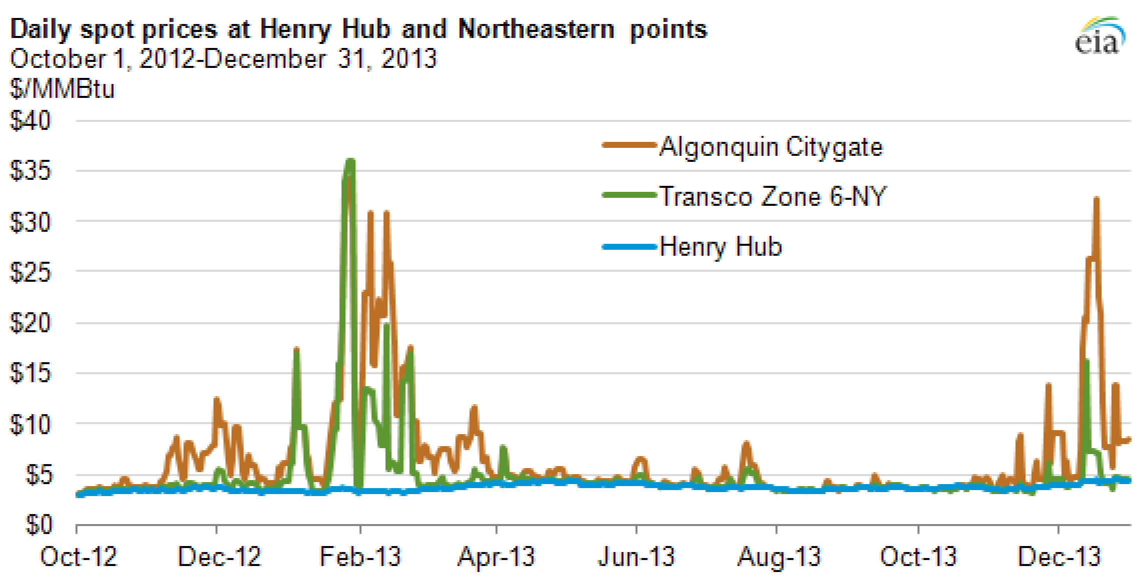


Figure 0-6: Daily spot prices at Henry Hub and Northeastern points

(Source: U.S. Energy Information Administration)

- ***Infrastructure Disruption***: An interruption or pressure loss in natural gas pipeline systems may lead to a loss of multiple natural gas-fired power generators, which could dramatically reduce the supplied power and jeopardize the power system security. Although, in the case of certain pipeline contingencies, underground natural gas storage facilities can provide the backup for the natural gas supply to certain generating units, the electric power dispatch and pertinent market decisions could be affected by natural gas pipeline constraints and natural gas storage shortfalls. In the event of outages in natural gas pipelines or power transmission systems, inconsistent curtailment proceedings of natural gas supplies to natural gas-fired generators, without dual fuel capacity, could constrain the power system operation and even lead to additional outages. Figure 0-7 provides a visual representation of a hypothetical pipeline that could be affected by the sudden failure of a single compressor station (all compressors and backup compressors). In this example, a compressor station failure at a downstream location would impact natural gas pressure and flows over a wide dispersion of power generators as the downstream natural gas demand draws down pressure in the pipeline. For simplicity, only natural gas-fired power plants are considered and dual-fuel units are excluded. Also, remedial pressure and flow options from other pipelines are not considered, although other pipelines, natural gas storage, and LNG could potentially help the affected compressor station. Figure 0-8 shows that under this scenario, approximately 3,500 MW is lost over a span of 80–110 minutes, depending on the pressure of the pipeline at the time of the contingency.

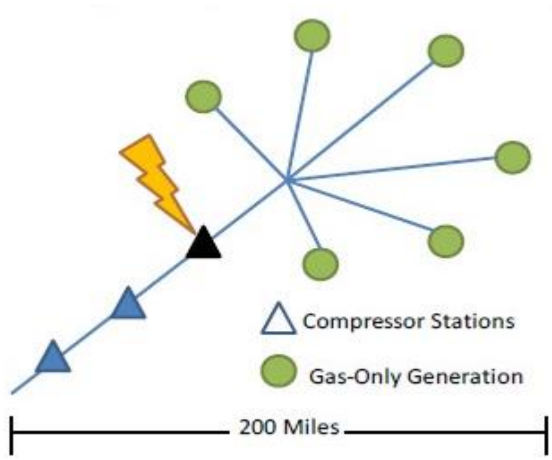


Figure 0-7: Compressor Failure Scenario

(Source: North American Electric Reliability Corporation)

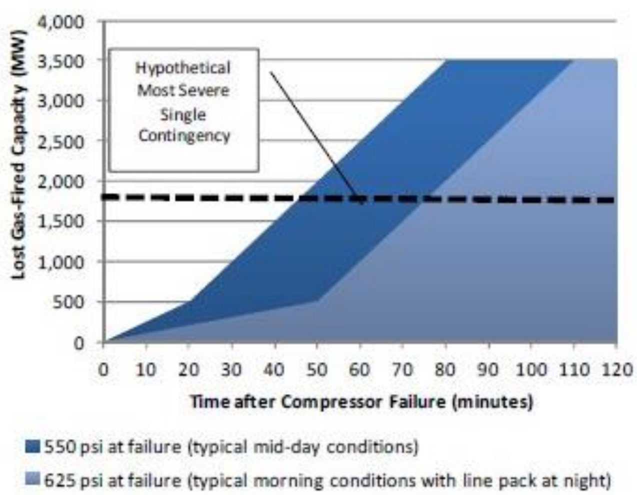


Figure 0-8: Time profile of capacity lost due to loss of compressor station

(Source: North American Electric Reliability Corporation)

These issues have concerned industry on natural gas supply and infrastructure adequacy issues in some geographical areas, causing policymakers to refocus attention on natural gas - electricity interactions. Several regional efforts have been made to analyze the potential problems and to consider fuel supply and transportation adequacy concerns as part of electric power reliability assessments. Some of the mitigating strategies for increasing the coordination and securing natural gas and electricity supply infrastructures are outlined below:

- ***Energy Resource Diversity***: Deployment of renewable and distributed units (such as pumped-storage hydro, photovoltaic (PV)/battery, and cogeneration which captures waste heat for energy) at electricity delivery sites could promote energy efficiency, reduce the dependence of electricity infrastructure on the natural gas infrastructure, and enhance the security of electric power systems.
- ***Fuel Diversity***: The ability of a generating unit to switch from natural gas to other types of fuels (fuel switching capability) at peak hours and at high demand for natural gas seasons can buffer short-term pressures on the balance of natural gas and electricity supply/demand. The installation of generating units with fuel switching capability can reduce excessive natural gas consumptions over the life of the units in a competitive electricity market.
- ***Infrastructure Coordination***: Natural gas and electricity infrastructures are often operated independently which are based on their respective operating guidelines and market competition rules. However the coordination of natural gas and electricity will be absolutely essential for maintaining a least cost, reliable, and resilient supply of service to end users. This extended coordination may utilize the global positioning system (GPS) and geographical information system (GIS) for a joint online control and monitoring of the two infrastructures.
- ***Command and Communication***: Remedial actions for natural gas supply contingencies should be communicated regularly to electric power grid operators, while the electric power grid operators are obliged to reciprocate by sharing the pertinent remedial solutions with natural gas companies.
- ***Least Cost Scheduling***: As long as the natural gas is readily available, electric power companies will utilize the cleaner and more efficient combined-cycle units for supplying loads in a competitive electricity market. However, the utilization of more sophisticated energy management techniques, such as SCUC, could utilize the least cost commitment and dispatch of power generating units while preventing an excessive utilization of natural gas units, which could inflate natural gas prices. The least cost dispatch of other generating units could mitigate shortages of natural gas supply at peak electricity load periods while maintaining the power system security.
- ***Load Shedding and Control Scheme***: Although it is not a favorable approach to maintaining the security of the natural gas supply and electric power network, the respective industries must prepare a comprehensive approach to load shedding and system restoration for retaining the security of the two infrastructures in the case of blackouts and massive regional contingencies.
- ***Integrated Resource Planning***: It is essential to include the natural gas infrastructure planning in the electricity planning model. The coordinated system planning could identify the optimal locations for new generating units and the required enhancements of transmission lines in order to utilize fuel diversity and mitigate the intense reliance of the electric power system operation on the natural gas infrastructure.

0.3 Electric Power Industry Basics

0.3.1 Overview of the Electric Power Industry

Electric power systems are regarded as real-time energy delivery systems. Real time means that power is generated, transported, and delivered when consumers turn on electrical devices. Electric power systems do not have storage like those in other major facilities including water and natural gas systems. Instead, power generators produce energy as the demand calls for it. Figure 0-9 shows the basic building blocks of an electric power system which starts with generation, by which electric energy is produced in the power plant. High-voltage (HV) power transmission lines can efficiently transmit the stepped-up electric energy over long distances to consumption locations. Finally, substations would step down this HV electric energy into lower-voltage energy that is transmitted over distribution power lines to its destination. Once at its destination, the energy is again stepped down for residential, commercial, and industrial consumptions.

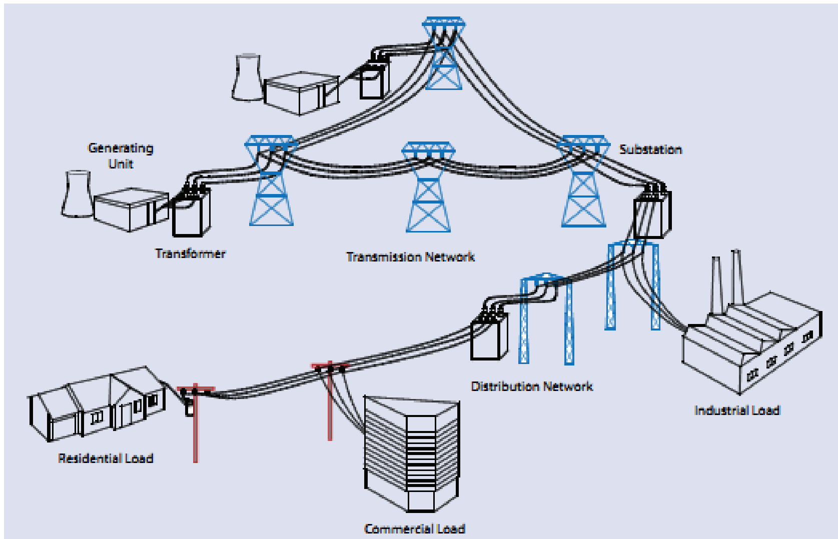


Figure 0-9: Electricity from the generation to the consumer

(Source: Energy Information Administration)

0.3.2 Electric Power Generation

Electric power is produced by generating units, housed in power plants, which convert primary energy into electric energy. Primary energy comes from a number of sources, such as fossil fuel and nuclear, hydro, wind, solar, and geothermal power. The process of converting this energy into electric energy depends on the design of generating units, which are partly influenced by the primary source of energy. Thermal generating units burn fuel to convert chemical energy into thermal energy, which is then used to produce high-pressure steam. This steam then flows and drives the mechanical shaft of an AC electric generator. Nuclear generating units use an energy conversion process similar to thermal units, except the thermal energy needed to produce steam comes from nuclear reactions. Hydro and wind generating units convert the kinetic energy of water and wind, respectively, directly into rotation of the electric generator's mechanical shaft. Solar-thermal and geothermal generating units use the sun's radiation and the earth's heat, respectively, to warm up a fluid and then follow a thermal conversion process. Solar photovoltaic generating units are quite different and convert the energy in solar radiation directly into electric energy. Combustion turbine burn a pressurized mixture of natural gas and air in a jet engine that drives the electric generator. Combined cycle natural gas turbine plants have a natural gas turbine and a steam turbine. They reuse the waste heat from the combustion turbine to generate steam for the steam turbine and hence achieve higher energy conversion efficiencies.

From operation perspective, generating units in electric power systems are classified into three categories: baseload, intermediate, and peaking units. Baseload units, which are reliable and economic, run continuously except when they have to be shut down for repair and periodic maintenance. Nuclear and coal plants with their low fuel costs are generally used as baseload units, as are the large hydroelectric plants. However, nuclear and coal baseload units are expensive to build and have slow ramp rates, that is, their output power can be changed only slowly (on the order of hours). Intermediate units, also called cycling units, operate for extended periods of time and have the ability to vary their output more quickly than baseload units. Combined-cycle natural gas turbine plants and smaller thermal generating units generally are used as intermediate units. Peaking units operate only when the system power demand is close to its peak. Peaking units are able to start and stop quickly, but they run only for a small number of hours in a year. Natural gas turbine and smaller hydroelectric plants with reservoirs are generally used as peaking units. Natural gas turbines are the less expensive to build but have high operating costs. In addition to the main generating units, distributed and smaller generation, including combined heat and power (CHP), units operate at lower voltage distribution system level. Such units as may be single phase.

0.3.3 Electric Power Transmission

Large generating units generally are located outside densely populated areas, and the power they produce has to be transported to load centers. They produce three-phase ac voltage at the level of a few to a few tens of kV. The transmission system carries electric power over long distances from the generating units to the distribution system. The transmission network is composed of power transmission lines and substations. Power transmission lines are attached to high towers. However, in cities, where the real estate is valuable, transmission lines are made up of insulated cables and buried underground. Substations house transformers, switchgear, measurement instrumentation, and communication equipment. To reduce power losses during onward transmission, this voltage is stepped-up before transmission to a few hundred kV using a transformer. Switchgear includes circuit breakers for disconnecting parts of the transmission network for system protection or maintenance. Measurement instruments collect voltage, current, and power data for monitoring, control, and metering purposes. Communication equipment transmits these data to control centers and also allows switchgears to be controlled remotely.

Transmission networks which carry power over long distances possess higher capacity, limit conductor cross-sectional area, narrower rights-of-way, large clearance from the ground, trees, and any structures. Transmission voltages vary from region to region and country to country. The transmission voltages commonly (but not exclusively) used in the U.S. are 138 kV, 230 kV, 345 kV, 500 kV, and 765 kV. Higher voltages require greater distances between conductors as well as better insulators and higher towers, but the net effect is still a significant increase in the power transfer capability for a given width of right-of-way.

The power that can be transmitted on a transmission line is limited by either thermal, voltage stability, or transient stability constraints, depending on which is the most binding. The thermal constraint arises due to the resistance of the transmission line that causes excessive power losses and hence heating of the line when the power flowing through it exceeds a certain level. The voltage stability constraint arises due to the reactance of a transmission line that causes the voltage at the far end of the line to drop below an allowable level (typically 95% of the nominal design voltage level) when the power flowing through the line exceeds a certain level. The transient stability constraint relates to the ability of the transmission line to deal with rapid changes in the power flowing through it without causing the generators to fall out of synchronism with each other. Generally, maximum power flow on short transmission lines is limited by thermal constraints, while power flow on longer transmission lines is limited by either voltage or transient stability constraints. These power flow constraints cause so-called congestion on transmission lines, when the excess capacity in the lowest-cost generating units cannot be supplied to loads due to the limited capacity of one or more transmission lines. Some very large consumers take electric power directly from the transmission or subtransmission network. However, the majority of consumers get their power from the distribution network.

HVDC transmission lines present no reactive impedance to dc, require two conductors instead of three (i.e., less right-of-way for similar amounts of transfer capability), and require expensive converter stations (utilizing power electronics technology) at both ends of the line to connect to the rest of the ac system. HVDC transmission systems can transmit large amounts of power between two asynchronous AC systems, and offer power flow control and enhanced system stability. For example, the high-capacity contingency rating of an HVDC overlay could accommodate the loss of a large conventional generator and be stable.

Transformers at transmission substations convert transmission voltages down to lower levels to connect to the subtransmission network or directly to the distribution network. The subtransmission network carries power over shorter distances than that of transmission system and is typically used to connect the transmission network to multiple nearby relatively small distribution networks. In the U.S., the commonly used subtransmission voltages are 69 kV and 115 kV. Transmission and subtransmission line configurations are mesh networks (as opposed to radial), meaning there are multiple paths between any two points on the network. This redundancy allows the system to provide power to the loads even when a transmission line or a generating unit goes offline. Because of these multiple routes, however, the power flow path cannot be specified at will. Instead, power flows along all paths from generating units to loads. The power flow through a particular transmission line depends on the line's impedance and the voltage amplitudes and phases at its ends. The presence of multiple paths leads to flows on undesirable paths known as loop flows.

0.3.4 Electric Power Distribution

The connection between distribution networks and transmission or subtransmission occurs at distribution substations. Distribution networks carry power within the last few miles of transmission or subtransmission network to consumers. Distribution networks are distinguished from transmission networks by their lower voltage level and smaller topology which require less clearance. Primary distribution lines leaving distribution substations are called feeders which are then separated to feed different neighborhoods. Distribution substations have transformers to step voltages down to the primary distribution level (4 to 35 kV range in the U.S.), circuit breakers, and monitoring equipment. However, distribution substations are generally less automated than transmission substations.

Distribution networks usually have a radial (star) topology with only one power flow path between the distribution substation and a particular load. Distribution networks sometimes have a ring (or loop) topology, with two power flow paths between the distribution substation and the load. However, these are still operated as star networks by keeping a circuit breaker open. In highly dense urban settings, distribution networks also may have a mesh network topology, which may be operated as an active mesh network or a star network. The presence of multiple power flow paths in ring and mesh distribution networks allows a load to be serviced through an alternate path by opening and closing appropriate circuit breakers when there is a problem in the original path. When this process is carried out automatically, it is often referred to as "self-healing." Distribution networks usually are designed assuming power flow is in one direction. However, the addition of large amounts of distributed generation may make this assumption questionable and require changes in design practices.

Industrial and large commercial users usually get three-phase supply directly from the primary distribution feeder, as they have their own transformers and in certain cases can directly utilize the higher voltages. However, for the remaining consumers, who generally require only single-phase power, power is usually transmitted for the last half-mile or so over lateral feeders that carry one phase. A distribution transformer, typically mounted on a pole or located underground near the customer, steps this voltage down to the secondary distribution level, which is safe enough for use by general consumers. Most residential power consumption in the U.S. occurs at 120 V or 240 V. In suburban neighborhoods, one distribution transformer serves several houses.

0.3.5 Electric Power Consumption

Electricity is consumed by a wide variety of loads, including lights, heaters, electronic equipment, household appliances, and motors that drive fans, pumps, and compressors. Heaters and incandescent lamps have purely resistive impedance, while motors have impedance that is resistive and inductive. Hence, generating units have to supply both real and reactive power. Since capacitors produce reactive power, they often are connected close to large inductive loads to cancel their reactive power (i.e., increase the effective power factor of the load) and reduce the burden on the network and the generators.

From the power system's operational perspective, the aggregate power demand of the loads in a region is more important than the power consumption of individual loads. A useful representation of this load across the year is the load duration curve, which plots the load for each hour of the year, not chronologically, but instead by beginning with the hour with the largest load and continuing in a monotonically decreasing fashion, as shown in Figure 0-10. For each point on this curve, the horizontal coordinate is the number of hours in the year for which the load is above the power given by the vertical coordinate.

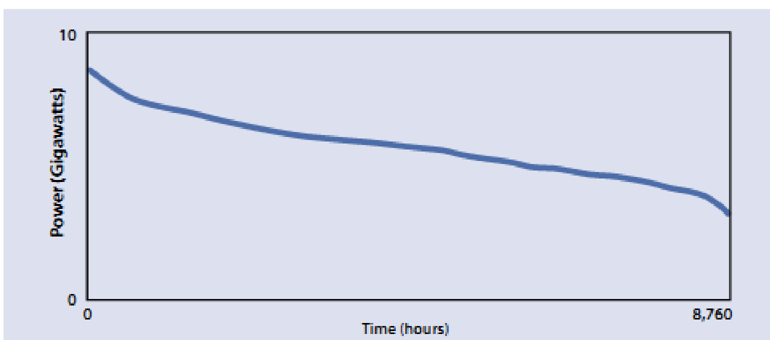


Figure 0-10: Electric load duration curve

(Source: IIT Galvin Center)

The load duration curve provides a reasonable perspective of how widely the load varies and for how many hours in a year it is above a particular level. It is more expensive to meet the needs of a spiked load duration curve than a flat one, as generation capacity to meet the peak load is needed, while the generation's utilization is related to the average load. One useful metric of power consumption is the load factor, which is the ratio of average to peak load.

0.3.6 Electricity Grid

Interconnected power systems (i.e., electricity grid) are built to take advantage of larger inertia for maximizing system stability, reliability, and security. Interconnection helps reduce the overall cost of providing reserves, maintain frequency, avoid voltage collapse, and reduce the chance of undesirable load-shed situations. Further, interconnected power companies benefit from information exchange on joint planning studies, cooperation during emergencies (such as storm damage), and sharing new technologies, especially in the areas of telecommunications, system control centers, and energy management.

The U.S. electricity grid, shown in Fig. 0-11, consists of approximately 170,000 miles of high-voltage (above 200 kilovolts or kV) electric transmission lines and associated equipment, and almost 6 million miles of lower-voltage distribution lines. These include approximately 2,400 miles of 765 kV and 3,000 miles of 500 kV dc lines. Investor-owned utilities own about 66% of the system, and federal enterprises own 14%. The rest is divided among other publicly owned entities (7%), cooperatives (6%), independent transmission companies (4%), and others (3%). The U.S. Federal Energy Regulatory Commission (FERC) has jurisdiction over wholesale electricity sales and transmission rates.

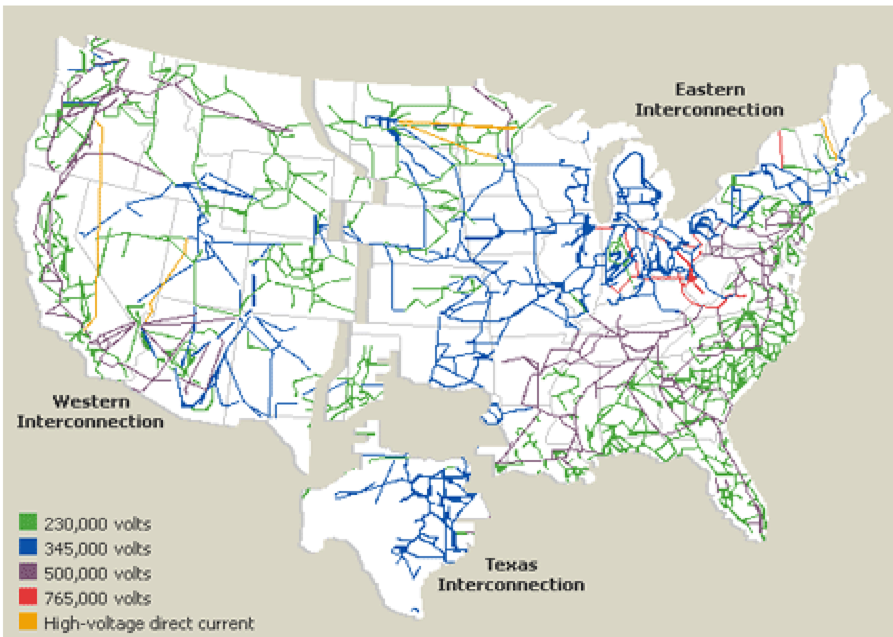


Figure 0-11: The U.S. electricity grid

(Source: U.S. Energy Information Administration)

At the highest level, shown in Fig. 0-12, the electric power system of the continental U.S. consists of three independently synchronized grids: the Eastern Interconnection, the Western Interconnection, and the Electric Reliability Council of Texas (ERCOT). The three grids are composed of regions and/or utilities with interconnected transmission lines and control centers. They share similarities such as 60 Hz frequency and system transmission voltages, yet they have individual requirements such as ownership, topography, and fuel resources. All the generation units in each grid are synchronized together, sharing the total load, and providing very large and reliable power flows. The North American Electric Reliability Corporation (NERC) formed in 1968 is responsible for ensuring that the bulk electric power system in North America is reliable, adequate, and secure. NERC has acquired the duties of overseeing operating standards compliance with enforcement powers.

The organizational structure of the electric power industry has changed significantly over the last 15 years. Until the mid-1990s, the electric power industry in the U.S. mostly was vertically integrated: a single entity, a regulated monopoly, owned and operated generation, transmission, and distribution in each region. However, in 1996 the Federal Energy Regulatory Commission issued Order No. 888, which required that the transmission network be made available for use by any generator. In many regions, ownership of generation and transmission has been separated, and ISOs and RTOs coordinate organized wholesale electricity markets in which independent decisions of electricity market participants set the price of energy considering the temporal constraints. Figure 0-13 shows the geographic scope of organized wholesale electricity markets which cover two-thirds of the U.S. population and meet about two-thirds of the U.S. electricity demand. Regions without ISOs and RTOs (such as the Pacific Northwest and the majority of Southeastern states) must conform to the FERC's open access mandate; the power exchange among utilities is mostly facilitated through bilateral contracts and power purchase agreements that limit the scope of market between buyers and sellers.

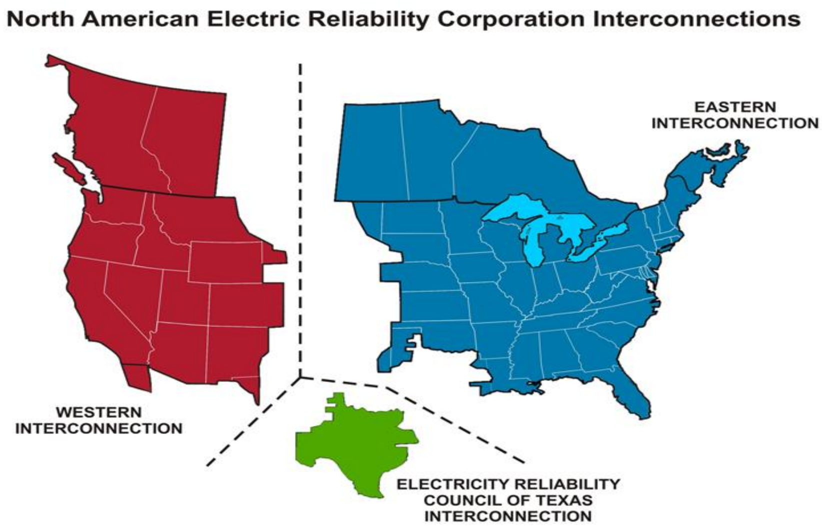


Figure 0-12: North American power grid interconnections

(Source: North American Electric Reliability Corporation)

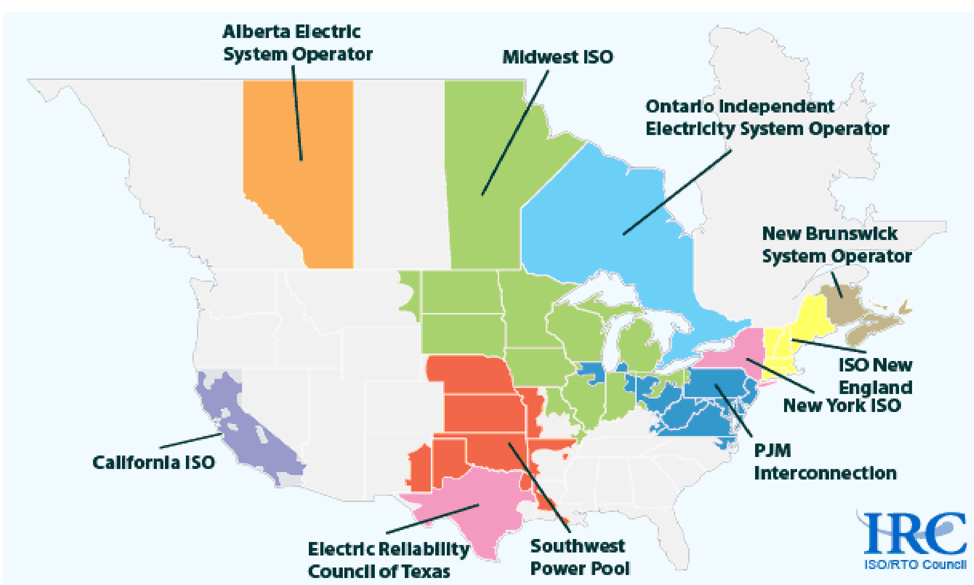


Figure 0-13: Regions with organized electricity markets

(Source: ISO/RTO Council)

0.4 Natural Gas Industry Basics

0.4.1 Development of Natural Gas Industry

A. Early History

Natural gas is a combustible mixture of hydrocarbon gases which typically consists of 70-90% methane, is a vital component of the world's supply of energy, and represents one of the cleanest, safest, and most versatile sources of energy. The early growth of the natural gas utility industry in Europe and America was based on the distribution of manufactured natural gases, particularly coal natural gas for lighting. Coal carbonization (through destructive heating in retorts), although a relatively expensive operation, was used to manufacture most of the natural gas used during the early days. Coke usable for space heating and steel manufacture was a by-product. During most of the 19th century, most of the natural gas produced from coal, rather than coming from a well, was used for lighting because, without a pipeline infrastructure, it was difficult to transport the natural gas very far or into homes for heating or cooking. Near the end of the 19th century, with the advent of electricity, electric lights took the place of natural gas lights, which led natural gas producers to look for new markets for their product.

One of the first major natural gas pipelines was constructed in 1891. This pipeline was 120 miles long, and carried natural gas from wells in central Indiana to the city of Chicago. However, this early pipeline was not very efficient at transporting natural gas. It wasn't until the 1920s that significant effort was put into building a pipeline infrastructure. After World War II, new welding techniques, along with advances in pipe rolling and metallurgy, further improved pipeline reliability. This post-war pipeline construction boom lasted well into the '60s, and allowed for the construction of thousands of miles of pipeline in America. Once the transportation of natural gas was possible, new uses for natural gas were discovered. These included using natural gas to heat homes and operate appliances such as water heaters, ovens, and cooktops. Industry began to use natural gas in manufacturing and processing plants. Also, natural gas was used to heat boilers used to generate electricity. The expanded transportation infrastructure had made natural gas easy to obtain, and it was becoming an increasingly popular energy choice.

B. Restructuring of the Natural Gas Market

Given the rising importance of natural gas for energy production, and potentials for significant price hikes, the Natural Gas Act was passed by the Congress in 1938. The Act imposed regulations and restrictions on the price of natural gas to protect consumers. In the 1970s and 1980s, natural gas shortages and price irregularities indicated that a regulated market was not best for natural gas consumers. In the 1980s and early 1990s, the industry gradually moved toward less regulation and a significant market-based price competition. The competition led to a strengthening of the natural gas market, lowering consumer prices, and allowing for more natural gas to be discovered. Although not as active as the 1990s, the beginning of the 21st Century brought in significant FERC regulations concerning natural gas quality, standards of conduct for interstate pipelines, and price reporting.

The natural gas industry has existed in this country for over 150 years and continues to grow. And new production techniques now allow us to produce natural gas from shale formations. Technologies are continually being developed that allow Americans to use natural gas in new and exciting ways. At the same time, the electricity restructuring and the move toward cleaner-burning fuels have created an enormous market for natural gas applications in the electricity industry. With all of the advantages of natural gas, it is no wonder that it has become the fuel of choice in this country, and throughout the world. The natural gas flow path from the well to the consumer is shown in Figure 0-14.

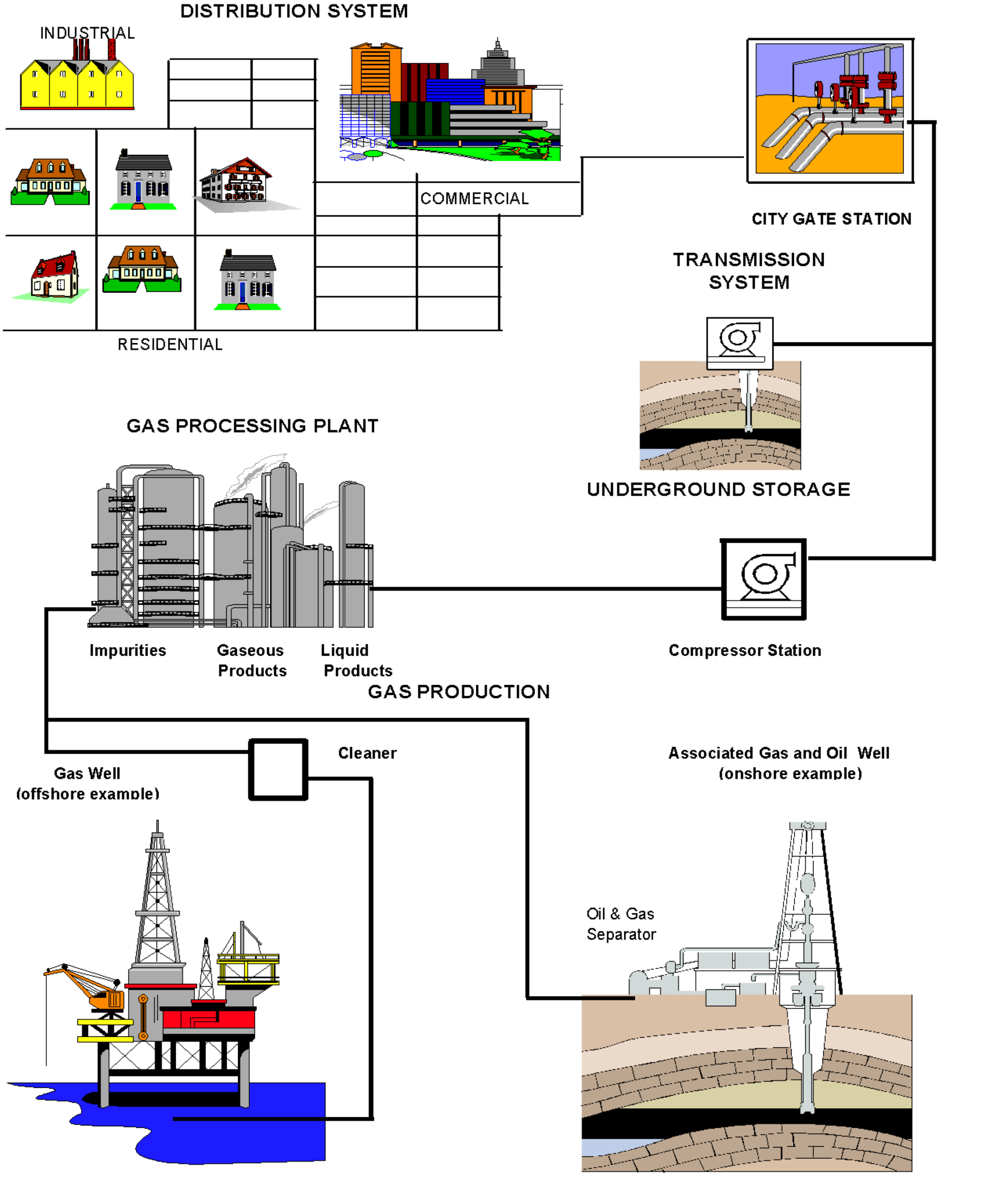


Figure 0-14: Natural gas flow path from the well to the consumer

(Source: Chemical Engineering Department, IIT)

0.4.2 Natural Gas Production

Although natural gas originally distributed by the gas utilities was manufactured using coal and oil, for decades the source has been almost totally natural gas. Before it can be distributed, however, it must be found in nature in porous and permeable rock deposits in quantities suitable for production. The initial step is the exploration for accumulations contained in porous sedimentary rock formations, commonly thousands of feet below the surface. When suitable deposits are found, exploration is followed by development drilling, production, purification, processing, transportation by pipelines to centers of usage, and, finally, by delivery through distribution systems to residential, commercial, industrial, and electric power plant customers. The natural gas flow path from the well to the consumer is discussed as follows.

A. Natural Gas Well Completion

Once a well is drilled and the various strings of casing are cemented in place, it must be suitably equipped for production. To do this, arrangements must be made to confine the natural gas and/or oil flow to the production casing, to prevent water and cave-ins from entering the production tubing, to control the rate of production with suitable valves at the well-head, and to separate dirt and liquids from the natural gas produced. To confine the natural gas to the casing and support the formations exposed by drilling (Figure 0-15), a final casing string can be cemented into the hole.

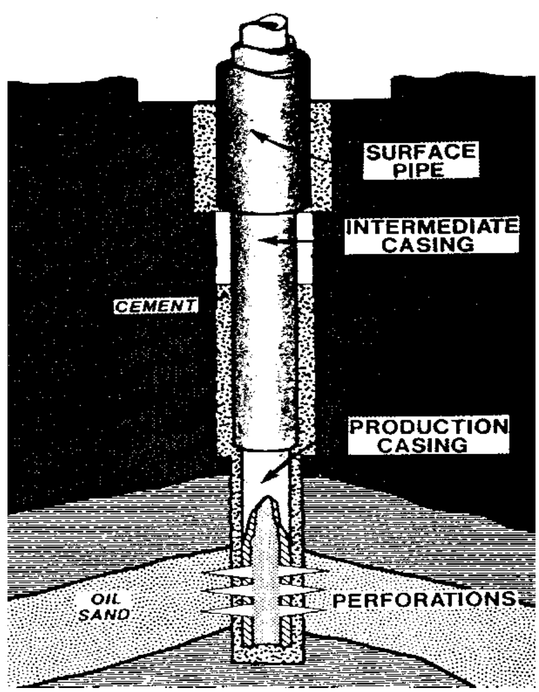


Figure 0-15: Perforated natural gas well completion

(Source: Gas Technology Institute)

This production string or liner must then be perforated to permit fluid (natural gas or oil) to flow in from the reservoir. If the producing formation is weak or not well consolidated, graded sand may be flushed behind the perforations to support the formation (Figure 0-16). Flow rate tests are made as soon as possible. If the productive formation is "tight," that is, if it does not permit natural gas or oil to flow freely, it may be stimulated (made more permeable) by shooting (exploding nitroglycerine or other high explosives in the hole to shatter the rock), by flushing with acid, or by fracturing with a high-pressure fluid pumped from the surface. All these treatments create enlarged flow passages in the rock around the wellbore so that the reservoir fluids can flow with less resistance into the well. Following initial testing, if a well does not appear capable of an economically reasonable rate of production, it is abandoned as a "dry hole."

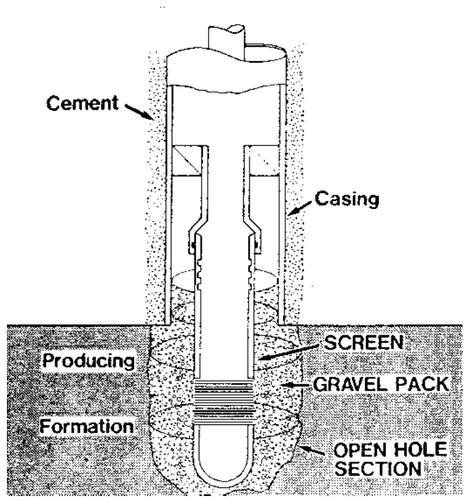


Figure 0-16: Natural gas well completion technique - open hole gravel pack

(Source: Gas Technology Institute)

If the various tests indicate that the well is likely to be a satisfactory producer, the final step in completion is the setting of the surface equipment. The heavy casing head that holds the tubing hanger, the master control valve, and valve and bypass arrangements are called collectively the "Christmas tree" (Figure 0-17).

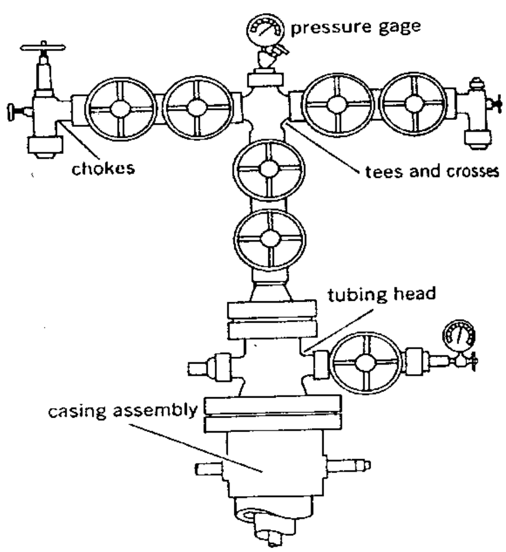


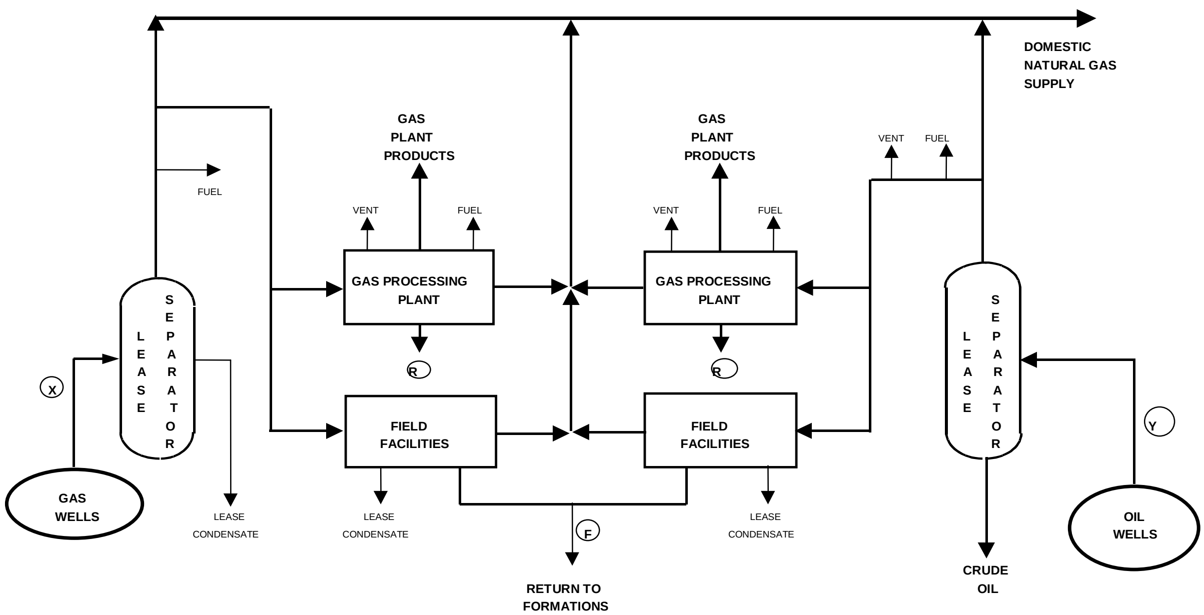
Figure 0-17: Diagram of casing and a Christmas tree

(Source: Gas Technology Institute)

B. Natural Gas Field Operation

When several natural gas wells have been drilled successfully, a gathering system (the piping to collect the natural gas from the natural gas wells in a field) is installed. Equipment to separate entrained fluids and dirt is installed at the wellheads, and cleaned natural gas from the natural gas wells then flows to a central location for further processing. Note: Dehydration and sweetening facilities are not shown.

Figure 0-18 shows a simplified operational flow sheet of natural gas and oil production. Lease condensate is ordinarily mixed with crude oil for shipment to the refinery. Some natural gas is returned to the oil-producing reservoirs (R + F) to keep the pressure up in them to enhance oil recovery, and some natural gas is used as fuel to operate various facilities at the producing sites. The diagram shows the processing facilities where dehydration and sweetening are performed and natural gas liquids (NGL) are removed as natural gas plant products. NGL are known as natural gas plant liquids to distinguish them from quite similar but not identical liquids that are formed and produced in petroleum refineries. Lease condensate is a natural gas liquid, but not a natural gas processing plant liquid.



X = unprocessed natural gas-well natural gas

Y = unprocessed oil-well natural gas

X+Y = gross production (unprocessed)

R = return to formation from natural gas processing plants

F = return to formation from field facilities

Note: Dehydration and sweetening facilities are not shown.

Figure 0-18: Simplified operational flow sheet of natural gas production

(Source: API Technical Report No. 1)

C. Natural Gas Processing

Natural gas, as produced at the wellhead separator, may contain entrained sand or clay particles, liquefiable hydrocarbons, hydrogen sulfide, and noncombustible natural gases such as nitrogen, helium, and carbon dioxide. It is usually saturated with water vapor because it coexists with water in the reservoir rock. Dirt, moisture, entrained water, and certain impurities must be removed before the natural gas is acceptable for transmission. At the natural gas processing plant, scrubbers remove particulate matter from natural gas, either mechanically by screens or baffles or by passing it through a liquid. Then, dehydrators reduce the moisture content to a suitable degree, which is commonly prescribed in the sales contract. Most dehydrators contain either solid drying agents or water-absorbing liquids, especially the latter. Dehydration is required to avoid formation of solid compounds of natural gas components with water. These ice-like solids, called hydrates, can plug regulator facilities and transmission lines. Dehydration also mitigates internal corrosion of pipe and fittings. Sulfur compounds are generally malodorous, toxic and corrosive; they are removed by a sweetening process. A certain amount of carbon dioxide (corrosive when present with moisture) and/or nitrogen may also be removed. When present in significant amounts, the LPG (propane and butane) and the natural gasoline are removed from natural gas at a separation plant. Lease separators produce lease condensate, which is a type of natural gas liquid. The U.S. Department of Energy reports as natural gas liquids only those produced at natural gas processing plants. Lease condensate is generally mixed with crude oil; production amounted to 158 million barrels in 1990. Natural gas liquids produced at natural gas processing plants and field facilities amounted to 574 million barrels in 1990.

0.4.3 Natural Gas Transmission

The natural gas transmission from producers to local distribution companies and end-users is the responsibility of pipeline companies in the natural gas industry. Pipeline companies are classified as intrastate (operations entirely in one state) or interstate (facilities in more than one state). Interstate pipeline companies are regulated by FERC and recent orders promulgated by the agency have drastically altered the role of pipeline companies. Historically, pipeline companies had their own production and also purchased natural gas from producers. The natural gas was then sold to local distribution companies and, in some cases, directly to large industrial customers. Through a series of orders issued by FERC, the well-head price of natural gas was deregulated and the function of the pipeline companies has been redefined.

An interstate pipeline company is required to separate its sales and marketing functions from its transportation operations and provide a pipeline open access for the natural gas transportation. Open access also applies to underground storage facilities owned by pipeline companies. The new rules enable a local distribution company, a large industrial customer, or a group of customers to purchase natural gas directly from a producer or a marketer and contract separately for its pipeline transportation.

- ***Pipeline***: Pipeline planning and development occurs at several stages. First, a certificate of public convenience and necessity must be obtained from FERC. This usually requires submission of an exhibit including construction plans and economic studies; the documents must indicate a demand for natural gas in an area and an available adequate supply in another. Also, a study and statement of impact on the environment of the construction and presence of the pipeline is made. Then, if the certificate is granted, the purchase of right-of-way and the leasing of surface property along the path of proposed construction can begin. When all arrangements involving the pipeline location are completed, pipe and fittings can be specified, ordered, and delivered. Pipelines require regular patrol, inspection, and maintenance, including internal cleaning (pigging) and checking for signs of leakage. Special "pistons" (pigs) are blown through the pipe to remove dirt and corrosion products. If not removed, this material significantly increases friction and results in lower flow rates. It also causes wear by eroding downstream equipment such as regulators and meters. Corrosion may be detected by the use of a specially designed pig that contains equipment to measure pipeline wall thickness and detect any other structural abnormalities of the pipe. Leakage in the streets or parkways from mains and services or in public buildings is detected by periodic patrolling with portable leak detectors that can detect natural gas by physical principles at very low concentration. Vegetation shows the drying effect of escaping natural gas by changing color from green to brown or yellow and is an indicator of leakage during growing seasons. Aerial patrols are also conducted to detect yellowing vegetation, identify earth washouts and to observe nearby construction activities by others.

- ***Compressors***: Natural gas is compressed for transmission to minimize pipe size and cost. As the natural gas flows through a pipeline, friction causes the pressure to decrease. Thus, it must be recompressed at compressor stations (Figure 0-19) placed at intervals along the pipeline. Commonly, stations are at intervals of between 50 to 100 miles (80 to 160 kilometers) and are powered by compressors rated at several thousand horsepower (kilowatts) each. When a pipeline is designed, the choice of natural gas pressure, pipe diameter, pipe wall thickness, compressor type, and compressor station spacing is based on economic optimization - getting the job of transporting a specified quantity of natural gas per day done safely at minimum cost. Both reciprocating and centrifugal compressors are used. Reciprocating compressors can have relatively high compression ratios (ratio of outlet to inlet pressure) and limited capacities; they are connected in parallel at a compressor station. They are usually driven by two-stroke-cycle internal combustion natural gas engines, although four-stroke-cycle engines have also been used, as have large electric motors and, in a few cases, steam engines. Centrifugal compressors have relatively lower compression ratio limits and higher capacities. These machines rotate at top speeds of between 4000 and 7000 RPM and are usually driven by natural gas turbines; steam turbines or internal combustion engines with step-up gears have also been used. Because of their high capacity, compact size, and lower installed cost per horsepower, centrifugal compressors are much in favor when the cost of natural gas is low. Their energy efficiency, however, is less than that of reciprocating compressors especially at partial loads. Higher natural gas costs tilt the economics of compressor selection in favor of reciprocating compressors whenever operating hours per year are considerable.

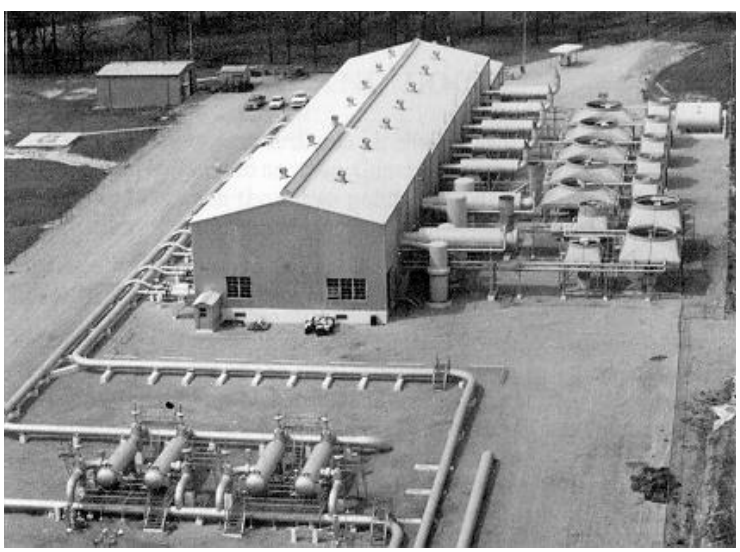


Figure 0-19: Typical transmission compressor station

(Source: Gas Technology Institute)

Natural gas transportation could utilize liquefied natural gas (LNG). Natural gas is a major source of energy, but many towns and cities that need the energy are located far from the natural gas fields. Transporting natural gas by pipeline can be costly and impractical. So LNG is created by cooling the natural gas to a liquid to -160^{oc}, which we can then ship out, safely and efficiently. LNG is a clear, colorless, non-toxic liquid that can be transported and stored more easily than natural gas because it occupies up to 600 times less space. LNG is transported using tanker truck, railway tanker, and purpose built ships known as LNG carriers. When LNG is transported over long distances, it is often by sea. In most cases, LNG terminals are purpose-built ports used exclusively to export or import LNG. When LNG reaches its destination, it is returned to a natural gas at regasification facilities. It is then piped to homes, businesses and industries. On a per kilometer transported basis, emissions from LNG are lower than piped natural gas, which is a particular issue in Europe, where significant amounts of natural gas are piped several thousand kilometers from Russia. However, emissions from natural gas transported as LNG are higher than for natural gas produced locally to the point of combustion as emissions associated with transport are lower for the latter.

0.4.4 Natural Gas Storage

Transmission lines are costly because of the investment in land rights, very large compressors, and very large amounts of high-strength, large-diameter pipe. Because of the magnitude of the investment involved, it is highly desirable to operate at close to capacity throughout the year so as to distribute fixed costs over a greater volume of natural gas. Nevertheless, the demand for natural gas is highly variable seasonally because of the great amounts used for space heating in winter. Thus, the industry has devised ways to level the rate of natural gas delivery as much as possible to hold natural gas transportation costs at a minimum. Transmission and distribution companies use a variety of strategies to maintain steady pipeline flow. One method is the development of underground storage facilities near market areas.

Natural gas storage can help relieve pipeline congestion. In a local natural gas market high seasonal variation in natural gas prices may reflect pipeline capacity constraints in peak periods. A storage operator can use the available pipeline capacity in off-peak periods, when natural gas prices are low, to inject natural gas into storage, and then sell this natural gas in the local market for higher prices during peak periods. The storage operator reaps the benefits of high peak prices, but it also pushes peak prices toward competitive levels because the availability of natural gas from storage relieves congestion, at least partially. And its high profits will attract additional storage facilities to the market, which will further lower prices.

The most important type of natural gas storage is in underground reservoirs. There are three main types: depleted natural gas reservoirs, aquifer reservoirs, and salt cavern reservoirs. Each of these types has distinct physical and economic characteristics which govern the suitability of a particular type of storage type for a given application. Wherever feasible, natural gas is stored in depleted natural gas or oil reservoirs or in water-bearing formations of suitable characteristics, called aquifers (Figure 0-20), during the summer when customer demand is lower. It is withdrawn during periods of high demand, which occur during the winter.

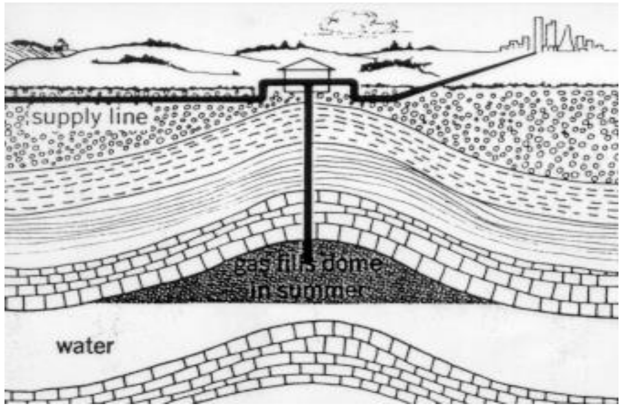


Figure 0-20: Typical aquifer storage field

(Source: Gas Technology Institute)

0.4.5 Natural Gas Distribution to Customers

A natural gas distribution system (Figure 0-21) consists of (1) the piping network that carries the natural gas to the ultimate consumers from the various sources of supply; (2) city gate stations where natural gas is received from cross-country transmission pipelines, natural gas storage facilities; and (3) supplemental sources, if any. Supplemental sources are used to meet cold weather peak demands because of their greater costs. Such sources may be liquefied petroleum natural gas (LPG) plants, substitute natural gas (SNG) plants fed by liquid feedstock, or liquefied natural gas (LNG) facilities. LNG may be a supplemental source if shipped in as liquid or it may be a form of storage if pipeline natural gas is liquefied to fill such storage.

A. City Gate Stations

The primary source of natural gas for most distribution systems is pipeline natural gas, fed through one or more city gate stations, sometimes called town border or tap stations. The basic function of these stations is to meter the natural gas and reduce its pressure, from that of the pipeline to the considerably lower distribution systems. After natural gas arrives at a city gate station, it may pass through a cleaner to remove entrained liquids and dust. Most stations measure the natural gas with orifice meters, although other types of meters may be used alone or with orifice meters. Pressure is reduced with mechanical devices called pressure regulators. These devices control the rate of natural gas flow through the station to maintain the desired pressure level in the distribution system. If the pressure reduction is appreciable, there is substantial cooling. For this reason, the natural gas may be preheated to prevent frost, ice, or ice-like hydrates from forming in the downstream piping and prevent frost heaving in the ground surrounding the pipe. Natural gas received with insufficient odor must be odorized before leaving the city gate station. This process, required by Federal Pipeline Safety regulations, is very important because natural gas commonly has very little odor, especially after sweetening. An odorant that confers a "natural gassy" smell is added to make the presence of escaping unburned natural gas recognizable at a very low concentration in the atmosphere, thereby warning customers well before it can accumulate to a hazardous concentration. Mixtures of air and natural gas are explosive over the range of 5 to 15 percent natural gas. The lower explosive limit (LEL) is 5% natural gas in air. Natural gas should be detectable at 20% of the LEL (1% natural gas to air mixture) or less to ensure safety.

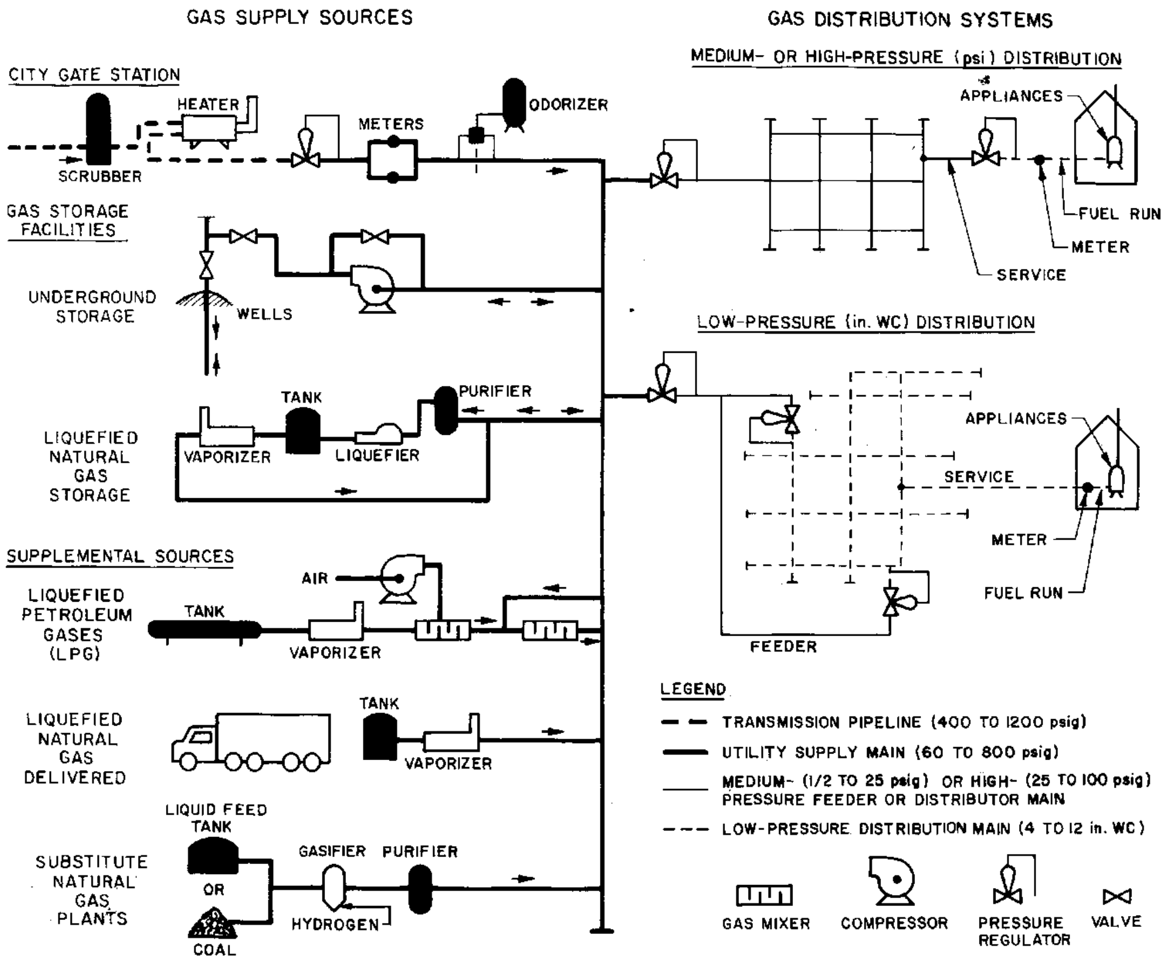


Figure 0-21: A typical natural gas distribution system

(Source: Gas Technology Institute)

B. Distribution System Piping

Distribution system consists of several superimposed networks of mains operated at different pressure levels. Natural gas from the high-pressure supply mains is fed through pressure regulators (district regulator stations) into the distribution networks. The piping in a distribution system is classified into five categories:

- **Supply mains** receive and carry natural gas from city gate stations to lower pressure distribution systems. In some cases, the supply main may be a few hundred feet in length; others comprise a complex network of many miles. Although at a pressure lower than in a transmission pipeline, the natural gas pressure in a supply main is higher than most distribution mains. Supply mains may have a few high-pressure services, such as those serving large industrial customers directly connected to them.
- **Feeder mains** supply natural gas from major sources, such as a regulator station fed by a supply main, to distribution mains. Feeder mains may also have services directly connected to customers.
- **Distribution mains** supply natural gas primarily to residential, commercial, and smaller industrial services.

- **Service lines** deliver natural gas from a distribution main in the street to the customers' meters. Service lines are usually the property and responsibility of the utility. However, some utilities only own the portion of the service line in the public right-of-way and the customers own the portion on their property.
- **Fuel lines** are customer piping beyond the meter to appliances and are the property and the responsibility of the building owner.

C. Supplementary Natural Gas

Although natural gas is the primary fuel for distribution companies, many companies supplement their supplies with other types of natural gas. Supplementary natural gas is generally produced only at times of highest demand (peak load), such as on cold winter days. This operation, called peak shaving, reduces substantially the additional costs that would be incurred by contracting for higher daily quantities of natural gas. During the natural gas shortages in the 1970s, many companies installed baseload SNG plants using naphtha as feedstock to supplement curtailed natural gas supplies. These plants are not used when supplies are ample and reasonably inexpensive because of the high production cost of such natural gas. Peak shaving plants can be either LP-air (store propane or butane as a liquid under pressure) plants or LNG plants. During periods of operation, the liquid is pumped to a vaporizer and natural gasified. The propane natural gas is then usually mixed with air, at a ratio that makes it more compatible with natural gas appliances, and injected into the natural gas stream. LNG plants may include liquefaction process facilities. Natural gas from the pipeline is liquefied during periods of low demand on the system and stored in specially constructed cryogenic tanks. It is vaporized and injected into the natural gas stream during periods of peak demand. Other facilities consist only of storage and vaporization facilities and a loading station, contracting LNG from liquefaction plants and shipping via tanker trucks. Several terminals in the U.S. import LNG from foreign sources delivered from specially designed ships and stored for redelivery by pipeline or tanker truck. Liquefying natural gas reduces its volume by 620:1.

LNG is natural gas chilled to -161ºC so that it becomes a liquid. Once it has been liquefied, the methane takes up much less space. Because LNG occupies about 1/600 the space of methane in its natural gaseous form, it can be exported in purpose-built tanker ships. Both Europe and the U.S. have shared characteristics resulting from the emergence of international trade in LNG. LNG is still slightly more expensive than pipeline natural gas, but costs are coming down. LNG has a much higher flexibility of supply: tanker capacities for transporting LNG is increasing, and an intensification of international trade is expected, eventually even the development of a deep spot market. The current role of LNG for EU imports is small (~ 10%) but rising, and it is important in specific countries, e.g. Spain and France, where LNG accounts for 60% and 25% of total imports, respectively. It is suggested that the state can take the following measures to facilitate the trade of LNG: (1) Develop cheaper LNG storage devices; (2) Develop more advanced cooling technology to chill the natural gas to LNG.

0.4.6 Natural Gas Utilization

Natural gas consumers are commonly classified as residential, commercial, or industrial. Electrical power plants are often classified as industrial natural gas consumers, but may be considered separately as listed in Table 0-1.

Commercial natural gas customers include hotels, restaurants, and institutions such as hospitals and schools. In this sector, natural gas is used for large-volume cooking, water heating, space heating, and air conditioning. Industrial customers account for about 44% of the annual natural gas consumption and the greatest variety of applications for natural gas. Natural gas is sold to tens of thousands of factories, plants, and mills throughout the country for a great variety of uses, from large metal stress-relieving furnaces, into which work-laden cars can be run to minuscule natural gas flames used to anneal glass tubes. Applications for natural gas are limited only by the ingenuity of the applications engineers and manufacturers. Natural gas used for electric power generation has increased significantly as a result of the availability of low cost natural gas and to assist electric utilities in compliance with emission standards established by the Environmental Protection Agency (EPA) to meet requirements of the Clean Air Act.

Another promising natural gas market is the Compressed Natural Gas (CNG) for vehicular fuel. The CNG advantages include: far less air pollution, reduced engine maintenance, and lower fuel costs. Natural gas vehicles (NGVs) are particularly well suited for fleet applications and buses. Automobile manufacturers are offering factory installed CNG fuel systems, and kits are available for converting natural gasoline-powered vehicles. Systems usually have dual fuel capability (natural gas/gasoline) because of the limited range at the natural gas fuel tank and the limited number of refueling stations.

Table 0-1: U.S. natural gas consumption in 2010-2013, (Billions of Cubic Feet)

Classification	2010	2011	2012	2013
Residential	4,782,412	4,713,777	4,148,970	4,940,063
Commercial	3,102,593	3,155,319	2,895,358	3,289,440
Industrial	6,826,192	6,994,120	7,223,835	7,463,103
Vehicle Fuel	28,664	29,974	30,056	32,850
Electric Power	7,387,184	7,573,863	9,110,793	8,153,285
Total	22,127,046	22,467,053	23,409,012	23,878,742

(Source: U.S. Energy Information Administration)

1. Electricity and Natural Gas Market Structures

Scope of work:

Task 1: Explain market structures for both the electric power system (such as RTOs and nonmarket regions) and each of the elements of the natural gas system.

Deliverable: Explanation of various types of market structures for the electric power system and each of the elements of the natural gas system.

1.1 Electricity Markets

In the last decade of the 20th century, Congress and the FERC acted to create competitive markets for wholesale electricity and to spur entry into the generation business by new players. The restructuring of electricity industry began in the 1990s. The market structure is complicated due to the distinct nature of the electricity whose production and consumption must match in real time. Market participants would have nondiscriminatory transmission access and transmission ownership is separated from control. The ISOs/RTOs control the transmission system for maintaining the system's reliability. The market structure should allow long-term wholesale bilateral trading and a voluntary short-term spot market with transparent and justifiable prices of energy and ancillary services. The spot market would include both a day-ahead function to coordinate resource commitment and a real-time balancing function. The price of electricity is driven by economic forces in a competitive and fair market which maximizes the social welfare, such as reducing primary energy source consumption and pollution.

In the United States, FERC Orders 888 and 889 defined how independent power producers (IPPs) and power marketers would be allowed fair access to transmission systems, and mandated the implementation of the OASIS to facilitate the fair handling of transactions between electric power transmission suppliers and their customers. In general, market participants have responsibility for providing accurate data, certifying the performance of their equipment, and following the dispatch requested by the ISO/RTO. The ISO/RTO has the responsibility of ensuring that each market participant meets its reliability rules and coordinating the dispatch of the electricity supply to meet the demand, such that the power system will also meet the operational reliability objectives at the lowest possible cost. NERC has already included ISOs/RTOs and market participants in its governance structure, with the traditional reliability criteria updated appropriately to meet the needs of restructured electricity markets.

Many electricity markets are designed based on the concept of Locational Marginal Price (LMP). The LMP at a node in the power grid is defined as the additional operation cost to supply the next unit increment load at that node. One key feature of LMP is that there is a consistency between the electricity price and delivery price for the transmission system. The transmission congestion cost is defined as the difference of the LMPs at the source node and sink node. Therefore, a market participant who injects power at node A and withdraws the same amount of power at node B will pay exactly the same price with a participant who pays the transmission congestion charge from A to B. If there is no transmission congestion and loss in the system, then the LMPs are the same for all locations in the system. The power loss component is a relatively small part in LMP. Due to transmission congestions, LMPs at different nodes in the grid vary. Consequently, a new concept Financial Transmission Right (FTR) is proposed in the day-ahead market to hedge the congestion. FTRs are financial instruments that entitle the holder to a stream of revenues (or charges) based on the hourly LMP differences across a transmission path in the day-ahead market.

In a restructured electricity market, a traditional utility is unbundled into generation companies (GENCOs), transmission companies (TRANSCOs), and distribution companies (DISCOs). Along with other non-asset owners such as energy brokers, marketers, aggregators, and retailers (RETAILCOs), GENCOs, TRANSCOs, and DISCOs are collectively known as the market participants. A competitive electricity market structure with energy flow and information flow among its entities is illustrated in Figure 1-1.

Market participants' functions are further discussed as follows:

- ***GENCOs***: A GENCO is an entity that operates and maintains existing generating plants which are not affiliated with ISOs or TRANSCOs. A GENCO may own generating plants or interact on behalf of plant owners with the short-term market (power exchange, power pool, or spot market). GENCOs have the opportunity to sell electricity to entities with bilateral contracts. They may also opt to sell electricity to the spot market from which large customers such as DISTCOs and aggregators may purchase electricity to meet their demand requirements. GENCOs may also trade reactive power and other ancillary services. One key difference between electricity markets and a vertically integrated structure is that GENCOs' electricity prices are not regulated. GENCOs also have the responsibility to communicate generating unit outages for maintenance to the ISO/RTO. In electricity markets, a GENCO's objective is to maximize its payoff. So GENCOs may choose to take part in various markets (energy, ancillary services, etc.) and take various actions (arbitrage and gaming) for their payoff maximization.

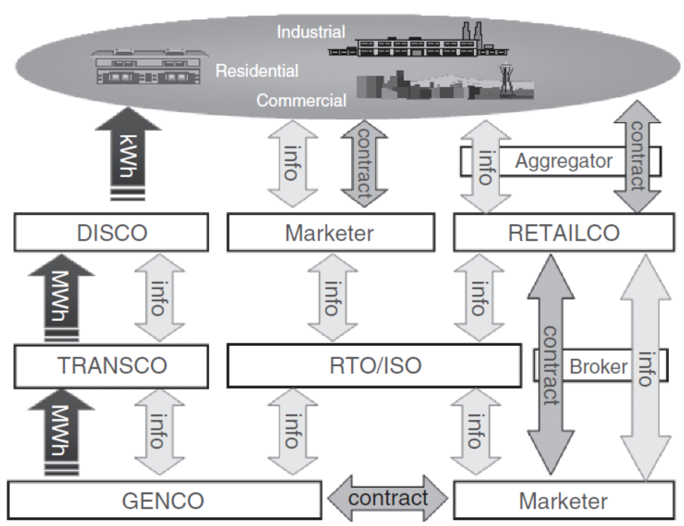


Figure 1-1: A competitive electricity market structure

(Source: Cheung, 2010)

- ***TRANSCOs***: A TRANSCO is an entity with the role of building, owning, and operating transmission systems in a geographical region for maintaining the overall reliability of the electrical system. The use of TRANSCO assets is under the control of the regional ISO. The transmission system is the most critical element in electricity markets. A TRANSCO transmits electricity using a high-voltage bulk transport system from GENCOs to DISCOs who delivers electricity to customers. TRANSCOs are regulated to provide non-discriminatory open access and comparable service for cost recovery. TRANSCOs communicate with the ISO the list of equipment outages or any changes to the scheduled outages. Transmission maintenance and expansion is coordinated between TRANSCOs and the ISO/RTO. Authorities at state and federal levels regulate TRANSCOs which recover their investment and operating costs of transmission facilities using access charges (which are usually paid by every user within the area/region), transmission usage charges (based on line flows contributed by each user), and congestion revenues collected by the ISO.

- ***Independent System Operator (ISO)***: The independent operation of the grid is guaranteed by an independent entity which is referred to as Independent System Operator (ISO). Prior to establishing the ISO, power pools controlling the access to regional transmission systems had established complex operating rules and financial arrangements that made it difficult for non-members to use pool members' transmission facilities. ISO is a neutral, independent entity responsible for maintaining secure and economic operations of an open access transmission system on a regional basis. ISO is responsible for maintaining the system energy balance by controlling the dispatch of flexible resources. An ISO provides transmission availability and pricing services to all users of the transmission grid. One of the main tasks of the ISO is the transmission congestion management including the collection and distribution of congestion revenues. The ISO also coordinates the maintenance scheduling and has a role in coordinating long-term planning. Most ISOs are set up as nonprofit corporations. During the market operation, there are five ancillary services that might be cleared and provided by the ISO to market participant: (1) Reactive Supply and Voltage Control, (2) Regulation and Frequency Response Services, (3) Energy Imbalance Service Operating Reserve, (4) Spinning and Supplemental Reserve Services, and (5) Transmission Constraint Mitigation. If these services are called by the ISO, the service providers are paid extra to cover its operating cost.
- ***Regional Transmission Organization (RTO)***: According to the FERC Order 2000, published in November 1999, energy transmission entities are required to participate in RTOs (Regional Transmission Organizations). A region is a collection of zones with more than one ISO in a region. The purpose of establishing RTOs is to eliminate regional discriminatory transmission practices and pancaked transmission prices. The formation of an RTO will make energy transmission more fluid in the region. The relationship between RTO and ISO are illustrated in the Figure 1-2. The responsibility of ensuring the reliability of a control area is delegated to ISO and RTO.

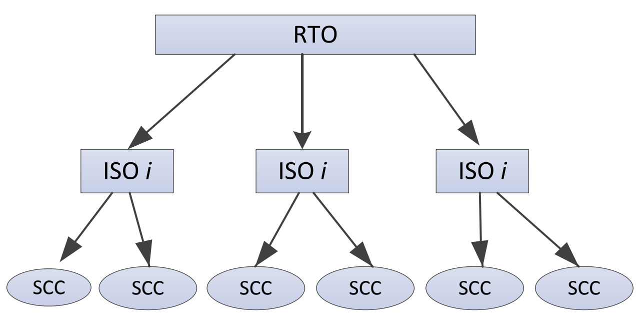


Figure 1-2: Control hierarchy of RTO

- ***DISCOs***: A DISCO is a regulated (by state regulatory agencies) electric utility that builds, owns, and maintains distribution wires connecting the transmission grid to retail customers. DISCOs are responsible for maintaining a certain degree of reliability and availability at the distribution level.

DISCOs are responsible for responding to distribution network outages and power quality concerns. DISCOs are also responsible for maintain the distribution voltage support as well as ancillary services.

- ***Aggregators***: An aggregator is an entity or a firm that combines customers into a buying group for buying large blocks of electric power and other services with a cheaper price. The aggregator may act as an agent (broker) between this group of customers and a retailer. When an aggregator purchases power and re-sells it to customers, it acts as a retailer and should initially qualify as a retailer.
- ***Marketers***: A marketer is an entity or a firm that buys and re-sells electric power but does not own generating facilities. A marketer takes title, and is approved by FERC, to market electric energy services. A marketer performs as a wholesaler and may acquire required transmission services. An entity may handle both marketing and retailing functions.
- ***Customers***: A customer is the end-user of electricity with certain facilities connected to the distribution system, in the case of small customers, and connected to transmission system, in the case of bulk customers. In a vertically integrated structure, a user obtains electric energy services from a utility that has legal rights to provide those services in the service territory where the customer is located. In a restructured system, customers are no longer obligated to purchase any services from their local utility company. Customers will have direct access to generators or contracts with other providers of power, and choose packages of services (such as the level of reliability) with the best overall value that meets customers' needs. For instance, customers may choose providers that would render the option of shifting customer loads to off-peak hours with lower rates.

1.1.1 Electricity Market Models

As discussed earlier, generation owners in electricity markets compete for supplying the regional loads. Transmission and distribution functions are regulated. The ISO will operate the transmission grid and maintain the security of power system. The following electricity market models present the following issues: (1) who will maintain the control of transmission grid; (2) what types of transactions are allowed; (3) what level of competition does an electricity market warrant:

A. PoolCo Model

A PoolCo is defined as a centralized marketplace that clears the market for buyers and sellers. Sellers and buyers submit their bids to inject power into and out of the pool. Sellers compete for the right to inject power into the grid, not for specific customers. If a power provider bids too high, it may not be able to sell power. On the other hand, buyers compete for buying power. If demand side is passive, a forecast of demand is used. An ISO within a PoolCo would implement the economic dispatch and produce a single price for electricity, giving participants a clear signal for consumption and investment decisions. Market dynamics in electricity market will drive the spot price to a competitive level. PoolCo does not own any generation or transmission components, and centrally dispatches all generating units within the service jurisdiction of the pool. PoolCo controls and maintains the transmission grid and encourages an efficient operation by assessing non-discriminatory fee to generators to cover operating costs.

B. Bilateral Contracts Model

Bilateral contracts are negotiable agreements on delivery and receipt of power between buyers and sellers, who set terms and conditions of contracts independent of the ISO. The ISO would verify that a sufficient transmission capacity exists to complete the transactions and maintain transmission security.

The bilateral contract model is very flexible as trading parties specify their desired contract terms. Disadvantages of the bilateral contract model include the high cost of negotiating and writing contracts, and the risk of the credit worthiness of counter-parties. Trading is a private arrangement between seller and buyer in which the price/quantity negotiated directly. Trades are facilitated by brokers or electronic market operators. Unlike MCP, there is no "official price" here. The bilateral contract model has two main characteristics that would distinguish it from the PoolCo model. The ISO's role is more limited and buyers and sellers could negotiate directly. Suppliers pay charges to a transmission company to acquire access and pays similar charges to a distribution company to acquire access to the distribution grid. A distribution company may function as an aggregator for a large number of retail customers in supplying a long term capacity. There could be three types of bilateral trading:

- ***Customized Long-Term Contract***: Its duration could be from several months to several years. The price is fixed for a long period with high cost of negotiations and terms are flexible which can be negotiated between the parties. It is worthwhile only for large amounts of energy.
- ***Over the Counter Trading***: It is used for smaller amounts of energy with much lower transaction costs. It is delivered according to standardized profiles. Over the counter trading is used to refine position as delivery time approaches.
- ***Electronic Trading***: In the electronic trading, participants (both buyers and sellers) remain anonymous. Participants will enter binds directly into computerized marketplace where they can observe the price and quantities offered. Bids and offers are matched automatically. It is a fast and cheap method which can provide accurate information about the market.

C. Hybrid Model
Hybrid model combines various features of the PoolCo model and bilateral model. In hybrid model, the utilization of a PoolCo is not obligatory any more, and any customer would be allowed to negotiate a power supply agreement directly with suppliers or choose to accept power at the spot market price. The Pool would serve all participants (buyers and sellers) who choose not to sign bilateral contract.

As in the Pool model, if generators opt to compete through the pool, they would submit competitive bids to spot market. All bilateral contracts would be scheduled to meet their load considering the transmission congestion, and the loads not provided bilaterally would be supplied by economic dispatch of generating units though bids in the pool. The existence of the pool can efficiently identify individual customer's energy requirement and simplify the balance process of energy supply.

1.2 Settlements in Electricity Markets

1.2.1 Classified Based on Time Scales
Based on the time scale for settlement, the electric market can be classified as day-ahead market, hour-ahead market and real-time market. The first two markets are forward markets. In the day-ahead market, hourly clearing prices for next operating day are calculated based on market participants' bids and offers submitted into the day-ahead market. ISO/RTOs usually run security-constrained unit commitment and security-constrained economic dispatch calculations using the bid and offers. The real-time market is a balancing market in which the market clearing prices are calculated every 5-15 minutes based on the actual system conditions.

- ***Forward Market (Day-Ahead Market, Hour-Ahead Market)***: Electricity market participants are able to trade electricity at binding prices in the day-ahead market. Generators with capacity contracts must submit a schedule into day-ahead market, and other generators can submit offer either into the day-ahead market or the real-time market. Transmission customers are also able to schedule the bilateral transactions based on locational market prices. Load serving entities can submit hourly demand schedules to the day-ahead market. All spot sales and purchases are settled at the day-ahead price in the day-ahead market. ISOs/RTOs apply SCUC to calculate security-constrained least-cost day-ahead schedule, based on bids and offers submitted by market participants. SCUC considers constraints on system, generation, and regulation, and calculates the hourly generation unit dispatch as well as LMPs for the day-ahead market. It is noted that some RTOs/ISOs incorporate generation reserve obligations into SCUC (co-optimization procedure).

- ***Real-time Market (Balancing Market)***: In the real-time market, forecast errors in generation and demand are addressed. Real-time market provides an easy way to reduce the mismatch between supply and demand in real-time. The competitive bids are incorporated for generation adjustments and real-time prices are calculated at this time.

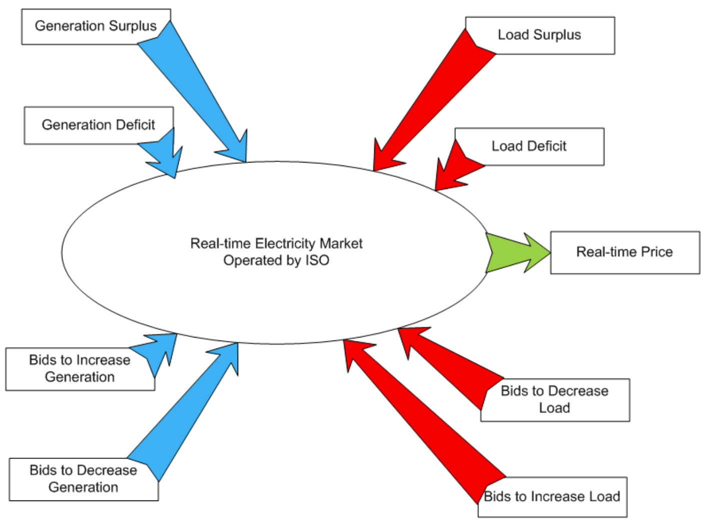


Figure 1-3: Real-time electricity market

(Source: Galvin Center for Electricity Innovation)

1.2.2 Traded Commodities in Electricity Markets

Based on the commodities traded, electric markets are classified into transmission service, energy, and ancillary services markets.

- ***Transmission Service Market***: The RTO/ISO offer transmission customers nondiscriminatory, standard transmission services. In LMP-based markets, power transmission is subject to congestion charges. To hedge against transmission congestion charges, financial rights are offered in the form of FTRs (obligations or options). FTRs may be allocated as long-term, mid-term, or short-term rights. FTRs provide congestion price certainty, but they do not have any bearing on the operator's congestion relief re-dispatch decisions. Electricity market transactions may also be conducted without holding any FTRs. However, for any energy interchange scheduling external to the RTO/ISO region, an OASIS reservation is required.
- ***Energy Market***: Energy market includes a day-ahead market and a real-time market which represent a multi-settlement energy market design. The day-ahead market provides: (1) opportunity for the

system to commit sufficient generating units and transmission elements to meet the bid-in loads for the next day; (2) opportunity for a generator to have an increased level of financial certainty with respect to the operational constraints and costs of generating units through the use of multi-part bids; and (3) better scheduling opportunities for the demand side to participate in the market. The day-ahead market shall be cleared to achieve the objective of maximizing the combined economic value of transmission service, energy, and ancillary services based on the submitted bids while ensuring reliability standard are met. The real-time market shall be operated using the same LMP-based methodology. The real-time LMPs are applied for settling all deviations and imbalances from the schedules determined in the day-ahead market.

- ***Ancillary Services Market***: Ancillary services are necessary for a secure operation of power systems. Since the same generating capacity may be used for supplying energy and ancillary services, it is imperative to apply a market co-optimization for the two commodities. The key is that the joint market must allow for flexible substitution of energy and ancillary services products in real-time operations.

1.3 Wholesale Electricity Markets

There are various models of ISOs, and the functioning and operation methodologies of which differ from market to market. In the U.S., there are several ISO models as shown in Figure 1-4, including California ISO (CAISO), New York ISO (NYISO), ISO New England (ISONE), PJM (Pennsylvania-New Jersey-Maryland), Midwest ISO (MISO), Southwest Power Pool (SPP), and Electric Reliability Council of Texas (ERCOT).

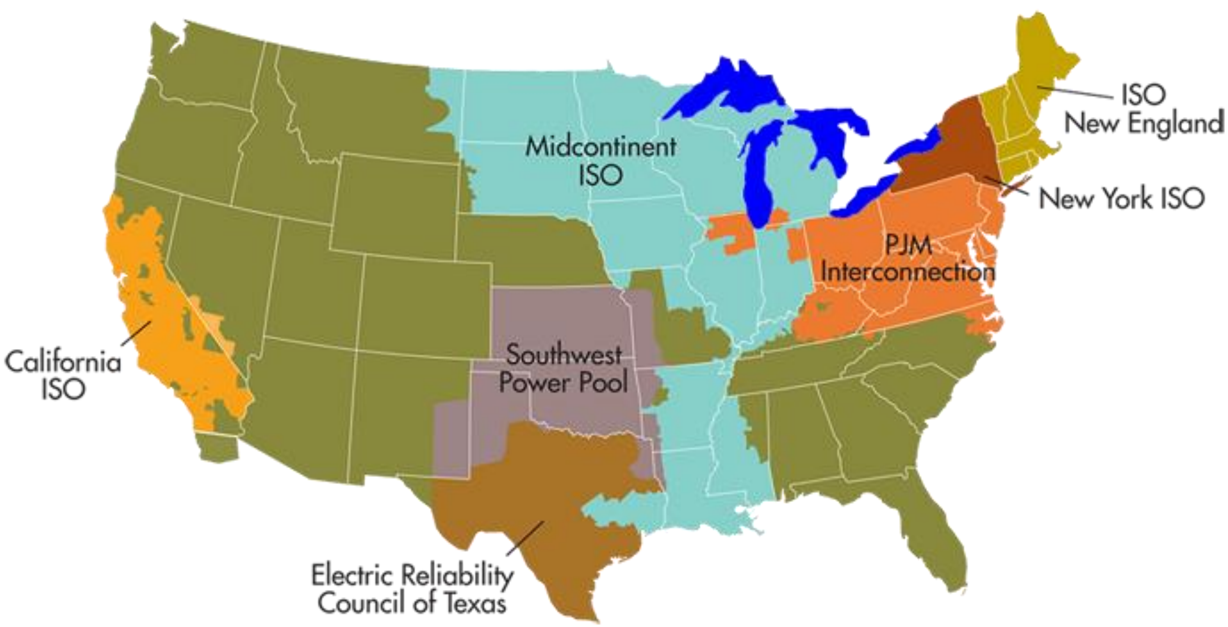


Figure 1-4: ISO/RTO region in U.S.

(Source: ISO/RTO Council)

These ISOs have advantages and shortcomings of their own. The structures of ISOs are discussed below briefly.

- ***CAISO***: The energy markets (day-ahead, hour-ahead and real-time) in CAISO use a full network model that models transmission losses and reactive power load and produces LMPs at every point in the system. Day-ahead market opens seven days prior to the trade date and closes the DAM 10:00 a.m. Results are published at 1:00 p.m. The real-time market is a spot market to procure energy (including reserves) and manage congestion in the real-time after all the other processes have run. The market opens at 1:00 p.m. prior to the trading day and closes 75 minutes before the start of the trading hour. The results are published about 45 minutes prior to the start of the trading hour.

- ***NYISO***: is responsible for bulk power system operations, including coordination of maintenance outage schedules and provision of transmission on non-discriminatory basis. The model used by NYISO clears energy and ancillary service markets at the same time. SCUC software is used for scheduling day-ahead and hour-ahead to dispatch energy, load, reserves and regulation considering network constraints and schedules outages. Locational Based Marginal Prices (LMP) is also calculated by the software.
- ***ISONE***: commits generating units first through a financially binding Day-Ahead Market (DAM). The DAM is a forward market that operates one day prior to the delivery day, which is a standard 24-hour calendar day. In the DAM, the base hourly unit commitment is scheduled as well as the generation dispatch. The hourly LMPs for DAM are also calculated in the security-constrained unit commitment.
- ***PJM***: market includes day-ahead market, real-time market, FTR market, and ancillary services market. It also have a reliability pricing model (RPM) used to clear capacity for up to three years in the future. The day ahead scheduling takes place on the day prior to the operating day, and hourly scheduling would take place with 60-minute leading the operating hour.
- ***ERCOT***: schedules and centrally dispatches the grid within a single control area, ensures transmission reliability and wholesale open access, and manages financial settlement in the wholesale power market. It also administers the Texas competitive retail market, including customer switching. ERCOT operates wholesale markets for balancing energy and ancillary service markets with zonal congestion management. Market participants trade electricity bilaterally directly, through brokers and through the Intercontinental Exchange (ICE). Physical products predominantly use the ERCOT hub pricing point, but physical and financial products priced at the four ERCOT zones are also traded.

1.4 Natural Gas Market

1.4.1 Natural Gas Industry Structure

The structure of the natural gas industry has changed dramatically since the mid-1980's. Before 1985 the industry was vertically separated into production, pipeline transportation, and distribution. But with all transactions tightly regulated and completed under long-term contracts, the industry was de facto vertically integrated. Distribution companies could not choose a pipeline company unless their long-term supply contract expired. Most marketed production was sold under long-term take-or-pay contracts between producers and pipeline companies. The prices for which producers could sell natural gas to transportation pipelines was federally regulated, as was the price at which pipelines could sell to local distribution companies. State regulation monitored the price at which local distribution companies could sell natural gas to their customers.

The open access to interstate pipeline transportation in 1985 limited the use of long-term contracts and introduced competition to the wholesale natural gas market. Natural gas marketing emerged as a new segment of the natural gas industry. Local distribution companies (LDC) and large end users with direct connections to the interstate pipelines started to contract natural gas directly from producers. Many large end users constructed new connecting pipelines to bypass local distribution companies and gain access to the wholesale market. The unbundling of interstate pipeline transportation in 1992 completed the transformation of the wholesale market into a fully competitive market which is illustrated in Figure 1-5.

After unbundling, wellhead prices are no longer regulated, and the price of natural gas is dependent on supply and demand interactions. Interstate pipelines no longer take ownership of the natural gas commodity; instead they offer only the transportation component, which is still under federal regulation. Local distribution companies continue to offer bundled products to their customers, although retail unbundling taking place in many states allows the use of their distribution network for the transportation component alone. End users may purchase natural gas directly from producers or LDCs.

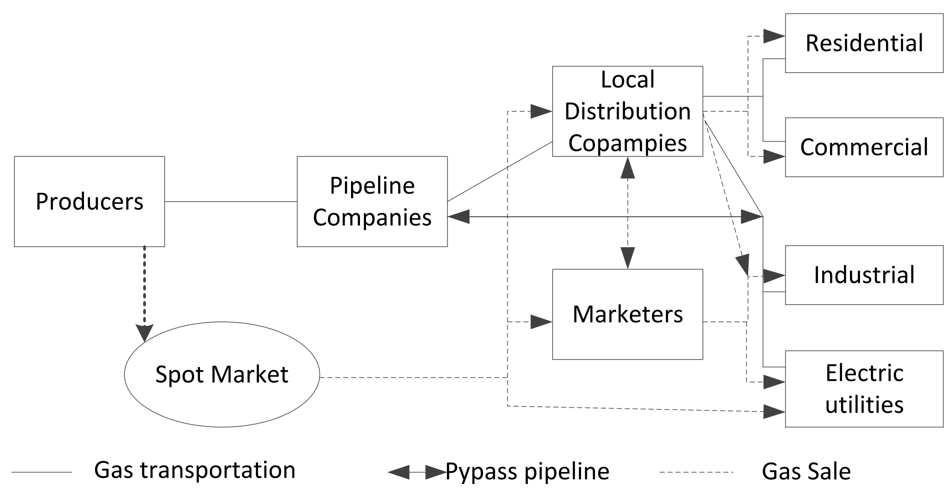


Figure 1-5: Structure of the U.S. natural gas industry after unbundling of sales from pipeline transportation in 1992

(Source: Andrej Juris, 1998)

1.4.2 Natural Gas Commodity Market

In the natural gas industry, the increasing flexibility of natural gas price and market has promoted the development of market centers and hubs. Transactions in the wholesale market have gradually moved from wellheads or consumption sites to hubs at major interconnections of interstate and intrastate pipelines. Hubs were formed and are typically operated by one or several interstate pipeline companies that own the pipelines interconnecting at the hub. Hubs allow market participants to acquire natural gas from several independent sources and ship it to several different markets. This eliminates the need to contract natural gas and pipeline capacity all the way from the wellhead to the consumption site. Instead, shippers can combine supply routes across several hubs to diversify supply risks. Hubs have become very popular among marketers and other players in the natural gas market. In addition to physical transfer of natural gas, hub also provides services such as storage, processing, and trading services. More shippers use hubs for transportation and acquisition of natural gas. The recent introduction of electronic trading systems has allowed the separation of trading from physical infrastructure and led to the development of market centers connected to one or several hubs by electronic networks. Electronic trading allows market participants to trade natural gas and pipeline capacity at all interconnected hubs and pipelines.

In competitive wholesale natural gas market trading takes place through bilateral decentralized transactions among producers, marketers, LDCs, and large end-users. Trading has become concentrated in spot markets organized by a number of market centers/hubs in producing regions and consumer areas. These spot markets generate efficient price signals about the market value of natural gas, instantly reacting to actual and expected changes in supply and demand. Deregulation of the natural gas industry has facilitated the separation of physical and financial trading. Natural gas market participants minimize supply risks by balancing their demand with natural gas supply contracts in the short and long term. They minimize price risk by taking financial positions on their natural gas supply contract portfolio. As a result, two distinct markets have developed in the wholesale natural gas market in the United States: a physical natural gas market, where contracts for physical natural gas delivery are traded, and a financial natural gas market, where contracts for price risk management are traded. These markets are discussed as follows.

A. Physical Natural Gas Market (See Task 4 for more information)

The physical wholesale natural gas market in the United States is very competitive. Both supply and demand sides of the physical market involve participants from all segments of the industry. Producers, pipelines, marketers, LDCs, and large-end users trade positions to minimize the costs and risks of natural gas supply. Transactions are concluded on a bilateral basis between market participants; many of them involve intermediation by natural gas marketers. The natural gas trading would mostly takes place in spot markets organized by market hubs and facilitated by electronic trading systems.

There are three types of contracts which are long-term, medium-term, and short-term contracts in the physical market. A long-term contract covers the deliveries and receipts for more than 18 months with flexible price which are used primarily by firms that require reliable natural gas supply. A medium-term contract covers delivery for up to 18 months which usually specifies the volume of monthly or daily natural gas deliveries and allowed variation. A short-term contract covers the delivery less than one calendar month with fixed price specified by spot contract.

Pipeline companies and LDCs use storage facilities and liquid natural gas to meet seasonal and peak natural gas demand during heating seasons and to balance pipeline operations on a daily basis. The traditional role of storage was to ensure high reliability of natural gas supply; cost-effectiveness in storage operations was neglected. A new role for natural gas storage is to promote efficient transactions in the deregulated natural gas market. Storage operators take advantage of swings in spot prices by selling natural gas at high prices and buying at low prices. Storage also contributes to more productive use of pipeline capacity.

B. Financial Natural Gas Market (See Task 4 for more information)

Traditionally bilateral, transactions now often involve intermediation by natural gas marketers. Marketers aggregate the demand of many end-users and small LDCs and trade natural gas on their behalf, reducing the cost of transactions in the natural gas market. The concentration of trading in market centers and hubs has led to the development of natural gas spot markets. And the introduction of electronic information systems has promoted electronic trading in such spot markets. Spot markets have been organized at almost all major market centers and hubs in the United States as well as at major city gates. The most important role of spot markets is to generate efficient price signals about the market value of natural gas. The value of marginal unit of natural gas traded in the spot market determines the sport price at a particular time which reflects the market value of natural gas at that time. Financial intermediaries and natural gas marketers offer customized financial instruments that transfer risk among industry participants. In addition, two organized exchanges offer several standardized natural gas futures and options contracts used by traders and industry participants to minimize price risk in many natural gas delivery locations.

The contracts in financial natural market include: *Futures* (a standardized, exchange-traded contract between a buyer and a seller for the delivery of a particular quantity of a commodity at a predetermined price on a future delivery date). *Swap* (a custom-tailored, individually negotiated transaction which aims to manage financial risks for about 1 to 12 years). *Option* (gives its holder the right, but not the obligation, to purchase or sell the underlying futures contract at a specified price within a specified period in exchange for a one-time premium payment). *Hedge* (a position taken in the financial market to offset a position in the physical market).

1.4.3 Natural Gas Transportation Market

A natural gas transportation market is a marketplace where pipeline capacity and transportation services are traded. There are two main natural gas transportation markets in the United States: a primary market and a secondary market. In the primary market, pipeline companies sell transportation contracts to marketers, LDCs, or end-users. Typical services are firm, no-notice, and interruptible transportation. In the secondary market, pipeline companies and holders of transportation contracts resell unused capacity in the form of firm or interruptible transportation.

The interstate pipeline transportation market is the most competitive transportation market in the United States. The supply side of the market consists of interstate pipeline companies and the demand side of shippers which purchase pipeline capacity and transportation services from the pipeline companies. Shippers are usually marketers, LDCs, producers, or large end- users. Transactions take place through transportation contracts that define the conditions for transportation and natural gas delivery. The open access regime and unbundling of interstate pipeline transportation have transformed the way in which end users receive their natural gas deliveries. Many customers purchase the natural gas deliveries in the wholesale market and pay fees to pipeline and local distribution companies.

The two main natural gas transportation markets are further discussed as follows:

- ***Primary Transportation Market***: The interstate pipeline transportation market is dominated by primary transportation services, which are used for 70 percent of natural gas deliveries. The primary transportation market facilitates the initial distribution of transportation contracts. The most active players in the primary market are local distribution companies. Pipeline companies sell transportation contracts to shippers for prices that are regulated by FERC. Transportation contracts differ primarily in the reliability, timing, and location of natural gas delivery. Shippers purchase transportation contracts in combinations that allow them to achieve the desired service reliability at the minimum cost and to take advantage of time and locational price differentials in the natural gas market. There are Firm transportation contract, No-notice firm transportation contract, Limited firm transportation contract and interruptible transportation contract in the market. The reliability of services covered in these contracts varies a lot. FERC determines tariffs for firm and interruptible transportation services using the straight fixed variable rate-making method, a cost-based price mechanism that uses the average accounting cost pricing concept. FERC has recognized the problems faced by pipeline companies and shippers in the primary transportation market and adopted several measures that expose the interstate pipeline segment to market forces.
- ***Secondary Transportation Market***: Secondary transportation services account for 30 percent of natural gas deliveries. Transactions in the secondary transportation market are dominated by marketers. The share of secondary transportation services has been steadily increasing since the

secondary market was created in 1993. A secondary transportation market is a marketplace where holders of transportation contracts can resell temporarily or permanently unused capacity to other shippers. The capacity release program established rules for trading firm capacity contracts owned by shippers. Holders of firm transportation or storage contracts can resell them to other parties through a pre-arranged deal or an open bid. The prices of transportation contracts traded in the capacity release market are regulated by FERC, using the price cap method. Shippers sell capacity for a price that reflects its opportunity cost and makes both buyer and seller better off. The allocation of capacity among shippers on the basis of their willingness to pay should lead to efficient allocation of resources and greater utilization of pipelines. One of the most important conditions for the efficient allocation of capacity, however, is market pricing. But the price cap imposed by FERC, which prevents the market price of released capacity from exceeding the maximum firm rate, leads to distorted prices and thus inefficient allocation of capacity. The gray market represents a market solution to the distortive regulation of capacity release prices. The market facilitates the trading of pipeline capacity bundled with natural gas and sold in congested markets. The market facilitates the trading of pipeline capacity bundled with natural gas and sold in congested markets. Shippers with firm capacity rights can earn the market value for their temporarily or permanently available capacity by using it to ship natural gas to congested markets. Since the price of natural gas is not regulated, shippers can charge the price that maximizes their profits.

2. Electricity and Natural Gas System Operations

Scope of work:

Task 2: Explain system operations for both electricity and natural gas. This should include the timely sharing of information to address the needs of both the natural gas and electricity industries; the electricity industry's intra-hour (as low as 5 minute intervals) compared to the intra-day nomination processes used by the natural gas industry; and contracting issues due to the different schedules, load shapes and load duration curves for both the natural gas and electricity industries with a discussion of the implications of the industry load characteristics.

Deliverable: Explanation of system operations for both electricity and natural gas.

2.1 Electric System Operation

In the United States, there are several wholesale markets, including California ISO (CAISO), New York ISO (NYISO), ISO New England (ISONE), PJM (Pennsylvania-New Jersey-Maryland), Midwest ISO (MISO), Southwest Power Pool (SPP) and Electric Reliability Council of Texas (ERCOT). Most of the ISOs have the responsibility of ensuring the reliability of one or more control areas. Most markets have adopted nodal LMPs and a multi-settlement system (Day-ahead market (DAM) and real-time market (RTM)) with FTR as a financial instrument to hedge transmission congestion risks.

The power market designs vary from region to region. However, they follow the common criteria for successful market operations to guarantee the power system reliability. Ancillary services markets cleared by ISO would address electricity reliability issues. Market transparency, financial certainty and operational efficiency are considered in all U.S. electricity markets. Most ISOs play two roles as depicted in Figure 2-1, one is to maintain the reliability as a system operator, and the other is to clear the market price based on supply offers and demand bids.

The basic electricity market operation procedure is illustrated below using the PJM market as an example. In addition to DAM, RTM, FTR market, and ancillary services market, PJM operates a reliability pricing model (RPM) used to clear capacity for up to three years in the future. A diagram of the timeline in the PJM market is shown in Figure 2-2.

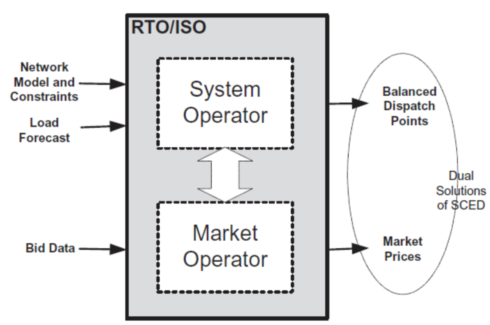


Figure 2-1: Dual functions of RTO/ISOs and the dual solutions of SCED

(Source: Cheung, 2010)

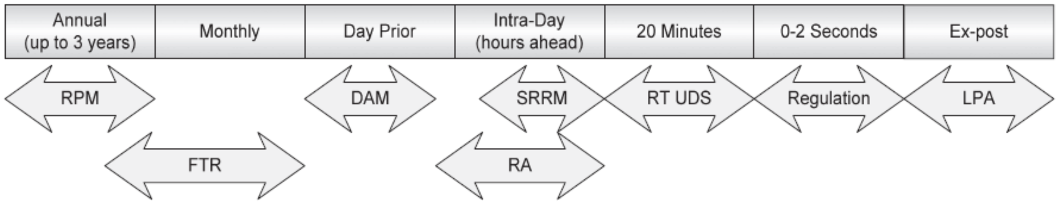


Figure 2-2: PJM market timeline

(Source: Cheung, 2010)

The PJM DAM is cleared each day for the next operating day. At 12:00 p.m. before the operating day, the DAM bid period closes. SCUC will determine the hourly commitment schedules and LMPs for DAM. FTR credits are also calculated using transmission congestion LMPs between the point of receipt and point of delivery of FTR. At 16:00 p.m., the day-ahead hourly schedules are posted by PJM. Between 16:00-18:00 p.m., PJM opens the balancing market offer period. During this period, the market participants can submit revised offers for resources not selected in the first clearing period. At 18:00 p.m., the balancing market offer period closes. PJM performs a reliability resource commitment using start-up and no-load costs for additionally committed resources. Between 18:00 p.m. and the operating day, PJM may revise the schedules based on the updated information.

The PJM RTM optimizes the schedule for the available dispatchable resources subject to the current system conditions, real-time load changes, and other latest information. The real-time pricing settlement uses an ex-post pricing process (LPA). The RTM will jointly optimize energy and reserves. Resource owners receive the instructions in real-time. Real-time LMPs are calculated in 5-minute intervals. To conduct the real-time market, PJM utilizes sophisticated software platforms to dispatch energy, and ensure adequate reserves in real-time and regulation in near time. The applications jointly optimize the products on a 5-minute basis to ensure that all system requirements are met using the least cost resource set. Every market participant is supposed to follow the ISO's real-time dispatch instructions.

2.2 Natural Gas System Operation

Different from the transportation of electricity, the transportation of natural gas from the wellhead to final natural gas consumers involves several transfers of custody and processing steps. Natural gas produced from well or field is sent to natural gas processing plant or directly to main transmission systems depending on the original quality of the wellhead product.

Natural gas market centers and hubs, where pipelines intersect and flows are transferred, evolved beginning in the late 1980s. FERC Order 636 issued in 1992 mandated that interstate natural gas pipeline companies strictly are natural gas transporters which cannot be natural gas sellers/buyers anymore. Market centers and hubs were developed to provide new natural gas shippers with many of physical capabilities and administrative support services. These services were formally provided by interstate pipeline companies as bundled services. Two key services offered by market centers/hubs are transportation between and interconnections with other pipelines and the physical coverage of short-term receipt/delivery balancing needs. The services commonly include wheeling, parking loaning, storage, peaking and so on.

Natural gas is sold through brokered markets in a separate transaction. Transportation services with various priorities are offered by pipeline companies. FERC regulates the service charges and provides regulated rates of return to pipeline owners. Most of the pipeline capacities with the highest priority are sold to LDCs according to expensive firm contracts. LDCs resell those capacities not utilized in the market each day.

Transactions in a deregulated natural gas industry are coordinated to achieve simultaneous clearing of natural gas and transportation markets at the minimum total cost. Market participants in the U.S. natural gas industry match the available supply of natural gas and transportation contracts with their demand through decentralized bilateral transactions. Each market participant minimizes its own costs of natural gas and transportation. But the total costs of natural gas to end-users may not be minimized if transportation is inefficient because of suboptimal operation of pipelines.

The natural gas transportation system is shown in Figure 2-3. Typical operations in the pipeline system include scheduling, balancing, central dispatch, and emergency control of natural gas flows. Natural gas supply and transportation services are coordinated by scheduling and balancing. With the shippers' pipeline capacity demand and information on the volumes of natural gas, a pipeline company carries out scheduling and balancing activities, and then determines the natural gas flow in the pipeline which can minimize transportation costs while satisfying shippers' demands. Central dispatch and emergency control maintain the natural gas system balance and guide natural gas flows through the pipeline system in real time. In some circumstances, the liquid natural gas and underground natural gas storage can also satisfy the natural gas demand.

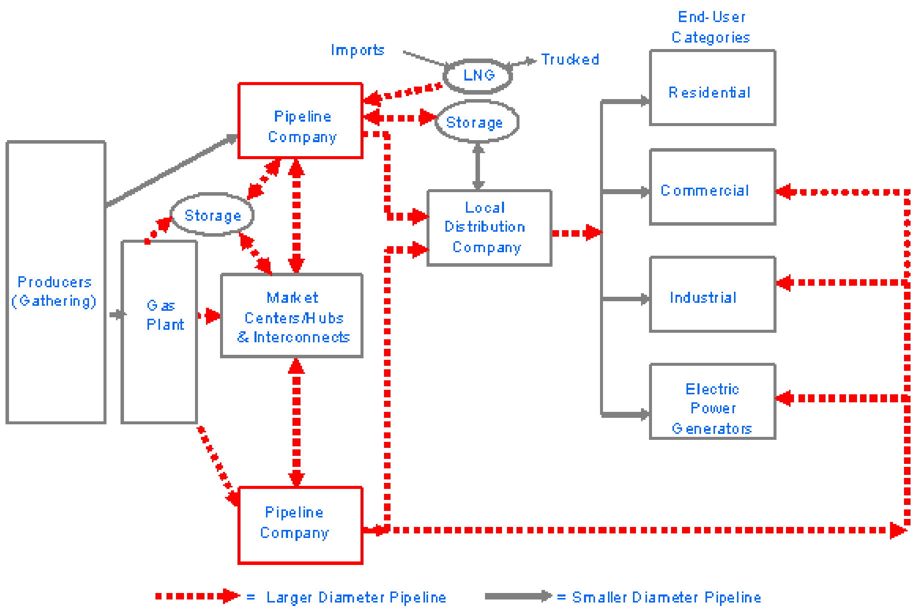


Figure 2-3: Natural gas transportation

(Source: U.S. Energy Information Administration)

2.3 Information Flow between Electricity and Natural Gas Systems

Changes in market rules for a better cooperation between electricity and natural gas markets would require an enhancement of information flow. This is especially true if natural gas firm contracts would incorporate fuel and pipeline capacity. Currently, there is no formal data exchange to verify firm natural gas pipeline capacity among pipeline companies, natural gas generators owners, power market operators, and regulatory organizations, such as FERC and NERC. In this section, several information sharing issues related to natural gas and electricity operations are discussed.

- ***Natural Gas Supply Disruption***: With the trend in increasing natural gas-fired generators, natural gas supply becomes more important than before in electricity markets. Electricity market operators would then require accurate information on natural gas supply from pipeline companies and natural gas-fired generator owners before they make scheduling decisions. In the fall of 2005, the Gulf of Mexico was hit by two hurricanes which shut down almost all oil and natural gas productions. Accordingly, the access to a portion of the nation's energy supplies was crippled which required many hours to get the operation back to normal. In November 2007, the natural gas supply contingency in Nova Scotia significantly depleted natural gas injections into the Maritimes & Northeast pipeline which resulted in outages of certain natural gas-fired generating plants and power brownouts in Maine. The power outages occurred because the ISO did not receive any notices or information on the fuel shortage supply from generator owners or pipeline companies.
- ***Natural Gas Pipeline Maintenance***: Natural gas-fired generators become unavailable occasionally due to natural gas pipeline inspections and maintenances. In pipelines' off-peak season (summer), outages tend to occur when is the peak season of the electric system. In the summer, the power system experiences peak load, and if the pipeline maintenance impacts the fuel supply to some critical natural gas-fired generators, there is a big chance that reliability issues occur. In this case, the prompt notice and information from pipeline companies are critical factors electricity market operator needs to consider in the DA market and RT market. During the week beginning June 6, 2011, several natural gas pipelines experienced issues related to the high electrical load coupled with pipeline maintenance, resulting in restrictions on generators. A year later, during the week of June 4, 2012, ISONE was made aware of a pipeline inspection that could cause a capability reduction of the Algonquin pipeline, with effects ranging from immediate reductions of up to 65% capability to no reduction at all. In order to prepare for anticipated restrictions and potential interruptions of fuel supply to New England generators, ISONE committed 650 MW of non-natural gas-fired additional capacity to provide greater fuel diversity.
- ***Scheduling of Natural Gas-fired Generations***: Natural gas pipeline and storage operators as well as LDCs with natural gas generating units in their distribution systems would require more comprehensive information on planned operation and maintenance of the natural gas-fired generators so that they can optimize the pipeline usage.
- ***Transmission Line Maintenance and Outage in Power System***: The transmission network topology and its availability would determine electricity market LMPs. If a transmission line is on scheduled maintenance, natural gas-fired generators may adjust their production in accordance with the variation in LMPs in order to supply regional electricity loads. The adjustment may impact the natural gas flow and pressure on natural gas pipelines. At the same time, transmission line forced outages may also have similar impacts on natural gas pipelines. Some natural gas-fired generation units may change their natural gas consumptions irrespective of their previous nomination in order to follow the distich instructions from ISOs. These unexpected usages of pipeline may also cause some discrepancies in natural gas markets.

2.4 Consumption Patterns for Electricity and Natural Gas

In the late 1980s and early 1990s, demand for natural gas grew rapidly in the United States, from around 17 TCF in 1983 to around 22 TCF in 1995, a 30 percent increase. During most of this period, natural gas was a less expensive fuel than oil. The expectation that natural gas price would stay low contributed to large investments in gas-fired generators. In addition, increasingly strict environmental regulations and the clean-burning qualities of natural gas have promoted the use of natural gas.

The peak of electricity load exists for only a few hundred hours in a year as shown in **Error! Reference source not found.** for the PJM system, where the system demand is mostly smaller than 120,000 MW. However, ISOs spend a lot of efforts to deal with peak loads within those limited hours when the electricity is much more expensive. As a comparison, the natural gas consumption duration curve is illustrated in **Error! Reference source not found.**. It shows a pattern similar to that of electricity. However, natural gas can be stored in large quantities and a large sum of liquefied natural gas in underground storages can be used to relieve the electrical congestion at peak hours.

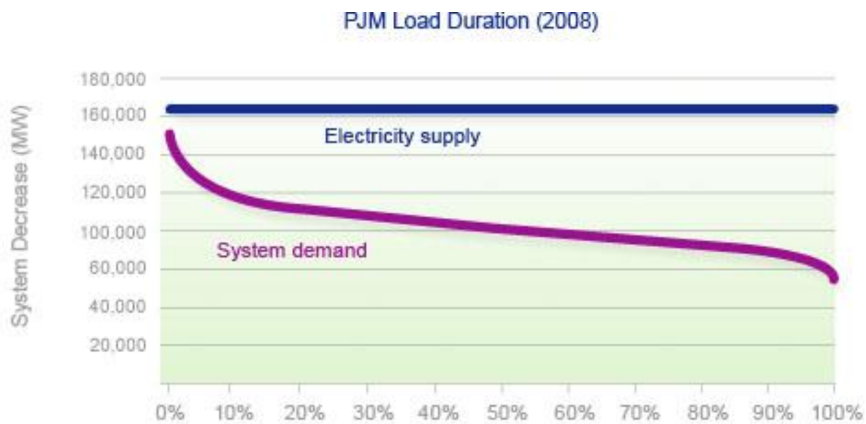


Figure 2-4: PJM load duration for 2008

(Source: U.S. Federal Energy Regulatory Commission, 2010)

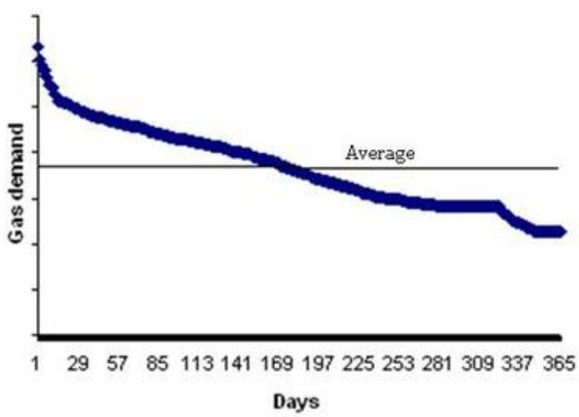


Figure 2-5: Natural gas load duration curve

2.4.1 Natural Gas Consumption by Sectors

Figure 2-6 shows the industrial sector is the largest user of natural gas, typically consuming more than 35 percent of total use. The residential sector has been the next largest user of natural gas, consuming approximately 22 percent of the total. However, the use of natural gas by electric generators has increased tremendously since the late 1990s, driven in part by the ease of getting permits to build natural gas-fired generation relative to other types of generation and by the low cost of natural gas. In fact, the capacity of natural gas-fired generation has tripled since 1999, and the quantity of natural gas used by the electric power sector grew by more than 50 percent between 1997 and 2013.

The natural gas consumption by the power industry has exceeded those of residential and industry consumers. In contrast, most generator companies still have non-firm contract with pipeline companies while most LDCs hold firm contracts. The delay in adjusting contracts for generator owners with pipeline companies may cause serious fuel supply issues and power system reliability concerns due to the additional natural gas consumptions by the electric power industry.

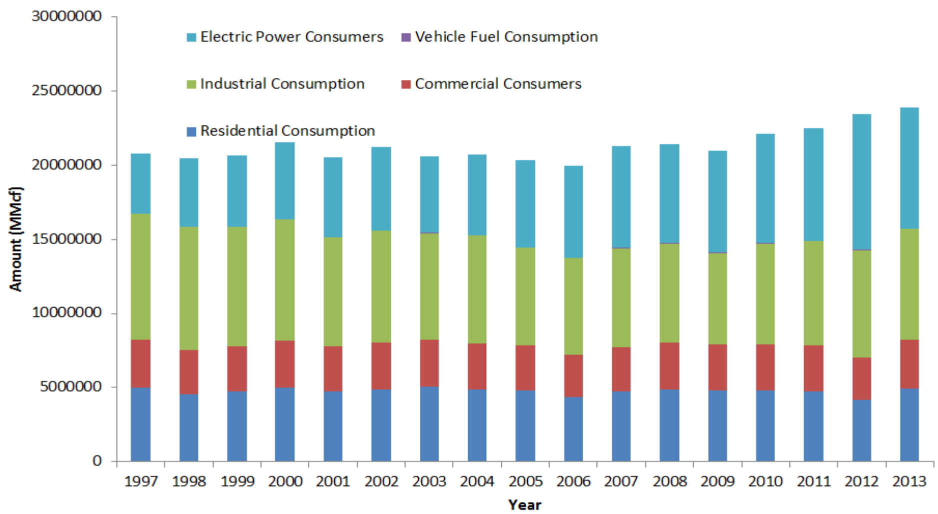


Figure 2-6: U.S. natural gas consumption by sector, Jan. 1990 - Dec. 2005

(Source: U.S. Energy Information Administration)

2.4.2 Seasonal Patten of Natural Gas Consumption

More than 60 million U.S. households use natural gas for water heating, space heating, or cooking. In total, natural gas accounts for more than 50 percent of the fuel used to heat U.S. homes. Residential and commercial heating demand for natural gas is highly weather-sensitive, as illustrated in Figure 2-7, making weather the biggest driver of natural gas demand volatility in the short term. seasonal nature of heating demand can cause the price of natural gas to vary widely at different times of the year. In the meantime, natural gas pipelines and distribution companies must plan to meet every customers' needs during peak demand periods.

Heating demand for natural gas increases natural gas prices in winter months, contributing to the tighter market that exists for natural gas, and serving to compensate those who place natural gas in storage during lower-price, off-peak periods. Regulated LDCs, however, will place natural gas in storage for peak demand independent of prices because of their regulator mandate for serving customers' peak demands. Thus, natural gas inventory is driven, in part, by regulatory factors in addition to market factors.

Due to the natural gas release to the atmosphere (about 4%), processing plant fuel consumption, and leaks in pipes, the amount delivered to consumers is smaller than the total consumption in Figure 2-7. Also summer is the peak season for electric power consumers while the consumption by residential customers is relatively low. In July 2013, the electricity industry consumes almost half of the total consumption.

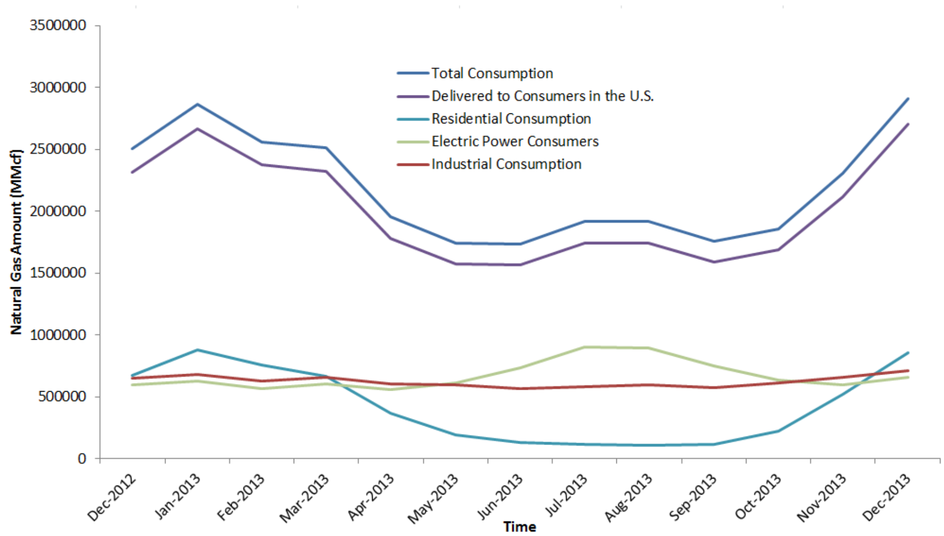


Figure 2-7: U.S. natural gas consumption by end use, Dec. 2012-Dec. 2013

(Source: U.S. Energy Information Administration)

2.4.3 Daily Patten of Natural Gas Consumption

Figure 2-8 shows the differences in timelines between the natural gas and electricity industries, as well as the hourly concentration of natural gas generator starts during the year. As shown in Figure 2-8, the electric morning load increase begins at approximately 3:00 a.m. The majority of daily generator starts occurs in this time period; most of these generators are those with the flexibility to cycle, which at this time is the natural gas fleet.

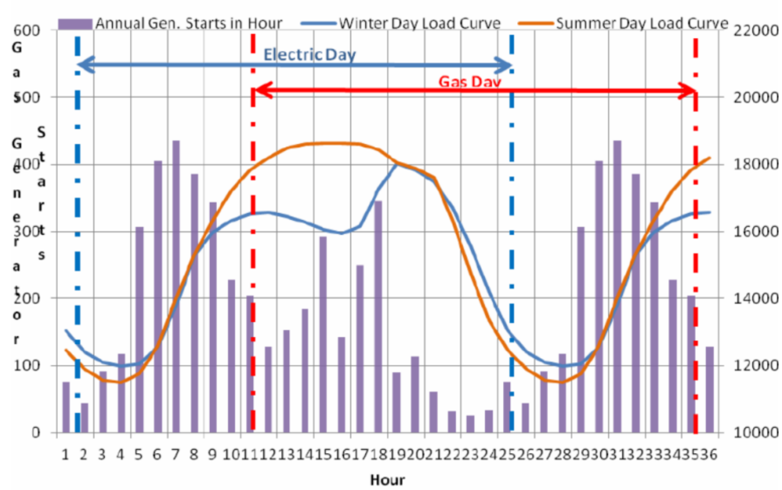


Figure 2-8: Average system demand, 2010-2011

(Source: ISO New England)

Ideally, a standard natural gas day would accommodate the morning load pickup and ensue the peak period in a single operating day. A closer coordination of electricity and natural gas operating days would synchronization electric generators' purchases of natural gas with their daily unit commitment.

2.5 Timeline Differences in Electricity and Natural Gas Markets

Although pipelines in general require natural gas supply be procured and scheduled in advance so that they can meet the actual market consumptions, it may still be necessary for natural gas-fired generators to consume more natural gas than they have nominated in the operating day based on the actual power system condition and the ISO's instructions.

The overall impact of natural gas-fired generator withdrawals when they consume more natural gas than they have nominated would vary a lot depending on the pipeline operating conditions in real time. In most cases, the impacts are minimal if the natural gas pipeline has sufficient capacity to deliver and time to recover from the over-draw before the next operating day. However, in critical cases the situations may get worse if pipelines have a limited ability to meet the additional demand during periods of pipeline maintenance, outages or heavy system demands.

The lack of scheduling coordination between natural gas and electricity industries is one of the reasons of the failure of generators to consume the natural gas nominated. Without the dispatch schedules posted by ISOs, natural gas-fired generator owners cannot nominate the accurate pipeline capacity for the next operating day. Some ISOs apparently have taken some major steps toward the coordination. On April 25, FERC issued an order approving acceleration of the daily schedule for bidding in and clearing New England's DAM. More market adjustments are still necessary for better coordination. In this section, the timeline prior to the FERC mandate is discussed to further illustrate timing issue at ISONE, which also explains why ISONE would still needs to change its DAM timeline.

2.5.1 Electricity System Timeline

ISONE applies SCUC to calculate hourly LMPs and commit generating units through a financially binding DAM. The DAM is a forward market that operates one day prior to the delivery day, which is a standard 24-hour calendar day. Figure 2-9 shows the ISONE market operations.

At 10:00 a.m. on the day prior to the electric operating day, ISONE posts the hourly load forecast for the next operating day. At 12:00 p.m. on the day prior to the operating day, DAM is closed which means most of the supply offers, demand bids, Increment/Decrement (virtual) offers, and external transactions that were entered for the next operating day are fixed at this time. ISONE uses SCUC to clear DAM, and posts the DAM hourly schedule and LMPs by the standard deadline of 4:00 p.m which are also available in downloadable files.

The next step in ISONE operations is the re-offer period, which occurs after the DAM results are published. The re-offer period opens at 4:00 p.m. and closes at 6:00 p.m. One of the intents of the re-offer period is to allow updates for spot market fuel prices, which may have changed from noon to 4:00 p.m. The re-offer period also allows a generator not committed in the DAM to self-schedule as a price-taker in the real-time market. During the re-offer period, market participants can submit certain revisions to supply offers and demand bids, revise prices on priced external transactions, and revise regulation offers. All assignments of forward reserve obligations and all bilateral transactions for forward reserve for the next operating day must be submitted to the ISO prior to the close of the re-offer period. Generators that have been committed in DAM can only change their energy price offers.

Using the most recent energy price offers, ISONE next conducts the Reserve Adequacy Assessment (RAA) process. The purpose of RAA is to ensure that sufficient capacity will be available to meet real-time energy demand, reserves, and regulation requirements. The RAA process marks the final interface between DAM clearing and real-time operations. The initial RAA is published at 10:00 p.m., two hours prior to the start of the operating day, and is updated at intervals throughout the operating day, at 1:00 a.m., 5:00 a.m., 8:00 a.m., 12:00 p.m. and 5:00 p.m., with updates to real-time generation unit commitment to deal with unexpected events, including load forecast errors, scheduling deviations in generation, and unplanned equipment (generation or transmission) outages, as well as forced contingency responses.

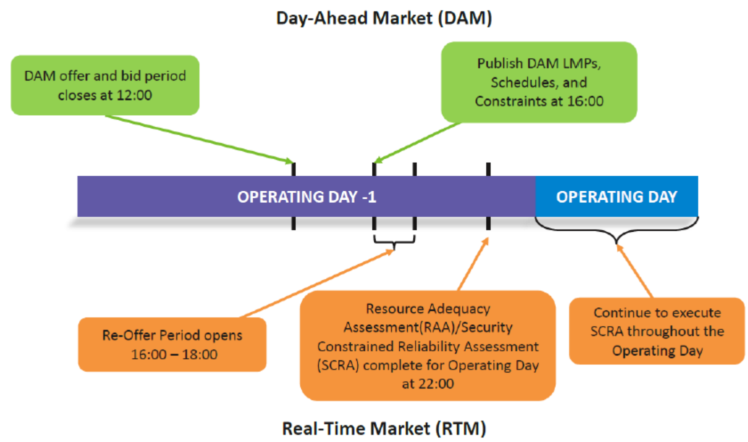


Figure 2-9: Day-ahead and real-time market timeline

(Source: ISO New England)

2.5.2 Natural Gas System Timeline

In comparison with the electricity market, the natural gas industry operates on a different set of time frames. Natural gas transport is nominated and scheduled on a one-day advance basis, using a 24-hour natural gas day which starts from 10:00 a.m. Eastern Standard Time. The purchase for the next natural gas day is a separate transaction, generally through the brokered markets (e.g., Intercontinental Exchange). A generator would nominate (request) pipeline capacity to transport natural gas from one specified location to another over the natural gas day. Submitted nominations are confirmed and scheduled by the pipelines based on priority of service, available pipeline capacity and ability to maintain pressure within prescribed limits for reliable operation along the designated contract path.

The timeline of each nomination is shown in Figure 2-10. Much like the electricity market, the timeliness is critical for coordinating the natural gas flow from gas well and storage to end-use customers. The nominations in Figure 2-10 fall into three categories: Timely, Evening, and Intra-day. Timely nominations give assurance to shippers that they will receive the nominated amounts of pipeline capacity throughout the next natural gas day, as long as they do not exceed the scheduled contract quantities. Under industry standards, firm customers that do not nominate their full entitlements at or before 12:30 p.m. for the Timely cycle nomination deadline effectively free up capacity for other shippers that have a lower pipeline service priority. During the Evening nomination cycle (which occurs from 12:31 p.m. to 7:00 p.m.), "bumping" can occur. Bumping is the process by which a shipper with a higher priority can force its nomination to take precedence over a lower priority shipper's nomination. As the natural gas day progresses, the two remaining natural gas scheduling periods, Intra-Day 1 and Intra-Day 2, become windows of last resort with respect to nominating additional fuel as a result of a revised dispatch order from ISONE. In addition, natural gas trading does not typically take place over weekends and holidays, meaning generators must plan days in advance of weekends and holidays.

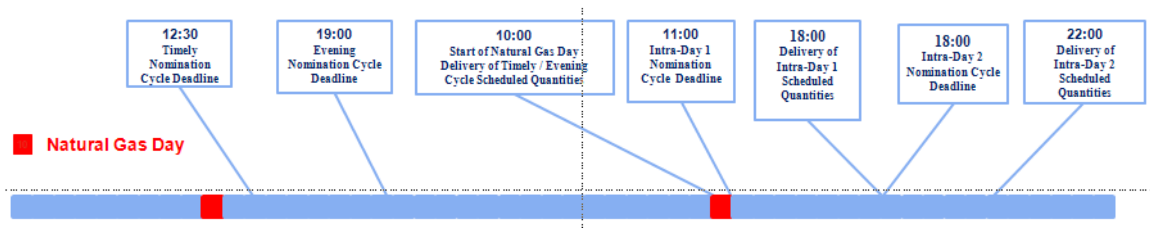


Figure 2-10: Natural gas day and nomination timeline

(Source: ISO New England)

The disparate schedules used by the natural gas and electricity markets pose challenges for natural gas-fired generators. In New England, ISONE's DAM closes at noon, with the results not posted until 4:00 p.m. – well after natural gas-fired generators must submit their initial natural gas demands (at or before 12:30 p.m. for the Timely cycle nomination deadline). In other words, to be assured of natural gas delivery, generators must purchase and schedule natural gas before they know that they have been scheduled to generate electricity. Conversely, when the pipelines indicate that their systems will have constraints the next day, ISONE will not know which generators have a DAM obligation until 4:00 p.m.

The RAA determinations are published at 10:00 p.m. (after the Evening natural gas nomination deadline of 7 p.m.). This can result in a situation where the generating unit committed to generate, but is unable to procure the fuel in subsequent nomination periods. As a result, the generator would be unavailable, leaving ISONE little time to re-commit the replacement energy to reliably operate the power system. The long lead-times required by non-natural gas generators exacerbate the reliability challenges.

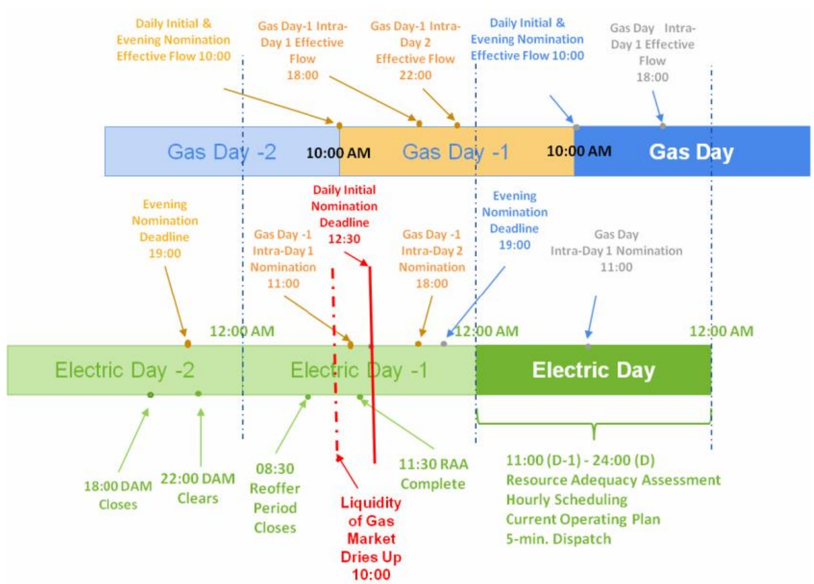


Figure 2-11: Comparison of natural gas and electricity days

(Source: ISO New England)

A comparison of the natural gas and electricity days is shown in Figure 2-11. For each electric operating day, natural gas-fired generators must manage fuel procurement and scheduling spanning two natural gas days. For hours ending 11:00 a.m. through midnight, they can purchase and nominate by the Timely cycle deadline the projected amount of natural gas they expect to use, or wait for ISONE's DAM results and then nominate their respective natural gas demands by the Evening cycle (7:00 p.m.), when there is a higher risk of not being able to schedule natural gas. For hours ending 1:00 a.m. through 10:00 a.m., they must rely on the Intra-Day nomination cycles from the previous natural gas day to schedule their fuel requirements in the overnight hours. There is an even greater risk of not being able to schedule the natural gas within the Intra-Day cycles.

At this time, generators buy natural gas ahead of time for matching their DAM commitment so that they would not be forced to sell any unused fuel portion at loss. This causes problems if load conditions in real-time are materially different than the DAM schedule. Advancing the electric DAM and RAA timelines to precede the natural gas Timely nomination deadline will allow generators to purchase natural gas to meet DAM and supplemental commitments for enhancing the power system reliability. Moving the natural gas day start time from 10:00 a.m. to no later than 4:00 a.m. would allow generators to procure and schedule fuel for their entire daily commitment.

3. Electricity Supply Issues in Relation to the Natural Gas Industry

Scope of work:

Task 3: Provide an explanation of the following electric issues: a. The ability to better integrate variable resources using natural gas facilities; b. The potential for substantial increases in natural gas-fired generation due to issues like rigorous carbon regulation and the associated effect on the nation's utilization of coal-fired power plants; c. The potential implications for electricity industry reliability with an expanded dependency on natural gas.

Deliverable: Explanation of electricity issues including the integration of variable resources, the potential for increases in natural gas-fired generation in light of rigorous current/future carbon and other emissions regulations, and the potential implications for electric reliability with an increased dependence on natural gas.

3.1 Integration of Variable Generation Resources with Natural Gas Units

Natural gas and renewable energy are the two most vital energy resources in the electric power industry's transition to an environmental-friendly operation. The use of natural gas and renewable energy in electric power sector has grown significantly in recent years. The U.S. natural gas consumption by the electric power sector increased from 34% of the total consumption in 2011 to 39% in 2012. Meanwhile, the natural gas-fired units accounted for 40% of the total existing generating capacity in 2012. The attractive utilization of shale gas has introduced the lowest natural gas prices in a decade, which may further expand the investments on natural gas generating plants in electric power systems. Natural gas-fired units are expected to serve more than 50% of the peak electricity demand in the North America by 2015.

On the other hand, renewable (and variable) energy has long held the promise of making significant contributions to the future of electric power systems. In addition, technological advancements in distributed control, off-grid generation and microgrid applications, and various government incentives have demonstrated a rapid growth in renewable energy deployments and utilizations throughout the world. The renewable energy accounted for about 5% of the total installed capacity by 2011, which mainly included wind, geothermal, biomass and solar. The installed wind capacity in the U.S. grew five times between 2005 and 2012 to approximately 50 GW. However, wind energy (including off-shore) remains to be a critical part of electricity supply over the next decades.

Natural gas and renewable energy operations appear to be complementary in many respects concerning fossil fuel price and availability, environmental impacts, variability of renewable resources, and accessibility of such resources in load centers. Hence, the coordination between natural gas and renewable energy in coordinated resource planning would need to be reinforced.

First, natural gas has experienced significant price variations which would directly affect the cost of commitment and generation of generating units. Also a growing level of natural gas consumption by the electric power sector has increase challenges associated with natural gas transmission network planning and operation. A pressure loss or interruption in natural gas pipelines could lead to the loss of multiple natural gas-fired generators and raise the power system security concerns. On the contrary, variable renewable energy units have zero fuel costs and relatively fixed operating cost when adequately distributed throughout a geographic region.

Second, additional environmental emission regulations are being proposed to promote the further use of clean energy in the near future. Renewable energy will not be subject to certain environmental constraints which offer additional benefits to long-term electric power system operations. Accordingly, the proliferation of natural gas-fired and renewable energy units in electric power systems could be heightened as more stringent low-carbon thresholds are enforced globally.

Third, while the renewable generation does not incur fuel costs or emission caps, it experiences resource variability and low capacity factor values. These uncertain characteristics of renewable energy introduce new challenges and additional costs to the power system operations. The variability of large-scale wind energy may have intense impacts on power system operations. The natural gas units can offer flexible dispatch and quick ramping capability in such cases for firming power system operations.

Consider a case when the available wind energy of 96MW representing 30% of a power system capacity. Figure 3-1 shows the available load and wind energy forecasts. In Table 3-1, load shedding occurs when the wind energy is below 20MW at peak hours 16 and 17. In such cases thermal units are dispatched at hour 16 with additional load shedding for compensating the lower availability of wind energy. The ramping capability of thermal units would accommodate the wind energy variability for maximizing the utilization of wind generation. Figure 3-2 shows that higher rates of thermal ramping would accommodate a higher level of wind energy.

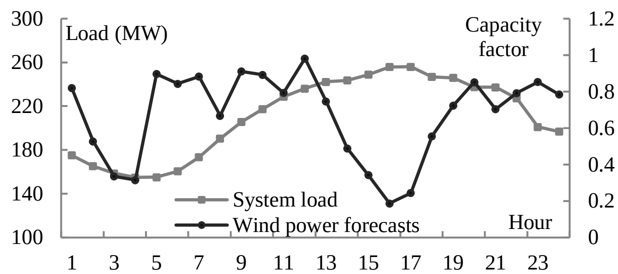


Figure 3-1: Load profile and wind energy forecasts

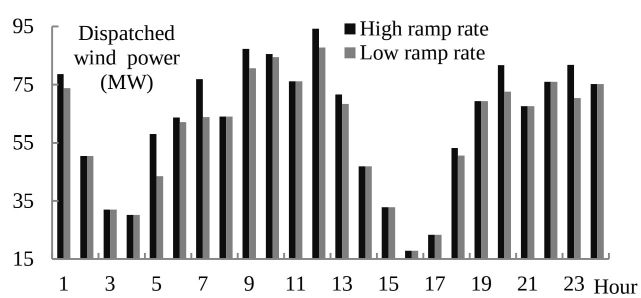


Figure 3-2: Hourly dispatched of wind energy unit

In Table 3-2, the wind energy penetration level is varied from 5% to 30%. However, the total system capacity will remain the same by lowering the thermal capacity. In Table 3-2, the daily operation cost decreases when the wind energy penetration is smaller than 15%. This is because the wind energy would accommodate the power system with a quick ramping of thermal units while wind energy does not incur any fuel costs. However, load shedding occurs at higher daily production costs when the wind energy penetration reaches 20%. This is mainly caused by a lower level of wind energy at hours 16 and 17 when the quick-ramping capability is insufficient for picking up the load supplied by wind energy. While the variable wind energy does not incur any fuel costs, it does experience dynamic resource variability in an hourly or shorter time scale. This example support the notion that a balanced electricity portfolio with conventional supply (e.g., natural gas) and renewable energy can result in a continuous optimization of generation resource availability, fuel cost, and environmental requirements.

Table 3-1: Hourly dispatched wind energy

Hour	Wind power (MW)	Load shedding (MW)	Hour	Wind power (MW)	Load shedding (MW)	Hour	Wind power (MW)	Load shedding (MW)
1	78.69	0	9	87.37	0	17	23.41	13.71
2	50.56	0	10	85.61	0	18	53.26	0
3	32.12	0	11	76.11	0	19	69.35	0
4	30.18	0	12	94.26	0	20	81.72	0
5	58.16	0	13	71.68	0	21	67.56	0
6	63.69	0	14	46.87	0	22	76.04	0
7	76.86	0	15	32.81	0	23	81.86	0
8	64.04	0	16	17.93	18.97	24	75.27	0

Table 3-2: Results for wind penetration levels

Wind penetration (%)	5%	10%	15%	20%	25%	30%
Wind unit cap. (MW)	16	32	48	64	80	96
Daily product. cost ($)	92104	85120	80722	78232	75896	73497
Load shedding (MW)	0	0	0	4.15	15.95	32.68
Load shedding cost($)	0	0	0	4150	15950	32680
Total cost	92104	85120	80722	91847	106177	115516

3.2 Carbon Emission in Electricity System with Natural Gas System

The majority of the world's electricity is currently produced by fossil fuel. However, fossil fuel is not readily available in every country and it pollutant. Renewable energy can be a potentially less expensive and cleaner alternative to fossil fuel; though it also poses some physical constraints. Sunlight, wind, hydro, tides, waves and geothermal energy are used to some extent for power and heating applications. According to IEA, the total consumption of renewable sources in the United States is about 9 quadrillion Btu in 2012 which is about 12% of the U.S. electricity production. However, variability has long been the Achilles' heel of renewable energy. Solar energy is available only when the sun is shining and a wind turbine will be in the idle mode when the wind is not blowing. Furthermore, wind energy is not dispatchable. The output of powers

Natural gas-fired unit with its flexible operation and fast ramping capability represents a key solution to renewable power variability. Some natural gas turbines can cold start in five minutes. This flexibility would offer additional values for generating energy and ancillary services. A balanced generation portfolio of thermal and renewable energy assets can adjust supply loads based on continuous optimization of resource availability, physical and financial limitations, and emission requirements.

In recent years, a number of emission regulations affecting power plants have been proposed or finalized. While judicial reviews have delayed implementation and prompted the reconsideration of certain regulations, the broad industry expectation of environmental regulations have accelerated the scheduled retirement of aging coal plants and reinforced the belief that no new coal plants will be built in the near future unless their emissions can be reduced by carbon capture and sequestration, an as yet unproven and costly technology.

Figure 3-3 compares the thermal efficiencies of natural gas and coal power plants. Since about 2000, the penetration of combined-cycle natural gas (CCNG) power plants has increased the efficiency of natural gas units, and a new set of strict environmental regulations and policies have further decreased coal power plant energy efficiencies. EIA reports that carbon emission of coal and natural gas units are 95 and 53 kgCO2/MBtu respectively. The combination of carbon factors and thermal efficiency has contributed to the carbon emission differences per unit power generation of coal and natural gas. Fuel switching capability of thermal units can potentially curbed power plant emissions and increase the plant efficiency.

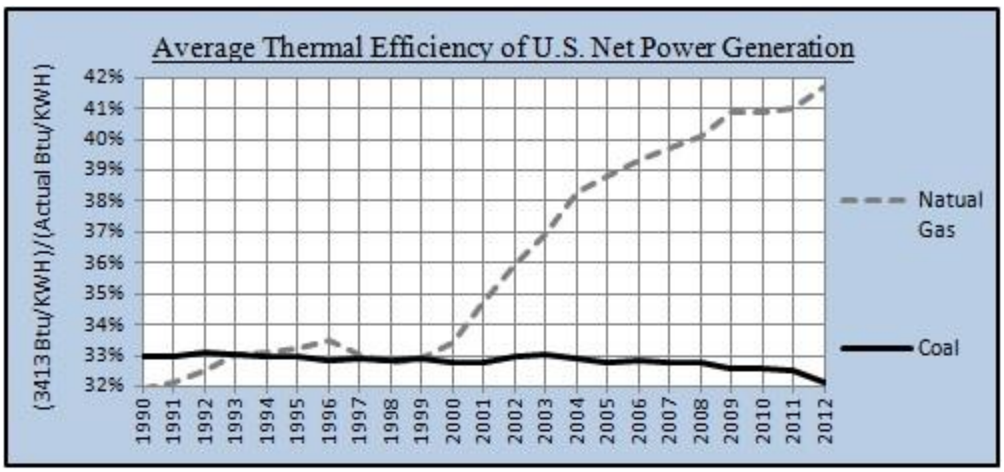


Figure 3-3: Average thermal efficiency

(Source: EIA MER data Tables A2.6 and 7.2b.)

Figure 3-4 shows that complying with stricter regulations on sulfur dioxide, particulate matter, nitrogen oxide and mercury, could make nearly two-thirds of the nation's coal-fired power plants as expensive to run as natural gas plants. Figure 3-5 and Table 3-3 show the annual progressive natural gas marketed production in 2004 -2013. Natural gas appears to be plentiful with low prices for supplying electric power plants, which is due to the increased production from shale. According to EIA, the 2008 wellhead price of natural gas was approximately $8.00/MBtu and by 2035, natural gas will cost approximately $6.00/MBtu.

According to EIA, in 2035, twenty five percent of electricity will be generated from natural gas. The New England region’s electricity during the 1990s was produced primarily by oil, coal, and nuclear generating plants. In 2011, approximately 51% of New England’s electricity was produced by natural gas-fired plants as compared to approximately 5% of energy twenty years earlier. According to the EIA, power generated from renewable resources will be increased by 1.7% annually between 2010 and 2023. This trend is expected to hold as the price of natural gas continues to be low.

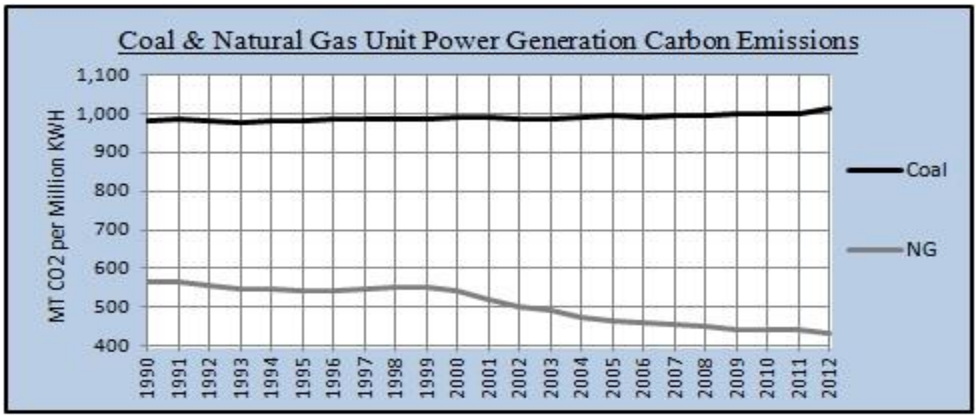


Figure 3-4: Coal and natural gas carbon emissions

(Source: EIA MER data Tables 12.6 and 7.2b.)

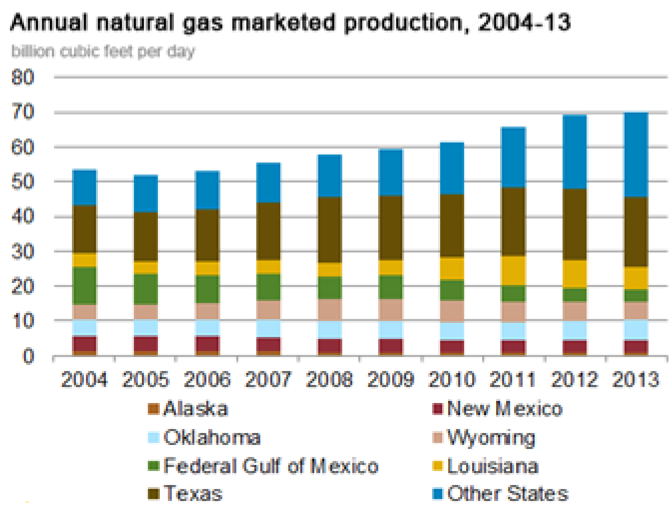


Figure 3-5: Annual natural gas production

(Source: EIA natural gas annual)

Table 3-3: Natural gas-fired power generation

Year	Natural gas-fired power generator(BKWh)	Year	Natural gas-fired power generator(BKWh)
2014	1,113.03	**2024**	1,230.88
2015	1,131.83	**2025**	1,252.49
2016	1,226.23	**2026**	1,274.24
2017	1,201.89	**2027**	1,306.12
2018	1,187.60	**2028**	1,329.39
2019	1,186.75	**2029**	1,352.49
2020	1,184.50	**2030**	1,379.39
2021	1,188.85	**2031**	1,412.82
2022	1,195.23	**2032**	1,444.19
2023	1,209.58	**2033**	1,472.32

(Source: Energy Information Administration)

Although having desirable attributes, natural gas has other attributes that limit its desirability. For one, natural gas must be piped to market and, thus, pipelines are essential. The availability of pipeline capacity can be limiting in the natural gas life-cycle.

3.3 Electricity Reliability Issues with Natural Gas System

In general, the natural gas system is reliable for the electricity supply due to the following reasons:

- Since the natural gas system is underground, the probability of its outage is lower;
- Many compressor stations that maintain the pipeline pressure are powered from the natural gas in the pipelines themselves, allowing continued operation;
- Interruptible delivery contracts can be curtailed, further reducing demand. Risk of interruptions to natural gas supply during this type of outage can be reduced by enrolling in firm delivery contracts with transmission companies;
- Most natural gas appliances work even when the electricity is out. In addition, demand for natural gas would decrease if the natural gas-fired electricity generation becomes offline.

However, because natural gas is largely delivered on a just-in-time basis, vulnerabilities in natural gas supply and transportation from a planning perspective must be sufficiently evaluated to inform the operators about credible contingencies and flexibility options. As supply chains multiply and lengthen, these infrastructures have become increasingly vulnerable to both malevolent attacks and natural disasters. Pipelines, processing facilities, LNG terminals and tankers are “soft targets,” i.e. easy to locate and destroy, usually undefended and vulnerable to attacks, including cyber attacks. As shown in Figure 3-6, the supervisory control and data acquisition (SCADA) systems is created to monitor the operation of the natural gas system and transmit a set of important parameters such as natural gas pipeline pressure, valves parameters and so on to the control center. The control center then uses these data to locate and operate compressors, valves, switches, pressure settings, and other pipeline operations for the purpose of economic operation and reliability.

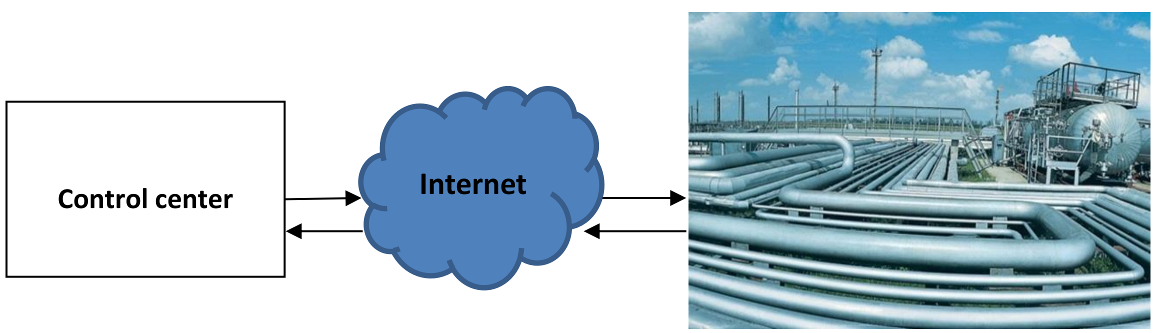


Figure 3-6: Natural gas control systems

Due to the open access of the communication, an attacker can use a lot of spying techniques to obtain the sensitive information of the operational and technical details. With knowing the sensitive information of the operational and technical details, the attacker can launch a cyber attack to control, or alter the operation of the pipelines, including usernames, passwords, personnel lists, system manuals, and pipeline control system access credentials. Furthermore, an attacker can use the data to blow up compressor stations, sabotage natural gas pipelines through extreme pipeline pressures or unsafe valve settings that could result in explosions or other critical failures.

According to several studies on cyber securities in power systems [18]-[19], it is believed that the natural gas system may also be vulnerable to cyber attacks and could be easily attacked by attackers without knowing too much information. Thus, defenders must develop effective protection strategies to mitigate the high risk of cyber attacks. First, policies and procedures should be formalized to provide a foundation for achieving the desired level of security. Next, it is suggested that a scheme for the optimal protection, which is composed of three steps including identifying critical components, assessing risk, and applying appropriate countermeasures, should be implemented to enhance the security of a company's sensitive assets. The scheme is illustrated in Figure 3-7.

In the natural gas systems, there exist a set of critical components whose failures would lead to the severe damage effects for the system. Estimates of the potential consequences, including economic implications, of not mitigating identified vulnerabilities or addressing security concerns are necessary in order to effectively apply risk management approaches to evaluate mitigation and security recommendations. The procedure of determining the critical components is shown in Figure 3-8. We assign each component a binary variable v_i. Component i is attacked if $v_i=1$ and not attacked otherwise. Then, a corresponding mixed integer programming problem can be formulated to determine the most damaging component j. In the next iteration, set $v_j=0$ which represents component j will not be a candidate component any more. In other words, the most damaging component in the next iteration would be the second most damaging component. Therefore, the defender can rank the top-k critical components by k iterations.

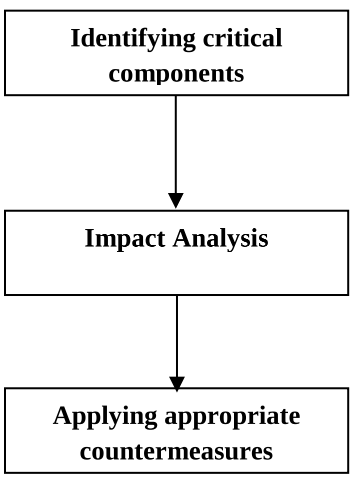


Figure 3-7: Flowchart of the optimal protection strategy

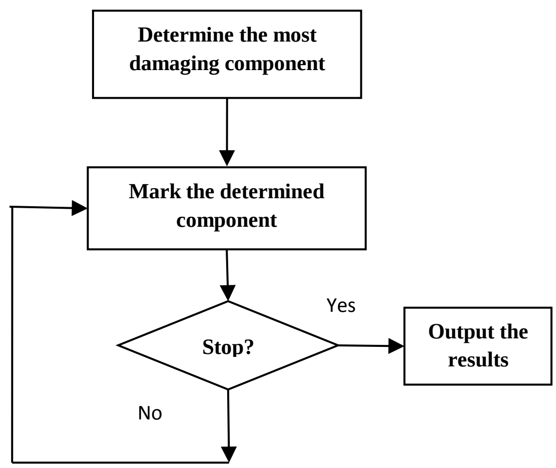


Figure 3-8: Flowchart of an optimization model to determine the critical components

Considering the vulnerability of the natural gas infrastructure, effective protection strategies should and must be set up against cyber attacks on the natural gas infrastructures. It is suggested that the damage effects can be mitigated by increasing the attacking cost of an attacker such that the attacker cannot launch an attack due to limited capacity. In practice, the attackers must pay certain cost to attack the target. For example, in order to attack a power station, the attackers have to employ teammates, buy necessary tools and so on. In fact, if the defenders deploy a budget to protect one component of a power system, the attackers have to use more resources to attack the target. Therefore the attacking cost of the component increases. Obviously, the more budget the defenders deploy to the component, the higher the attacking cost of the component becomes.

Assume that an attacking plan consists of m component, whose attacking cost is $C_1, \cdots, C_m$ respectively, and the attackers have an attacking capacity. If the attackers can carry out the attacking plan successfully, the following conditions must be satisfied: $R \geq \sum_{l=1}^{m} C_l$. From the perspective of protection, if the defenders aim to defeat the attacking plan, they should deploy budgets to a set of lines in the plan, making the attacking cost of the plan greater than R, i.e., $\sum_{l=1}^{m} C_l > R$.

Thus, the defenders' objective is to reduce the damage effect due to intentional attacks. If the defenders are going to limit the damage effect caused by attacks to an expected level LS, how much budget is needed? Which lines should be protected? Another possible protection strategy is to secure the critical information that an attacker needs to launch a successful attack. However, this must be dependent on the analysis of how much information is needed if an attacker aims to attack a component. After the critical information for each component is determined, the least information to be protected can be determined by solving an optimization problem. The principle is illustrated in Figure 3-9. Suppose the critical information of components 1, 2, 3 are S_1, S_2, S_3, then the protected information is the intersection $S = S_1 \cap S_2 \cap S_3$.

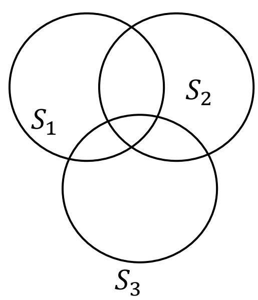


Figure 3-9: Illustration of Critical information

4. Contracting Issues for Natural Gas and Electricity Industries

Scope of work:

Task 4: Detail the contracting procedures and issues for the natural gas and electricity industries. The Subcontractor shall provide a discussion of: (i) typical contract process that reflects the operational requirements of both industries; (ii) typical terms and conditions for power generators purchasing natural gas (the commodity, pipeline, storage); (iii) potential changes being considered by the natural gas industry in their contracting procedures to better accommodate the range of operating requirements of electric generators; (iv) potential changes being considered by the electricity industry in their contracting procedures to better accommodate the natural gas industry's operating requirements; (v) an independent assessment of what changes in the natural gas and electric contracting process, terms, and conditions that might better accommodate operational requirements in both industries; (vi) address if there is a role for RTOs/ISOs to facilitate contracting and construction of required facilities; (vii) address if there is a constructive role for states to facilitate contracting and construction of required facilities?

Deliverable: Discussion of items (i), (ii), (iii), (iv), (v), (vi), and (vii), as described above

4.1 Basics of Natural Gas Contracts

Deregulation has changed the structure of the natural gas industry in the United States. Before 1985, the industry was vertically separated into production, pipeline transportation, and distribution. Distribution companies could not choose a pipeline company unless their long-term supply contract had expired. Most marketed natural gas production was sold under long-term take-or-pay contracts between natural gas producers and pipeline companies. The introduction of open access to interstate pipeline transportation in 1985 limited the use of long-term contracts and introduced competition to the wholesale natural gas market. The unbundling of interstate pipeline transportation in 1992 completed the transformation of the wholesale operation into a fully competitive market. In the current competitive wholesale natural gas market, trading takes place through bilateral decentralized transactions among producers, marketers, LDCs, and large end-users.

The deregulation of the natural gas industry has facilitated the separation of physical and financial trading. As a result, two distinct markets have been developed in the wholesale natural gas market in the United States: a physical natural gas market, where contracts for physical natural gas delivery are traded, and a financial natural gas market, where contracts for price risk management are traded.

4.1.1 General Terms and Conditions in Natural Gas Contracts

The following terms are generally used in natural gas contracts.

- A ***British Thermal Unit (Btu)*** is the amount of energy required to raise the temperature of one pound of water by one degree Fahrenheit. This is the most common unit used for buying and selling natural gas.
- ***Alternative Damages*** means such damages, expressed in dollars or dollars per MMBtu, as the parties shall agree upon in the transaction confirmation, in the event either seller or buyer fails to perform a firm obligation to deliver natural gas in the case of seller or to receive natural gas in the case of buyer.
- ***Business Day*** refers to any day except Saturday, Sunday or Federal Reserve Bank holidays.

- ***Confirm Deadline*** means 5:00 p.m. in the receiving party's time zone on the second business day following the day a transaction confirmation is received, provided, if the transaction confirmation is time stamped after 5:00 p.m. in the receiving party's time zone, it shall be deemed received at the opening of the next business day.
- ***Contract Price*** means the amount of dollars per MMBtu as evidenced by the transaction confirmation.
- ***Base Contract*** means a contract executed by the parties that incorporates general terms and conditions, specifies agreed selections of provisions, and sets forth other information required herein and any special provisions and addendum(s) as identified by the parties.
- ***Contract Quantity*** means the quantity of natural gas to be delivered and taken as agreed to by the parties in a transaction.
- ***Cover Standard*** means that if there is an unexcused failure to take or deliver any quantity of natural gas pursuant to a contract, then the performing party shall use commercially reasonable efforts to (1) if buyer is the performing party, obtain natural gas, or (2) if seller is the performing party, sell natural gas, in either case, at a price reasonable for the delivery or production area, as applicable, consistent with (1) the amount of notice provided by the nonperforming party, (2) the immediacy of the buyer's natural gas consumption needs or seller's natural gas sales requirements, as applicable, (3) the quantities involved, and (4) the anticipated length of failure by the nonperforming party.
- ***Credit Support Obligation*** means any obligations to provide or establish credit support for, or on behalf of, a party to a contract such as a standby letter of credit, a margin agreement, a prepayment, a security interest in an asset, a performance bond, guaranty, or other good and sufficient security of a continuing nature.
- ***Delivery Period*** is the period during which deliveries are to be made as agreed to by parties in a transaction.
- ***Delivery Point*** means such points as are agreed to by parties in a transaction.
- ***EDI*** shall mean an electronic data interchange pursuant to an agreement entered into by parties, specifically relating to the communication of transaction confirmations under a contract.
- ***EFP*** means the purchase, sale or exchange of natural gas as the physical side of an exchange for physical transaction involving natural gas futures contracts. EFP shall incorporate the meaning and remedies of Firm, provided that a party’s excuse for nonperformance of its obligations to deliver or receive natural gas will be governed by the rules of the relevant futures exchange regulated under the Commodity Exchange Act.
- **Commodity Exchange Act (CEA)** regulates the trading of commodity futures in the United States. The CEA establishes the statutory framework under which the U.S. Commodity Futures Trading Commission operates and has authority to establish regulations that are published in title 17 of the Code of Federal Regulations.
- ***Firm*** means that either party may interrupt its performance without liability only to the extent that such performance is prevented for reasons of Force Majeure; provided that the party invoking Force Majeure be responsible for any imbalance charges.
- ***Imbalance Charges*** mean any fees, penalties, costs or charges assessed by a transporter for failure to satisfy the transporter's balance and/or nomination requirements.
- ***Interruptible*** means that either party may interrupt its performance at any time for any reason, whether or not caused by an event of Force Majeure, with no liability, except such interrupting party may be responsible for any imbalance charges.
- ***Spot Price*** means the price listed in the publication indicated on the base contract, under the listing applicable to the geographic location closest in proximity to the delivery points for the relevant day;

provided, if there is no single price published for such location for such day, but there is published a range of prices, then the spot price shall be the average of such high and low prices. Otherwise, the spot price shall be the average of the following: (1) the price for the first day for which a range of prices is published that next precedes the relevant day; and (2) the price for the first day for which a range of prices is published that next follows the relevant day.

- ***Termination Option*** means the option of either party to terminate a transaction in the event that the other party fails to perform a firm obligation to deliver natural gas in the case of seller or to receive natural gas in the case of buyer for a designated number of days during a period as specified on the applicable transaction confirmation.

4.1.2 Transportation Market and Service Contracts

Natural gas is transported to natural gas-fired plants through natural gas transportation system based on predefined transportation service contracts. A natural gas transportation market is where the pipeline capacity and transportation services are traded. The interstate pipeline transportation market is the most competitive transportation market in the United States because of the unbundling of this industry segment. The supply side of the market consists of interstate pipeline companies, and the demand side of shippers that purchase pipeline transportation capacity from pipeline companies. Shippers are usually marketers, LDCs, producers, or large end users. Natural gas transaction takes place through contracts that consider transportation conditions for the natural gas delivery.

There are two main transportation markets in the United States which include a primary and a secondary market. In the primary market pipeline companies sell transportation contracts to marketers, LDCs, or end users. Typical services are firm, no-notice, and interruptible transportation. In the secondary market pipeline companies and holders of transportation contracts resell unused capacity as firm or interruptible rights. The U.S. interstate transportation market for natural gas is regulated by FERC.

The primary transportation market facilitates the initial distribution of transportation contracts. Pipeline companies sell transportation contracts to shippers at prices that are regulated by FERC. Transportation contracts differ primarily based on the reliability, timing, and location of natural gas delivery. Shippers purchase transportation contracts in combinations that allow them to achieve the desired level of service reliability at the minimum cost and to take advantage of time and locational price differentials in the natural gas market.

The deregulation of the U.S. natural gas industry has led to the development of transportation contracts that differ in many dimensions. The most important and frequently used contract dimensions are reliability of transportation service, time and duration of shipment, location of points of injection and withdrawal, pipeline pressure, and charges for pipeline capacity and transportation services. The contracts most commonly used in the U.S. natural gas industry are of four types:

- ***Firm transportation contract***: contract that gives its holder the right to pipeline capacity and transportation of natural gas during the entire duration of the contract, regardless of the season. A firm transportation contract specifies the maximum daily quantity of natural gas that can be transported through the pipeline, the points of injection and withdrawal, and the charges for reserved capacity and transportation services. The holder of a firm contract may use all or part of the reserved capacity, depending on its needs, but if it exceeds the maximum daily quantity, it will incur a penalty.
- ***No-notice firm transportation contract***: contract that gives its holder the right to pipeline capacity and transportation of natural gas under the conditions specified in the contract. The main difference

between regular and no-notice firm contracts is that the holder of a no-notice contract is not required to maintain a daily balance between nominated and delivered natural gas (for more information on nominating and balancing natural gas, see the section below on the optimization of pipeline operation).

- ***Limited firm transportation contract***: contract that provides for limited firm service, which is subject to interruption for a specified amount of time each month, for example, up to 10 days a month. This contract is designed to offer less expensive firm service to customers that can tolerate greater risk of delivery interruption and is often used by customers with fuel-switching capability.
- ***Interruptible transportation contract***: contract that gives its holder the right to transport an agreed on volume of natural gas within a certain period. The exact timing of transportation is determined by the pipeline company according to the availability of capacity.

Currently, although generators have an obligation to perform in accordance with their offers and their declared operating characteristics, the performance incentives in the wholesale electricity market design are not strong enough to cause generators to procure firm fuel supplies (natural gas or oil) and to operate in accordance with their obligations.

Most natural gas-fired generators have made business decisions to purchase interruptible natural gas delivery service. Pipeline delivery service tariffs for firm service typically contain a fixed monthly charge for reserving capacity that is not recovered from the electric marketplace for the low capacity factor operation typically seen by combustion turbine generation in peaking service. Thus, it is economically infeasible for a peaking generator to make capacity reservation payments for firm service that it cannot recover from its sales of electricity. Unlike firm service, which has a fixed monthly reservation fee paid to reserve capacity, interruptible service is priced solely on a volumetric basis. The shipper only pays for the volume of transportation service that it receives. This is an attribute that is often desirable for power generation customers of the pipeline, particularly those that have relatively low annual capacity factors. In addition, the regional availability of transportation service for natural gas is also a factor. Due to traditional supply arrangements and supply availability, firm natural gas supply cannot be obtained at any cost in some regions. Therefore, economics is not the sole reason a generator may not hold firm natural gas transportation.

Under average annual operating conditions, most pipelines have some level of capacity that is not used by firm customers and is therefore available for non-firm (interruptible) loads, including natural gas generators with non-firm contracts. If the requirements for non-firm deliveries are communicated to the pipeline within the nomination cycle timeline, the pipeline can use facilities to allow for delivery of natural gas requested up to the physical capabilities the system can allow. This is the normal procedure for interruptible transportation service or capacity release from firm shippers. In some power markets or regions where there is excess natural gas pipeline capacity available, these low capacity factor units can rely upon interruptible service with a reasonable degree of certainty that service will be available.

However, as growth in natural gas system requirements in a region reaches the point where new pipeline capacity is required or when market conditions result in simultaneous peak electricity and natural gas demand, the availability of interruptible service capacity has declined. If such a generator served by interruptible transportation has no alternative source of fuel, then that generating capacity could be unavailable to the electric grid at peak times. Meanwhile, the differences in the structures of the two industries can result in a mismatch between the availability of natural gas delivery services and natural gas demand for electricity generation. This can be particularly challenging in areas where a significant amount of the generation capacity, or more importantly reserve capacity is susceptible to natural gas transportation interruptions and the resulting generator outages.

4.1.3 Physical Natural Gas Contracts

Natural gas is traded through bilateral natural gas contracts that specify delivery conditions. These contracts have many dimensions that are determined by the conditions of natural gas supply, the most important being volume, unit price, calorific value, and location, time, and duration of delivery. Natural gas supply contracts differ a great deal in almost all these dimensions. But the main differentiation in natural gas contracts is the duration of supply. Three main types of natural gas contract were developed after the deregulation, which include long term, medium term, and short term contracts.

- ***Long-term natural gas contract*** is usually responsible for deliveries and receipts which are longer than 18 months. The contract is traded at a fixed quantity of natural gas to be delivered on a monthly basis. The contract is used primarily by firms that require reliable and long-term commitment to natural gas supply.
- ***Medium-term natural gas contract*** is usually responsible for deliveries and receipts which are a year or shorter. The contract usually specifies the volume of monthly or daily natural gas deliveries, including allowed variation.
- ***Short-term natural gas contract*** is usually responsible for deliveries and receipts which are a month long. The contract is traded on in spot market and specifies a natural gas price equal to the prevailing market price at the time of contract completion.

4.1.4 Financial Natural Gas Contracts

Financial natural gas contracts are used to manage two types of risks in natural gas markets: price risk and basis risk. Price risk is generated by the volatile spot market prices of natural gas. Basis risk is the risk of change in the price differential between locations, time periods, and qualities of natural gas deliveries and between natural gas and other commodities. Financial natural gas contracts include:

- ***Futures contract*** is a standardized, exchange-traded contract between a buyer and a seller for the delivery of a particular quantity of a commodity at a predetermined price on a future delivery date. Futures contracts are traded on regulated exchanges and are settled daily based on their current value in the marketplace.
- ***Swap contract*** is a custom-tailored, individually negotiated transaction which aims to manage financial risks for about 1 to 12 years. Swaps can be conducted directly by two counterparties or through a third party such as a bank or brokerage house.
- ***Option contract*** gives its holder the right, but not the obligation, to purchase or sell the underlying futures contract at a specified price within a specified period in exchange for a one-time premium payment.
- ***Hedge*** is a position taken in the financial market to offset a position in the physical market.

4.1.5 Typical Contracting Procedures

There are two typical contract procedures: oral transaction and written transaction.

- ***Oral Transaction Procedure***: The parties will use the following transaction confirmation procedure in an oral transaction. Any natural gas purchase and sale transaction may be accomplished in a mutually agreeable electronic means with the offer and acceptance constituting the parties' agreement.

- ***Written Transaction Procedure***: The parties will use the following transaction confirmation procedure in a written transaction. The parties should come to an agreement regarding a natural gas purchase and sale transaction for a particular delivery period. The confirming party shall, and the other party may, record that agreement on a transaction confirmation and communicate such transaction confirmation by a mutually agreeable electronic means, to the other party by the close of the business day following the date of agreement. If there are any material differences between timely sent written transaction confirmations governing the same transaction, then neither transaction confirmation shall be binding until or unless such differences are resolved.
- ***Enhancement of Information Communications***: To facilitate a better environment of contracting in natural gas market, ISOs are making a set of changes in information communication policies that would allow the wider sharing of information. The enhancement would improve the system operator's ability to make more accurate determinations both of an individual generator's, and the wider region's ability to meet its electricity supply obligations. Such changes, together with improved communication and coordination of the scheduling of planned maintenance, would provide regional electricity system operators, with an enhanced understanding of the limitations that natural gas-fired generators may be operating under and improved ability to dispatch the electrical system to mitigate physical constraints.
- ***Flexibility Clause***: The flexibility clause is a method to commit producers to sell output above the long-term contract at the indexed price, because all energy sold within the contract arrangement is sold at the predetermined price. The clause states that the deliveries could be above the obligatory take-or-pay element in long-term natural gas contracts which typically consists of 80% of the nominal quantity of the contract. The option provide for an increase in delivery by 40% points of the nominal quantity of the contract at a similar price level. Natural gas sector deregulation, coupled with oversupply of natural gas, weakens the strategic role of the flexibility clause.
- ***Align the Timing of Regional Electricity and Natural Gas Markets***: In the current market, there is a difference of the timings frames between the natural gas and electricity markets. On the electric side, generating units are committed first through a Day-Ahead Market (DAM), which operates one day prior to the delivery day. The DAM, as a forward market, is to provide a platform for generators for hedging the price volatility to provide a base unit commitment schedule for the operating day. However, the natural gas industry adopts a different time frame. Natural gas is traded in separate transaction between 8:00 and 9:00 a.m. on the day prior to the electric operating day. Natural gas transport is nominated and scheduled on a one-day advance basis, using a 24-hour natural gas day from 10:00 a.m. to 10:00 a.m. Eastern Standard Time. Nominations fall into three categories: Timely, Evening, and Intra-day. As a result, generators have to make a fuel commitment before knowing if their supply offer has been accepted. If the offer has been declined, the generator will not generate the power according to the offer. To address the problem, a few ISOs are proposing to envisage the adjustment of the DAM timing for making generating schedules available earlier to allow generators to commit to the purchase of the appropriate amount of natural gas to meet their accepted supply offer. Such a change would not only benefit the pipeline operators, but also facilitate natural gas-fired generators' ability to secure natural gas for each electric operating day.
- ***Allow Generators More Flexibility to Reoffer***: In practice, some natural gas-fired generators will choose to consume more natural gas than they have nominated before the operating day. In most cases, the impact of generators' withdrawal of more natural gas than they have nominated is not significant if the pipeline has sufficient capacity to deliver the natural gas and time to recover from the over-draw before the next operating day. However, for the cases of pipeline maintenance, outages or heavy demands, the impact would be significant. Considering the natural gas price

volatility, market participants should be allowed to revise their offers into the electricity DAM for a limited period and not during the actual operating day the offer refers to. By doing so, the output of power of generators can be redispatched. In other words, the generators should generate less power or not generate when the offers are below their production cost. This change in contracts can better accommodate both the natural gas and electric operational requirements.

- ***CO2 Reduction Policy Designed to Create a Level Playing Field***: To maximize the value to society of the substantial U.S. natural gas resource base, a more stringent carbon emission reduction policy is considered to create a level playing field, in which all energy technologies can compete against each other in an open market place conditioned by legislated CO2 emissions goals. This would probably require the complete de-carbonization of the power sector which makes it imperative that the development of competing low-carbon technology continues apace. However, a major uncertainty that could impact this picture in the longer term is a technology development for lowering the cost of alternatives, in particular, renewables, nuclear and carbon capture and sequestration.
- ***Integrated Global Natural Gas Market***: Currently world natural gas trade is concentrated in three regional markets: North America, Europe and Asia. The natural gas trade is limited among them. Different pricing structures hold within these regional markets. For some transactions, prices are set in liquid competitive markets; in others they are dominated by contracts linking natural gas prices to prices of crude oil and oil products. The increasing demand for natural gas consumption due to rising world energy prices leads to the emergence of numerous local or national natural gas markets. As a result, policy makers aim to enhance the connections and integrations between various natural gas markets. The development of new technologies of natural gas production and transportation and the expansion of LNG trade has made it possible for the emergence of a global natural gas market where natural gas can be sold at spot prices or with long term contracts. Natural gas production in the most developed markets is stepping into the stage of the depletion. And in some regions, natural gas has not been fully developed although it has a large amount of reserves. Thus, it is necessary for accelerating the process of the integration of global natural gas market. With the tendency of both economy and global security, the U.S. is considering making policies to encourage an integrated global natural gas market, governed by economic considerations. As a result, natural gas suppliers and consumers would operate on an economic basis, no effective natural gas cartel is formed, and suppliers exploit their natural gas resources for maximum national economic gain.
- ***Hard Expiration Position Limits***: An Exchange could impose hard expiration position limits on its natural gas financially settled contracts. The limits would subject natural gas contract to more oversight, allowing the Exchange to better track trading in the contract and prevent market manipulation. This plays an important role in setting the price for the underlying commodity. Natural gas contract would also be subject to position limits and accountability levels, which restrict the number of contracts certain traders can control at any one time. Regulators are looking for ways to curb excessive speculation in commodity markets, particularly in energy where crude oil and natural gas prices could spike excessively amid potential market manipulation.
- ***A Proper Mix of NG and LNG Contracts***: In Alaska, the local utilities have entered into long-term contracts with local natural gas producers that use a price index to other locations or products since there are no local spot markets. Among the indices used in these natural gas contracts are NYMEX natural gas futures, NYMEX crude oil futures, and lower-48 production indices. These contracts have provisions that are designed to smooth the price of natural gas rather than make them subject to daily or monthly volatility. Some contracts adjust only annually, while others adjust quarterly, based on simple averages of the indices over specified time periods. In essence, some contracts may take a simple average of the index prices over the 36-month period prior to the annual adjustment date.

Others may take averages of the indexes over the prior 3 months, and adjust either annually or quarterly. However, many of these contracts are subject to price caps and price floors to further limit volatility.

4.2 RTO/ISO and State Participation in Natural Gas Contracting

4.2.1 Participate in the Mitigation of Natural Gas Price Volatility

Natural gas price volatility poses a challenge to the natural gas industry and its consumers. Volatility is a measure of the pace and magnitude of price changes. Price changes send signals to consumers and producers that would lead them to adapt their behavior to match market conditions. Consumers tend to consume more when prices are lower and less when prices rise. Higher natural gas prices tend to encourage the availability of additional supply, while lower prices tend to discourage the additional supply. Well-functioning and transparent commodities futures markets provide natural gas producers and consumers the ability to mitigate price volatilities.

North American natural gas markets, with its vast domestic supplies, have been relatively insulated from global supply and demand shocks. Despite this, there have still been fluctuations in the U.S. natural gas prices due to supply and demand imbalances, especially in the past decade. Figure 4-1 shows the natural gas prices at the Henry Hub in U.S. Dollars per MMBtu for the period of 1998-2014. Here, the price has a significant fluctuation with several price spikes.

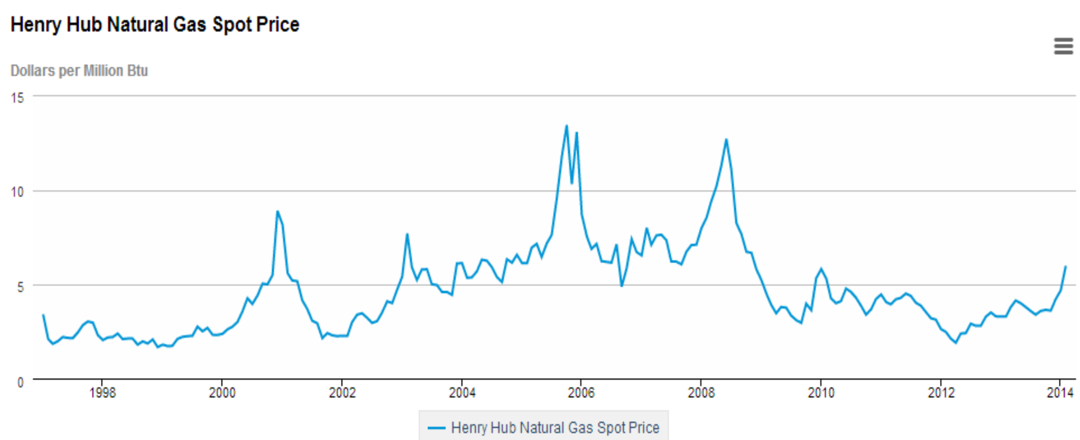


Figure 4-1: Natural gas prices at the Henry Hub in U.S. dollars per MMBtu, 1998-2014

(Source: U.S. Energy Information Administration)

Electricity price uncertainty poses a risk to natural gas contracts. Therefore, to encourage trades across borders, there must be the possibility for electricity market participants to hedge the risk of price volatility through FTRs issued by ISOs or service providers acting on ISOs' behalf. An FTR (financial transmission right) is a contract between a market participant and the ISO, which is related to network capacity and entitles its holder to claim the price difference between two price zones, i.e. the value of access to the interconnector at that time. FTR is designated by an amount from a source node to a sink node in the network, and is valid over a defined period of time. FTRs, which do not provide exclusive rights over a transmission pipeline, can be acquired through auctions or in a secondary market. Once the market participants have submitted their FTR bids and offers to the auction, the ISO allocates the FTRs by solving an optimization problem that maximizes the FTR sales revenue subject to network capacity constraints.

4.2.2 Participate in the Optimization of Pipeline Scheduling and balancing

Pipeline scheduling is the process of determining the optimal flow schedule — the order and the direction of natural gas flows in the pipeline systems that minimize the total cost of transportation and delivery. Balancing is the process of maintaining and restoring the balance in the pipeline system and individual shipments. Natural gas is moved through pipelines from natural gas producers or wells to end customers, which entail natural gas producers, pipelines, underground storages, compressors, and valves. A natural gas well is commonly located at sites which would be far from load centers.

The optimal pipeline operation is achieved through scheduling, balancing, central dispatch, and emergency control of natural gas flows in the pipeline system. The natural gas pipelines have similar functions as those of the electric transmission network. A pipeline company carries out these activities by acquiring information on natural gas volumes and the pipeline capacity demanded by shippers, and then determining the natural gas scheduling and balancing to coordinate natural gas supply and delivery with transportation services.

When the cost of constructing new capacity is less than the congestion rent, the option could be to plan a new pipeline capacity. Under a decentralized regime, a pipeline company operates as a contract carrier and does not have an obligation to construct new capacity. If demand grows beyond the available capacity in a location, market participants will face high spot prices for natural gas in that location because of the resulting congestion. Once the expected present value of congestion payments exceeds the present value of the costs of constructing and operating a pipeline, market participants will add to the pipeline capacity.

4.2.3 Participate in the Planning of Natural Gas Storage Facilities

The main purpose of natural gas storage is to satisfy load variations. During off-peak periods, the surplus natural gas supply will be stored in the storage and then supplied back during peak periods. Natural gas storage can also help promote efficient transactions in the deregulated natural gas market. Storage operation is unbundled from pipeline transportation and deregulated for emphasizing cost-effectiveness. As the unbundling of pipeline transportation has improved the natural gas price discovery at various pipeline locations, storage facilities have increasingly been used to arbitrage locational and time differentials using natural gas proces. Storage operators take advantage of swings in spot prices by selling natural gas at high prices and buying at low prices. These transactions benefit market participants through greater availability and more efficient pricing of natural gas in the spot market.

The state is responsible for the construction of the natural gas storage facilities and the planning of natural gas storages. U.S. storage operators have responded in the past ten years by increasing the natural gas capacity. In addition, FERC, has enacted new storage regulations for tariff structures which promise storage operators greater rates of return on storage investments. These regulatory measures as designed to spur investment in underground storage working natural gas capacity with the twin goals of restoring a more historical relationship to summer and winter price spreads and reducing spot market volatility.

4.2.4 Participation in Securing the Natural Gas Consumption Metering

It is expected that more meters will be installed to collect the real-time data and monitor the operation of natural gas system. These meters measure the parameters of compressors, valves, switches, pressure settings, and pipeline operations and then transmit the data to control centers via communication networks. In practice, most natural gas companies will collect monthly meter readings over the phone or through the Internet. However, meter measurements could be compromised in different ways, such as Denial of Service (DoS) attacks on RTUs, deceptive attacks on communicated data, or attacks directed to SCADA. The data management hierarchy is shown in Figure 4-2.

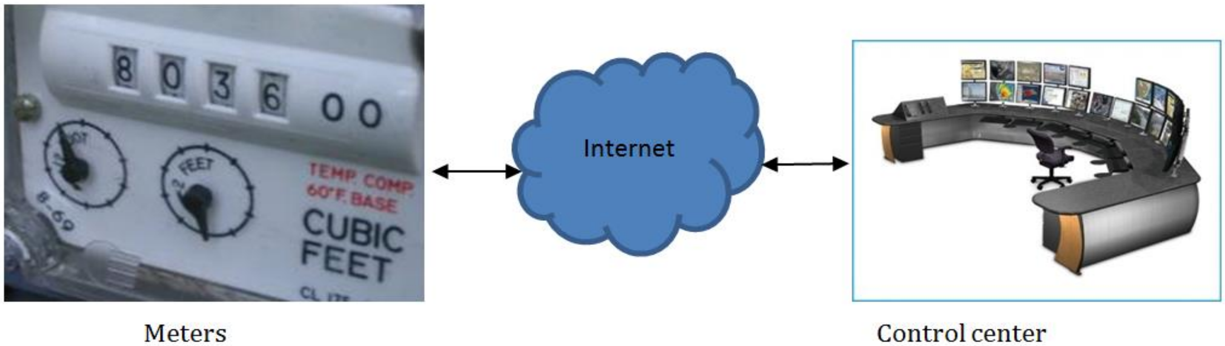


Figure 4-2: Natural gas metering
(Source: Gas Technology Institute)

In electricity grid, smart meter technology is a key component of the Advanced Metering Infrastructure (AMI) that will help smart grid link the two-way flow of electricity with the two-way flow of information. The meter's essential functions include (1) recording near-real time data on consumer electricity usage and transmitting the data using a variety of communications technologies; and (3) providing data to consumers from the smart grid via communication channels, such as real-time energy prices or remote commands that can alter a consumer's electricity usage to facilitate demand response.

The AMI data usage is expanding rapidly, and like the early Internet, many applications are yet to be developed. At a basic level, smart meters will permit utilities to measure, collect, and analyze energy consumption data for grid management, outage notification, and billing purposes. The meters may increase energy efficiency by giving consumers a greater control over their use of electricity, as well as permitting better integration of devices such as plug-in electric vehicles and renewable energy sources. They may also help decrease peak demand for electricity and aid in the development of a more reliable electricity grid that is better equipped to withstand cyber attacks and natural disasters. An attacker, using the infrastructure network topology and the corresponding parameter information, can alter without being detected the metered data transmitted to the control center. In such cases, the attack on either electricity or natural gas system will impact the operation of the other system. False data injection attacks could also lead to significant financial loss and operation damage to power and natural gas utilities. Hence, control entities in the coordinated electricity and natural gas infrastructures should work closely and with state regulators to set up a set of security mechanisms or protection strategies to endure the accuracy of the metered data in the coordinated infrastructures.

5. Electric Power Transmission and Resource Planning

Scope of work:

Task 5: Address planning issues including the limitations imposed on coordinated electric transmission and resource planning. This discussion should include FERC's, NERC's, and, where applicable, Market Monitor's perspectives.

Deliverable: Explanation of planning issues including the limitations imposed on the coordinated electric transmission and resource planning.

5.1 Stages of Power System Planning

Power system planning is a process of adding new components to power systems at certain periods in the planning horizon. Planning will optimize given objectives, such as investment and operation costs, and environmental mandates which are subject to a set of temporal constraints including reliability, load forecasts, emission, component capacity, construction costs, etc. The calculation of planning decision variables will respond to issues such as where to install, when to install, what to install (from the list of candidates), how much to install. There are three stages of planning, based on the allocated time in the planning horizon, which include long-term, midterm, and short-term planning. Figure 5-1 depicts the stages.

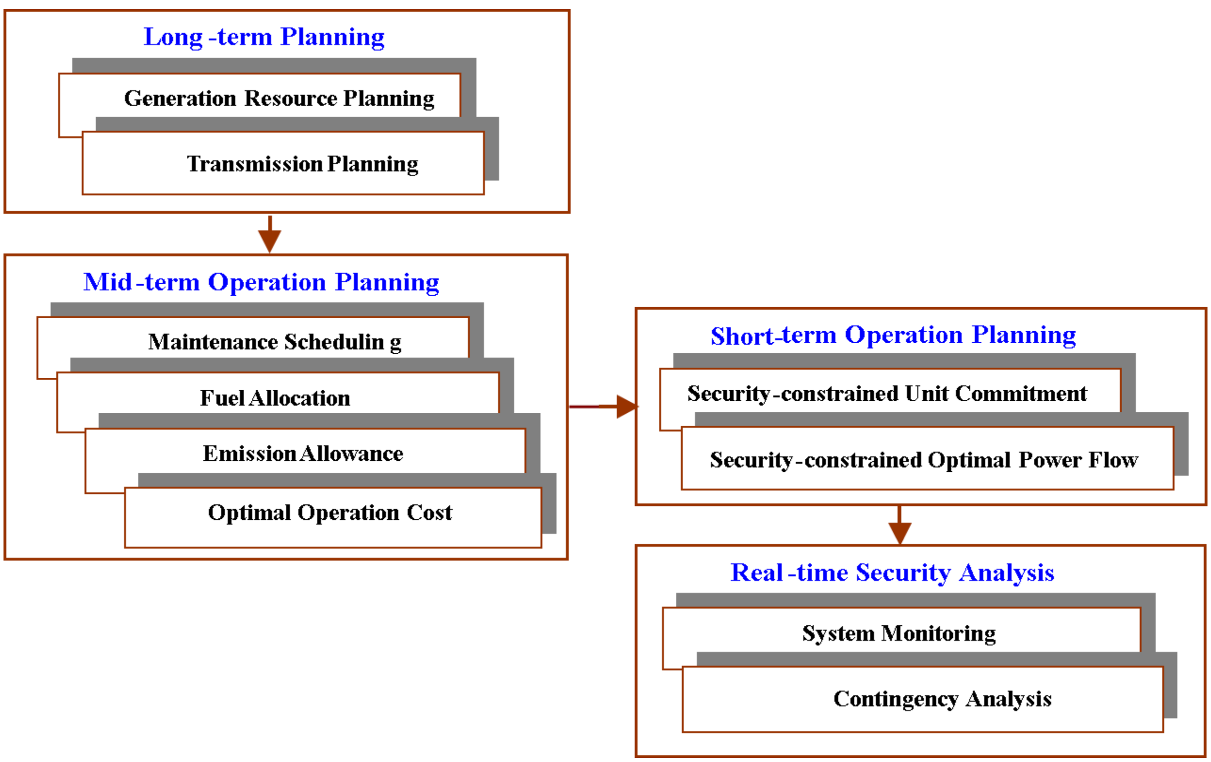


Figure 5-1: Power System Planning Stages
(Source: Galvin Center, IIT)

Real-time (on-line) operation planning: The on-line security analysis is performed by energy management systems (EMS) at power system control centers. On-line security analysis encompasses two main parts: System monitoring and Contingency analysis.

- **System Monitoring**: power system is monitored through the SCADA system installed at control centers. SCADA collects real-time data from remote terminal units installed in substations and power plants, distributed throughout the power system. System operator monitors and controls the system in real time with the help of a state estimator (SE) program. SE's most important function at present is providing information on system operation directly to operators to aid them in taking correction actions.
- **Contingency Analysis (CA):** is performed on the state estimator network model to determine whether steady-state operating limits would be violated by the occurrence of credible contingencies. CA includes contingency selection and contingency evaluation. Contingency selection (Screening and ranking): First iteration of fast decoupled power flow for each contingency or by bounding which exploits localization. The selection is performed by a scalar performance index (PI) for each contingency. Contingency evaluation: Includes Preventive and Corrective Actions. A preventive dispatch for uncontrollable contingencies is included for maintaining the economics and the secure operation of a system in the event of contingencies. The corrective actions represent post-contingency control actions for eliminating system violations. Such contingencies are referred to as controllable contingencies.

Short-term (day ahead and weekly) operation planning: encompasses security-constrained unit commitment (SCUC) and security-constrained optimal power flow (SCOPF). Short time operation problem would balance the load with generation or meet the constraints of operation. For instance, there are two lines feeding a substation, for the peak loading in coming year, one line would be overloaded by 10% of its rating, while, the other one would be loaded by 60% of its rating. To fix this, a control device is installed on one line, the load distribution may be balanced on both lines. Once decided, the installation process of this device can be performed in such a way that no problem arises for the coming year. From operation point of view, short-term and real-time planning are schedules of dispatching units in most economical way.

Mid-term (monthly and yearly) operation planning: encompasses optimal maintenance scheduling of equipment and optimal allocation of resources (e.g., fuel, emission, and water) for maintaining the system security. A proper maintenance outage scheduling provides a wider range of options for managing the short-term security and economics. Furthermore, short-term operation strategies may yield useful economic and security signals for maintenance outage scheduling over a longer time span.

Long-term (yearly and beyond) planning: encompasses generation resource and transmission system planning for maintaining the system security. With the load growing each year, suppose all the available and planned generations cannot meet the load at peak hours at year 5, so more generations need to be built to feed the load. After carefully study, the planner decides on adding a new 2*500 MW steam power plant at a specific bus in that year. The construction should start in advance so it would be available at the required time. And suppose the load growth is not balancing, such as, it grows at one bus too quick which leads to a congestion on the line connecting it to the grid. There are load shortages at year 7, so after another carefully study, one line paralleled with the congested one is planned to be ready at that year and starting to build beforehand. These are typical long-term (10-year) generation and transmission planning.

5.2 Components of Power System Planning

Components of power system planning include load forecasting, generation expansion planning, transmission network expansion planning, and coordinated generation and transmission planning. In the planning process, GENCOs and TRANSCOs will hand investment proposals to ISO who will optimize generation and transmission adequacy, and meet security and reliability constraints.

5.2.1 Load Forecasting

The short-term forecasting of hourly loads uses time factors (hours of the day, day of the week, season of the year), weather conditions, class of customers, special events, population, and economic indicators (per capita income, Gross National Product (GNP), Gross Domestic Product (GDP), etc.). In utilizing these factors, weather conditions would have the highest influence on short-term load forecast. Temperature and humidity are the most commonly used load predictors. This is for operational purposes and known as short-term load forecasting. GENCOs would have to forecast the system demand along with the corresponding price to make an appropriate decision.

There are limitations in the short-term load forecasting. The weather forecasting is quite important in this topic; so when the weather prediction is not accurate or even worse when it is wrong, the forecast of load will be affected a lot. So, the dependence on weather forecasting tools is the key limitations of short-term load forecasting. We predict peak loading conditions using midterm and long-term load forecasting. Historical load, weather data, number of customers in different categories, population rate increase, GDP (Gross Domestic Product) and similar terms have dominant effects in such cases.

We forecast the peak demand for long-term planning and the peak load forecasting is important because it would directly influence the required annual generation capacity. The forecasted energy sales are then calculated by multiplying the energy forecast with an empirically determined load factor coefficient. We notice in Figure 5-2 that the peal load pattern is upward, while its local values are declining in some years. In such cases, peak load is extremely sensitive to weather, and the base line prediction must be adjusted to normalize them relative to the weather. So once the baseline prediction is made, the forecast is adjusted based on the sensitivity to weather and the peak load is then predicted with the desired degree of confidence (Stoll 1989).

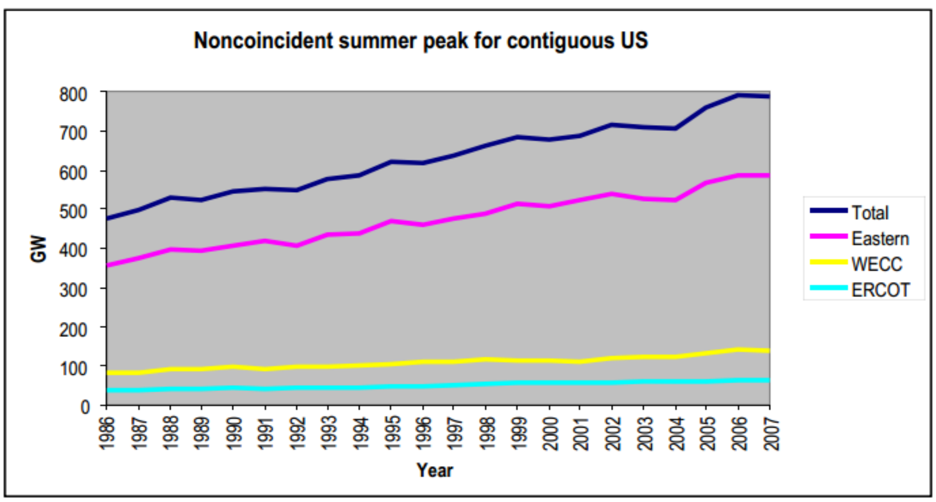


Figure 5-2: Non-coincident summer peak for contiguous U.S.

(Source: U.S. Energy Information Administration)

There are still limitations to forecasting peak loads. Severe cold weather in 2013 and extremely hot summer in 2012 in North America are the examples which lead to unusual load forecasting. If the power system planning is done based on forecasts, energy shortages would have occurred during such years. Also, 2008 economic recession had a negative impact on the peak load growth.

NERC Reliability Standards are the planning and operating rules that electric utilities follow to support and maintain a reliable electric power system. NERC prepares seasonal and long-term assessments of the overall reliability and adequacy of the North American bulk power systems. Figure 5-1 shows the annual peak demand changes since the 2011 summer. In the Eastern Interconnection, peak demand is projected to show slight growth after several years of decline following the 2008 economic recession. The Western Interconnection peak demand is projected to increase by 2.7 percent. The increasing peak demand projected in Texas also raises concerns due to ongoing resource variations. As highlighted in the 2012 Long-Term Reliability Assessment, the peak demand growth rate in Texas is projected to be the highest in the United States. There are many factors may affect the peak load forecasting and the common numerical methods cannot consider all the factors as there are factors which may not be realized by forecasters at all as shown Figure 5-1.

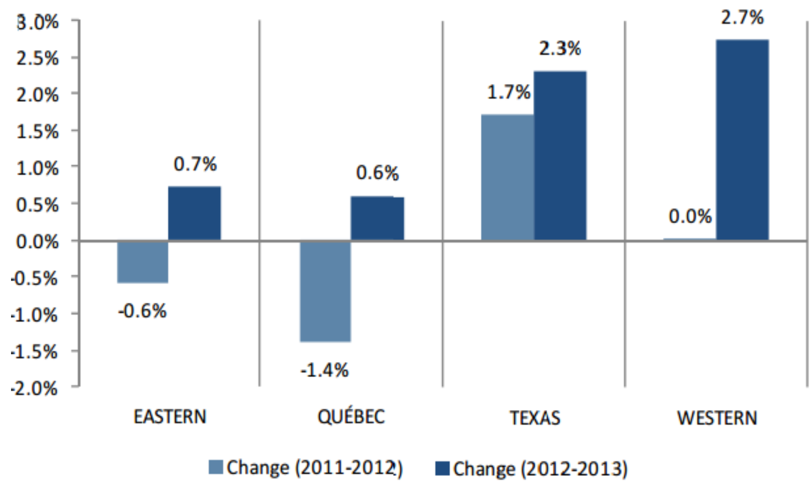


Figure 5-1: Summer peak demand annual changes, 2011–2013

(Source: North American Electric Reliability Corporation)

5.2.2 Generation Expansion Planning

Generation Expansion Planning (GEP) is an important step in long-term planning, once the load is properly forecasted for a specified period. GEP is an optimization problem in which the aim is to determine the new generation plants in terms of when the new capacity to be available, what type of capacity, and where to allocate the capacity so that planning objective functions are optimized and various constraints are met.

In Figure 5-2, the energy usage is increasing between 1980 to 2040 and various types of large generators are installed. So the issues with when, what, and where to install resources would have to be planned effectively. The aggregate use of fossil fuel as a portion of the total energy would decline from 82 percent in 2011 to 78 percent in 2040, while renewable energy usage grows rapidly. The renewable share (including biofuels) of total energy usage would grow from 9 percent in 2011 to 13 percent in 2040 in response to federal mandate for renewable portfolio standards, availability of federal tax credit for renewable power generation and state renewable portfolio standard (RPS) programs. Natural gas consumption grows by about 0.6 percent per year from 2011 to 2040, led by the increased use of natural gas in electricity generation and, at least through 2020, the industrial sector.

Decisions to add capacity, and the choice of fuel for new capacity, depend on a number of factors. With growing electricity demand and the retirement of 103 gigawatts of existing capacity, 340 gigawatts of new generating capacity is added in the Annual Energy Outlook (AEO2013) Reference case from 2012 to 2040 (Figure 5-3).

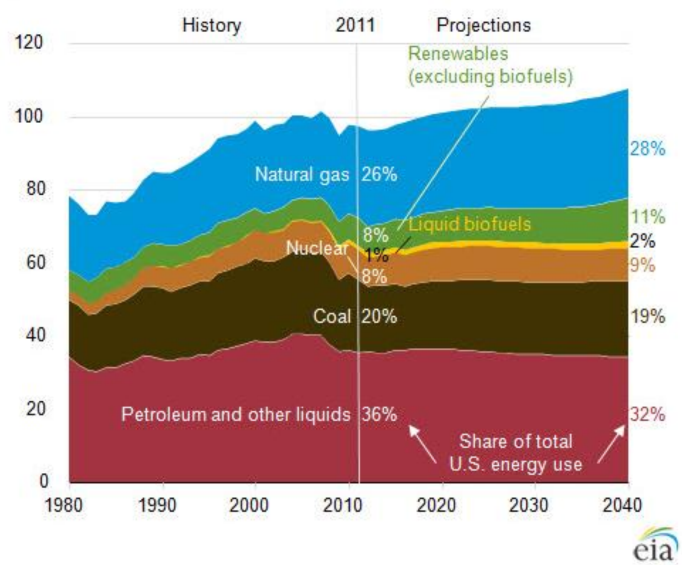


Figure 5-2: Primary energy usage by fuel, 1980-2040 (quadrillion Btu)

(Source: U.S. Energy Information Administration)

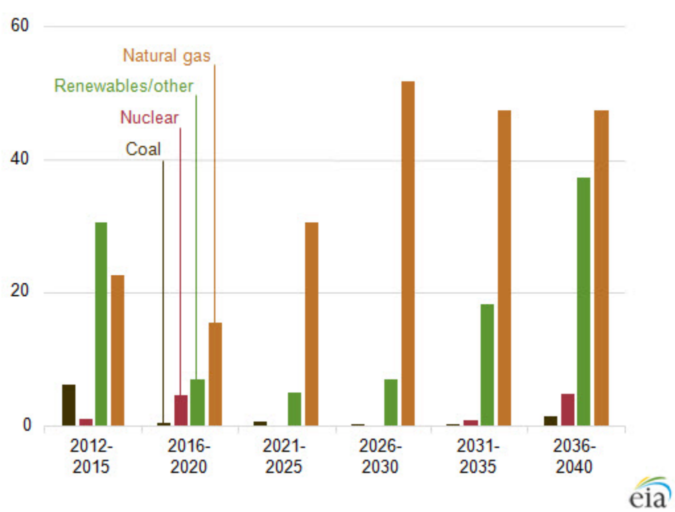


Figure 5-3: Electricity generation capacity additions by fuel type, including combined heat and power, 2012-2040 (gigawatts)

(Source: U.S. Energy Information Administration)

Natural gas-fired plants account for 63 percent of added capacity between 2012 and 2040 in the Reference case, compared with 31 percent for renewables, 3 percent for coal, and 3 percent for nuclear. Escalating construction costs have the largest impact on capital-intensive technologies, which include nuclear, coal, and renewables. However, federal tax incentives, state energy programs, and rising prices for fossil fuels increase the competitiveness of renewable and nuclear capacity.

Current federal and state environmental regulations also affect the use of fossil fuels, particularly coal. Uncertainty about future limits on Greenhouse Gas (GHG) emissions and other possible environmental programs also reduces the competitiveness of coal-fired plants (reflected in the AEO2013 Reference case by adding 3 percentage points to the cost of capital for new coal-fired capacity).

The uncertainty in electricity demand growth and fuel prices also affects capacity planning. In Figure 5-7, the total added capacity between 2012 and 2040 range from 252 gigawatts in the Low Economic Growth case to 498 gigawatts in the High Economic Growth case. In the Low Oil and Natural Gas Resource case, natural gas prices are higher than in the Reference case, and new natural gas-fired capacity added from 2012 to 2040 totals 152 gigawatts, or 42 percent of total additions. In the High Oil and Natural Gas Resource case, delivered natural gas prices are lower than in the Reference case, and 311 gigawatts of new natural gas-fired capacity is added from 2012 to 2040, accounting for 82 percent of total new capacity.

Another limitation of generation expansion planning comes from the stock of resources such as coal in Figure 5-5. The coal production worldwide would decline starting from year 2025. And the GHG limit will also minimize the use of coal as a source of power generation. Although coal-fired power plant construction cost per MW is lower, we can no longer afford its base load application as more coal-fired power plants are scheduled to retire in the near future. In Figure 5-3, the renewable energy capacity is increasing. However, from the reliability point of view, increased wind and solar capacity across North America would increase the supply uncertainty during peak-load hours.

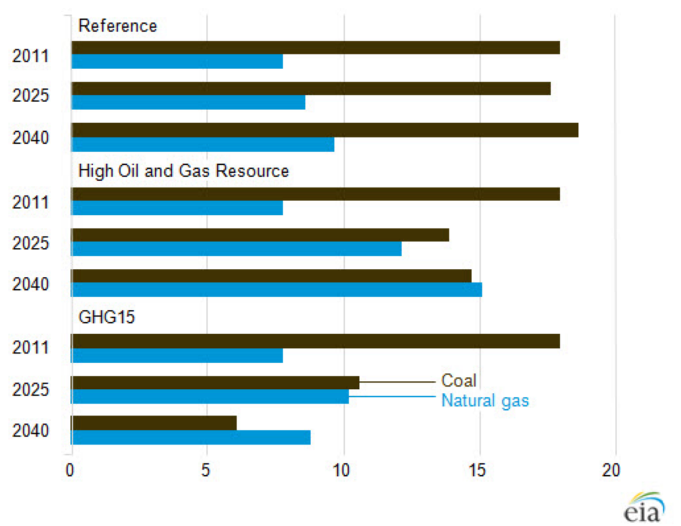


Figure 5-4: Coal and natural gas use in the electric power sector in 2011, 2025, 2040 (quadrillion Btu)
(Source: U.S. Energy Information Administration)

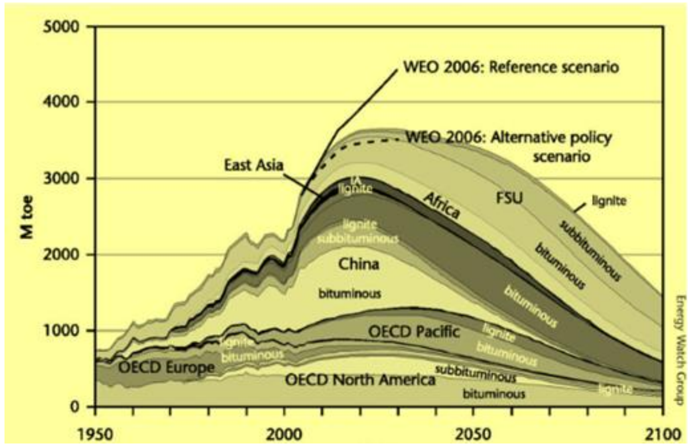


Figure 5-5: Worldwide potential for coal production
(Source: Energy Watch Group)

NERC is concerned that the renewable energy cannot serve peak hour loads. Especially wind energy could pose a significant variability and result in major power shortages at peak load hours. The variability of wind energy could be compensated by large storage devices such as pumped-storage hydro or battery system. Also, without storage, the excess wind energy at night would have to be curtailed to maintain the load balance. Such curtailments would be costly which easily justify the use of storage by power companies. The pumped-storage system has its own limitation including the availability of large reservoirs. The battery storage poses high cost with low capacity and limited life limit.

In GEP, both investment and operation costs would have to be minimized. Table 5-1 and Table 5-2 show that the operation cost of wind energy is low while its construction cost is significant. Other sources have their own pros and cons which are represented by constraints in GEP.

Table 5-1: Cost of construction

Technology	Cost of construction $/kW
Pulverized coal	1600
CCGT	850
CT	650
Nuclear plant	2000
Hydro	1500
Wind	2000

Table 5-2: Technology characteristics

Technology	Output in MW	Hear rate MMBTU/MWH
Coal	100-1300	10-15
Nuclear	900-1300	10-15
Natural gas combustion turbine	25-200	9.5-12.5
Natural gas combined cycle	400-600	6.8-7.5
Traditional natural gas and oil	25-500	10-15
Wind	0.5-1.5	NA

5.2.3 Transmission Expansion Planning

Transmission Expansion Planning (TEP) would find the optimal path between generation buses (determined by GEP) and load centers (determined from load forecasting). TEP will supply the loads in both normal and contingency cases. TEP decisions as depicted in Figure 5-6 should determine where, what capacity, and what type of lines (e.g., AC or HVDC) are to be built. There are many limitations posed on TEP decisions such as the availability of right-of-way and the potential crossing of protected lands, when the TEP path would have to be altered. Figure 5-7 shows the Rock Island Clean Line, which is a planned 500-mile ±600kV HVDC line extending from the northwest Iowa to northern Illinois, and is expected to deliver 3,500 megawatts of wind power. The estimated to cost for the development and construction of the line is approximated at $2 billion, which is estimated to be completed in 2017 at the earliest. However, the project has not started yet as of late 2013 and there are strong indications that it could be delayed because of the existing difficulties with the siting of interstate projects.

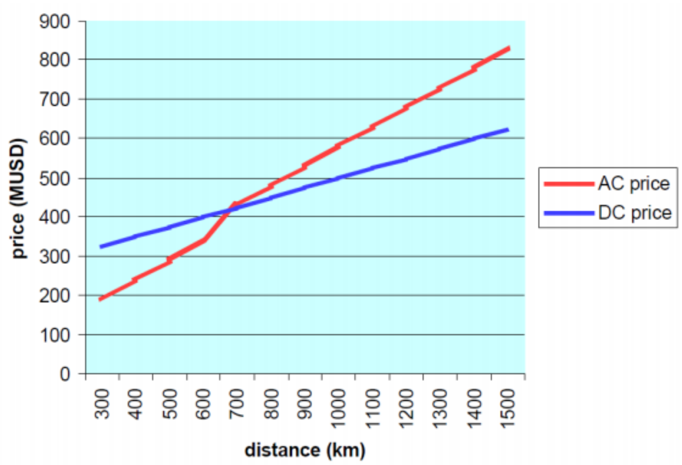


Figure 5-6: Price variation for an AC transmission compared with an HVDC
(Source: Roberto Rudervall, HVDC Transmission Systems Technology Review Paper)

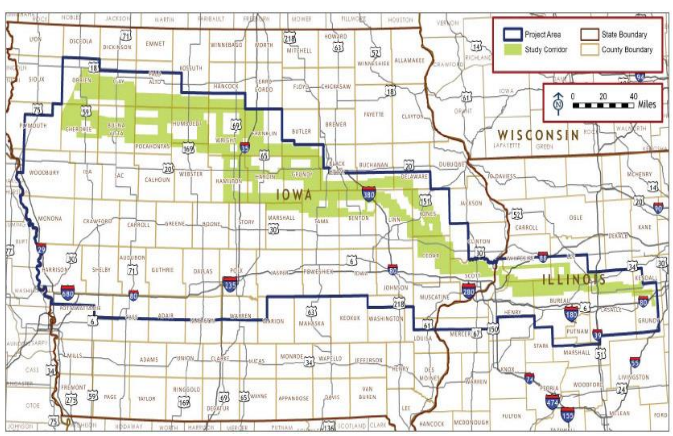


Figure 5-7: Corridor map of Rock Island Clean Line
(Source: E&E Publishing)

FERC in its Order No. 1000 required each public utility transmission provider to participate in regional transmission planning processes that would satisfy the Order No. 890 principles. Accordingly, local and regional TEP processes must consider public policy requirements established by state or federal laws or regulations. Public utility transmission providers in each pair of neighboring transmission planning regions must coordinate their plans to determine if there are more efficient or cost-effective solutions to their respective transmission requirements.

The Order No. 1000 has additional requirements on cost allocations and non-incumbent developer reforms. In cost allocation reforms, participating public utility transmission providers must satisfy six regional cost allocation principles in the regional cost allocation method applied to new transmission facilities. Incumbent transmission providers may rely on regional transmission facilities to satisfy their reliability needs or service obligations. The rule requires each public utility transmission provider to amend its tariff for the reevaluation of the regional transmission plan to determine if delays in the development of a transmission facility deem alternative solutions, including those proposed by the incumbent, to ensure incumbent transmission providers can meet reliability needs or service obligations.

In the NERC's 2013 Summer Reliability Assessment, there were region-specific challenges across North America indicating that the additional renewable energy capacity would introduce more uncertainty to on-peak supply, retirements and retrofits of power plants that would meet environmental regulations are not anticipated to cause any reliability concerns, and above-average growth in peak demand is projected in ERCOT and WECC. Though resources were added and reinforcements were completed in southern California, reserve margins still remained tight and, as in prior years, significant levels of imported power were used to fortify reserve margins for preserving reliability. This condition resulted in heavily loaded transmission lines during peak load conditions, particularly on extra high-voltage transmission lines from the east (Sunrise and Southwest Power link). Hence, forced outages or extreme temperature/demand may lead to further inadequacy of resources. In such cases, TEP would be a critical subject in states like New England with insufficient generation resources.

The cost effectiveness of a new transmission line depends on how much power the line can carry. Small lines (230 kV or less) cost more per megawatt carrying capability which pose greater economic challenges. A larger line costs less per megawatt, but the load carrying efficiency would be lost if the line's capacity is not fully utilized. Long distance transmission magnifies these factors, posing extra economic challenges on small generating resources that are far from loads. In addition to economic challenges, environmental issues and other siting considerations often present barriers to the development of new transmission lines. Some of the key issues and considerations include potential impacts on individual animal and plant species and their habitats, cultural and historic resources, and specially designated areas (e.g. parks, monuments, recreation drainages), limited land offerings and ownership of right of way, and the strategic location of other critical infrastructures (e.g. pipelines, roads, and railways).

The TEP projects currently under construction and in advanced development stages are primarily intrastate which do not cross state lines. Regional transmission lines will be needed would supply local demand and generation resources, and respond to regional policies, costing limitations, reliability and emissions. Corridors are sited specifically to avoid sensitive resources, land use conflicts, and extreme terrain while maximizing the opportunities to connect energy development areas with demand centers by reinforcing the existing transmission system.

TEP must satisfy operating constraints such as thermal, voltage, and angle stability, and reactive power requirements. In addition, the conflict between economics and security is inevitable and a global analysis of security options could provide additional opportunities for seeking optimal and feasible solutions in various time scales.

6. Planning Issues in Natural Gas Industry

Scope of work:

Task 6: Explain what the planning issues are in the natural gas industry including those of producers, pipelines, storage, and local distribution companies.

Deliverable: Explain what the planning issues are among the natural gas industry elements including producers, pipelines, storage, and distribution companies.

6.1 Introduction

Natural gas is one of the most abundant energy sources in the world. Like oil, it is created by the decomposition of organic matter. The lightest of all hydrocarbons, natural gas is commonly found in underground formations either by itself, associated with or lying atop oil deposits, or dissolved in crude oil. From its source at a wellhead, natural gas traverses through a series of production, transmission and distribution processes enroute to its final use at load centers. As natural gas leaves the processing plant, it enters a compressor station where it is pressurized for transmission. As the pressure is increased, the volume of natural gas is reduced and more natural gas can be filled into the same unit space while the pressure needed to move natural gas through pipelines is achieved. As natural gas travels through pipelines, some pressure is lost due to fluid friction caused by the natural gas rubbing against the inside walls of the pipes. This loss of pressure is made up at compressor substations located every 50 to 100 miles along the transmission pipelines.

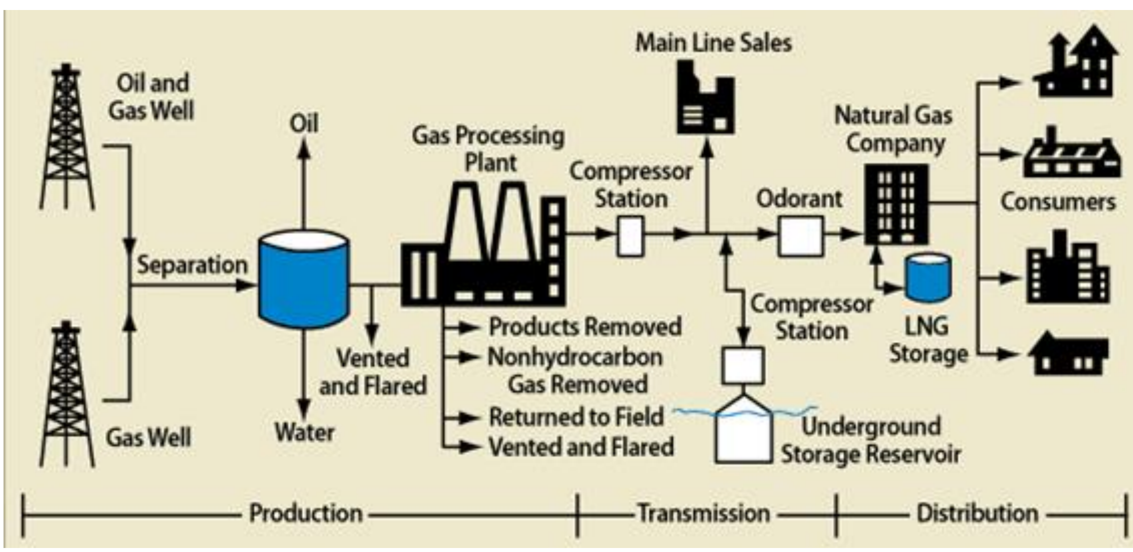


Figure 6-1: Natural gas industry's production, transmission and distribution system
(Source: U.S. Energy Information Administration)

6.2 Natural Gas Production

Natural gas is extracted through subsurface drilling. Natural gas does not require refining as crude oil does, but it does require cleaning, to remove other natural gases and liquids. These are removed at a natural gas processing plant where, as a safety measure, an odorant called mercaptan is added to the naturally odorless methane, giving it a distinctive rotten egg smell. Before natural gas is distributed, it must be sent to a processing or stripping plant where it is cleaned and separated. At the processing plant, the natural gas is sent through a separator where secondary byproducts (including oils and impurities) and heavier hydrocarbons (including butane, ethane, and propane) are removed. Most of these byproducts are reprocessed, packaged and sent to market.

Most of the natural gas consumed in the United States is from domestic production. U.S. natural gas production and consumption were nearly in balance through 1986 (see Figure 6-2). After that, consumption began to outpace production, and imports of natural gas rose to meet the domestic demand. The natural gas production increased from 2006 through 2011, when it reached the highest recorded annual production since 1973. The increase in production was the result of more efficient, cost-effective drilling techniques, notably in the production of natural gas from shale formations.

Shares of 2011 natural gas marketed production included:

- Texas (29%)
- Wyoming (9%)
- Federal Offshore Gulf of Mexico (8%)
- Louisiana (13%)
- Oklahoma (8%)

In 2011, 90% of net U.S. imports were by pipeline, primarily from Canada, and 10% by LNG tankers carrying natural gas from five different countries.

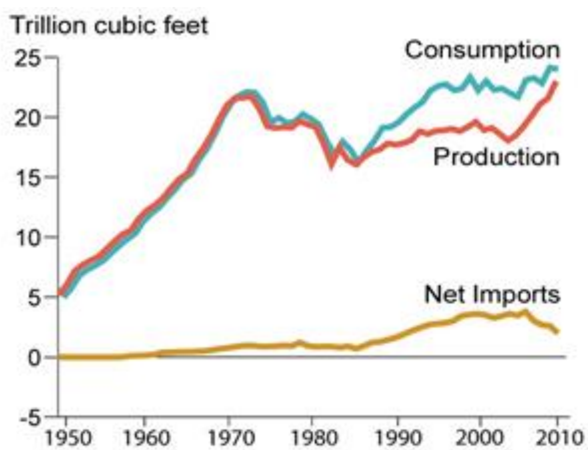


Figure 6-2: U.S. natural gas consumption, production and net imports (1949-2011)
(Source: U.S. Energy Information Administration)

6.3 Coordinated Resource Planning for Natural Gas Production

Determining whether to drill a natural gas well depends on a variety of factors, including the economic potential of the natural gas reservoir. It costs exploration and production companies a great deal to search and drill for natural gas, and there is always the inherent risk that no natural gas will be found. The exact placement of the drill site depends on many factors, including the nature of the potential formation to be drilled, the characteristics of the subsurface geology, and the depth and size of the target deposit. Once the geophysical team identifies the optimal well location, it is necessary for the drilling company to ensure that it completes all the necessary steps so that it can legally drill in that area. This usually involves securing permits for drilling operations, establishing a legal arrangement to allow the natural gas company to extract and sell resources in under a given land area, and designing gathering lines that will connect the well to the pipeline. Once the presence of commercially viable quantities of fossil fuel is verified and a well is drilled, the next step is lifting the natural gas out of the ground and processing it for transportation.

The coordinated resource planning process which explores social, regulatory and market landscapes must ultimately provide the necessary supply of natural gas to customers. There are certain assumptions and historical trends applied to the coordinated resource planning which are based on forecasted natural gas loads and correspond to the natural gas regulatory uncertainty, increasing supply and delivery capacity, and fluctuating natural gas market prices. The planning process would impact the safe, reliable, and cost effective delivery of natural gas. Extensive modeling and analyses were performed to understand the various conditions that the natural gas company must respond to forecasted loads over a long term period.

The coordinated resource planning process includes identifying future demand and supply conditions in order to recommend actions needed over the next ten years to meet the forecasted demand. Consider the long-term plan called the "Natural Gas Integrated Resource Plan (GIRP)" which was implemented by Colorado Springs Utilities. GIRP combines rigorous technical analyses and public participation to ensure safe, reliable, and cost effective natural gas supply. The goal is to manage and evaluate all resource options in order to economically determine the natural gas supply and delivery scenarios required for forecasted annual, peak-day and peak-hour demands. The other factors besides cost that must be considered in the context of resource planning include a high level assessment of risks, as well as environmental and regulatory issues associated with each supply and delivery scenario to meet customer demands.

Coordinated resource planning identifies areas of concern within the natural gas infrastructure, evaluates alternative solutions, and provides a corrective action plan. Awareness of potential system performance issues also provides the opportunity to incorporate corrective action into normal maintenance or replacement projects. This proactive approach avoids costly "reactive" methods and creates value for customers. There are three primary elements of planning including:

- Supply: Natural gas production, transmission, and storage capacity sufficient to meet distribution system demand.
- Delivery: Natural gas distribution system for adequately providing a reliable delivery of natural gas to end-users based on a peak-hour design day.
- End-Use Demand: A full economic spectrum of consumers which includes industrial, electric power generation, residential, commercial, and others.

There are three types of demand forecasts including annual, peak-day and peak-hour. Annual demand forecasts are for preparing revenue budgets and developing long term natural gas procurement plans. Peak-day and peak-hour demand forecasts are critical for determining the adequacy of existing supply resources, or the timing for new resource acquisitions or capital investments required to meet customers' natural gas needs during a peak use event. Demand forecasts for natural gas depend on residential and industrial usage. Natural gas usage is driven by weather sensitive heating loads and the industrial base in Colorado Springs is relatively small compared to other cities of similar size (Figure 6-3). Since there is a substantial weather volatility, daily and hourly demand forecasting is a challenging process. Therefore, demand forecasts include wind speed in addition to average temperature as fundamental demand-influencing factors.

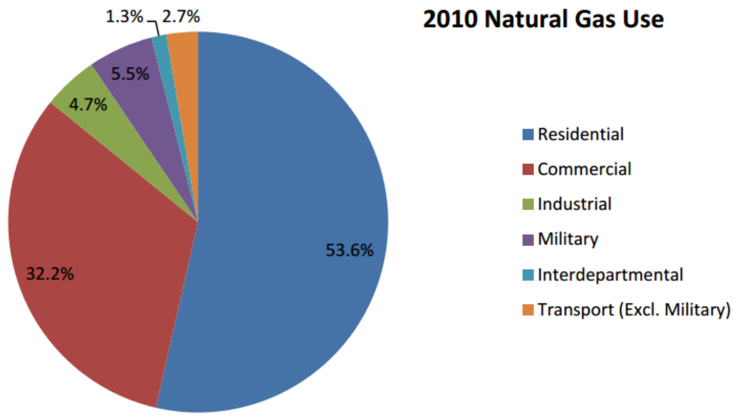


Figure 6-3: Natural gas usage by customer type

(Source: 2011 Natural Gas Integrated Resource Plan, Colorado Springs Utilities)

In addition to average temperature and wind speed, demand forecasting recognizes two other drivers, which include the customer growth and the demand response of existing residential, commercial and industrial customers. Factors that influence new demand include population, employment trends, traffic area zones (TAZ) based on the Pikes Peak Area Council of Governments planning information, construction trends, and new use development (e.g. natural gas vehicles). Demand response recognizes customers' willingness to adjust consumption in response to price and modify their demand through conservation measures such as, installing insulation, weather stripping, energy efficient windows, replacement of existing appliances with higher efficiency appliances, and behavioral adjustments such as, lowering thermostat settings. Over the past two decades, natural gas demand response has lowered the annual usage per residential customer by approximately 25%.

Although it is difficult to predict future natural gas prices, the experience with market conditions help shape the overall trend for market participants. The pricing strategy includes hedging, storage utilization, term purchases and index purchases. Although the specific provisions of pricing are dynamic, the principles guiding natural gas prices include safety, reliability, cost effectiveness, portfolio diversity and market risk mitigation through ongoing analysis and experience. Based on market conditions, natural gas utilities would negotiate contracts for the natural gas delivery capacity to city gate stations to adequately serve their respective community.

6.4 Pipelines for Natural Gas Transmission and Distribution

Distribution and transmission system network planning facilitates the understanding of existing operational conditions as well as planning for future expansion within a natural gas utility's service territory.

The goal of natural gas distribution system planning is to design, construct, operate and maintain a delivery system, which starts at the city gate and extends to customer meters, and would deliver natural gas to every customer in a safe, reliable and cost effective manner. Meeting the goal of reliable cost effective natural gas delivery is enhanced by the recent integration of customer growth forecasting and localized distribution planning enabling coordinated targeting of distribution projects that are responsive to specific customer growth patterns.

The oil and natural gas industry plans to massively expand a labyrinth of pipelines to market natural gas extracted from the Marcellus Shale and other rock formations using hydraulic fracturing, or fracking. But allowing the industry to build out its sprawling pipeline infrastructure and to lock-in decades more of U.S. dependence on natural gas would be a colossal mistake. Due to the complexity of the network planning process it seems both necessary and beneficial to subdivide it into two separate planning stages, see Figure 6-4.

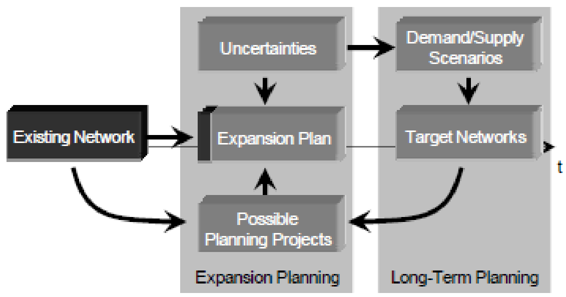


Figure 6-4: Expansion and long-term planning

(Source: Michael Hübner, Hans-Jürgen Haubrich, Long-term Planning of Natural Gas Networks)

- ***Long-Term Planning***: Regarding a planning horizon of several decades the existing network structure and operating facilities may be ignored. The long-term planning is based on the aforementioned assumption that is often referred to as Greenfield development. Therefore the long-term planning will identify cost-efficient network structures neglecting the existing facilities.
- ***Expansion Planning***: The expansion planning determines cost-efficient step-by-step development strategies starting with the existing network structure and aiming at the identified target networks on the basis of the outcomes of the long-term planning. Uncertainties concerning e.g. load growth, changes in interest rates etc. may be considered in this planning stage.

The pipeline routes are planned under certain rules which minimize length of crossing large wetland complexes, number of water body crossings, and length of crossing of designated wildlife habitats (wildlife management areas; designated rare, endangered and threatened species habitats). And avoid abandoned mines, historic landmarks, cemeteries, documented cultural sites, superfund hazardous waste sites and landfills. A new path even without these conditions may involve land ownership problem which may lead to failure of the construction plan.

Furthermore, natural gas pipeline companies prefer to operate their systems as close to full capacity as possible to maximize their revenues. However, the average utilization rate (flow relative to design capacity) of a natural gas pipeline system seldom reaches 100%. Factors that contribute to outages include:

- Scheduled or unscheduled maintenance
- Temporary decreases in market demand
- Weather-related limitations to operations

Most pipeline companies try to schedule maintenance in the summer months when demands on pipeline capacity tend to be lower, but an occasional unanticipated incident may occur that suspends transmission service.

6.5 Natural Gas Storage

Natural gas storage is used to meet load variations while to save more pipelines. If there is no storage, to meet the peak load in winter, more pipelines would have to be erected which may not be fully utilized in summer. So, in summer months, when the demand for natural gas is low, natural gas companies can store their excess supply in a number of ways. The most common method is to pipe the natural gas into depleted oil or natural gas reservoirs where it can be stored indefinitely and withdrawn as needed.

There are three main types of natural gas storage facilities widely in use in the United States and Canada, which include depleted oil and natural gas reservoirs, salt cavern storage, and aquifer storage. United States is typically represented by three main regions for natural gas consumption and production. These are consuming East, consuming West, and producing south.

Underground storage is used to meet peak winter demand when the capacity of the pipelines cannot deliver what is needed. There are more than 380 underground storage systems operated by 80 companies in 26 states (see Figure 6-5). More than half of the total underground storage systems are located in Illinois, Michigan, Pennsylvania, Ohio and West Virginia.

Figure 6-5: U.S. natural gas storage facilities as of August 2007
(Source: U.S. Energy Information Administration)

Another storage method is converting natural gas to LNG which takes up only 1/600th of the space it does as natural gas. When LNG is ready to be used, it can be easily converted back to natural gaseous form simply by increasing the temperature.

Natural gas storage is also used for a variety of secondary purposes including:

- Balancing the flow in pipelines. This is performed by mainline transmission pipeline companies to maintain operational integrity of the pipelines, by ensuring that the pipeline pressures are kept within design parameters.
- Maintaining contractual balance. Shippers use stored natural gas to maintain the volume they deliver to the pipeline system and the volume they withdraw. Without access to such storage facilities, any imbalance situation would result in a hefty penalty.

- Leveling production over periods of fluctuating demand. Producers use storage to store any natural gas that is not immediately marketable, typically over the summer when demand is low and deliver it when in the winter months when the demand is high.
- Market speculation. Producers and marketers use natural gas storage as a speculative tool, storing natural gas when they believe that prices will increase in the future and then selling it when it does reach those levels.
- Insuring against any unforeseen accidents. Natural gas storage can be used as an insurance that may affect either production or delivery of natural gas. These may include natural factors such as hurricanes, or malfunction of production or distribution systems.
- Meeting regulatory obligations. Natural gas storage ensures to some extent the reliability of natural gas supply to the consumer at the lowest cost, as required by the regulatory body. This is why the regulatory body monitors storage inventory levels.
- Reducing price volatility. Natural gas storage ensures commodity liquidity at the market centers. This helps contain natural gas price volatility and uncertainty.
- Offsetting changes in natural gas demands. Natural gas storage facilities are gaining more importance due to changes in natural gas demands. First, traditional supplies that once met the winter peak demand are now unable to keep pace. Second, there is a growing summer peak demand on natural gas, due to electric generation via natural gas fired power plants.

Research is being conducted on many fronts in the natural gas storage field to help identify new, improved, and more economical ways to store natural gas. The U.S. Department of Energy studies show that salt formations can be chilled allowing for more natural gas to be stored. This will reduce the size of the formation needed to be treated, and have salt extracted from it. This will lead to cheaper development costs for salt formation storage facility type. Another aspect being looked at, are other formations that may hold natural gas. These include hard rock formations such as granite, in areas where such formations exist and other types currently used for natural gas storage do not. In Sweden a new type of storage facility has been built, called "lined rock cavern". This storage facility consists of installing a steel tank in a cavern in the rock of a hill and surrounding it with concrete. Although the development cost of such facility is quite expensive, its ability to cycle natural gas multiple times compensates for it, similar to salt formation facilities. Finally, another research project sponsored by the Department of Energy is that of hydrates. Hydrates are compounds formed when natural gas is frozen in the presence of water. The advantage being that as much as 181 standard cubic feet of natural gas could be stored in a single cubic foot of hydrate.

As with all infrastructural investments in the energy sector, developing storage facilities is capital intensive. Investors usually use the return on investment as a financial measure for the viability of such projects. It has been estimated that investors require a rate or return of 12-15 percent for regulated projects, and close to 20 percent for unregulated projects. The higher expected return from unregulated projects is due to perceived higher market risks. In addition significant expenses are accumulated during the planning and location of potential storage sites to determine its suitability, which further increases the risk.

The capital expenditure to build the facility mostly depends on the physical characteristics of the reservoir. First of all, the development cost of a storage facility largely depends on the type of the storage field. As a general rule of thumb, salt caverns are the most expensive to develop on a Bcf of Working Natural Gas Capacity Basis. However one should keep in mind that because the natural gas in such facilities can be cycled repeatedly, on a Deliverability basis, they may be less costly. A Salt Cavern facility might cost anywhere from $10 million to $25 million/Bcf of working natural gas capacity. The wide price range is because of region difference which dictates the geological requirements. These factors include the amount of compressive horsepower required, the type of surface and the quality of the geologic structure to name a few. A depleted reservoir costs between $5 million to $6 million/Bcf of Working Natural Gas Capacity. Finally another major cost incurred when building new storage facilities is that of base natural gas. The amount of base natural gas in a reservoir could be as high as 80% for aquifers making them very unattractive to develop when natural gas prices are high. On the other hand salt caverns require the least amount of base natural gas. The high cost of base natural gas is what drives the expansion of current sites vs the development of new ones. This is because expansions require little addition to base natural gas.

7. Planning Coordination in Natural Gas and Electricity Industries

Scope of work:

Task 7: Provide a discussion on the coordinated planning issues concerning natural gas and electricity industries.

Deliverable: Explanation of coordinated planning issues between natural gas and electricity industries

7.1 Overview

The North American electric power sector has transitioned from being the smallest consuming sector within the natural gas industry to the largest consuming sector. As shown in Figure 7-1, the electric power accounted for 34% of the natural gas consumption in 2013. Going forward, the electricity sector will likely account for the vast majority of the natural gas demand growth. On the other hand, the natural gas-fueled generators have reached 42% of the total nameplate capacity by the end of 2012 (Figure 7-2).

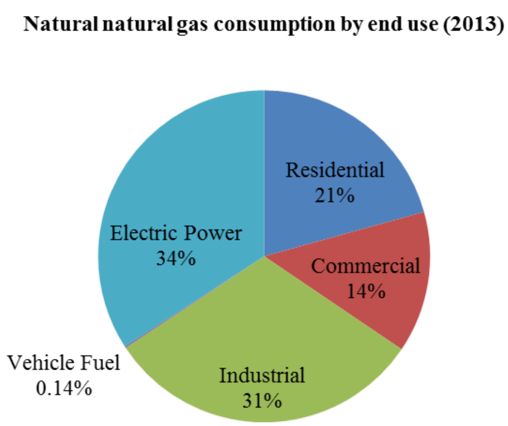


Figure 7-1: Natural gas consumption by end user

(Source: U.S. Energy Information Administration)

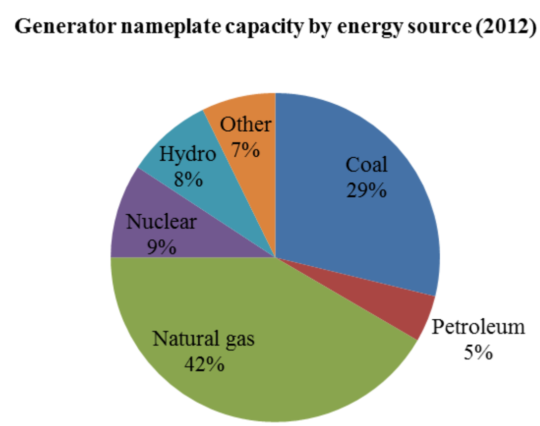


Figure 7-2: Generator nameplate capacity by energy source

(Source: U.S. Energy Information Administration)

Furthermore, the majority of new North American generating capacity projected for the next ten years will rely on natural gas as its primary fuel. As the natural gas industry incorporates more electric compressors within its transportation systems, the interdependency of these two critical industries continues to grow.

The shift to natural gas-fired generation is largely attributable to the price natural gas, which is lower than that of oil or coal. The natural gas industry estimates that North American shale natural gas reserves hold a 100-year supply; this increase in supply has pushed natural gas futures prices on the NYMEX to a 10-year low. Given the low prices, power generators are using Marcellus shale natural gas where possible to reduce costs, which, in turn, results in low wholesale prices that ultimately benefit electricity consumers. This shift to natural gas is further driven by improved performance, reduced construction time, more expeditious permitting, and environmental compliance of natural gas-burning combined-cycle units. The integration of variable renewable energy resources in the electricity system require greater flexibility in generation resources. Moreover, the older oil-and coal-fired power plants could opt for retirement in the near future due to market pressures and the cost of complying with environmental regulations.

7.2 Coordination in Natural Gas and Electricity Industries

Over the past decade, the U.S. application of natural gas-fired generation increased significantly from 17% to 25% and natural gas is now the largest thermal fuel source for power generation. Natural gas use is expected to continue to increase in the near future, both in absolute terms and as a share of total power generation. Figure 3 shows the planned generation capacity in the North America which are highlighted in NERC's 2012 Long-Term Reliability Assessment. The trend shown in this figure identifies natural gas-fired generation as the primary choice of new generation capacity.

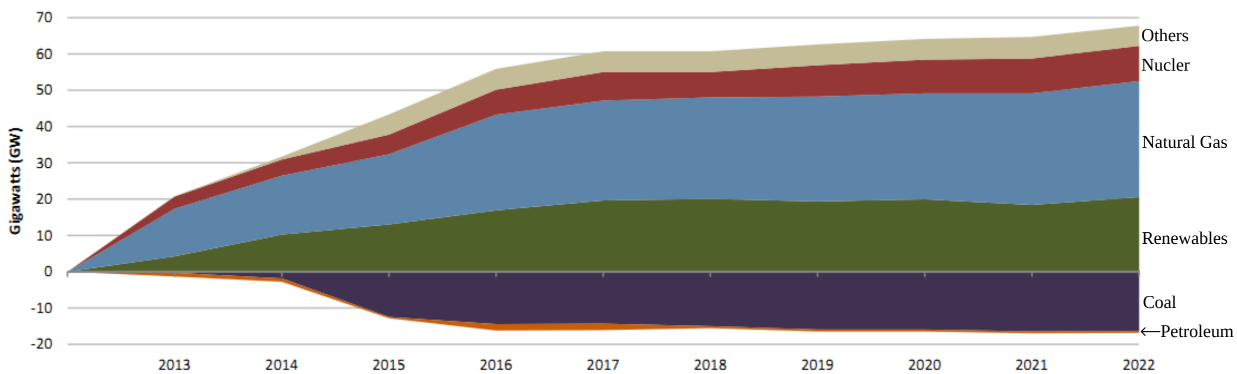


Figure 7-3: NECR-wide planned capacity by resources
(Source: PennEnergy)

Recent and pending EPA regulations make natural gas-fired generation a premier choice for new generating capacity, replacing coal-fired capacity. Natural gas is expected to play a growing role in offsetting the variability associated with renewable resources (mainly wind energy). The swings in variable generation may call for the dispatch of natural gas-fired generation at larger and less predictable rates. It is expected that natural gas would serve more than half of the electric peak demand in North America by 2015.

The U.S. natural gas consumption is projected to increase by an average 1.6 percent per year through 2035. As shown in Figure 7-4, the total natural gas use across all sectors is projected to rise to about 110 Bcfd in 2035. Incremental demand growth between 2010 and 2035 is 35 Bcfd, of which 26 Bcfd or 75 percent occurs in the electric power sector. The U.S. regions with largest increases in demand are the southeast followed by the northeast and the southwest with a significant power generation growth.

Unlike coal and fuel oil, natural gas is not easily stored on-site. As a result, real-time delivery of natural gas through a network of pipelines and bulk natural gas storage is critical to support electric generators. The increased dependence on natural gas for power generation could expose power plants to interruptions in natural gas supply and delivery. Mitigating strategies that contribute to managing this risk include natural gas storage, firm fuel contracting, alternate pipelines, dual-fuel capability, access to multiple natural gas basins, and nearby plants using other types of fuel. Going forward the interdependency of natural gas and electricity sectors would grow rapidly, which causes both industries to focus sharply on coordination, particularly at regional levels. Disruptions in natural gas supply and/or transportation for power generation have prompted both industries to seek an understanding of the reliability implications associated with increasing natural gas-fired generation.

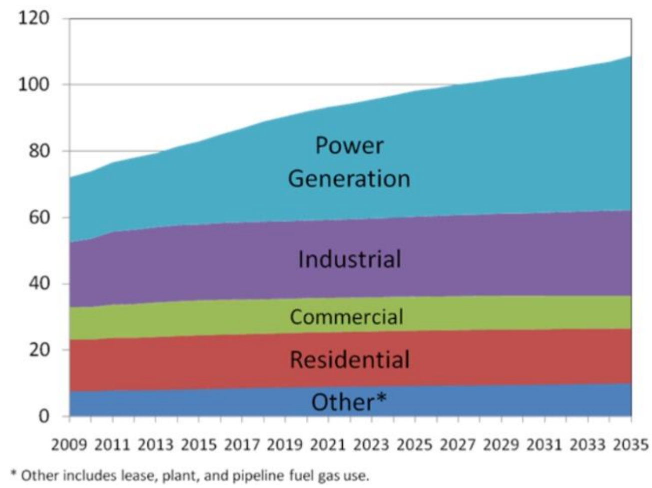


Figure 7-4: U.S. and Canadian natural gas consumption (average annual Bcfd)
(Source: The INGAA Foundation, Inc.)

The electricity sector's growing reliance on natural gas raises concerns from the viewpoints of ISOs and market participants regarding the ability to maintain electric system reliability when the capacity to deliver natural gas supplies to power generators is constrained. The extent of these concerns is most acute in territories where power generators rely heavily on interruptible natural gas pipeline transportations and where the growth in natural gas use for power generation is fastest (such as in ISONE). In responding to the concerns raised in both industries, FERC in August 2012 and February 2013 held technical conferences regarding the coordination of natural gas and electricity markets. The conferences covered issues such as coordination and information sharing, scheduling, market structures, and reliability concerns.

As the growth in regional natural gas system requirements reaches the point where new pipeline capacity is required, a mismatch would exist between the availability of natural gas delivery services and the natural gas demand for power generation. This can be particularly acute in territories where a significant amount of the generation capacity is susceptible to natural gas delivery interruptions. New contracts may need to be signed for the construction of additional natural gas transportation infrastructure. Furthermore, Figure 7-5 compares the 2012 firm and non-firm contracts in Gigawatts (GW). At present, interruptible (less costly) natural gas contracts dominate the electricity industry. From the operation point of view, power generators that are primarily required for maintaining the reliability at peak hours tend to run for a few hours daily; accordingly, asset operators may prefer interruptible natural gas services for power generation. Firm natural gas transportation services, in which purchases are charged at fixed reservation fees, do not provide customers time-of-day use rates and do not vary based upon the volume of natural gas delivered, may not be cost-effective when considering the annual level of natural gas required for the peak hour supply.

There are differences between natural gas and electricity industries. The two sectors have different structures, physical attributes, regulatory processes, and cost recovery mechanisms. The core of these differences is represented by market driven natural gas transportation compared to the reliability driven electric transmission development mechanisms.

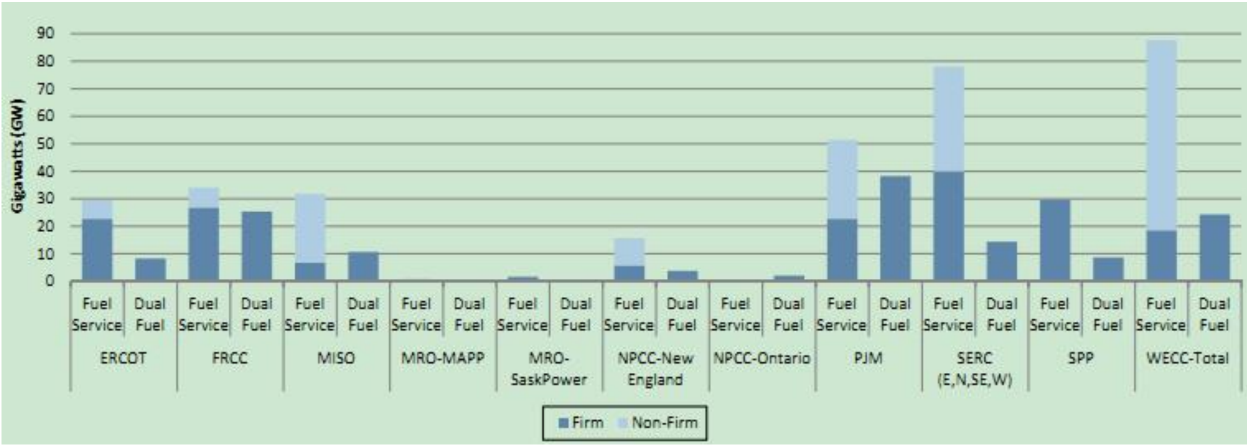


Figure 7-5: 2012 Natural gas services and dual-fuel capabilities for power generation by area
(Source: North American Electric Reliability Corporation)

The planning process for a new natural gas pipeline and storage infrastructure is based on contracts for firm services, in which most of the new or expanded pipeline capacity is constructed with long-term (at least 10 years) contractual commitments from natural gas shippers; while in some cases suppliers will fund a pipeline development to bring their product to a liquid trading. Natural gas suppliers are often unable to obtain the required certificate for new capacity without these contracts. Within this model, no capacity is constructed specifically to serve interruptible service requirements.

The planning process of electric power system, on the other hand, is more concerned with reliability and power quality. It is required that the future power grid provide secure, reliable, clean and high quality power supply, and be able to adapt to variety of power generation including that from renewable resources. According to a load forecast, power system planning would seek an economic scheme with an acceptable level of system reliability. Therefore, reliability assessment plays a critical role in power system planning. One major concern with current electric reliability assessments is that it assumes historically that most fuels are always available. These concerns have heightened the interest in studying natural gas–electricity reliability issues and have increased the importance of questions that power market participants, regulators, and system planners have about the adequacy of natural gas to satisfy growing natural gas-fired generation over time.

Most natural gas transportation failures result in pipeline capacity reductions. If the event requires any reductions in firm service rights, best efforts are made to retain service to human needs; that is, residential customers and other buildings, such as hospitals and nursing homes, where people reside. Therefore, in the event of a severe outage there is the potential that electric generators with firm transportation service could be curtailed. This risk of fuel inadequacy for the natural gas-fired generation has served as an impetus for electric system planners to employ both resource adequacy review and reliability review to assess infrastructure requirements. The result of these reviews allows the bulk power system to be operated in a manner that is resilient to disruptions.

7.3 Interface of Natural Gas and Electricity Infrastructures

Natural gas-fired plants provide an important linkage between natural gas and electric power transmission systems. While a variety of natural gas-fired power generation units is currently in operation, the most common ones are the newer and larger natural gas-fired combustion turbine (CT) and combined cycle (CC) units. While CTs usually are used as peaking units, CC units are used primarily as either cycling or base load units. These units require high pressure natural gas (i.e., 350 to 600 psi) which place greater requirements on pipelines and thus, heighten the need for coordination between natural gas and electricity.

Unlike other plants, natural gas plants operate on a just-in-time-inventory principle in the natural gas pipeline system for purchases, transportation, and the scheduling of deliveries. With the rapid growth in the utilization of natural gas-fired generators, the natural gas supply chain principle has an immediate impact on the operation of the electricity system. Pipeline deliverability can impact the operation of electricity system in several ways. A physical disruption in a pipeline, or compressor station, can interrupt the flow of natural gas or reduce pressure to multiple power generating units. At peak loading hours in the natural gas pipeline system, interruptible customers may be curtailed so that the pipeline may fulfill its contractual obligations to firm customers. As noted, firm customers usually contract up to 100 percent of the capacity in a pipeline, since pipelines do not build capacity to serve interruptible customers.

Electricity system also has the ability to adversely impact the pipeline deliverability. The sudden loss of a large generator can cause several smaller CTs to be started in a short period of time, assuming the capacity is there and other generators are available. This sudden demand may cause a sharp drop in the pipeline pressure that could reduce the quality of service to other pipeline customers, including other generators. Electric power transmission system disturbances may also interrupt services to electric motor-driven natural gas compressor stations.

7.4 Planning Issues in Natural Gas and Electricity Industries

7.4.1 Pipeline Infrastructure Capacity Adequacy

Transportation service contract define the priority of natural gas supply for different customers in the natural gas transportation system. While the power industry's further dependence on natural gas-fired generation increases, natural gas generation will begin to serve base load, intermediate load, and peaking load requirements, whereas historically natural gas-fired generation has been used almost exclusively for intermediate and peaking loads. This shift is expected to cause a change in the demand for natural gas transportation services, from the historical reliance on interruptible transportation services to more firm transportation services. However, one major concern with natural gas-electric planning issues is that is there sufficient physical delivery capability to deliver natural gas to power plants at a time of peak demand.

ISOs, RTOs, market participant, and other government officials have conducted some studies to assess the capacity of the natural gas pipelines to supply generators under winter and summer design conditions looking out several years. The pipeline capacity adequacy varies for different regions based on the distribution of generation capacity and natural gas infrastructures.

A study conducted by ICF International about ISONE's concerns about pipeline limitations stated that each of the scenarios and cases examining natural gas supply and demand under winter design day conditions, there is not enough natural gas supply capability remaining to meet the anticipated power sector natural gas demand. The study also noted that the additional pipeline capacity that exists in non-winter periods, which is currently used by New England's natural gas-fired generators, will diminish as the LDC load continues to grow. Notably, the study was conducted assuming that all pipelines are fully available in each scenario (i.e., no contingencies, maintenance, etc.) and that flows on the various pipelines are perfectly coordinated in order to maximize the throughput on the pipeline system. Given those assumptions and the use of theoretical maximums, ICF has acknowledged that the study overestimates natural gas availability. The additional capacity that exists in the natural gas transmission pipeline system during non-winter periods is the capacity that is subsequently used by New England's natural gas-fired generators to convert natural gas into electricity. As this capacity diminishes over time, due to LDC load growth, it equally diminishes the amount of interruptible pipeline capacity, thus directly impacting the amount of natural gas-fired generation able to operate under non-firm natural gas transportation agreements.

The report prepared by Black&Veatch presents the risk of natural gas supply curtailment to electric generators within the service region of the ERCOT over a 1-Year, 5-Year and 10-Year time horizon. This study conducted a survey of electric generators within ERCOT's service region to assess their access to natural gas infrastructure to serve their natural gas demand. Based on survey responses, ERCOT's electric generators demonstrate reliability and redundancy of supply through their interconnections with multiple pipelines and access to a level of capacity that is well in excess of their peak natural gas needs. 60% of survey respondents (corresponding to 51,550 MW of nameplate capacity1) indicated interconnects with more than one natural gas pipeline. All the survey respondents that provided sufficient data to make an assessment of adequacy indicated access to capacity in excess of their peak needs. Natural gas pipeline infrastructure serving ERCOT generators was found to be adequate to meet anticipated peak demand during the analysis period in the scenarios analyzed. Although there is potential for isolated incidents, the fundamental supply/demand analysis undertaken in the study indicated the robustness of the natural gas pipeline infrastructure in meeting the needs of electric generators within ERCOT, even in the presence of strong competing demand from other markets and sectors.

EnVision Energy Solution prepared the "Embedded Analysis" for MISO to determine the number of days in which pipeline capacity would have been insufficient, based on the potentially higher capacity factors for the MISO natural gas fleet, without year-round firm transportation arrangements for the simultaneous maximum natural gas capacity requirements of the existing or "embedded" CTs and CCs separately and combined. This study presents that there is insufficient mainline capacity to the serve the potential 12.6 GW of coal-to-natural gas conversions operating at expected and maximum capacity factors. However, for the period 2016-2030, almost 90% of the pipelines have insufficient capacity for the existing embedded units plus the incremental 12.6 GW coal-to-natural gas retirement scenario.

7.4.2 Natural Gas Supply Vulnerabilities

Historically, large curtailments of natural gas to both electric generation and consumers within other demand sectors are generally considered rare events. The natural gas industry is considered by most industry observers to be relatively safe and to offer a high degree of reliable service. However, incidents leading to curtailments do occur. In addition, there are instances of upstream natural gas supply loss. Regions that depend heavily upon natural gas-fired generation can be particularly sensitive to such incidents, as they can impair electric reliability and cause regional wholesale prices to increase for a short period of time.

Natural gas supply sources, natural gas processing plants, and LNG import terminals may also have scheduled and unscheduled outage scenarios. For wellhead supplies, the most common form of significant forced outages are freeze offs caused by extremely cold weather, and hurricanes that lead to abandonment and shut-down of offshore production platforms and damage to various kinds of onshore and offshore production facilities. In the fall of 2005, the Gulf of Mexico was hit by two back-to-back hurricanes (Katrina and Rita). Almost 100% of both oil and natural gas production within the Gulf, both offshore and onshore, was shut-in.

While most of the natural gas-fired generation relies on the natural gas delivery system, the failure of pipeline plays an important role to consider the supply vulnerabilities. Unlike electric transmission lines, pipelines are able to operate with a temporary supply disruption, provided the natural gas pressures are maintained within acceptable limits. However, natural gas pipeline system usually presents a radial pattern, in which the critical pipelines connect a large number of distribution pipelines. On the interstate pipeline grid, the long-distance, wide-diameter, high capacity trunklines carry most of the natural gas that is transported throughout the nation. Some of the largest level of pipeline capacity exists on those natural gas pipeline systems that link the natural gas production areas of the U.S. Southwest with the other regions of the country (Figure 7-6).

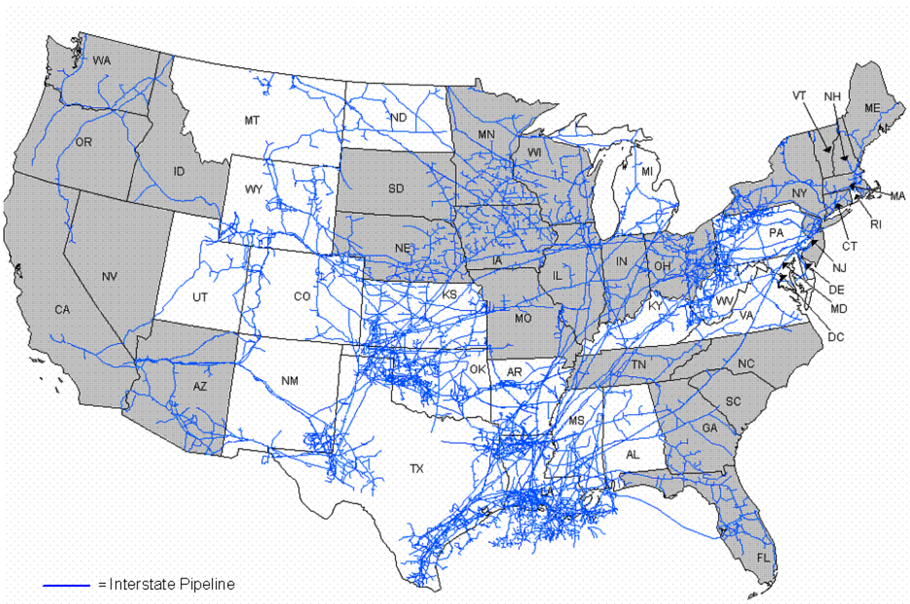


Figure 7-6: Interstate natural gas pipelines
(Source: U.S. Energy Information Administration)

In this case, a critical interstate pipeline may provide natural gas to a large number of natural gas-fired generators along with the distribution pipelines. Natural gas-pipeline disruptions (e.g., declines in production, pipeline failure) can propagate upstream through the rest of the natural gas delivery chain, ultimately disrupting delivery in areas outside a given electrical control area—or even outside an interconnection. Within a relatively short time, a major failure along an interstate natural gas pipeline could result in a loss of electric generating capacity that could exceed the electric reserves available to compensate for these losses.

On occasion, natural gas-fired generators become unavailable due to pipeline inspections and maintenance. Pipeline outages tend to occur during the pipelines' off-peak season (summer) – which coincides with the peak season of the electric system. While pipeline maintenance outages are to be expected, issues have occurred both due to the timing of planned pipeline maintenance relative to high electric load conditions as well as short notice of pipeline outages.

7.5 Strategies to Enhance the Industry Coordination

7.5.1 Improving the Coordination between Natural Gas and Electricity Operation

The scheduling discrepancy of natural gas and electricity system creates fuel procurement risk for natural gas-fired generators. Power units must base their requests for natural gas on estimates rather than a confirmed power schedule. From the perspective of electricity operation, to facilitate generators' ability to procure fuel, the markets must allow generators to modify their offers to recover their costs of acquiring fuel intra-day, and the timing of the electricity market must better align with the natural gas markets to facilitate reliable electric operations.

Currently, resources can only submit one energy market offer for each hour of the electric operating day and cannot change their energy market offer after 6 p.m. on the day prior to the electric operating day. This constrains generators in two ways. First, generators cannot reflect price differences over the two natural gas days that span a single electric operating day. Second, generators cannot reflect changes in fuel prices within the electric operating day in their energy market offers. Given these limitations on bidding behavior, when the cost of producing electricity (given real-time natural gas market prices) exceeds the real-time electricity prices, resources fueled by natural gas may choose not to generate energy by redeclaring their operating limits or using Limited Energy Generation (LEG) rules to remove all or part of their energy production capability from dispatch.

Hourly offer and intra-day offer solutions proposed by ISONE aims to improve the condition such that resources are able to reflect changes to costs in the energy market closer to the hour of operation. Accordingly, resources that must buy intra-day natural gas will be able to reflect their true costs, and generators that might not be able to get natural gas in real-time and want to switch to oil will have the ability to reflect the cost of switching.

The timing differences between the natural gas and electricity sectors may be contributing to the increasing incidence of natural gas-fired resources informing ISO that they do not have sufficient fuel to meet their generation commitments. To alleviate this problem and give system operators more notice of unavailability, so that long-lead time replacement generation can be secured and reliability maintained, ISONE proposes to move the timing of the day-ahead market so that generating schedules are published before the Timely nomination deadline for natural gas, and before the primary natural gas trading period (i.e., before 10:00 a.m.).

Information enhancements between the electricity and natural gas operators also play a critical role to reduce the uncertainty for both systems. Regarding information from generators, information on fuel schedules and any differences between cleared amounts are considered to be submitted. Better information from the pipelines regarding their operations including the schedules, maintenance, and outages are also needed for ISO to make evaluation of the fuel availability of the natural gas-fired units.

Conversely, pipeline and storage operators as well as LDCs with natural gas generation in their distribution system need improved information about the potential impacts on their operations from planned or unplanned generation or transmission outages, expected changes in electricity demand, and expected changes in renewable generation. Outages on the electric transmission system can impact natural gas flow and pressure on natural gas pipelines due to dispatch of natural gas generation that does not have a nomination.

7.5.2 Natural Gas Storage

There are several kinds of natural gas storage systems, including abandoned natural gas and oil reservoirs, horizontal wells, salt dome caverns and aquifers. In addition, natural gas can be stored at low pressure in large above ground vessels (i.e., this is very expensive and not typically used by industry) or it can be liquefied (i.e., liquefied natural gas) and stored in large, insulated, above ground vessels. Typically, natural gas storage is connected to natural gas transmission systems in the production area. However, for some large LDCs, natural gas storage can be integrated into their systems at the market area. Either way, natural gas storage is a critical key element in maintaining both reliability and flexibility.

Currently there are approximately 430 storage fields in the United States and another 28 in Canada. There are numerous ways to describe this capacity, with the most common measures being working natural gas capacity and maximum deliverability. In addition, there is a significant range in the capabilities of these fields, as some are very small and others are part of large complexes, such as Leidy, Pennsylvania and Dawn, Ontario. Furthermore, as a result of geology, U.S. storage fields are fairly concentrated. For example, storage facilities in the states of Pennsylvania, Ohio and West Virginia account for about 24 percent of the total working capacity, whereas Michigan and Illinois, in the Midwest, account for approximately another 23 percent and in the Gulf and southwest production area, Texas, Louisiana and Oklahoma account for approximately an additional 22 percent. These eight states plus California (i.e., about six percent) account for about 75 percent of the U.S. working capacity for storage with the remaining 25 percent spread out over 22 other states. 21 states currently have no natural gas storage capability.

Historically, the primary reason for natural gas storage was that it was the least expensive means of accommodating the large difference between summer and winter demand requirements. As a result, natural gas traditionally has been injected into storage fields in the non-winter months and withdrawn in the winter months to meet peak load requirements. The storage helps to balance the flow in the pipeline system and maintain contractual balance.

With the growth in natural gas demand for the electricity sector, natural gas storage is now also used to provide a variety of services for electric utilities, which can have large swings in their daily load requirements. Self-owned natural gas storage might be one option for the large-scale natural gas-fired plant in the future. When traditional supplies cannot meet the demand of natural gas-fired generation in the peak demand, natural gas storage facilities could help to balance the natural gas consumption as back up fuel. Storage could also be used to reduce the risk of fuel availability caused by unforeseen accidents. These may include the factors such as severe weather conditions, or malfunction of natural gas delivery system.

7.5.3 Dual-fuel Switch Capabilities

Unlike coal and oil-fired generators, natural gas-fired generators are supported by the real-time delivery of natural gas through the available pipelines. In this sense, dual-fuel switching capabilities may help mitigate natural gas fuel shortage risks during natural gas peak demand or other extreme conditions. Fuel switching enables a simple or combined cycle generating turbine to alternate between fuel sources, typically natural gas and some type of fuel oil. Fuel switching can be as simple as a control room operator pushing a button which automatically switches to oil, or as complicated as having to remove natural gas injectors and install oil injectors in every position around the boiler, a process that can take days rather than minutes. It is common for units that switch to an alternate fuel type to experience a capacity derate, since normally each unit is designed to most efficiently burn a particular fuel.

The choice to perform fuel switching is primarily based on four factors: 1) reliability; 2) cost; 3) environmental restrictions; and 4) the availability of natural gas. Running the generating unit on alternate fuels, such as fuel oil, may cost up to twice as much on a MW basis with similar gains in pollutants. And environmental and air quality control restrictions, which vary by state, may limit the number of hours per year a generator is allowed to run on fuel oil. However, if a unit is needed for reliability, systems should be in place to ensure energy security—that is, reliability should be maintained regardless of other conditions. Fuel switching capability was a more desirable option in the past, when the relative prices of natural gas and oil fluctuated, making one or the other more economical at any given time. Given the decline in natural gas prices, this option has become less valuable.

However, given a rise in the amount of natural gas-fired generation, as well as projected into the future, a higher-degree of reliability is realized where fuel-switching is available. In essence, should a pipe disruption occur and loss of natural gas fuel imminent, generators with the ability to run on an alternate fuel, could withstand and “ride-through” the pipeline disruption without a significant impact to the bulk power system. With sufficient pipeline packing and the ability to quickly switch to an alternate fuel (and as well as sufficient fuel) these generators could reduce the risk from the fuel availability caused by the natural gas delivery system and ultimately enhance the overall reliability of a given power system.

7.6 Summary

Over the past decade, natural gas-fired generation rose significantly from 17 percent to 25 percent of U.S. power generation and is now the largest fuel source for generation capacity. Natural gas use is expected to continue to increase in the future, both in absolute terms and as a share of total power generation and capacity. The power sector’s growing reliance on natural gas has raised concerns by ISOs, RTOs, market participants, national and regional regulatory bodies and other government officials regarding the ability to maintain electric system reliability when natural gas supplies to power generators are constrained. The extent of these concerns varies from region to region; however, concerns are most acute in areas where power generators rely on interruptible natural gas pipeline transportation and where the growth in natural gas use for power generation is growing the fastest. The misalignment of scheduling and natural gas transportation capability also contributed to the gap between uncertainty of natural gas availability and electric system operation. From the perspective of long-term operation, dual-fuel capability and a variety of storage facilities may provide options to mitigate the risk with fuel availability. Meanwhile, improve the coordination and enhance the connection between the operation of the two industry is needed.

8. Implications of Regulatory Regimes for Coordinated Planning

Scope of work:

Task 8: Explain what the planning implications are due to various regulatory regimes and the issues that result from those differences. This should be an assessment of both intra-industry (natural gas and electric) as well as inter-industry (natural gas and electricity).

Deliverable: Explanation of planning implications, given the various regulatory regimes and issues that arise from those differences

8.1 Natural Gas Industry Regulation

8.1.1 Beginning of Industry Restructuring

Regulation of the natural gas industry in the United States has historically been a tumultuous ride, resulting in dramatic changes in the industry over the past 30 or more years. In April 1992, FERC issued its Order 636 and transformed the interstate natural gas transportation segment of the industry forever. Under it, interstate natural gas pipeline companies were required to restructure their operations by November 1993 and split-off any non-regulated merchant (sales) functions from their regulated transportation functions. This new requirement meant that interstate natural gas pipeline companies were allowed to only transport natural gas for their customers. The restructuring process and subsequent operations have been supervised closely by FERC and have led to extensive changes throughout the interstate natural gas transportation segment which have impacted other segments of the industry as well.

8.1.2 Overview of Current Regulations

The current regulatory environment in which the natural gas industry operates is much less stringent and relies more heavily upon competitive forces than in the past. The last twenty years have seen dramatic changes throughout the natural industry, spurred by its ever-changing regulatory environment. However, despite the restructuring and deregulation of some portions of the natural gas supply chain, there still exist significant regulatory oversights in the transportation and distribution of natural gas.

In the current regulatory environment, only pipelines and LDCs are directly regulated with respect to the services they provide. Natural gas producers and marketers are not directly regulated. This is not to say that there are no rules governing their conducts, but instead there is no government agency charged with a direct oversight of their day to day businesses. Production and marketing companies must still operate within the confines of the law; for instance, producers are required to obtain the proper authorization and permitting before beginning to drill, particularly on federally-owned land. However the prices they are charged are a function of competitive markets, and are no longer regulated by the government.

Interstate pipeline companies, on the other hand, are regulated in the rates they charge, the access they offer to their pipelines, and the siting and construction of new pipelines. Similarly, local distribution companies are regulated by state utility commissions, which oversee their rates, construction issues, and ensure proper procedure exists for maintaining adequate supply to their customers.

* ***Interstate Level***: The current regulation of transportation pipelines by FERC has designated that interstate pipelines can serve only as transporters of natural gas. In the past, interstate pipelines acted as both a transporter of natural gas, as well as a seller of the commodity, both of which were rolled up into a bundled product and sold for one price. However, since FERC Order 636, interstate pipelines are no longer permitted to act as merchants and sell bundled products. Instead, they can only sell the transportation component, and never take ownership of the natural gas themselves. Pipelines must also now offer access to their transportation infrastructure to all other market players equally, referred to as open access to the pipelines. This allows marketers, producers, LDCs, and even end users themselves to contract for transportation of their natural gas via interstate pipeline, on an equal and unbiased basis. FERC has jurisdiction over the regulation of interstate pipelines and is concerned with overseeing the implementation and operation of the natural gas transportation infrastructure. FERC obtains its authority and directives in the regulation of the natural gas industry from a number of laws; namely the Natural Gas Act of 1938, the Natural Gas Policy Act of 1978, the Outer Continental Shelf Lands Act, the Natural Gas Wellhead Decontrol Act of 1989, and the Energy Policy Act of 1992.
* ***Intrastate Level***: The regulation of local distribution companies has much the same objective as regulation of interstate pipelines, including avoiding the exercise of market power, protecting customers who rely on their supply of natural gas from a single source (captive customers), and ensuring that the rates and prices set by an LDC are fair and equitable. State regulatory utility commissions have oversight of issues related to the siting, construction, and expansion of local distribution systems. Although these general objectives generally hold across states, there are different processes and regulations in place across the country.

Regulation of distribution is currently undergoing a process of change, with the adoption by many states of programs aimed at exploring and instituting retail choice programs. These programs allow natural gas consumers more flexibility in arranging the delivery of their natural gas, including allowing many customers the option of purchasing their own natural gas, and using the distribution network of their LDC simply to transport that natural gas.

8.2 Electric Power Industry Regulation

The vertically integrated utility characterized the early history of the electric power industry. During the 1990s, Congress and the FERC acted forcefully to create competitive markets for wholesale electricity and to spur entry into the generation business by new players. FERC allowed most generation owners to use "market pricing" rather than cost-based pricing. FERC, in its 1996 Order 888, required investor-owned utilities who owned transmission facilities to make them available to their competitors, so that they could compete on comparable terms. FERC also encouraged utilities to create corporations called independent system operators (ISOs), which were later converted into RTOs. ISOs and RTOs in the U.S. are regulated by FERC because they provide transmission service and wholesale sales in interstate commerce. The FERC's oversight of ISOs and RTOs concentrates on transmission rules, reliable real-time operation of the electric grid, independence from market participants, competitiveness of power markets, and ensuring adequate supply. ISOs took over many of the grid operation functions.

Electricity deregulation in the United States which restructured and unbundled electric power generation, transmission and distribution is now more than 15 years into operation. Currently, the electric power industry in the United States is regulated by both state and federal regulatory bodies. Some aspects of the industry, such as interstate transmission and wholesale power sales, are federally regulated; others, such as retail rates and distribution service, are state-regulated; and finally some activities, such as facility siting and environmental impacts, may be regulated locally. In this hierarchy, some functions, such as customer billing, are treated as monopoly services in many jurisdictions, and are treated as competitive in others.

In most cases, the U.S. Constitution allows federal intrusion into private economic activity only where interstate commerce is involved. Interstate transmission of electricity and natural gas clearly meets this test, and the courts have concluded that other parts of the electricity and natural gas supply system that affect interstate commerce, notably wholesale energy transactions, are subject to federal regulation, federal guidance, and/or federal oversight.

FERC handles most of the federal regulation of the energy sector, but some activities are regulated by EPA, federal land agencies (such as the Bureau of Land Management), or other federal bodies. State regulators adopt construction standards for lower-voltage retail distribution facilities, quality of service standards, and the prices and terms of service for electricity provided by investor-owned utilities. They also regulate consumer-owned (i.e., cooperative and municipal) utilities in some states, but in most states this is left to local governmental bodies and elected utility boards.

FERC has clear authority to regulate wholesale power sales, except when the seller is a public agency. The federal power marketing agencies, such as the Tennessee Valley Authority and Bonneville Power Administration, and local municipal utilities are specifically exempt from general regulation by FERC. Hundreds of companies are registered with FERC as wholesale power suppliers. While some own their respective power plants, marketers often do not; instead they buy power from multiple suppliers on long-term or spot-market bases, then re-sell it. Brokers arrange transactions, but never actually take ownership of the electricity.

8.3 Intra-industry Issues with Natural Gas and Electricity Planning

Many similarities exist between the natural gas pipeline planning and operations and the electrical transmission system planning and operations, but significant differences also exist. These differences occur because transmission system owners have less control over the size or the location of electrical loads served by the transmission system, or in the timing of the use of electricity by the ultimate customer. A pipeline, on the other hand, knows the exact location of customers who have a firm right to transportation capacity, and has contracts in place that describe exactly how much firm transportation capacity each customer may call upon.

8.3.1 Electric Power System Planning

Electrical systems are regulated by a combination of federal, state, and local authorities. FERC approves the rates for transmission service for wholesale electrical transactions. State or federal authorities usually approve electrical system expansion for major facilities—but it is not required for all projects. Retail electric rates are approved by state commissions for regulated utilities, local governments for municipal utilities, or consumer-owner boards for cooperative utilities. Interstate transmission is usually planned regionally. In RTO/ISO areas, RTO/ISO plans transmission through a stakeholder process according to the FERE Order 890. In non- RTO/ISO areas, transmission is planned by utility territory or collaboratively within states.

In general, the owners of electrical systems anticipate load growth, and plan, design, and construct a transmission system that meets specific NERC Reliability Standards and that is capable of serving the forecast customer demands. The nature of the electrical grid, with numerous nodes where facilities are interconnected, and multiple parallel paths for electricity to flow, results in a flexible, robust electrical delivery system. Often, capability exists to accommodate growth in demand or to provide service to customer demands from alternative generation sources. NERC Reliability Standards dictate a layer of protection in transmission planning—utility planners must look at adding system backup, or robustness, to cover a scenario called a “single contingency situation” such as the failure of a transformer or other significant event that causes the outage of a transmission line or large generator. These single contingency scenarios are known as N-1 (N minus one) conditions. The general philosophy is that no single failure of a piece of equipment connected to or comprising the transmission network should cause a large number of customers to lose power. Transmission designers further test the system design by looking at scenarios involving two or more equipment failures (known as N minus one minus one scenarios or N-1-1). To recognize the specific regional attributes of its transmission grid, some operation and planning areas require additional planning standards. For example, some systems must be designed so that it can handle electric demand under extreme weather conditions (often referred to as a 90/10 load), the outage of the two most critical generators, and/or limitations on the use of fossil fuel-fired peaking generation units. By using these and other criteria to plan and design the generation and transmission system, transmission utilities seek to ensure that customers rarely lose power because of a problem on the bulk power system. Most customer outages are caused by a local problem on the distribution system such as a tree coming in contact with an overhead wire.

8.3.2 Natural Gas System Planning

Since the interdependency between electric power system and natural gas system is more concerned about the natural gas transmission, so we focus more about the planning of new pipelines which include the compressors. With restructuring, FERC regulations evolved to rely on contractual commitments by the shippers on the pipeline as a demonstration of market need along with the coexistence of supply. The contractual commitments of pipeline customers known as shippers is considered a superior method to evaluating need in a competitive market setting, compared to a review of competing projects conducted by regulators. The evaluation of need requires that the pipeline bring to FERC legally binding precedent agreements showing that the pipeline will be fully or nearly fully subscribed for a minimum of 10 years. Contracts for interruptible service are not included in the demonstration of market need. Only contracts for firm service are included within that evaluation. The rates charged for firm service, which include fixed, monthly reservation, or “demand” charges to reserve the capacity, are often higher than non-firm charges and can present challenges to any pipeline customer wishing to receive natural gas transportation service during a limited number of hours each month.

In general, pipelines react to load growth. FERC will generally not authorize new pipeline capacity unless customers have already committed to it (firm delivery contracts), and pipelines are prohibited from charging the cost of new capacity to their existing customer base. Thus, additional customers request firm service from a pipeline that then adds new facilities or improves existing facilities, results in new pipeline capacity closely matches the requirements of the new customers. If all of the pipeline’s firm customers use their full capability, little or no excess pipeline capacity will be available. This is a major difference between electric transmission and pipeline infrastructure construction. Electric transmission does not necessarily need to be approved by FERC, but transmission must be built to support speculative growth and socialized cost. Additionally, pipeline contingency planning standards, similar to transmission planning standards, do not exist. However, this does not mean that the pipeline system is not redundant. First, buried steel pipelines are inherently robust than and, therefore more resilient to extreme weather than transmission wires. Second, pipelines use series of side-by-side pipelines (called “loops”) that provide redundancy—even if one gets corroded, needs maintenance, or even loses integrity, the other loops can increase their pressure and make it up. The same is true of compressor stations.

Interstate natural gas pipelines are regulated by FERC, and approval for new major pipeline facilities is obtained from FERC. A significant amount of electric generation is served by LDCs and intrastate pipelines that are regulated at the state level. Pipeline tariffs for firm service, like electric transmission tariffs, are cost based. Interruptible natural gas service is provided on an as-available basis at volumetric rates.

An interstate natural gas pipeline construction or expansion project takes an average of about three years from the time it is first announced until the new pipe is placed in service. The project can take longer if it encounters major environmental obstacles or public opposition. A pipeline development or expansion project involves several steps: determining demand/market interest, publicly announcing the project, obtaining regulatory approval, construction and testing.

8.4 Inter-industry Assessment of Planning Issues

From the perspective of the natural gas industry, it is much more difficult to meet the needs of electric customers than it is to meet the needs of its residential, commercial and industrial customers. There are several reasons associated with the electric power natural gas loads. These characteristics represent significant challenges for the natural gas industry and in particular, the pipeline segment of natural gas industry.

8.4.1 Large Loads

Relative to other customer, electric power natural gas load usually represent larger loads than many of the LDC loads and in some cases, can exceed the capabilities of the smaller diameter pipelines. In addition, for the most part, these electric utility loads occur at a single point, whereas almost all the LDC loads are served over multiple city gates. Figure 8-1 compare the natural gas loads for individual residential, commercial and industrial customers with that of typical peaking and combined cycle units.

Relative Size (compared to residence-zero HDD)	Gas Requirement (CF per Hour)	Type of Customer/Application
0.05	4	Residence-summer day* (residential)
1	74	Residence-zero heating degree day (HDD)** (residential)
7	500	Major gas-heating shopping center in winter (commercial)
40	3,000	Major shopping center in summer w/gas cooling equipment (commercial)
2,700	200,000	Large urban food-processing plant (industrial)
20,000	1,500,000	100 MW combustion turbine (electric utility)
116,000	8,600,000	500 MW combined-cycle plant (electric utility)

**Well-insulated modern 2,500 square feet home with gas forced-air heat, gas hot water, and gas cooking.*
***Zero heating degree day refers to a day with no degrees below 65°F.*

Figure 8-1: Representative customers' natural gas requirements

(Source: Special Reliability Assessment: A Primer of the Natural Gas and Electric Power Interdependency in the United States, 2011, North American Electric Reliability Corporation)

8.4.2 High Pressure

Another challenging aspect for electricity loads is the associated high pressure natural gas requirements. Modern CTs have more stringent natural gas delivery requirements than older units. Higher required pressures and complex on-site natural gas cleanup and processing systems result in the potential for additional points of failure for the combustion turbine. A delivery pressure of 450-475 psi at the fuel skid is required for most popular CTs—recent technology requires even higher pressures. Consistent fuel quality is necessary for generators to meet operational and environmental requirements. These newer, larger, CT/CC units are less tolerant to variations in natural gas quality and pressure than older units. Some CTs require the natural gas to be heated prior to burning (hot natural gas units), thereby significantly increasing the start-up time from 10 minutes to 45 minutes. LDCs, on the other hand, have relatively low pressure requirement of about 1000 psi for their loads at city gates. In general, residential, commercial and industrial customers do not have high pressure requirements.

As the power industry has transitioned from the less efficient steam generator technology to the more efficient combined cycle technology for natural gas-fired generation, the pressure requirements in the power industry have increased steadily. While the normal operation pressure for interstate pipeline range from 900 to 1200 psi which is greater than the pressure requirements for newer generates, the key dilemma is the loss of pipeline flexibility to deal with the unexpected, or abrupt, changes in load requirements. This occurs because natural gas moves relatively slow (e.g., about 20 mph). As a result, interstate transmission companies typically would need to pack their pipelines in the evening, which results in increasing the pipeline pressure, in order to serve the required loads (i.e., nominated loads) the next day. Then during the day as customer requirements are met, the pipeline pressure declines.

The dilemma occurs when an unexpected event occurs (e.g., weather or unplanned outages) that increases load requirements. Such an event causes the pipeline to reduce system pressure in order to meet the unexpected loads. Usually the pipeline encounters little difficulty in meeting such unexpected load changes from LDCs. However, the large increased loads associated with an unexpected generating unit coming online can exhaust the line pack rather quickly for a pipeline, as well as reduce the pressure in the pipeline to below the pressure requirements for generators. These conditions are possible even when natural gas is nominated 24 hours in advance and the unit has firm transportation. While some natural gas-fired units have contractual requirements for the delivery of natural gas at certain pressures, real-time conditions may not necessarily allow for the desired pressure to be reached in a given extreme situation.

Electric utilities continue to increase their pressure requirements in order to improve their overall fuel efficiency. However, from the pipeline's perspective, pressure is not free and increased pressure requirements can impair overall system flexibility or response capability. Hence, there is a tension between the two industries that needs to be carefully addressed and coordinated. Line pack is also not free, which drives up costs of firm services, parallel to ancillary services and determining how much reserve capacity is needed.

8.4.3 Large Variation

The other challenging aspect for electric loads of the natural gas system is their variability. This occurs because natural gas-fired generation is used primarily to fulfill the intermediate and peaking segments of an electric utility's load profile, however in a few areas, such as Florida and California, natural gas-fired generation is also part of the base load segment of the load profile. The natural gas delivery to electric power consumers in 2012-2013 is shown in Fig. 8-2. The monthly swing nature of electric utility natural gas load profile is illustrated in this curve, in which the electric natural gas load would peak in summer. With respect to the seasonal variation in electric natural gas consumption, the graph illustrates that, in general, electric utility natural gas requirements peak during the summer season and that, on average, summer natural gas requirements can be double the consumption levels during the winter. However, there can be significant differences from this basic seasonal pattern for individual electric utilities.

8.5 Implications for Natural Gas-Electricity Planning

8.5.1 Integrating Fuel Supply Availability in Electricity Planning

Electric power resource planning is one element of a broader process that leads, ultimately, to the construction of additional bulk power facilities. To assess various transmission and non-transmission (generation and load) alternatives, planning models require large amounts of data and projections related to loads forecasting, generation, and transmission. Resource planners use detailed electrical-engineering computer models to assess these alternatives. Model results, combined with information on costs, environmental effects, siting, and regulatory requirements, lead to financial and regulatory assessments of different projects. Ideally, these plans lead to the construction of needed projects, cost recovery (including a return on investment) for owners, and rates that charge users for the services they receive.

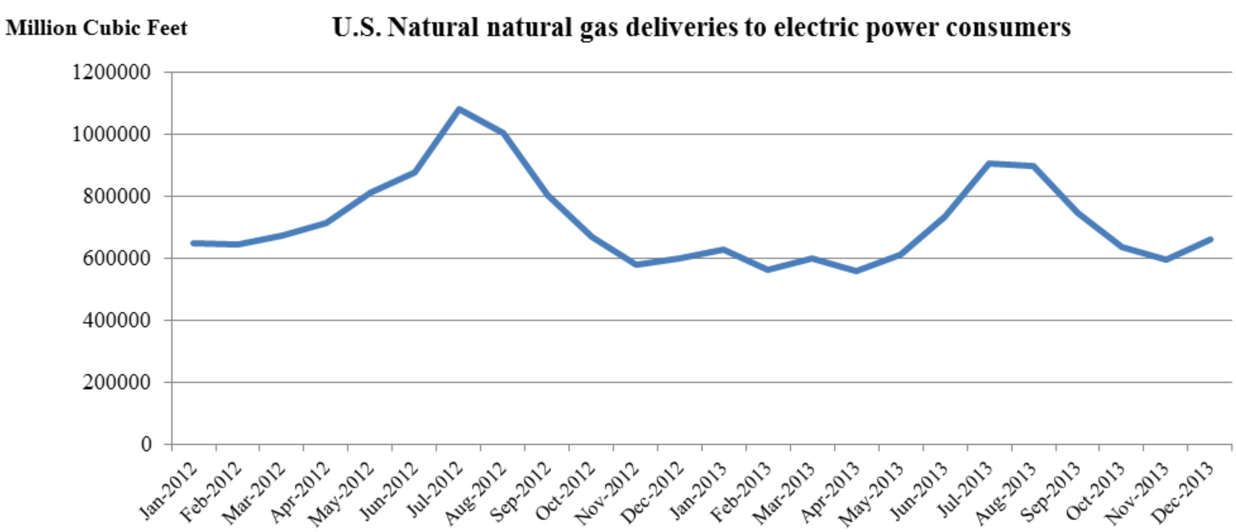


Figure 8-2: Natural gas deliveries to electric power consumers
(Source: U.S. Energy Information Administration)

The entire process is based on the assumption that the planned resources have access to the available fuel for redispatch. This is usually applicable to oil, coal, or nuclear units, which is not based on real-time delivery of fuel. While natural gas-fired generator owners are generally able to schedule and secure natural gas during the summer to meet seasonal peak demand, this flexibility decreases during winter months when pipeline use tend to peak and firm transportation customers have scheduled their full entitlements. Cold weather can also be responsible for increased infrastructure and supply disruptions, which are generally caused by freezing. Risks to natural gas wellheads, generators, and pipeline infrastructure due to freezing can expose the electricity industry to significant capacity shortages. While firm natural gas transportation significantly decrease the likelihood that fuel delivery will be curtailed, extreme events, such as wellhead freeze-offs causing decreased natural gas production (a force majeure event), could potentially lead to common mode failures of a significant amount of natural gas-fired generators. The expected increases in natural gas-fired generation will increase the amount of operational uncertainty that the system operator must factor into operating decisions. Therefore, integrating the fuel supply availability in electric resource planning is critical to ensure the reliable operation of the power system. In the traditional planning process, the fuel information associated with the generators need to be included (Fig. 8-3). Incorporation of a fuel supply availability model into a resource planning model would involve the natural gas supply network and other non-power natural gas load information.

8.5.2 Potential Adjustments in Electricity Sector

Electricity sector has been the largest consumers in natural gas industry. From the consumption side, electricity sector could design and adopt some solution to relieve natural gas infrastructure constraints by reducing the natural gas demand. The natural gas market usually experiences peak loads and widespread natural gas constraints in the winter, which is not within the electricity peak seasons. The electric market solutions would need to be able to reduce the requirement for natural gas-fueled generation in the natural gas constrained area during winter peak periods.

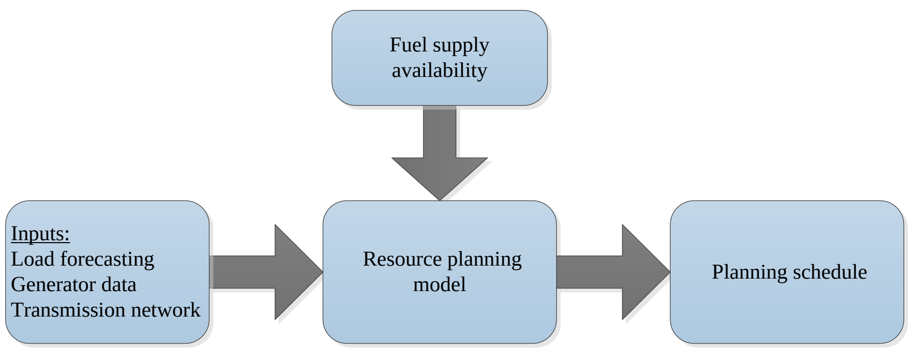


Figure 8-3: Integrating fuel supply availability into resource planning

Dual-fuel Capacity: Generators with dual-fuel capability could continue to provide energy during emergency situations when natural gas supply is not available or too expensive to dispatch. However, operators of dual-fuel generation capacity have been facing financial challenges over the last several years. The cost divergence between natural gas and oil-based fuel makes the dispatch of the alternative fuel out of economic merit most of the time. The environmental restrictions also limit the effectiveness of the dual-fuel capacity since the oil-fired generation usually has a much higher emission. If proper incentives are put into place, it is likely that a level of available dual-fuel capacity could provide at least a partial solution to natural gas-electric reliability issues.

Demand response: In current market structure, demand response and dual-fuel capacity could contribute to the natural gas demand reduction. The effectiveness of these solutions will be largely dependent on the level of demand reduction that could be achieved through implementing these solutions. Demand Response is a reduction in demand designed to reduce peak demand or avoid system emergencies. Hence, Demand response can be a more cost-effective alternative than adding generation capabilities to meet the peak and or occasional demand spikes. Most market operators have conducted demand response program in the system operations. For example, the demand response resource in ISONE is estimated approximately 1,100 MW, which represents 3.5% of total capacity. Figure 8-4 shows the cleared demand response in January 2013. This resource might be a relatively modest resource that is not offered on a large enough scale to significantly relieve natural gas infrastructure constraints. However, with the rapid growth of natural gas-fired generation and more stringent natural gas infrastructures, the demand response may be considered as a potential complement.

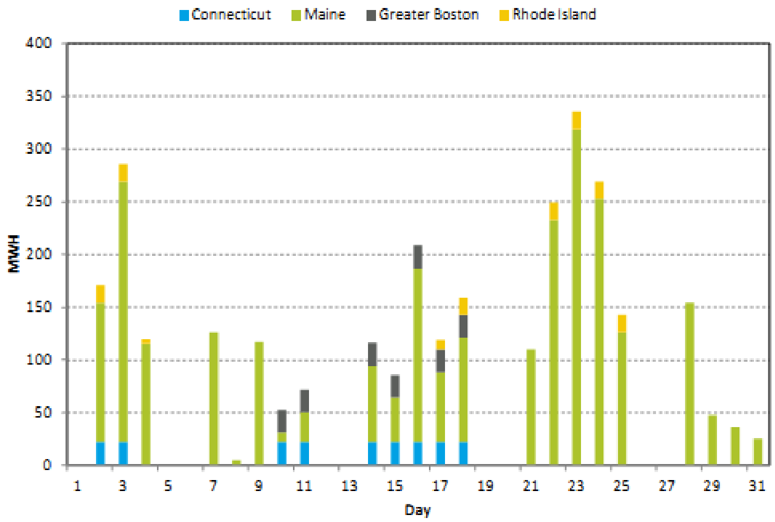


Figure 8-4: Cleared demand response in day-ahead market in January 2013
(Source: ISO New England, Black & Veatch Analysis, 2013)

8.5.3 Gas-Fired Generation Growth Projection for Natural Gas Infrastructure

Natural gas pipelines expand their capacity to meet customer loads who sign long-term firm contracts, whereas natural gas-fired power plants usually rely on interruptible transportation services. Many generators in wholesale electricity markets are reluctant to take firm pipeline service because current electricity market structures do not afford the opportunity to recover this higher cost of service. In addition, natural gas demand from residential, commercial, and industrial sectors is usually expected to grow modestly. Therefore the rapid growth of natural gas-fired power plants is usually not reflected in the natural gas planning process.

As illustrated in Fig. 8-5, electricity represents the largest sector (i.e., percent of primary) natural gas consumption, followed by industrial, residential and commercial consumers sectors. Through 2000-2013, electric power consumption has increased by 56%, which is much higher than the other three sectors. With the continuous transition of coal-to-natural gas fuel displacement which is driven by both the cost factor and environmental regulations, the natural gas demand from electric power is expected grow in the future.

A couple of alternatives are considered to potentially to address this issue.

- Providing incentives for generators to hold firm contracts, particularly the large-scale natural gas-fired power plants. Pipeline delivery service tariffs for firm service typically contain a fixed monthly charge for reserving capacity that is not recovered from the electric marketplace for the low capacity factor operation of natural gas-fired generation. Therefore, this would require the improvement of electricity market design to consider the generation cost of natural gas fired generation which is caused by the firm contract service.

- Fundamental institutional changes to the way natural gas and electric markets operate and interact, such as changing the economic regulatory regime to allow pipeline capacity to be constructed without firm commitments.

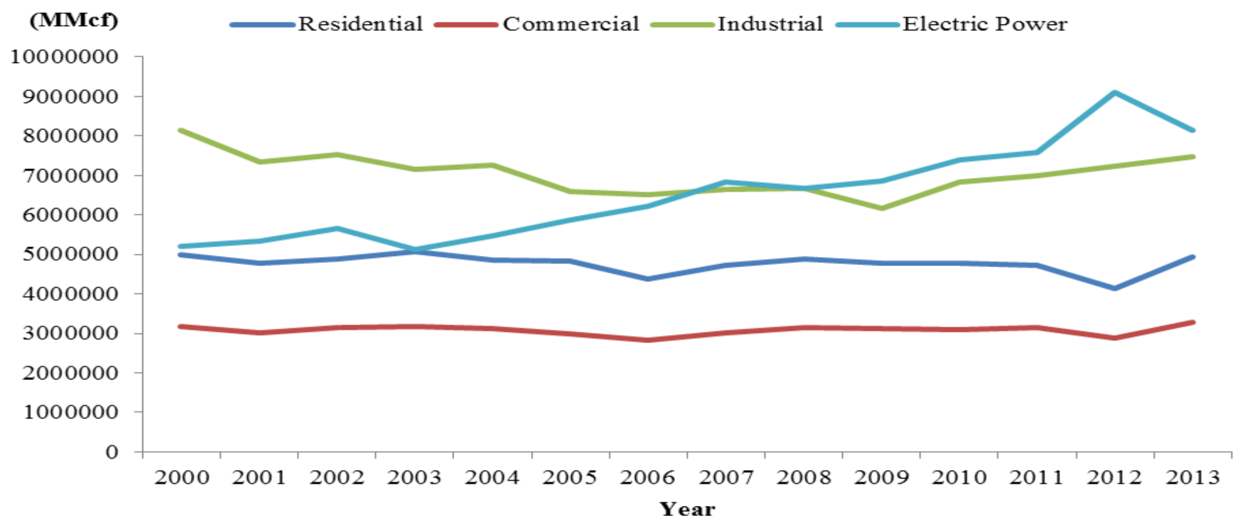


Figure 8-5: Natural gas consumption by end use through 2000-2013
(Source: U.S. Energy Information Administration)

8.6 Summary

Both natural gas and electricity industries have gradually grown from regulated market to today's restructured and competitive industries. The difference in the planning process still exists between the two industries because of the difference in physical infrastructures and regulatory processes. Planning process for a new natural gas pipeline and storage infrastructure is based on an underpinning of contracts for firm service entitlements for the contracting party. Generation capacity expansions are driven by a combination of resource adequacy requirements and market forces. The planning for power transmission infrastructure is triggered by reliability criteria under stressed system conditions.

As the largest consumer of natural gas, the electric power industry with its large loads, high pressures, and large variations bring significant challenges to the operation and the planning of natural gas system. Considering the gas demand in the natural gas infrastructure planning and integrating the fuel availability into the electric power system planning are necessary in order to better coordinate natural gas and electricity infrastructures. From the consumption side, the electricity sector can adopt certain solutions to relieve natural gas infrastructure constraints by reducing natural gas demand.

Regulatory measures to encourage fuel switching and pipeline expansion can take on several forms. Regulators should examine their policies to ensure that they do not discourage natural gas applications. They also should reduce transaction costs for potential fuel-switching customers and alleviate other obstacles with the goal of promoting efficient fuel markets. Overall, policies should identify and eliminate any regulatory barriers that threaten fuel switching or utility investments that are in the public interest. Particularly, they might want to review utilities' economic assumptions for assessing line expansion investments and review options to alleviate the burden of high upfront costs on potential customers.

9. Planning Tools in Natural Gas and Electricity Industries

Scope of work:

Task 9: Discuss the most often used planning tools available to the natural gas and electricity industries.

Deliverable: Discussion of the most often used planning tools for the natural gas and electricity industries.

Task 10: Explain the issues with the integration of natural gas and electricity planning tools.

Deliverable: Discussion on the integration of natural gas and electricity planning tools

9.1 Planning Tools for the Natural Gas Infrastructure

Existing planning tools available in the natural gas industry are mostly for operational planning. Examples of those tools and their vendors are shown in Table 9.1.

Table 9.1: Planning Tools for the Natural Gas Infrastructure

Planning Tools	Vendor
Synergi Pipeline Simulator (SPS)	DNV GL
Synergi Gas	DNV GL
Gas Price Competition Model (GPCM)	RBAC
GMM	ICF
North American Gas Model	Deloitte
Pipeline Optimizer	Energy Solutions International (ESI)

A brief discussion of those planning tools for the natural gas infrastructure is as follows.

- **Synergi Pipeline Simulator** (SPS, previously Stoner Pipeline Simulator) is used by engineering, planning and operational divisions to facilitate pipeline design, eliminate operational problems and improve performance for networks transporting natural gas, dense phase gas or (batched) liquid hydrocarbons. Utilizing a state of the art hydraulic model and web based GUI, a system can be quickly and easily configured to model a company's unique pipeline layout and simulate its pipeline operations. This model can then be used offline as an operations planning tool or connected to pipeline data (via SCADA or DCS) to provide critical real-time pipeline information. SPS is able to model a comprehensive range of pipeline assets including pipes, headers, block valves, check valves, regulators, compressors/pumps, instrumentation, controllers, sensors and actuators.
- **Synergi Gas** network modeling software identifies, predicts and helps address the operational challenges of a company’s gas assets, enabling the delivery of day to day operational efficiency for both distribution and transmission networks. Synergi Gas is built to analyze closed conduit networks of pipes, regulators, valves, compressors, storage fields, and production wells. Synergi Gas's steady-state, unsteady-state, and time-varying analysis engines can easily handle systems of 500,000 nodes or more, providing results needed to make crucial planning and operating decisions. Synergi Gas can be used to make daily operating decisions for load approval and operational support, to size main extensions and replacements for economy and performance, and to create long-term strategic plans that maximize your existing infrastructure.

- **Gas Pipeline Competition Model** (GPCM) was initially designed to forecast market shares among pipelines. It has been expanded to include all sectors in the natural gas market. GPCM has been designed to give analysts and managers a tool for forecasting natural gas availability and spot market prices in order to produce better analyses and make better decisions for their firms. It has been designed to be both powerful and flexible, enabling the user to analyze both short term and long term patterns and trends at whatever level of detail is desired. GPCM is used by medium to large size energy consultants, producers, pipelines, storage operators, and utilities companies. This includes most of the industry leaders in each area. GPCM computes Forecasts of natural gas industry activity. The output from GPCM consists of the following types of items: production and spot market prices by region; pipeline receipts from producers by zone; pipeline flows from zone to zone; transportation prices and discounting by pipeline and zone; transfers between pipelines at interconnects; injections into and withdrawals from storage; deliveries by pipelines to customers; gas supply available to each customer in each region; market clearing prices in each region. Each of the GPCM outputs is produced for each period of the scenario being run. The standard periodicity is monthly, with reports presenting results by month, season, and year.
- **Gas Market Model** (GMM), a nonlinear programming software model, provides clients with analysis and forecasts of regional gas markets throughout North America. The structure of GMM incorporates fundamental economic relationships between natural gas price, supply, storage, pipeline transport, and demand that act to equilibrate natural gas markets. A new short-term (36 month) forecast is calibrated with near-term information on a monthly basis. A new long-term forecast to 2025 is created quarterly. GMM solves for monthly natural gas production and demand, storage injections and withdrawals, pipeline flows, and natural gas prices in more than 110 regional market locations throughout North America. Weather, alternative fuel prices, pipeline capacity, and economic activity are just some of the key drivers of the model that can be changed for scenario analysis. GMM is ideal for studying supply and demand dynamics that drive the entire North American market and also ideal for studying regional developments given the broader trends driving the entire market.
- The **North American Gas Model** simulates how regional interactions of supply, transportation, and demand determine market clearing prices, flowing volumes, storage, reserve additions, and new pipelines throughout the North American natural gas market. The North American Gas Model is unique because of its ability to forecast market clearing prices and basis differentials among producing and consuming regions and thereby contributes to the valuation of a wide range of gas assets. It is based on the North American Regional Gas Model (NARG) that has been used for nearly every pipeline expansion decision and resource basin profitability evaluation in North America since 1983. Accompanying the North American Gas Model is a database that enumerates and quantifies all gas plays in North America. This database contains field size and depth distributions for every play, with a finding and development cost model included. This database connects these gas plays with other energy products such as coal, power, and emissions. It also includes factors to model the growth of synfuels, LNG imports, and oil-for-gas substitution. Finally, it contains over 300 demand nodes representing regional demands from residential, commercial, industrial, electric generation, and transportation consumers. There are both short- and long-term versions of the North American Gas Model. The long-term version covers 40 years based on fundamental economic factors. The short-term model expands the long-term model by embedding a dynamic behavioral model of natural gas storage. This has made it easier and more accurate valuing storage investments, identifying maximally effectual

storage field operations, positioning, optimizing cycle times, demand-following modeling, pipeline sizing and location, and analyzing the impacts of LNG.

- **Pipeline Optimizer** is an offline software package used for pipeline engineering and planning. Pipeline Optimizer performs accurate pipeline simulations to analyze the effect of various pipeline routes, pump station locations, pump unit selections and configuration, and pipe properties using a succession of steady-state model that accurately describe pipeline physics in non-transient situations. A comprehensive set of pipeline data can be configured for multiple pipelines using the graphical user interface. The user can apply Pipeline Optimizer to model and study capacity, Drag Reducing Agents (DRA) usage, operating costs, power contract usage, fuel usage, and downtime; Study realistic operational schedules and perform "what-if" scenarios; Choose optimal pump combinations and DRA injection rates during a run; Reduce both power consumption and DRA by 2-3% or more depending on the current efficiency of the pipeline operations.

Pipeline Optimizer's wide range of pipeline modeling capabilities includes the following functions:

- A comprehensive library of pipeline configuration modeling components
- User-adjustable tuning parameters to facilitate matching of historical data with Pipeline Optimizer results
- Detailed modeling of batch liquid operations, including:
- Batch origination and pumping at the pipeline inlet
- Batch origination and pumping at mid-line locations
- Full stream delivery at mid-line locations or the pipeline terminus
- Constant-percentage and fixed-rate strips or injections at mid-line locations
- Multiple operations at the same location for a single batch
- Specification of a fixed volume to bypass a terminal before initiating a strip or injection, between successive activities in the same batch, or after the end of the last activity
- Automatic strips and injections. These strips and injections occur at the slowest possible rate that the requested volume is delivered without violating any flow limits or slowing down the main-line flow.
- Simultaneous full-line delivery of one batch and pumping of another batch. Pipeline Optimizer synchronizes the two activities to end at the same time.
- Rule-based routing of batches based on origin, destination, and product in complex pipelines
- Extensive set of controls triggered by a specific time or a specific event (e.g., a batch arrival, or a certain product type being present at a certain location), including line shutdown controls
- Automatic bottleneck analysis, including:
- Finding bottlenecks due to pipe yield strength or inadequate head at a station
- Recording the bottleneck for each step as well as what fraction of the run each bottleneck condition was active
- Wide assortment of engineering reports.

9.2 Planning Tools for the Electricity Infrastructure

There are three main types of planning tools for electric infrastructure: reliability, production costing, and resource optimization. Examples of those tools and their developers/vendors are shown in Table 9.2.

Table 9.2: Planning Tools for the Electricity Infrastructure

Type	Name	Developer/Vendor
Reliability tools		
	COMposite RELiability (COMREL)	University of Saskatchewan
	Composite Reliability Using State Enumeration (CRUSE)	Powertech Labs Inc.
	Multi-Area Reliability Simulation (MARS)	General Electric
	PSSE/TPLAN	Siemens PTI
	Transmission Reliability Evaluation of Large Scale System (TRELSS)	Electric Power Research Institute
Production cost simulation tools		
	PCI GenTrader	Power Costs, Inc.
	Generation and Transmission Maximization (GTMax)	Argonne National Laboratory
	Multi Area Production Simulation Software program (MAPS)	General Electric
	Ventyx PROMOD	Ventyx
Resource optimization tools		
	Electric Generation Expansion Analysis System (EGEAS):	Electric Power Research Institute
	Integrated Planning Model (IPM)	U.S. Environmental Protection Agency
	PLEXOS	Energy Exemplar
	Regional Energy Deployment System (ReEDS)	National Renewable Energy Laboratory
	Ventyx Strategist	Ventyx
	WASP-IV	Argonne National Laboratory
Co-optimization tools		
	COMPETES	Energy Research Centre of the Netherlands
	GENTEP	Illinois Institute of Technology
	LIMES	Potsdam Institute for Climate Impact Research
	NETPLAN	Iowa State University
	PRISM	Electric Power Research Institute
	REMIX	German Aerospace Center DLR
	ReEDS	National Renewable Energy Laboratory
	SWITCH	University of California at Berkeley

A brief discussion of those planning tools for the electricity infrastructure is as follows.

- **Reliability tools** do not identify solutions but just evaluate them. Both deterministic and probabilistic tools exist and are heavily used in the planning process. Deterministic tools include power flow, stability, and short-circuit programs, providing yes/no answers for specified conditions. Probabilistic tools compute indices such as loss-of-load probability, loss of load expectation, or expected unserved energy, associated with a particular investment plan. A representative list of commercial-grade reliability evaluation models include COMREL, MARS, TPLAN, and TRELSS.

- **COMposite RELiability (COMREL):** The COMREL program is based on the analytical concepts of reliability assessment and makes use of the contingency enumeration technique for the evaluation of composite systems. The program handles independent outages as well as common mode events and station-originated outages when required. The program is equipped with three network solution techniques (i.e., a transportation model, a DC load flow algorithm and an AC load flow algorithm) for analyzing system contingencies.
- **Multi-Area Reliability Simulation (MARS):** The MARS engine enables electric utility planners to quickly and accurately assess the ability of a power system, comprised of a number of interconnected areas, and to adequately satisfy the customer load requirements. Based on a full sequential Monte Carlo simulation, MARS performs a chronological hourly simulation of the system, comparing the hourly load demand in each area to the total available generation in the area, which has been adjusted to account for planned maintenance and randomly occurring forced outages. Areas with excess capacity will provide emergency assistance to deficient areas, subject to transfer limits between the areas.
- **PSSE/TPLAN**: TPLAN is a probabilistic contingency analysis tool integrated into PSSE. The probabilistic contingency capabilities feature easy configuration, detailed modeling of remedial action schemes, effective identification of voltage collapse conditions, and automatic handling of generation dispatch and load shedding requirements. These combined features provide program users with an all-inclusive tool to evaluate transmission reliability performance in large or small power systems on a deterministic and probabilistic basis.
- **Transmission Reliability Evaluation of Large Scale System (TRELSS)**: TRELSS is a five program software package that uses enumeration of generation and transmission contingencies to evaluate power network reliability. TRELSS is designed to aid electric utility system planners in the reliability assessment of bulk power transmission systems. However, TRELSS is powerfully suited to perform traditional deterministic analysis. With its ability to systematically generate contingencies TRELSS makes possible rapid screening of large portions of the transmission grid. TRELSS expands on traditional contingency analysis by modeling protection system response to faults. Contingency analysis is widely understood to mean independent component outages TRELSS computes reliability indices using a contingency enumeration approach, which involves selection and evaluation of contingencies, classification of each contingency according to specified failure criteria and accumulation of reliability indices. Three basic methods of reliability assessment are available: the System Problem Approach and Contingency Screening. TRELSS incorporates a wide range of models for reliability assessment including: efficient ranking of contingencies based on circuit overloads and voltage problems, multiple load level analysis, AC or DC Network Models, generation dispatch including full economic dispatch, powerful linear-programming-based remedial actions utilizing control actions such as shunt switching, adjustment of phase shifters, transformer tap adjustment and three classes of load curtailment.

- **Production cost programs** have become the workhorse of long-term planning. These programs perform chronological optimizations, often hour-by-hour, of the electric system operation, where the optimization simulates the electricity markets, providing an annual cost of producing energy. Although production cost models make use of optimization, it is for performing dispatch, and not for selection of infrastructure investments. Therefore, production cost models are equilibrium/evaluation models with respect to an investment plan. A representative list of commercial grade production cost models include PCI GenTrader, GE MAPS, GTMax, Ventyx PROMOD. Production cost programs usually incorporate one or more reliability evaluation methods.

- **PCI GenTrader**: GenTrader is a generation portfolio optimization tool. GenTrader can be used across multiple time horizons to optimize portfolio positions for as little as 15-minutes and as long as 30-years. GenTrader features simultaneous local and global emission constraint optimization for NOx; multi-tier fuel constraint optimization; multi-area and multi-commodity capabilities for arbitrage decisions and operations; integrated platform for deterministic and stochastic simulations; unified modeling for both short-term and long-term studies with recursive outage adaptation; full co-optimization for all customer resources and obligations considering all commodities (energy, reserves, regulation, fuel, and emissions); deterministic and stochastic production costing runs, which can be used to simulate the impact of load uncertainty, forced outages, and fuel cost uncertainties on revenues, production costs, and profits and losses; market price scenarios to analyze how a portfolio's profit and loss would behave under varying market conditions.
- **Generation and Transmission Maximization (GTMax):** The GTMax model helps study complex marketing and system operational issues. It can be used by utility operators and managers can maximize the value of the electric system, taking into account not only its limited energy and transmission resources, but also firm contracts, independent power producer (IPP) agreements, and bulk power transaction opportunities on the spot market. GTMax maximizes net revenues of power systems by finding a solution that increases income while keeping expenses at a minimum. At the same time, the model ensures that market transactions and system operations remain within the physical and institutional limitations of the power system. GTMax considers detailed operational limitations, such as power plant ramp rates and hydropower reservoir constraints. GTMax also simulates power plant seasonal capabilities, limited energy constraints, transmission capabilities, and terms specified in firm and IPP contracts. GTMax produces financial market clearing prices, which can be used to determine whether an investment is financially viable, given the prevailing market rules for bidding, capacity credits, and ancillary services. In addition, GTMax looks at locational issues when building new power plants or transmission lines, identifying regions with high marginal values that may be more attractive for future investments.
- **Multi-Area Production Simulation (MAPS):** MAPS accurately models the economic operation of a power system, so decision makers can assess the value of generating assets or identify costly transmission bottlenecks. It analyzes hour-by-hour market dynamics to capture complex interactions between generation and transmission systems. MAPS gives users the flexibility of performing either zonal or nodal analysis. The MAPS nodal software recognizes normal and security-related transmission constraints to model the actual electrical system in detail. This allows users to analyze market opportunity for an individual company or examine the economic interchange of energy between several companies in a region.
- **Ventyx PROMOD**: Ventyx PROMOD is a Fundamental Electric Market Simulation solution which incorporates extensive details in generating unit operating characteristics, transmission grid topology and constraints, and market system operations to support economic transmission planning. As a generator and portfolio modeling system, Ventyx PROMOD provides nodal Locational Marginal Price (LMP) forecasting and transmission analysis by producing algorithms that align with the decision focus of management. Key features of PROMOD include LMP forecasting (for selected nodes, user-defined hubs, or

load-weighted or generator-weighted zones), Financial Transmission Right (FTR), Congestion Revenue Right (CRR) and Transmission Congestion Contract (TCC) valuation (for quantifying market prices, identifying binding constraints, and evaluating the economic impacts of constraints significant to the business), renewable energy curtailment (to simulate the effects of intermittent energy schedules from wind and solar projects on transmission congestion, and forecast the amount of energy that would be curtailed considering the opportunity costs from production tax credits), and economic transmission analysis (to quickly evaluate the economic benefit/cost, the increase/decrease in hourly/monthly congestion, and the increase/decrease in reliability metrics associated with transmission expansion and outage scheduling).

- **Resource optimization models** select a minimum cost set of generation investments from a range of technologies and sizes to satisfy constraints on load, reserve, environmental concerns, and reliability levels; they usually incorporate a simplified production cost evaluation, which includes a reliability evaluation. These optimization models identify the best generation investment subject to the constraints. However, at this point in time, these models generally do not represent transmission, or they represent it but do not consider transmission investments. A representative list of resource optimization models includes EGEAS, Plexos, Strategist, WASP-IV, IPM, ReEDS.
  - **Electric Generation Expansion Analysis System (EGEAS):** The EGEAS is a modular generation expansion software package. EGEAS is used by utility planners to produce integrated resource plans, evaluate independent power producers, develop avoided costs and environmental compliance plans, and analyze life extension alternatives. EGEAS is a set of computer modules that determine an optimum expansion plan or simulate detailed production costs for a pre-specified plan. Optimum expansion plans are developed in terms of annual costs, operating expenses, and carrying charges on investment. The objective is to find an integrated resource plan that meets the objective function specified by the user. The two objective functions in EGEAS include: minimizing total present worth costs and minimizing levelized annual customer rates. EGEAS can handle a wide variety of generation technologies including thermal (nuclear, fossil, combined cycle, combustion turbine), limited energy (hydroelectric, interruptible rates), storage (pumped hydro, cool storage batteries, compressed air), and non-dispatchable technologies (solar, wind, cogeneration, conservation load management). EGEAS can also analyze Demand-Side Management (DSM) options such as conservation, strategic marketing, load management, storage, and rate design.
  - **PLEXOS**: PLEXOS Integrated Energy Model is simulation software that uses mathematical programming techniques combined with the latest data models, to provide a high-performance, robust analytical framework that is auditable and transparent. PLEXOS meets the demands of market participants, planners, investors, regulators, consultants and analysts alike with a comprehensive range of features spanning all aspects of electric power and gas market modeling from economic dispatch and stochastic unit commitment, through medium-term market analysis and hydro and portfolio optimization, to long-term capacity expansion planning, all delivered through a single fully-integrated simulation engine, easy-to-use interface and common data platform. PLEXOS features seamless integration of unit commitment and economic dispatch, ancillary services, optimal power flow and locational marginal pricing, with Monte Carlo and stochastic optimization, renewables, emissions limits and gas production and transport; multiple integrated simulation phases from long through medium to short-term, decomposing constraints and optimizing hydro schedules; scalability

from single plant or portfolio optimization to simulation of large-scale systems with thousands of generating units and transmission nodes; optimizes from sub-hourly intervals as short as 1-minute to hourly, daily, weekly, annual and multi-annual timeframes.

- **Integrated Planning Model (IPM)**: The IPM is a resource optimization model used to evaluate the projected impact of environmental policies at a national level. It provides forecasts of least-cost capacity expansion, electricity dispatch, and emission control strategies for meeting energy demand and environmental, transmission, dispatch, and reliability constraints. IPM can be used to evaluate the cost and emissions impacts of proposed policies to limit emissions of sulfur dioxide (SO2), nitrogen oxides (NOx), carbon dioxide (CO2), and mercury (Hg) from the electric power sector.
- **Regional Energy Deployment System (ReEDS):** The ReEDS model is a multiregional, multi-period linear programming model of capacity expansion in the electric sector of the United States. The model performs capacity expansion but with detailed treatment of the full potential of conventional and renewable electricity generating technologies as well as electricity storage. The principal issues addressed include access to and cost of transmission, access to and quality of renewable resources, the variability of wind and solar power, and the influence of variability on the reliability of the grid.
- **Ventyx Strategist:** Strategist is an integrated resource optimization tool with a complete suite of utility resource planning applications. It can be used to assess the effects of market volatility on resource plans, analyze long-range rate strategies and its implications and optimize resources across multiple areas. Strategist includes forecasted load modeling, energy efficiency programs, production cost calculations including the dispatch of energy resources, optimization of future decisions, and nonproduction-related cost recovery. The PROVIEW module utilizes a proprietary dynamic programming algorithm to optimally select and rank alternative resource plans based on different objective functions including minimizing utility cost and average rates. Resource alternatives are evaluated while also considering purchases from and sales to a spot energy market. The DCE module calculates the benefit-cost ratios for each supply and demand alternative against a base resource plan. The CER module provides detailed capital project modeling that is critical to accurately evaluating the economics of resource alternatives that require capital outlay. It can be used to model the entire capital budget of a utility company or just the incremental capital projects associated with resource alternatives under evaluation
- **WASP-IV**: WASP-IV is designed to find the economically optimal generation expansion policy for an electric utility system within user-specified constraints. It utilizes probabilistic estimation of system production costs, unserved energy cost, and reliability, linear programming technique for determining optimal dispatch policy satisfying exogenous constraints on environmental emissions, fuel availability and electricity generation by some plants, and the dynamic method of optimization for comparing the costs of alternative system expansion policies.

- Co-optimization based planning models are a subset of the resource optimization model. Examples of co-optimization based planning models include COMPETES (Energy Research Centre of the Netherlands), GENTEP (Illinois Institute of Technology), LIMES (Potsdam Institute for Climate Impact Research), NETPLAN (Iowa State University), PRISM (Electric Power Research Institute), REMIX (German Aerospace Center DLR), ReEDS (National Renewable Energy Laboratory), SWITCH (University of California at Berkeley). More detailed discussion of these models can be found in the NARUC-sponsored Whitepaper on Co-optimization of Transmission and Other Supply Resources.

9.3 Integration of Natural Gas and Electricity Planning Tools

Nowadays, the planning of electricity system and natural gas system are carried out in a decoupled manner, i.e. different planning problems are performed where each system is self-contained. However, this does not mean that both systems are totally independent. In fact, the existing interactions are modeled by means of fixed coordinating parameters. Typically, three types of parameters can be identified: (a) the natural gas prices considered in the production cost functions of each natural gas fired power plant (NGFPP); (b) the natural gas availability for the NGFPPs; and (c) the natural gas consumption at each NGFPP. While the electricity planning requires, as input data, the (a) and (b) set of parameters, the natural gas planning needs, as input data as well, the (c) set of parameters. While the planning of the electricity system provides the natural gas consumption as a byproduct of planning process, the planning of the natural gas system would provide the natural gas price and availability as a byproduct. However, the following situations can occur:

- The total natural gas supply is not sufficient to meet the total natural gas demand. The natural gas supply to NGFPPs can be curtailed before than other demands, since NGFPPs usually have lower priority of supply. The limited transmission capacity in the natural gas pipeline network can imply that the same situation occurs in a specific node.
- The fixed natural gas prices, which determine the NGFPPs' production costs, cannot match with the natural gas marginal costs at nodes where NGFPPs are placed. These marginal costs depend on the natural gas consumption in the compressor stations and the binding pipeline's capacity constraints.

In a combined planning of the natural gas and electricity systems, the described coordinating parameters are endogenous results of the planning problem. This ensures that the optimal planning results for both can be achieved simultaneously.

While there are many software tools for the planning of the electric system and the planning of the natural gas system, very few tools so far have the capability of integrating the planning of both the electric system and the natural gas system. The electric planning models usually take into account a detailed representation of the electricity system, but do not consider the interaction with production, storage and transportation of the natural gas industry. That is, while a long-term electric planning process exists, what is missing is consideration of fuel security. The natural gas planning models usually consider gas consumption by electric generators only as loads, but do not consider the varying nature of such loads and the fact that such loads are subject to the constraints of a complex electric network. An integrated gas-electric model is needed to allow detailed modeling of the physical delivery of gas from fields, through pipelines and storage to gas and electric demands. In the integrated model, gas and electric models are solved simultaneously allowing decision makers to trade-off gas investments, constraints and costs against other alternatives. It should be noted that several planning tools for the electricity infrastructure has started to incorporate the modeling of natural gas infrastructure, such as the PLEXOS Integrated Energy Model.

The main issues of integrating natural gas and electricity planning tools include: data exchange between the two infrastructure systems, consideration of policy and contracts limitations of the two infrastructure systems, planning horizon differences of the two infrastructure systems (pipelines are not planned for forecasted growth; rather they are built to accommodate firm customers), scale of the integrated planning problem.

9.4 Economics of Coordinated Planning in the Two Infrastructures

The economics of coordinated planning in the natural gas and electricity infrastructures is a complicated topic because it is related to numerous factors such as policies, non-firm contracts, pipeline limitations, investment on natural gas unit, and economics of power systems.

The natural gas system focuses on minimizing the investment costs incurred by natural gas utilities which install new pipelines and city gates. Operation costs also include the cost of operating the natural gas facilities including compressors and storage. The natural gas system may also be developed in stages in order to reduce the cost associated with inaccurate natural gas demand forecasting.

Electricity planning often focuses on minimizing investment and operation costs over the planning period. Investment costs comprise the cost of building new generation and transmission facilities. Operation costs include the cost of operating the generation and transmission facilities as well as energy losses over the planning period. The planning is often developed in several stages in order to reduce the cost incurred by utilities for inaccurate forecasting of electricity demand.

The electricity planning tool would need to be synchronized to get information from natural gas system, including the price and the amount of natural gas that can be supplied to certain natural gas units. However, there are several challenges as listed below:

- Because the uncertainty associated with non-firm contracts in short-term planning and timing differences between natural gas and electricity days, it is hard to apply security constrained unit commitment (SCUC) to the planning tool.
- The long-term planning of natural gas and electricity systems has to be coordinated. Thus, the tool requires a large database for representing the two systems to analyze the economics issue in a non-trivial process.
- The locations of natural gas units are limited to the long-term availability of natural gas infrastructure which could be unpredictable; the natural gas load is also hard to forecast. Such conditions increase the difficulty for optimizing the coordinated planning of the two infrastructures.
- Pipelines are able to operate with a temporary supply disruption, provided the natural gas pressures are maintained within acceptable limits. However, within a relatively short time, a major failure along an interstate natural gas pipeline could result in a loss of electric generating capacity that could exceed the available electricity reserves for compensating such contingencies, which would lead to a random availability of power generators.
- On occasions, natural gas-fired generators become unavailable due to pipeline inspections and maintenance.

Besides, the coordinated planning is a new tool in which the two utilities are increasingly facing complex data management issues as discussed below:

- The electricity and natural gas models should be shared for coordinated modeling to save labor and minimize discrepancies in the application of the models.
- The electricity and natural gas models are very large and complex which are difficult and expensive to produce, debug, and keep up to date.
- Accurate analysis would require accurate models. Appropriate situational awareness cannot be achieved in coordinated systems without high quality models for electricity and natural gas. For instance, evolving power system models are needed (see Figure 9-1) to support real-time, midterm, and long-term planning contexts at transmission and distribution levels.

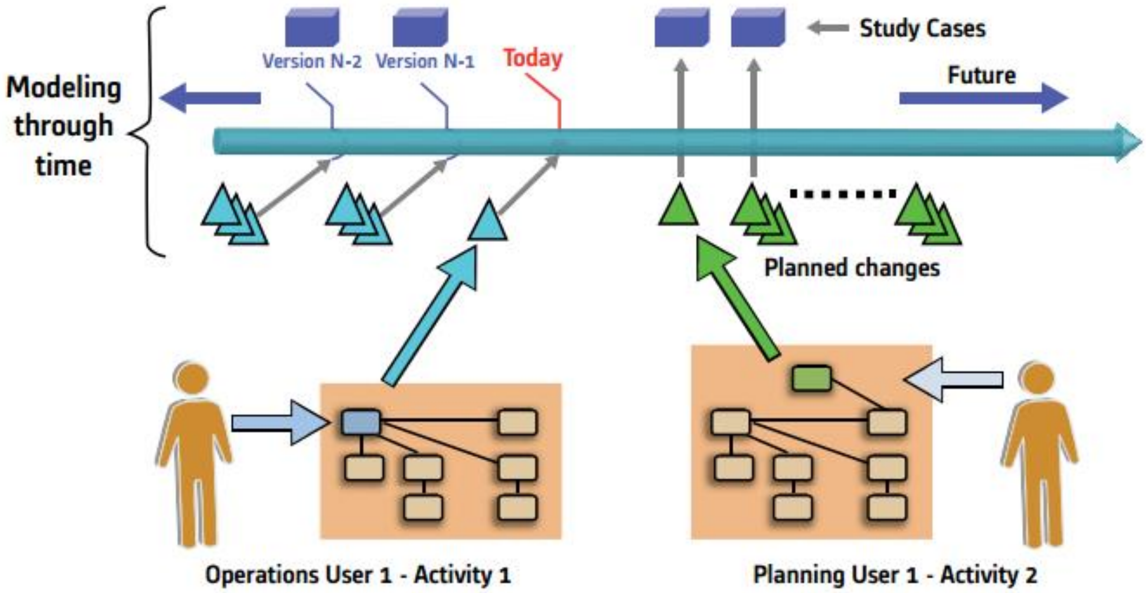


Figure 9-1: Past, present and future views of the power system can be managed by planning tool
(Source: ALSTOM)

10. Data Limitations and Concerns for Coordinated Planning

Scope of work:

Task 11: Address what the immediate and long-term data limitations and concerns are that may limit natural gas and electricity planning - for each respective industry as well as for coordinated natural gas and electricity planning. By way of examples, are there load forecasting issues that need to be addressed? Are there equipment availability/capability concerns that are important for improved planning in both natural gas and electricity industries?

Deliverable: Explanation of data limitations and concerns that could hinder natural gas and electric infrastructure planning.

10.1 Data Limitations and Concerns

NERC is responsible for the bulk power system reliability in North America. NERC prepares seasonal and long-term reliability assessments to provide key findings on resource adequacy, projected electricity demand and demand response resources, planned generation and transmission assets, emerging issues and their potential reliability impacts, and operational reliability trends. The reviews and assessments based on data submitted by each of NERC's eight regional centers in the spring and fall each year and periodically updated throughout the process. The high level demand and supply data collection process, for NERC's reliability assessments, is shown in Figure 10-1.

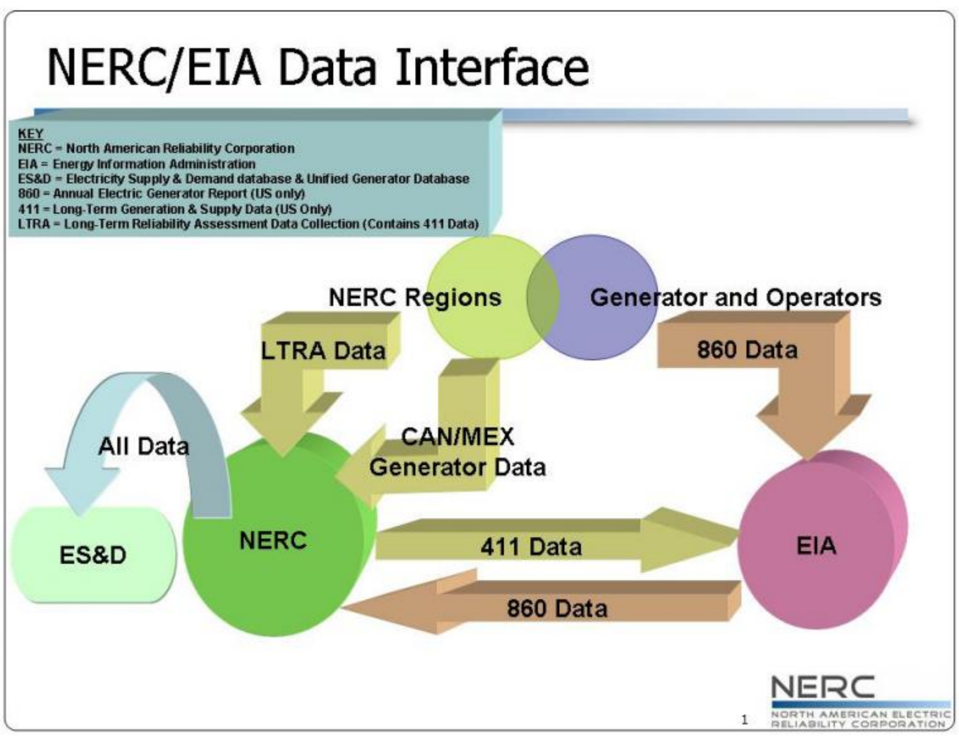


Figure 10-1: NERC and EIA data interface in power system reliability assessment and planning

(Source: North American Electric Reliability Corporation)

In Figure 11-1, NERC Regions, including Canada and Mexico, provide their demand and capacity resource information to NERC through the data collection process. The U.S. data are submitted to EIA on behalf of the industry through the EIA-411.10 Form, “Coordinated Bulk Power Supply Program Report”, which collects information on electricity supply (both capacity and energy) supplied by the North American power system planners for serving the current and forecasted demand. Generator owners and operators provide specific generator data to NERC which is also supplied to EIA through the EIA-860 Form. The EIA-860 Form includes specific information contains generator-specific information such as initial date of commercial operation, prime movers, generating capacity, energy sources, status of existing and proposed generators, proposed changes to existing generators, county and State location, ownership, and FERC qualifying facility status.

The basic principles of electric power system planning based on NERC’s basic reliability requirements include:

- Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions.
- Information necessary for planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the system reliably.
- Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented
- Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
- The security (operational reliability) of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis

From the NERC’s reliability assessment and planning process shown in Figure 10-1 and the system planning principles listed above, it is clear that a large set of information and appropriate data are needed regarding the system characteristics, generation, transmission and demand. As discussed above, the traditional electric power system planning assumes that the adequacy of fuel for generation is always guaranteed. However, as the share of natural gas-fired generation in the electric power system increase, more specific, accurate and reliable data are needed for the electric power system planning.

The natural gas and electricity planning are categorized into two time-frames: long-term planning and operation planning. The primary difference between long-term and operation planning is in the range and types of uncertainty that must be addressed. Long-term power system planning encompasses the development, evaluation and assessment of various potential outcomes for one or more years into the future. Operation planning can and does use similar concepts as long-term power system planning except that the focus is the time period between one day and one year into the future. Both long-term and operation planning must address the uncertainty in the assumptions, such as forecasted load, generation dispatch, status of transmission elements, and regional assumptions affecting loop flows, all of which define the operation state of power network.

10.1.1 Limitations on Natural Gas-Electricity Data for Long-Term Planning

In the long-term planning, generators and transmission elements are viewed as building blocks of bulk power systems. The number and the configuration of generators and transmission lines contribute to the reliability of bulk power systems. The planning process assesses the performance of existing bulk power systems with respect to reliability objectives to determine the power system ability to meet the forecast with adequate reliability. Such objectives and methods are typically described as either deterministic or probabilistic. The deterministic analysis is based on a set of general assumptions regarding the nearly infinite number of variables which define an operating state of bulk power systems while the probabilistic analysis describes events in terms of probabilities and requires the knowledge of performance characteristics of bulk power system components. As number of natural gas-fired generation units increases, the natural gas fuel availability and the natural gas-fired generation availability should be incorporated in the NERC's long-term and seasonal reliability assessments.

The key issues with data limitations associated with the long-term planning of power systems which incorporate a high penetration of natural gas-fired generation units are categorized into:

- Inadequate data and information regarding the natural gas industry and natural gas generation units for electric power system planners, including the information on natural gas fuel availability, natural gas transportation infrastructure, performance of natural gas turbines, reliability of natural gas delivery, etc.
- Inadequate data and information for natural gas industry planners regarding natural gas-fired generation units, renewable generation units, load profile and peak load information, and electricity markets etc.;
- Issues with data sharing between natural gas and electricity system planners, which could result from the absence of communication protocols, lack of knowledge about the industry counterpart, difference in the planning timeline in the two industries, etc.;
- Special consideration regarding proprietary and economic information when sharing data between the two industries.

The two industries have already made efforts to address these issues. For example, as one of the most important database in the long-term planning, the NERC Generating Availability Data System (GADS) is used to collect and record the operating data of electric generating equipment, support equipment reliability and availability analyses and decision-making by data users, and provide assistance to those researching the vast information on power planning availability stores in its database. NERC has upgraded the GADS by adding the new information on natural gas turbines and collecting performance data on natural gas turbines. However, immediate and long-term data limitations are still prominent in the natural gas-electric planning. The limitations could impose a variety of risks in the planning process. It is important to identify how risk assessments should be performed in different regions and use this information to develop recommendations on how to develop a uniform seasonal and long-term reliability assessment tool for the natural gas-electric planning. By integrating these risks into planning studies, potential generator outages due to natural gas interruptions and curtailments can be better understood. Through rigorous analyses, vulnerabilities can be identified in planning stages (1 to 10 years) and risks can effectively be minimized. These efforts can provide the foundations for state, federal, and provincial regulators, policymakers, and system planners to implement changes and send accurate signals to electricity markets for bulk power system analyses.

A. Data Sharing in the Long-Term Planning of Natural Gas-Electricity

Enhancements to data sharing and planning coordination can provide insights through additional studies and scenario analyses. There is no compiled statistical data on natural gas system outages that would be the equivalent to NERC GADS databases. Therefore, outage data would have to be estimated from various surrogate sources, including pipeline bulletin board notices, accident reports filed with government agencies, surveys of pipeline and distribution companies in the study region, and maintenance and repair information from equipment manufacturers and service companies. This type of information is important for complex analyses that rely on past performance to achieve an acceptable level of prediction and certainty. The increased coordination and information exchange for planning purposes can aid in developing the confidence around a distribution of potential scenarios. An appropriate mechanism should be designed for electricity planners and coordinators to work jointly with natural gas industry counterparts to identify data requirements for electric reliability analyses. Planning and/or reliability coordinators should identify critical natural gas-fired electric generators for mitigating or reducing the risks associated with fuel availability.

To collect the data on the region's natural gas supply and delivery, it is necessary to account for any planned changes to the existing infrastructure that would have a significant impact on the region's natural gas market. Such changes pertain to:

- New pipelines or incremental capacity increases on existing systems;
- Planned abandonments or conversion of existing natural gas pipelines that may reduce capacity;
- New storage facilities or storage field abandonments;
- Impact of new facilities or changes in the operation of existing facilities;
- Local natural gas peak shaving facilities;
- LNG import terminals, operations, and supply contracts;
- LNG export terminals;
- Large industrial natural gas-consuming facilities such as ammonia and natural gas-to-liquids (GTL) plants.

Any increases in natural gas-fired generation capacity are proportionally driven by the integration of renewable generation resources. The renewable generation characteristics exacerbate the data limitations on the natural gas supply. Certain grid operator make their renewable integration studies available to pipeline operators for assessing natural gas infrastructure needs, and provide support to pipeline operators with respect to projected electric power system needs as reflected in those studies.

Data limitations are also related to the lack of adequate and appropriate communications between the two industries. FERC mandates that communication protocols be established between interstate pipelines, power plant operators, and transmission owners/operators. However, this communication is mostly limited to emergency situations. The reality calls for more information sharing by both industries to ensure reliable operations and consistent planning processes. Some data sharing examples include maintenance schedules and outages, new facility planning and its perceived impact on the other industry, and load forecasts. Communication between the two industries is an extremely sensitive issue which stems out of the industry's restructuring. Unbundling the natural gas system during the 80s and electricity in the 90s has added several layers of business to the two industries. In such an environment, almost every piece of information with some economic value becomes proprietary. Increased segmentation and the number of market participants, another spillover effect of deregulation, adds to the growing complexity. The majority of regions, especially those with a high saturation of market-based business operations, face more resistance from different parties concerned with the loss of competitive advantage as data are shared.

10.1.2 Operation Planning of Natural Gas-Electricity Systems

The operation planning in electric power systems plays a critical role and should take into account not only the economic aspects but also stability constraints in order to guarantee a safe and adequate operation of electricity networks under normal and emergent conditions. With the increase in natural gas supply for power generation, data limitations have caused electric power system operators to make risky decisions. In preparation for summer and winter extreme conditions, electric system operators have limited observability of pipeline conditions, capacity availability, supply concerns, and potential issues affecting fuel for natural gas-fired generation.

With limitations on the availability of data, operation planners in natural gas and electricity industries are facing many questions, including:

- Is there sufficient physical delivery capability to deliver natural gas to power plants at peak hours?
- Do natural gas-fired power plants have contractual call options on natural gas supply and pipeline capacity at peak hours? Can power plant availability be considered firm if they do not have access to firm natural gas supply or pipeline capacity? If not, what is the probability that interruptible natural gas transportation will be available?
- How can utilities, electric power transmission organizations, and natural gas pipelines better coordinate their scheduling and contracting practices to ensure reliable and efficient operations in natural gas and electric power systems?
- Is there sufficient natural gas supply to satisfy the peak demand in a given power market? Will wellhead natural gas supplies be affected by more stringent upstream environmental rules?
- How and why might natural gas supply be limited under certain circumstances (e.g., wellhead freeze-offs and LNG disruption), and how would this limitation impact the reliability of natural gas and electric power system?
- How and why might natural gas delivery be limited under certain circumstances (e.g., compressor or pipeline failure), and how would this limitation impact natural gas and electric power system reliability?

Data limitation could also be related to weather conditions. As one of the factors that contribute to natural gas supply disruptions, cold weather can cause risks to natural gas wellheads and pipeline infrastructure due to freezing, which could expose the electricity industry to significant capacity shortages. The expected increase in natural gas-fired generation will exasperate the operation uncertainty that the system operator must factor into operating decisions. Therefore, in order to address the issue of data limitation, an efficient scheme should be proposed so that natural gas and electric power operation planners and operators can obtain data on extreme weather conditions and take into account natural gas supply risks such as the wellhead freezing condition.

The information on daily fuel supply adequacy and probable contingencies in natural gas pipelines or compressor stations, which could result in the loss of multiple natural gas-fired power plants, should be provided to electric system operators with as much notice as possible. Operational procedures should include formalized coordination of emergency procedures with the natural gas industry during extreme events. Timely information sharing is most important when natural gas suppliers and pipeline operators determine that potential shortages or interruptions may occur due to usage and transportation outages. Recommendations to address such issues include: system operators should re-examine inter-industry communication protocols during stress periods, and system operators will need access to sufficient flexible resources to mitigate the added uncertainty associated with natural gas fuel risks, including those introduced by interruptible natural gas transportation services.

A critical aspect in the operation planning is that for some electric utilities, natural gas generation will begin to serve base, intermediate, and peaking loads, whereas historically natural gas-fired generation almost exclusively served intermediate and peaking loads. This shift among grid operators is expected to cause a change in natural gas transportation services, from historical reliance on interruptible transportation services to more firm transportation services.

To address the issue of data inadequacy in operation planning, potential contingencies in the natural gas system that could adversely impact the natural gas supply and thereby adversely impact electricity reliability should be appropriately identified. First, it is necessary to identify the types of contingencies that can occur in the natural gas infrastructure and to compile data on frequencies, durations, and consequences of such contingencies for reliability assessments. A short list of potential natural gas system vulnerabilities that can result in the loss of natural gas services includes:

- Physical/Operational vulnerabilities such as the malfunction of a natural gas system equipment,
- Technical/Cyber vulnerabilities including SCADA system malfunctions or operational control system failures,
- Natural vulnerabilities and man-made damages to pipeline equipment under extreme weather conditions.

Fully assessing these vulnerabilities requires a review of existing studies and historical data (e.g., pipeline bulletin board data and well-level production histories), as well as consultation with the natural gas industry to establish the frequencies, duration, and consequences of the types of events listed above. Specific data could be compiled on the number of occurrences of events such as:

- Large-scale wellhead disruptions (such as freeze-offs, hurricanes and floods);
- Gathering line/field compressor problems;
- Outages of natural gas processing plants (scheduled outages, hurricanes or floods, loss of electricity service, physical attack);
- Pipeline outages (scheduled outages for pipeline integrity surveys, integrity failures, failures to control systems, accidents or damage from external forces, and loss of cover by ground erosion or physical attack);
- Prime mover or compressor outages (scheduled outages, failures of prime mover, hurricanes or floods, and loss of electricity service to electric-drive compressors).

Unfortunately, there is no compiled statistical data on natural gas system outages that would be the equivalent to NERC GADS databases. Therefore, outage data would have to be estimated from various surrogate sources, including pipeline bulletin board postings, including “nominal design capacity” and “operationally available capacity” postings, accident reports filed with government agencies, surveys of pipeline and distribution companies in the study region, and maintenance and repair information from equipment manufacturers and service companies. Upon finalizing the analysis of GADS data, NERC has identified recommended improvements to GADS cause code definitions and analysis. NERC suggests that future GADS analysis and trending capabilities focus on the following enhancements:

- Perform “deeper dive” analysis to a sample of individual generator outages to determine the cause of the outage. GADS should be able to identify if generator outages were the result of either fuel contract interruptions or uncontrolled natural gas curtailment events;
- Overlay GADS outage data on pipeline capacity trends to determine if there is a correlation and identify potential leading indicators;
- Determine natural gas pipeline and supply conditions during times of natural gas generator outages;

- Perform a study to determine approaches where dispatch trends and load duration curves can provide insights to future generator performance;
- Use GADS data for probabilistic adequacy models and develop scenarios around increased forced outage rates.

It is important to review the fuel supply-related outage data gathered in the GADS system and determine whether the adequacy and usefulness of the data could be improved to better serve the purposes of fuel supply NERC GADS analyses. The primary need would be to develop an estimate of generating unit rates excluding fuel availability issues (to avoid double counting). The second purpose would be to estimate the degree to Group which lack of fuel has added to generating unit unavailability in the recent past. Clear definitions of fuel related outages should include a distinction between those outages caused by supply or transportation interruptions and those caused by curtailment events.

ISOs need better information from the pipelines regarding their operations. While natural gas-electric coordination has been greatly improved in recent years, largely due to active communications between ISOs and pipeline operators and the establishment of a coordination committees composed of power grid operators and natural gas pipelines operators, ISOs need better information about scheduled outages on natural gas pipelines. Conversely, pipeline and storage operators with natural gas generation in their distribution system need improved information about the potential impacts on their operations from planned or unplanned generation or transmission outages, expected changes in electricity demand, and expected changes in renewable generation. Outages on the electric transmission system can impact natural gas flow and pressure on natural gas pipelines due to dispatch of natural gas generation that does not have a nomination.

A. Data Sharing in Operation Planning of Natural Gas-Electricity

The issue of data sharing in natural gas and electric operational planning focus on the difference of daily planning of the two industries. The multi-hour gap in the timing between the natural gas-day and electric-day increases the difficulty of providing the needed data and information to natural gas-fired generation. For example, in Figure 10-2 the electric-day completes its planning for the next day by 6 p.m. of the current day. While the completed electric utility plan identifies which electric units will run the next day (which in turn provides the basic information to project the next day's fuel consumption), the pipeline deadlines for nominations historically have been at 10 a.m. of the current day. Thus, there is a six-or-more-hour gap of incompatibility between the two traditional approaches to planning and scheduling. The net result of this scheduling gap is that electric generator nominations, with their relatively large natural gas loads, are based upon estimates by the individual fuel planners of each generator owner between 24 and 36 hours in advance. The issue could be magnified when scheduling on a Friday, since natural gas markets are closed for the weekend. This can result in significant differences between nominations and actual natural gas requirements. The nominating and scheduling process provides an opportunity for each Generator Owner to manage and effectively minimize its risk exposure. However, the amount of firm pipeline capacity needed, either through firm capacity entitlements or capacity release, should reflect the best possible estimate of actual natural gas requirements; although, inherent risk with estimates poses additional threats.

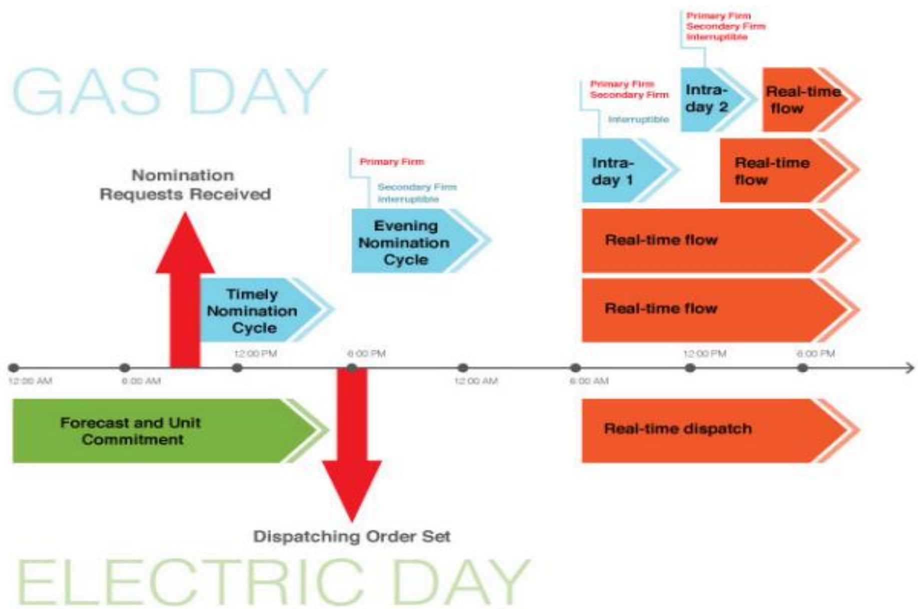


Figure 10-2: Timing in the natural gas and electricity markets

(Source: PennEnergy)

The electricity industry has expressed its concern regarding the data sharing limitations. The ISOs state that they are not getting all of the information needed to identify risks for reliable operations and to make more accurate decisions during the operating day. The ISOs have suggested that pipelines should provide additional pipeline operational data and generators should provide generator-specific data regarding fuel supply options. Some of the additional pipeline data that the system operator would like to receive include more frequent flow of data than what is already shared through pipeline postings as well as the information regarding pipeline pressures at all receipt and delivery points, day-ahead nominations confirmation changes, and fuel supply availability.

The pipeline operators expressed concern about how the shared data would be interpreted, specifically the pressure changes on pipelines. The pipeline operators also expressed that they do not have the fuel supply information and are not in the position to opine on fuel supply security in the market. Similarly, power generating company representatives expressed concerns about releasing certain generator-specific information to electric power system operators, and were especially concerned if such information was essentially provided to natural gas pipeline operators. Generating companies have stated that pipelines do not necessarily know a power generator's complete fuel supply requirements or options.

Representatives from both industries generally agreed that increased information sharing and communications should not be limited to emergency situations and that protocols for information sharing should be the same in all situations, whether in day-to-day operations, emergency conditions, or longer-term planning. However, protocols need to follow and reflect non-disclosure agreements and additional clarification is needed with regard to regulations. Specifically, pipeline operators sought confirmation that sharing information with individual generators will not be construed as engaging in undue discrimination or providing an undue preference in violation of the Natural Gas Act and Federal Power Act.

To address the issue of data sharing limitation in operational planning,

- several ISOs are developing practices to improve coordination and communication between the two industries not only during emergency situations, but also under normal operational conditions. In 2012, the New England States Committee on Electricity established the Natural Gas-Electric Focus Group to examine the challenges arising from the two industries' interdependence.
- Certain ISOs have taken the lead by improving the lines of communication, and advocated the concept of allowing the sharing of real-time electric operation information with natural gas pipeline operators.
- Other ISOs have formed Task Forces to work on general natural gas-electric coordination issues, which are expected to emerge pending the retirement of thousands of megawatts of coal-fired generation, likely leading to a greater reliance on natural gas-fired generators.
- ISOs have proactively searched for solutions to pending challenges, enhancing communications protocols, and sharing information during electric power contingencies that could affect pipeline operation, planning, forecasting, maintenance, and repairs.
- Some ISOs have disclosed the names of gas-fired generators needed to support reliability in the event of natural gas shortages, natural gas pipeline testing and maintenance, and other events leading to curtailments of natural gas supplies.
- ISOs are also making efforts to enhance the flexibility in adjusting their processes and refining scheduling requirements so that the critical data become available a few hours earlier in the traditional electricity day.
- Some ISOs have considered ways of changing the day-ahead unit commitment process to better coincide with the natural gas timely nomination cycle.
- Some ISOs are proposing to allow hourly offers and intra-day re-offers in the real-time energy market so that generators can adjust their bids to reflect changes in fuel costs.
- Some ISOs adjust the electric market day-ahead scheduling as well as the resource adequacy assessment process under which day-ahead awards may be released prior to the start of the electricity day in advance of the standard nomination deadline for natural gas pipeline capacity.
- Some ISOs already release the day-ahead dispatch results at 10 a.m., which allows natural gas-fired generators to be informed on the pipeline nomination cycle.

Other ISOs are reviewing the potential for aligning market schedules by clearing the electric market earlier in the day.

10.2 Load Forecasting Concerns in Natural Gas-Electricity Planning

The load forecast is developed in a variety of ways using a variety of assumptions, econometric models and statistical information. System planners incorporate load forecasts in transmission base cases and conduct analyses to identify generation and transmission expansion needs to meet the demand.

Even on non-peak flow days, natural gas-fired generation requires high-volume, high-pressure loads with large load swings that pipelines may not have been designed to accommodate. Pipelines need to align a slow-moving product (natural gas) with a fast- moving product (electricity) that is subject to large variations (natural gas-fired generators come on/off-line on short notices). The sudden demand swings from generators may cause pipeline pressure drops that could reduce the quality of service to all pipeline customers. The main issues are whether the requirements for the natural gas are predictable within the natural gas pipeline nomination cycle, if supplies are available and confirmed, if the pipeline is sized to handle the load variation, what the proximity to storage is, and whether volumes are taken in excess of confirmed nominations, including specified allowances for hourly swings.

If natural gas requirements are not known within the natural gas pipeline nomination cycle and the available capacity for interruptible loads is factored into the pipeline operating plans, or if hourly swings are excessive, a pipeline would need to allocate, reserve, or build facilities on the pipeline to provide service for the intra-cycle requirements. This may involve the creation of pipeline services that do not exist. While pipelines are capable of adding capacity in the form of more pipe, compression, or market-area storage deliverability, they are unlikely to do so without a cost recovery mechanism, which is traditionally in the form of a contract for that service.

10.3 Resource Availability and Adequacy in Natural Gas-Electricity Planning

Both natural gas and electricity industries are in agreement that the growth of natural gas-fired generation capacity has to be considered in pipeline infrastructure planning. Such requirements are not easy to implement as the equipment capacity and availability in the natural gas industry would become an issue when additional natural gas-fired generation are introduced in the electricity industry, in the following two respects:

- Long-term adequacy of the natural gas infrastructure to meet the long-term needs of the electricity industry;
- Short-term adequacy of natural gas operational flexibility to meet the operational flexibility needs with the ever increasing integration of renewable energy.

These issues correspond to differences in resource adequacy planning and infrastructure operation in the two industries.

With the growth of natural gas-fired generation, new infrastructure will be required to move natural gas from the regions where production is expected to grow to areas where demand is expected to increase. Not all areas will require additional pipeline infrastructure, but many areas including those that have a large sum of existing pipeline capacity, may require significant investments for connecting new power generation capacity to electricity markets. Going forward, power producers should continue to be motivated on the prospects of available outlets for natural gas supplies via pipelines. Abundant and geographically diverse shale natural gas contributes to a competitive electricity market that benefits consumers. Underutilized LNG import terminals also contribute less directly to competition on the electricity supply side.

New power generation supplies entering the interstate pipeline system will require added pipeline capacity to handle the projected increase in natural gas transportation. The reference case projects that over 43 Bcfd of incremental mainline capacity will be needed from 2010 to 2035. In addition to the new mainline transmission capacity, pipelines will be required to connect new power plants, new natural gas storage fields and new natural gas processing facilities to the network of natural gas transmission pipelines. New gathering system capacity also will be required to connect new producing wells to processing facilities and pipelines. The cost of new natural gas transmission infrastructure (including natural gas storage and lateral connections) needed over the next 25 years is projected to average approximately $5.7 billion per year, or over $141 billion total. Gathering and processing adds an additional $2.6 billion per year on average or about $64 billion total.

The concerns regarding infrastructure and equipment could also be attributed to the contractual mechanism in the natural gas industry. For example, natural gas pipeline companies do not build interstate pipeline projects unless shippers are willing to sign long-term contracts for natural gas transportation. These long-term contracts serve two important purposes. Firstly, the shippers' contractual commitments provide a basis for the pipeline company to raise the capital needed to build its project and secondly, the FERC is legally required to rule as to the need for a pipeline before it can issue a certificate authorizing the construction and operation of a proposed project.

There is an important relationship between the adequacy of natural gas transportation and storage infrastructure and the competitiveness of natural gas commodity markets. In its 2009 State of the Markets Report, FERC observed that due to investment in natural gas pipeline capacity, the United States was "closer than ever before to being a single natural gas market with congestion limited to a few markets for a few periods during the year." This was borne out in recent years as natural gas has become increasingly abundant and affordable notwithstanding the significant capital investments made in new pipeline infrastructure. New pipeline capacity linked consumers with increased supplies of natural gas and resulted in greater natural gas-on-natural gas competition to the benefit of consumers. Given that new, increased supplies of natural gas provide much of the impetus for the new pipeline construction that is forecast over the next 25 years as shown in Figure 10-3, it can be expected that consumers similarly will benefit from this investment. Consumers will be better off if capacity constraints that limit deliveries of natural gas are removed than if the investment in new pipeline capacity had not been made and such constraints had been permitted to remain in place.

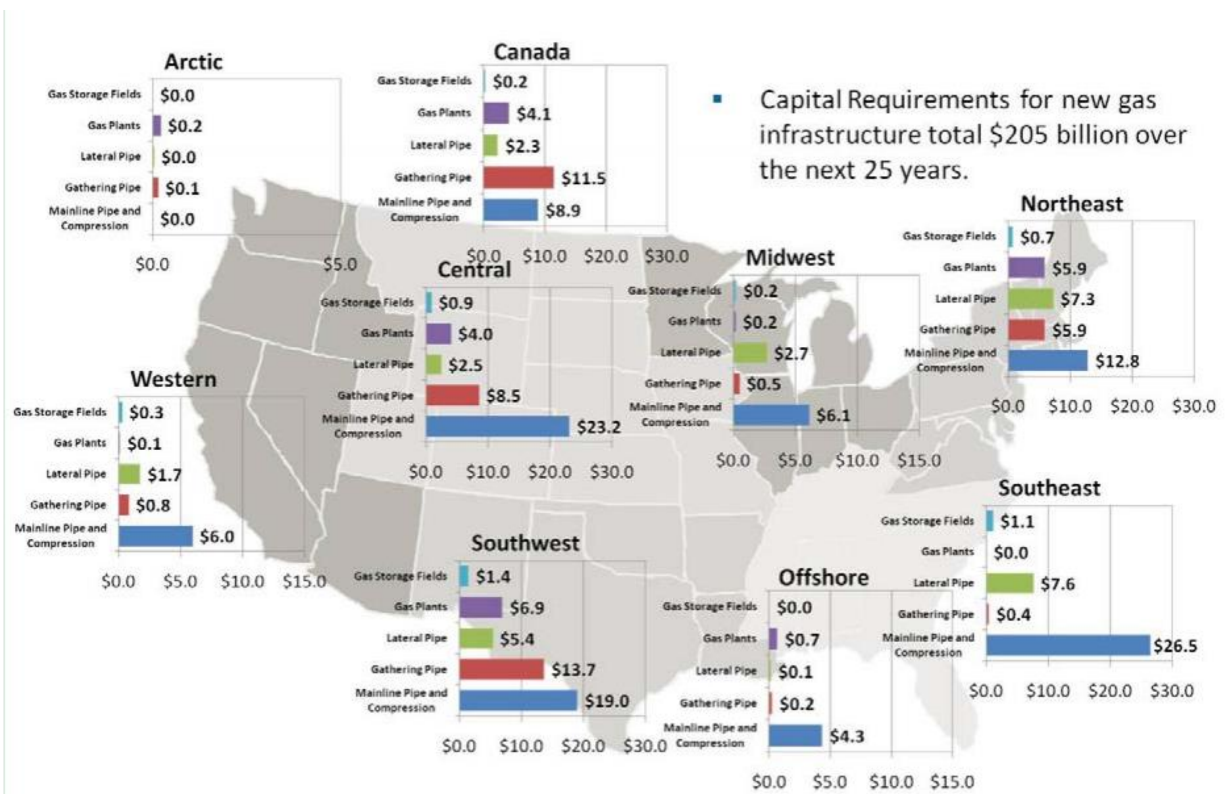


Figure 10-3: Capital requirements for new natural gas infrastructure in the next 25 years

(Source: The INGAA Foundation, Inc.)

11. Confidentiality and Critical Infrastructure Concerns

Scope of work:

Task 12: Discuss the confidentiality and critical infrastructure concerns and potential solutions to overcome the concerns to allow natural gas and electricity industries, states, and other stakeholders to engage in operational and long-term planning.

Deliverable: Description of confidentiality and critical infrastructure concerns and potential solutions to overcome the concerns

11.1 Confidentiality Concerns in Natural Gas-Electricity Planning

Regional natural gas and electricity industries in the United States had historically shared significant amount of information; however, industry deregulations resulted in classifying almost every piece of operation and planning information as proprietary and confidential. While it is a challenge to overcome the treatment of most confidential information, these challenges should not be insurmountable. For example, a recent NERC effort to request how much electric capacity is backed by firm transportation led to critical questions on proprietary information. However, all pipelines post a list of firm transportation and storage customers the first business day of each quarter. This posting, which is called an Index of Customers and is required by the Natural Gas Act (NGA), includes the names shippers, applicable rate schedules, effective and expiration dates of contracts, maximum daily contract quantity (MDCQ), receipt and delivery points, and other information on whether the contract is arranged by an asset manager, whether there are any affiliate relationships, and whether the contact is based on a negotiated rate.

It is agreed by both the natural gas and electricity industries that data and information sharing is important to enhance natural gas-electric planning and operational coordination. However, both industries also are concerned about the information sharing in the deregulated natural gas and electricity markets.

In the five regional conferences FERC solicited input from both industries regarding the coordination between the two markets, and natural gas and electricity industry representatives questioned whether the FERC Standards of Conduct are impeding further efforts to improve communication between the two industries. For example, one entity raised concerns that the information-sharing in an emergency situation could be a problem for companies where employees with operational knowledge are also wholesale merchant function employees. Many entities requested that FERC provides clarity on what types of information can be shared. Some pipelines and ISOs also noted that, although they make significant amounts of operational information publicly available, there is reluctance to share more granular level information because of concerns about violating statutory prohibitions against undue preference for any customer or customer class. So, for example, in response to one ISO’s comment that it was not able to interpret a pipeline’s posted outage information in terms of which specific generators would be affected, several pipeline companies expressed discomfort with going beyond what was publicly posted. Pipelines also noted that, in situations where the information regarding pipeline capacity limitations has been posted, they typically will be queried on how much interruptible or secondary transportation is available, but they are not required to provide more specific information beyond their public postings.

At FERC conferences, pipelines indicated a desire to receive timely information from ISOs on the dispatch of natural gas-fired generation fleets and the expected impacts after generation forced outages, while ISOs expressed interest in knowing whether the necessary natural gas supply and transportation arrangements would be in place for natural gas-fired units scheduled in day-ahead markets. At the same time, several generators and ISOs expressed concerns about the market sensitivity of sharing such information. They are concerned that information exchanged between a pipeline and an ISO may lead to unilateral action by either the pipeline or the ISO which could cause competitive harm to participating generators, or act as a conduit for third parties to gain access to information on specific generators causing competitive harm to respective generators in the marketplace.

11.1.1 Reasons for Confidentiality Concerns

There are many reasons contribute to the confidentiality concerns. The main reasons are categorized as follows:

- The issue of confidentiality could result from proprietary concerns. While improvements implemented during the course of the pipeline industries evolution are substantial and of significant benefit to the power industry.
- The creation of the deregulated natural gas industry has increased, to a degree, the difficulty of coordination between electricity and natural gas industries. This occurs because almost every piece of information concerning operations in a deregulated market is considered to have some economic value and thus, is considered to be proprietary information. This proprietary status on most operating information significantly increases the challenge of future coordination between the natural gas and power industries.
- The issue of confidentiality is also attributed to commercial value concerns. A reoccurring theme expressed by natural gas industry participants is the concern about communications among pipeline operators and power system entities (i.e., reliability coordinators, balancing authorities and ISOs). The pipeline will communicate with LDCs serving a generator, or will communicate with the generator itself, but will not freely communicate with a reliability coordinator. This lack of coordination is due to the confidentiality of commercially sensitive business information and regulatory restrictions.
- In addition to the above, communications between the two industries are hampered by the incompatibility between the traditional natural gas day, traditional electricity day, and the market day (in market areas), which increase the difficulty for the natural gas industry providing the needed services to its largest consumer. The issues are further compounded by different electric markets located across several time zones.

11.1.2 Potential Solutions

However, this is not to say that the confidentially challenges cannot be overcome. Vital information needed for the reliable operation of bulk power systems should be shared with system operators in both industries. Examples of this coordination include the sharing of maintenance issues for pipelines and generators, perceived impacts of new facilities, variations in load levels, dispatch principles, and general patterns or forecasts in both industries.

The electricity industry's concept of a reliability coordinator does not have a parallel entity in the pipeline industry. The public domain Information, however, is generally shared between pipeline operators and ISOs. Accordingly, establishing a coordinator in the natural gas industry that could be directly communicate with ISOs through appropriate protocols could be an option to solve the confidentiality problem and enhance the information sharing in natural gas-electric system planning.

Historically, most pipelines only allowed for a single intraday adjustment to the original nomination of natural gas loads. However, over time, and largely to accommodate the power industry, many pipeline companies have revised their tariffs to allow for additional intraday adjustments to the original nomination. For example, one major pipeline now allows three intraday adjustments to nomination. However, there are set times and protocols for each intraday adjustment and these adjustments will occur only if the pipeline is able to accommodate them. Similarly, some power pools are refining their planning and scheduling protocols so that the pertinent information can become available a few hours earlier in the traditional electricity day. The latter can facilitate and aid in refined intraday adjustments.

This NERC report summarized the findings of its Natural Gas/Electricity Interdependency Task Force Natural Gas/Electricity (GEITF). Chief among GEITF findings was that while the pipelines communicate with LDCs serving a generator or with the generator itself, they do not communicate with a regional reliability coordinator, primarily because of confidentiality restrictions. As a result, it was recommended that NERC, in concert with other energy industry organizations, increase the inter-industry cooperation for the purposes of education, planning and, most importantly, emergency response.

In November, 2013, FERC issued a NOPR for seeking comments on a proposal to revise its regulations to authorize electric transmission providers and interstate natural gas pipelines to share non-public, operational information for the purpose of promoting reliable service and operational planning. In the NOPR,

- FERC proposed to adopt a No-Conduit Rule that would prohibit all public utilities and interstate natural gas pipelines, as well as their employees, contractors, consultants, or agents, from disclosing, or using anyone as a conduit for the disclosure of, non-public, operational information they receive under this rule to a third party or to its marketing function employees.
- FERC stated that the No-Conduit Rule, in addition to protections already in place, would ensure that any non-public, operational information shared under the proposed regulations remains confidential and is shared among transmission operators in a manner that is consistent with the prohibition on undue discrimination.
- FERC noted the concerns expressed by some entities that generator-specific, non-public information provided to a pipeline by an electric transmission operator could provide the pipeline with a competitive advantage over the generator in pricing transportation services.
- FERC found no need to propose additional protections regarding interstate natural gas pipeline transportation. FERC reasoned that interstate pipelines are required to allocate services, on a not unduly discriminatory basis, based on their tariffs, at a rate not exceeding the just and reasonable rate on file.
- FERC explained that pipelines are not required to discount services, and if they choose to discount, are permitted to obtain information from any source to demonstrate that the shipper requesting the discount has competitive alternatives.
- FERC stated that unauthorized disclosure of any non-public, operational information may subject the entity or individual making the prohibited disclosure to the enforcement provisions of the Federal Power Act (FPA) and Natural Gas Act (NGA), including potential civil penalties.

Some commenters expressed concern with the scope of non-public and operational information that is requested to be shared under the rule based on competitive concerns about the use of that information. The Natural Gas Supply Association (NGSA) is also concerned that the NOPR could allow transmission operators to share commercially sensitive information that could harm producers and marketers by revealing their positions in the market to outside parties. NGSA states, for example, that a marketer's commercial strategy could be revealed if the confidential details of the scheduling priorities it has contracted with its clients were shared. NGSA further contends that while it may be useful for utility operators to share information on overall pipeline capacity, sharing commercially sensitive information such as individual shipper nominations offers little insight into the reliability of deliveries and could cause significant harm to some market participants. Along the same lines, the Public Utilities Commission of Ohio (PUCO) argues that electric transmission operators should be required to furnish pipelines with aggregated, non-unit specific generation data to ensure against inadvertently providing pipelines with confidential or proprietary information that could result in a competitive advantage concerning the pricing of natural gas to that facility.

Lastly, if the overall process were developed only with a small, core group of electrical industry representatives, this dilemma between confidentially concerns and commination needs likely could be resolved. Another option would allow protected sharing of information with nondisclosure agreements and FERC Standards of Conduct protections that the electricity industry has experience with in protecting proprietary information for the unregulated generation business.

11.2 Critical Infrastructure Concerns for Confidentiality

Infrastructure components include various segments of the natural gas chain including, production, processing, transportation, distribution, storage and other elements. With the rising interdependency of natural gas and electricity industry, the critical infrastructure and components in both industries would have more impact on the system planning and operation.

11.2.1 Critical Infrastructure Concerns in Natural Gas Industry

The types of natural gas infrastructure components shown in Figure 11-1 include:

- Sources (natural gas wells)
- Natural gas processing plants
- Natural gas transmission system (pipelines and compressor stations)
- Natural gas distribution system
- Natural gas storages
- LNG import terminals

In natural gas industry, pipelines also react to load growth. FERC will generally not authorize new pipeline capacity unless customers have already committed to it (Firm delivery contracts), and pipelines are prohibited from charging the cost of new capacity to their existing customer base. Thus, additional customers request firm service from a pipeline that then adds new facilities or improves existing facilities, results in new pipeline capacity closely matches the requirements of the new customers. If all of the pipeline's firm customers use their full capability, little or no excess pipeline capacity will be available. This is a major difference between electric transmission and pipeline infrastructure construction. Electric transmission does not necessarily need to be approved by FERC, but transmission must be built to support speculative growth and socialized cost. Additionally, pipeline contingency planning standards, similar to transmission planning standards, do not exist. However, this does not mean that the pipeline system is not redundant. First, buried steel pipelines are inherently robust than and, therefore more resilient to extreme weather than transmission wires. Second, pipelines use series of side-by-side pipelines (called "loops") that provide redundancy, i.e., if one gets corroded or needs maintenance the other loops can increase their pressure and make it up. The same is true of compressor stations.

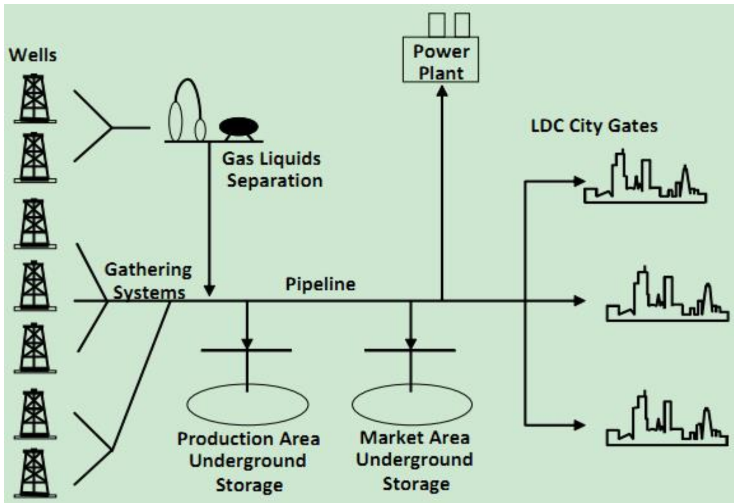


Figure 11-1: Natural gas infrastructure components
(Source: North American Electric Reliability Corporation)

One critical concern of the infrastructure in natural gas industry is wellheads freeze-offs. Natural gas producers use a wide variety of measures to prevent or minimize freezing impacts, such as adding chemicals and other heating systems to prevent freezing, and using different weatherization techniques for the wells. In the interdependent natural gas-electricity industries, the wellheads freeze-offs would be one of the major threats for the natural gas-fired generations under cold weather conditions.

As a cost efficient way to accommodate the large difference between summer and winter demand requirements, the natural gas storage is connected to natural gas transmission system in. Natural gas storage serves as a critical element in maintaining both reliability and flexibility of the natural gas transmission system. Furthermore, building new natural gas storage near the natural gas-fired power plants to address the risk of fuel disruption for natural gas-fired generators has draw attention of natural gas and electricity industries. Therefore, natural gas storage would be more critical in the future natural gas-electricity interdependent industry.

11.2.2 Critical Infrastructure Concerns in Electricity Industry

The owners of electrical components anticipate load growth, and plan, design, and construct a transmission system that meets NERC's Reliability Standards, which is capable of serving the forecast customer demands. NERC's Reliability Standards dictate a layer of protection in transmission planning, that is, utility planners must look at adding system backup to cover a single contingency condition (N-1 condition) such as the failure of a transmission line, transformer or a large generator. The general philosophy is that no single failure of a piece of equipment should cause a large number of customers to lose power. Transmission designers further test the system design by looking at scenarios involving two or more equipment failures (N-2). As the share of natural gas-fired generations continues to increase, the standard above may need an upgrade in the future.

When identify the critical electric infrastructure, additional attentions should be paid to those vulnerable to natural gas pressure reductions. While in most instances regional natural gas flows were restored rather quickly, in at least two cases natural gas flow was affected for longer periods of time. In such cases, pipeline pressures could be reduced. Natural gas-fired electric generation units, in particular, are very sensitive to such pressure reductions because of their unique requirements for high burner-tip pressures. In such instances, having access to on-site booster compression for certain (critical) natural gas-fired units within the region could enhance overall system reliability.

On occasions, natural gas-fired generators become unavailable due to pipeline inspections and maintenance. Pipeline outages tend to occur during the pipelines' off-peak season (summer) – which coincides with the peak season of the electrical system. While pipeline maintenance outages are to be expected, issues have occurred both due to the timing of planned pipeline maintenance relative to high electric load conditions as well as short notice of pipeline outages. For example, during the week beginning June 6, 2011, several natural gas pipelines experienced issues related to a high electrical load coupled with pipeline maintenance, resulting in the imposition of restrictions on generators in ISONE. A year later, during the week of June 4, 2012, ISONE was made aware of a pipeline inspection that could cause a capability reduction of the Algonquin pipeline, with effects ranging from immediate reductions of up to 65% capability to no reduction at all. In order to prepare for anticipated restrictions and potential interruptions of fuel supply to New England generators, ISONE committed 650 MW of non-natural gas-fired additional capacity to provide greater fuel diversity.

Another concern would be the weather events such as hurricanes. Hurricanes passing into the Gulf of Mexico may disrupt offshore natural gas production and pose damage to various kinds of onshore and offshore natural gas processing facilities. Disruption can be caused by the evacuation of personnel from the production area or by damages to production facilities or transmission pipelines that require replacement or repair.

11.2.3 Potential Solutions for Preserving Confidentiality

In January 2014 due to the extreme weather condition, FERC granted PJM temporary waivers of its confidentiality rules to allow the ISO to share information with natural gas operators during the arctic cold that strained natural gas supplies. However, this is only a temporary measure to address the confidentiality issue within the information sharing process. Appropriate solutions should be discussed and designed to solve this problem.

In the long-term, pipeline infrastructure planning must take into account the long-term growth of natural gas-fired generation. Pipeline infrastructure and capacity is expanded based on firm contracts from its consumers. Despite the growth and future expansion of pipeline capacity, more pipeline capacity will ultimately be needed to support the natural gas-fired capacity build out. Over the next ten years, a significant amount of natural gas-fired generation is projected. With environmental regulations potentially causing some coal-fired base-load units to retire, natural gas-fired generation will likely be needed to serve more base-load demand.

By incorporating results from a natural gas fuel and infrastructure assessment into probability-based resource adequacy models, an accurate representation of risk can be quantified and then translated into risk-based planning solutions. The results of this analysis also could serve as information for generators to determine the appropriate level of natural gas service to meet their reliability needs and, upon a generator making contractual commitments, for pipelines to determine if additional infrastructure is necessary to meet that demand.

With the rise of interdependence of natural gas and electricity industries, the system planners in both industries should upgrade resource adequacy review and critical infrastructure and components review processes to assess infrastructure requirements and vulnerabilities. At its most severe condition, a mechanical or other physical failure in electricity infrastructure can result in the immediate loss of service provided by generating units or transmission lines that can, under some conditions, produce cascading loss of firm loads. The nature of these events and the required instantaneous response of power system operators have generally served as an impetus for electric system planners to employ both resource adequacy review and reliability (system security contingency) review processes to assess infrastructure requirements. The result of these reviews allows bulk power systems to be operated in a manner that is resilient to disruptions.

In the near future, additional strategies ought to be incorporated in both industries' planning and operation procedures for identifying infrastructure vulnerabilities. The electricity industry should evaluate which generators may be most susceptible to pipeline disruptions (e.g., number of pipelines serving the generator, proximity to natural gas storage, and location relative to pipeline). The natural gas pipeline industry should consider electric system generation forecasts during the planning process. For operations, the sharing of real-time system information by both industries increases the ability for each to make informed decisions and reduce overall risk.

Specifically, from the viewpoint of electricity industry, the electric planners should also assess the infrastructure from a new perspective, which allow for analyze critical components for the interdependent natural gas and electricity industries. The electric planners should pay attention to the following aspects:

- The critical components (e.g., electric compressors and/or natural gas-fired generator units), in most instances, represent the core of the interdependency of the two industries, and would need to be identified and analyzed at the regional level;
- In addition to manual industry load shed plans, electric system planners and operators should avoid critical natural gas component loads in undervoltage/underfrequency load shedding schemes and identify natural gas loads as priority loads in restoration plans;
- Electric planning coordinators and reliability coordinators should identify critical natural gas-fired electric generation to ensure critical generators have the ability to mitigate or reduce risks associated with fuel disruptions and curtailments;
- As the share of natural gas-fired generations continues to increase, the N-1 and N-2 standards may need to be upgraded to include critical natural gas delivery components into case studies;
- To recognize the specific regional attributes of its transmission grid, some operation and planning areas require additional planning standards. For example, some systems must be designed so that it can handle electrical demand under extreme weather conditions, the outage of the two most critical generators, and/or limitations on the use of fossil fuel-fired peaking generation units. By using these and other criteria to plan and design the generation and transmission system, transmission utilities seek to ensure that customers rarely lose power because of a problem on the bulk power system.

On the other hand, from the viewpoint of natural gas industry, more attentions should be paid to the critical infrastructure and components which are powered by electricity, including natural gas producers, natural gas processing plants and storage facilities, and electric-driven compressors. Natural gas curtailments could be occurred as a result of shutting down natural gas processing plants, storage facilities and electric pumping units or compressors.

Single points of failure in natural gas supply due to weather events can be somewhat mitigated by increasing production in other unaffected areas. For example, increased Marcellus shale production could aid the mitigation of supply disruptions in the Gulf of Mexico. However, without transportation, mitigation through these alternative supply sources can be limited. Additionally, a higher risk of wellhead freeze-offs should also be considered within these types of mitigation strategies.

12. Federal and State Regulatory Issues for Electricity and Natural Gas

Scope of work:

Task 13: Describe federal and state regulatory issues with natural gas and electricity industries, and make recommendations to overcome any perceived obstacles. What, if any, actions can states take to facilitate the timely construction of new natural gas infrastructure?

Deliverable: Description of Federal and state regulatory issues for natural gas and electricity industries, and recommendations to overcome any perceived obstacles.

12.1 Introduction

The shale natural gas boom has offered remarkable opportunities for the U.S. to participate in the global energy market. The amplified supply of natural gas boosts the potential for cleaner electricity generation, cheaper domestic fuel prices, improved job opportunities, and a seat for the U.S. at the council of global natural gas exporters. When it comes down to the details that will drive the realization of this potential, we are in the preliminary steps of developing policies that will have a real effect on the natural gas and electricity providers doing business at either end of the nation's extensive network of natural gas pipelines. Most of the current natural gas regulations were developed in a time of perceived shortage and should be reevaluated to detect areas that may no longer be appropriate for today's and tomorrow's natural gas markets. As evidenced by the current natural gas abundance and the new realization that the domestic natural gas resource base will be adequate for domestic needs for many years, a farsighted response to these opportunities must incorporate both the near- and long-term perspectives.

Rising natural gas use in the U.S. is not just about exhausting more. The efficient use of natural gas and other forms of energy should endure to be a vital policy. State governments, public utility commissions, and natural gas LDCs should utilize full fuel-cycle analyses for a more precise valuation and comparison of various fuels and technologies; considering how natural gas can help improve total energy efficiency, reduce emissions and alleviate costs. In many circumstances, amplified use of natural gas to replace inefficient sources of energy may improve the overall energy efficiency of the economy. An opportunity currently exists to reevaluate business models, regulatory policies, financial outreach and technology revolution from a position of strong supply and expectations of long-term market price stability.

Incorporating the advantages of natural gas to new markets necessitates additional investments by natural gas LDCs and their customers. In some situations, substantial up-front costs may be required in order to recognize fuel cost savings over many years. Novel policies and regulations are required to guarantee that natural gas LDCs recuperate their farsighted investment costs and that high up-front costs do not discourage consumers from making futuristic fuel choices.

In addition, policy makers are integrating natural gas features into efforts to move the U.S. energy mix in a lightened greenhouse natural gas (GHG) direction. New pipelines and other infrastructure projects are being built to eradicate pipeline bottlenecks and distribute natural gas from new supply basins into growing market areas. Particular opportunities will differ from one region to another and may necessitate regulatory changes, policy supports, and financial and technological advancements to be fully apprehended. In the same manner, challenges to achieving these goals may vary regionally and may need regulatory, policy, financial, or technological measures if they are to be implemented.

The U.S. energy policy has historically concentrated on several objectives including price moderation, energy efficiency, cost efficiency, environmental protection, and energy security. The new stance for natural gas cost and accessibility has shaped new possibilities for succeeding toward these goals. However, real challenges exist for integrating more natural gas into the electricity sector. At the heart of the issue is the fact that electricity is a 24 hours a day, 7 days a week, 365 days a year business with daily and hourly changes in supply and demand. This complexity poses challenges to electricity grid owners and operators incorporating more natural gas-fired generation into electric power systems. Superior coordination among natural gas and electricity industries is needed to ensure that these challenges can be addressed. One challenge is that there are certain physical constraints such as whether current natural gas pipeline and storage infrastructure will be adequate to deliver an increasing amount of natural gas to power plants. Further, there are market and regulatory challenges in some regions such as scheduling natural gas supply to match up with electricity needs; many of these challenges are both state and federal ones.

The challenges of heavier reliance on natural gas generation have been highlighted by cold weather. Electricity demand goes up when the temperature goes down, but so does demand for natural gas to meet the heating needs of residential customers. As a result regions with high proportion of natural gas generation impose a dual burden on supplies during unusually cold weather. Federal and state regulations need to make sure that the lights stays on at affordable prices during times of inevitable and unanticipated situations.

12.2 Environmental Concerns and Regulations

Natural gas possesses one potential drawback from an environmental standpoint. Natural gas is about 95% methane; methane has about 28 times the global warming potential of CO2 when it is discharged into the atmosphere rather than combusted. Direct emissions of methane into the atmosphere— from upstream operations, leaks in the pipeline and distribution systems, or accidents anywhere within the natural gas system—have environmental catastrophes. A vital factor in grasping the climate advantage of fuel switching from other fossils fuels to natural gas is reducing methane emissions from natural gas production, processing, transmission, and distribution. The EPA regulations in the United States will necessitate reduced methane emission completions on all wells drilled after January 1, 2015. Such systems are currently extensively used throughout the United States and are required by several states as a remediation action.

In addition to the federal mandate, a framework of regulations is emerging at the state level that seeks to alleviate safety and environmental concerns related to well construction and completion practices. Two prospective market-based regulatory mechanisms that can be offered as models for states to adopt, either individually or in coordination with other states, include:

- CO2 emissions cap and trade program (i.e., a limit on total power sector emissions)
- Tradable performance standard (i.e., a requirement that fossil generating units achieve a specified average emission rate)

These programs would present a degree of flexibility and shrink overall CO2 emissions from covered sources more efficiently than would a unit-level based emission performance standard. EPA may also include other forms of flexibility, such as giving compliance credit for additional renewable power generation or demand-side efficiency measures. Some stakeholder proposals believe measures, such as energy efficiency initiatives, use of combined heat and power, and replacement of consumer electrical equipment with natural gas equipment, should be acceptable forms of flexibility. Still these latter forms of flexibility are likely to invite more legal inquiry and could be more vulnerable to court challenges for creating uncertainty. LDCs also have a role to play in reducing methane emissions. The EPA data imply that natural gas distribution activities are responsible for about 16% of total GHG emissions from the natural gas sector. Programs intended to replace aging pipe, safety priorities, and the fundamental economics of serving customers indicate the natural gas LDC interest in refining this important environmental metric.

12.3 Vital Role of Natural Gas LDCs

Natural gas-fired generation has a compound natural gas demand profile and new plants tend to connect directly to interstate pipelines. LDCs must facilitate continued value to electric power producers – such as helping balance short term changes in power loads, providing storage, and constructing laterals - in order to be significant participants in this sector. LDCs have the potential to contribute actively in managing real-time delivery of natural gas, given their pre-existing portfolios of natural gas, working with PUCs for the appropriate regulatory modifications.

The construction of distribution pipelines and the real time operation of fuel delivery are among the natural gas LDCs expertise. In general power plant developers are not experts in natural gas delivery systems, and do not have the desire to operate the gas delivery system. Federal regulations mandate that any pipeline outside the boundary of the power plant must conform to Department of Transportation standards for design, construction, operation, and maintenance. These are all functions for which the natural gas LDC or pipeline is preferably suited, the marginal cost is negligible, and the power plant operator usually lacks the proficiency and the aspiration to carry out those functions.

PUC policies in many states inspire natural gas LDCs to offer new services such as park and loan[1] to power generators that involve the use of existing facilities paid for by existing customers. In general PUCs oblige revenues from such services eventually be utilized to cut the rates of existing customers. Net income upside for natural gas LDC stockholders from growing sales to current customers or selling new services using present assets might be restricted by such policies. Alternative way that PUCs protect present customers is necessitating that costs, particularly for new services, be allocated away from present customers with the natural gas LDC stockholders held at risk for achieving sufficient revenue to cover the assigned costs. Both approaches often discourage natural gas LDCs from developing and offering new services that could be beneficial for both new and present customers in the long run.

Historical tests and policies impose redundant and uneconomic obstacles on natural gas distribution systems ‘expansion. Natural gas LDCs are required to take a leading role in encouraging a more receptive environment for system expansion, but regulatory and legislative support is also required.

- As the concerns regarding natural gas availability and price are subsiding, there is a strong justification for PUC policies that would support distribution system expansion.

[1] Park and loan service is a common way for natural gas pipeline shippers to optimize their daily variance in offtake natural gas (demand) with their natural gas supply contracts thereby managing their portfolio on one pipeline or within one pipeline segment. A natural gas shipper can take less natural gas than originally scheduled and then “park” the excess supply inside the pipeline at times when demand is lower than anticipated. At times when natural gas demand is higher than expected, pipeline shippers can adjust their offtake upward, in effect borrowing (“loaning”) from the pipeline. http://www.ferc.gov/market-oversight/guide/energy-primer.pdf,

- State governments and PUCs should adopt policies that not only encourage site energy efficiency, but also encourage the use of full fuel-cycle energy efficiency analysis, full fuel-cycle emissions standards, and full cycle cost analysis.
- If the long standing rules are incompatible with current regulatory objectives and conditions in the natural gas sector, PUC should build partnerships between customers, builders, utilities, economic development agencies to overcome the challenges.
- Economic tests used for evaluating line expansion investments should be re-evaluated by PUCs and natural gas LDCs.
- Options that may alleviate the burden of high up-front costs on potential customers need to be re-examined by PUCs and natural gas LDCs while considering both existing customers and competing fuel suppliers' rights.

Further, to promote the energy efficiency in the United States, natural gas LDCs can cooperate with PUCs, policy makers, and other stakeholders to:

- Detect new opportunities for natural gas to escalate the overall energy efficiency in a cost-effective manner. Given the projected growing gap between retail natural gas prices and the retail prices of electricity and oil, the issues like increasing natural gas use, decreasing the use of more expensive and less energy efficient sources of energy would have the potential to surge the overall energy efficiency.
- Adopt full fuel-cycle analyses in all energy savings and energy efficiency comparisons.
    - Overcome approaches in many energy efficiency rulemakings which discourage inter-fuel comparisons and result in promoting inefficient technologies. PUCs will need to guarantee that there is a level competitive playing field for all energies, but specifically between natural gas and electricity.
    - Collaborate with builders, local governments and other stakeholders to encourage builders to base their appliance decisions not on lowest first cost that tend not to be the most energy efficient option, but on full fuel-cycle and life cycle cost analyses.
- Regulatory support for recognizing societal advantages of increased energy efficiency or reduced emissions will let natural gas LDCs to provide efficiency programs to customers uninterruptedly.
- Educate potential converting and new customers on the economic and environmental advantages of natural gas. As most potential customers are doubtful to adapt until their current furnace or water heater requires replacement, a fruitful program needs to pinpoint prospective converting customers well before they need to switch their furnace or water heater.
- Update the terms of cost recovery mechanisms such as decoupling, if current mechanisms would act as a barrier to switching to a full fuel-cycle energy efficiency paradigm.
- Support efforts to set energy efficiency standards on a full fuel-cycle basis. Most current building codes and appliance standards are based on site-efficiency and overlook the losses related to producing and delivering natural gas or electricity to the site - in August 2013, DOE announced that it would use full fuel-cycle measures in future energy efficiency standards rulemakings.

12.4 Regulatory and Policy Adjustments for Combined Heat and Power (CHP)

When a power generation unit is integrated with a heat recovery system, it becomes a CHP plant, generating electricity and heat from a single source at the site of use. The fuel of choice for existing CHP plants is natural gas - with 71% of capacity consuming 3.4 Bcf per day of natural gas.

One of the biggest benefits of CHP includes the higher electrical efficiency that comes first from the cogeneration of heat and power on site and second from the avoidance of the losses associated with the transmission and distribution of moving power from a central generating unit to an end user site. As such, a number of states allow CHP to be part of their Renewable Portfolio Standards. Nevertheless, high costs (equipment, installation and maintenance costs) and the requirement for constant thermal loads are the two most important obstacles to more widespread acceptance of medium- and small-scale CHP in the United States.

For CHP to mature, regulatory and policy modifications are likely to be necessary, particularly at the state level. Some states include natural gas CHP in energy efficiency and renewable portfolio standard programs. It is important for all policy makers to realize that they may be biasing outcomes against natural gas-fired CHP and in favor of renewables or other technologies. Trying to include quantification of the benefits from intangible items into the return on investment metric may also support push the odds toward an outcome that favors CHP if concepts such as independence from the power grid, greenhouse natural gas reductions, petroleum displacement, economic development, or energy efficiency are purposely included. Natural gas-based CHP is likely to be fruitful in states that have a mixture of policies that enable permitting and construction, potential for electricity sales back to other end-users or the grid, and high spark spread values. In addition, the White House's Executive Order, Accelerating Investment in Industrial Energy Efficiency, of August 30, 2012, is spearheaded to stimulate American manufacturing by growing coordination among federal agencies to provide investment and elimination of barriers to new CHP installations; it aims the addition of 40 GW of new capacity by 2020. However, new business models are needed that better align the interests of customers, regulators, energy suppliers, and manufacturers of CHP technology. In essence, it would be helpful to

- Collaborate with regulators to magnify the number of states that consider CHP in Renewable or Energy Efficiency Portfolio Standards on the basis of efficiency gains.
- Collaborate with state regulators to form equitable standby provisions, charges, and policies for CHP and assist level policy playing fields for sale of power/heat/steam into wholesale and retail markets from CHP by gaining remuneration based on capacity value and voided costs of actual technologies.

12.5 Regional Practices to Overcome Potential Obstacles

There are several common concerns at the heart of regional and national efforts for the coordination of the two industries, including: the sufficiency of natural gas infrastructure and pipeline capacity for natural gas delivery and storage, harmonizing the operation of the natural gas and electricity markets to allow for more precise and flexible scheduling of required amounts of natural gas for electric generators, allocation and recovery of costs associated with ensuring reliable electricity and natural gas resources, and increasing the communication between the industries to provide more seamless coordination, while observing applicable legal boundaries on such communication.

State regulatory entities believe that regional efforts may be the best solution for solving interdependency issues since the challenges presented are unique to the various regions of the country.

- ***Natural gas/power harmonization***: Coordination between natural gas suppliers and power generators is a major focus of electric system regional transmission operators and the FERC. Two challenges stand out in current discussions surrounding natural gas/electric harmonization – boosting the coordination of daily operations between the two industries and assuring that pipeline infrastructure can service a growing fleet of natural gas-fired generators.

- ***Aligning daily market schedules***: Natural gas market day and the power market day are not perfectly synchronized. Natural gas timely nominations are due approximately a full day before the natural gas flows, and energy market day-ahead generation scheduling is concluded in the afternoon just hours before the power day begins. This scheduling inconsistency implies that natural gas-fired generators either purchase and schedule fuel delivery without knowing their power market energy dispatch status, or they bid into the energy market without knowing whether they will be able to successfully purchase and schedule natural gas. The misalliance in scheduling is manageable most of the time, but the situation can become challenging with potential reliability implications during peak natural gas demand and during pipeline maintenance or emergencies.

FERC has considered tariff changes to address the increasing reliance on natural gas-fueled generators. The proposed changes include earlier clearing of DAM and earlier completion of reserve adequacy analyses. The proposed changes are sought because of concerns with the current DAM schedule and increasing reliance of natural gas-fueled generators at times when there is an increasingly tight availability of pipeline capacity. For instance, ISONE proposed to increase the amount of Ten-Minute Non-Spinning Forward Reserves which aims to maintain reliability by guaranteeing the availability of adequate reserves in real time. The additional reserves would deal with concerns about resource performance during periods of jittery system conditions. FERC also approved to improve the settlement of DAM to better synchronize it with the natural gas market, providing the ISO more time to moderate the reliability risk in such incidents.

However, federal and state regulatory agencies are concerned that grid operators are not utilizing all of the information required to detect risks for reliable operations and to make more precise decisions during the operating day. The regulatory agencies suggest that pipelines should provide additional data and generators should provide generator-specific data regarding fuel supply options. The additional pipeline data that the system operator would like to be provided included more frequent flow data to what is already shared through pipeline postings along with information regarding pipeline pressures at all receipt and delivery points, day-ahead nominations confirmation changes, and fuel supply availability. The pipeline operators are, however, concerned about how these data would be inferred, particularly the pressure variations on the pipelines. The pipelines also expressed that they do not have the fuel supply information to provide the generators and are not in the position to speak out about fuel supply security in the market. Likewise, generator representatives are concerned about releasing certain generator-specific information to electric system operators, and are especially worried if that information were to be provided by pipeline operators. Generators indicated that pipelines do not essentially know a generator’s complete fuel supply picture or options available.

ISOs are looking into winter season challenges and identifying solutions that maintains the grid reliability in extreme circumstances. Proposals included using oil-fired generation as a back-up if the natural gas supply were to be reduced and using LNG resources. However, both industries agree with state and federal regulatory agencies that increased information sharing and communications should not be restricted to emergency situations and that protocols for information sharing should be the same in all situations, whether in day-to-day operations, emergency conditions, or longer-term planning. Nevertheless, protocols need to follow and reveal non-disclosure agreements and additional clarification is needed with respect to regulations.

Some of the national and regional recommendations to ease the natural gas/electric coordination include: integrating fuel availability into national and regional reliability valuations, increasing system operators' awareness of fuel arrangements in their areas, improving the Generator Availability Data System to improve the identification of trends in electric generator outages caused by fuel supply issues, and using formal communication between industries to increase coordination. The North American Energy Standards Board is examining cyber security issues to detect and address any vulnerabilities that may result from integrating natural gas and electric systems.

13. Payment Options for Improving the Natural Gas Infrastructure

Scope of work:

Task 14: Provide an explanation of potential payment options to increase the deliverability and the efficiency in the natural gas industry and to meet the needs of the electricity industry.

Deliverable: Explanation of payment options to meet the needs of the electricity and natural gas industries.

13.1 Introduction

In general natural gas distribution systems are subject to expansion only when they fulfill specific economic tests such as delivering an expected net present value that is greater than zero, delivering an internal rate of return that surpasses the natural gas LDC's cost of capital, or having a payback period that is shorter than some preset number of years. Such tests often pose obstacles to any system expansions, which are in fact economic. A combination of natural gas LDC initiatives, regulatory supports, and government policies can mitigate such obstacles, highlight economic potentials of natural gas, and serve the public interest in full-cycle energy efficiency.

Natural gas LDCs have established strategies to inspire further conversions to natural gas usage by consumers. When energy consumers are unaware of their options, information and outreach programs to educate consumers on the benefits of natural gas are particularly beneficial. Moreover, natural gas LDCs can offer loans and other financial assistance to potential customers, including payment plans that stretch upfront costs over several years and loans for upfront customer installation costs that can be recompensed from fuel savings.

LDCs can seek financial authorizing for promoting natural gas appliances. Although natural gas appliances often provide superior economic performance over the life of the appliance due to lower energy consumption, natural gas appliances are typically more costly than electric ones. Consumers may not be financially flexible to invest today for energy savings in the future, or they may not be assured that they will stay at the same residence long enough to recapture their initial investment. LDCs can also secure commitments for a system expansion from large anchor customers such as industrial customers, housing development or subdivisions, hospitals, power plants. Such commitments provide a secure base load that reduces required contributions from other new customers. Another option is to adopt the open season approach used by interstate pipelines to estimate customer interests in system expansions. If significant commitments were collected during open-season periods to make a viable system expansion argument, natural gas LDCs would proceed with a rational guarantee for cost recovery.

Moreover, any system expansions would require a regulatory support. PUCs can encourage expansion measures in several ways:

- Publicizing uniform standards that deliver natural gas LDCs a clear and foreseeable framework for planning and assessing potential system expansions.
- Pre-approving system investments when economic returns are backed by growth projections. The pre-approval would lower investment risks of natural gas LDCs, and encourage further expansion opportunities.
- Approving economic tests that account for revenues over the useful life of the investment.

- Authorizing financing for natural gas LDC of conversion to natural gas appliances.
- Encouraging financing by natural gas LDCs for customer contributions to the expansion through such devices as the free-feet mechanism.

Active promotion of natural gas at the expense of alternatives lies beyond the PUC's obligations, but state and local governments are authorized to make such policy choices, and can encourage natural gas system expansion as part of an overall energy and/or economic strategy. In pursuit of such a strategy, governments should consider:

- Approving the PUC to allow system expansion costs to be recovered through general tariffs applied to existing as well as prospective customers.
- Providing explicit subsidies for expansion of natural gas networks to unserved areas that meet established density criteria. These subsidies could take the form of economic development grants or state- backed bonds.
- Encouraging fuel conversion through educating costumers.

13.2 Boosting the Economics of Infrastructure Expansion

Any expansion measures that increase the projected customer loads or make the loads more certain will increase the viability of system expansion projects. Such measures fall into the following categories:

- Acquiring commitments from large anchor customers: Securing commitment from industrial customers, housing development or subdivisions, hospitals, and power plants facilitates a secure base load that shrinks the required contribution from other new customers and the risk related to load forecasts.
- Alleviating initial customer charges: Charging new customers for main-line extensions can upset the prospective growth that over the long term could pay for expansions. As such, some natural gas LDCs have suggested providing new customers with a specified number of free main-line feet. The cost related to those free feet is captured into the natural gas LDC's rate base, expecting that the revenue from new customers will cover the rate-base increment over time.
    - An unpublished survey by the American Natural Gas Association indicates that 49 out of the 83 respondent natural gas LDCs reported that they offer limited free line extensions. UGI's proposed Extension Tariff (i.e., Get Natural Gas) in Pennsylvania is an example of a proactive strategy for promoting fuel conversion and natural gas line extensions. The pilot plan would allocate the line extension costs to new customers connected to a new main, imposing a monthly surcharge that new customers can pay over 10 years, avoiding high upfront contribution in aid of construction payments.
- Amortizing consumer conversion costs: Natural gas LDCs can offer potential new customers the option to spread the cost of appliance replacement over several years to address this resistance to fuel conversion. Electric utilities have implemented payment plans with regulatory approval in many jurisdictions to boost energy-efficiency investments. A similar mechanism could be utilized to inspire new customers to sign up for natural gas service; both appliance expenses and pipeline costs could be amortized over a stretched period through charges on natural gas bills associated with an address rather than an individual customer.
    - For instance, NSTAR in Massachusetts has an aggressive outreach program that disseminates information on the substantial benefits for energy consumers who switch from oil to natural gas, and also offers financing arrangements. NSTAR estimates that up front costs for conversion to natural gas can exceed $14,000 for a household (including the sum of

the cost for new heating equipment, new service connection, and new main extension). With associated annual savings of $2,000 on average, however, many customers are willing to make the conversion if natural gas LDC amortization is available.
    - As an alternative, an unregulated affiliate of the natural gas LDC could offer financing that would not be paid through the natural gas bill but nevertheless could be eye-catching to a customer by offering longer payback periods than are typically available from commercial lenders.
    - Conversion costs typically range from $7,000 to $12,000; they vary depending on such factors as the age of the heating system, the need for new internal piping, and by location.
- Educating prospective customers: Many prospective customers are skeptical on long-term benefits of natural gas. Some costumers may believe that reliance on natural gas is economically risky, remembering the rise in price that occurred almost a decade ago. Others simply do not have the time or disposition to search the matter and cannot afford the transaction costs associated with signing up for natural gas service and switching to natural gas appliances. By educating the prospective customers in an area that is a candidate for system expansion, natural gas LDCs can raise awareness of the benefits of natural gas use and notify customers about the long-term potentials for stable natural gas price.
- Assuring price stability: Unregulated affiliates of natural gas LDCs in many cases can provide piece of mind by selling the natural gas commodity to customers directly, taking onto itself the risk of wholesale natural gas price instability, and ensuring the customer a stable price or at least a narrow band of price inconsistency.
- Aggregating bundled customer commitments: Adopting the “open season” approach, used by interstate pipelines that are considering system expansions, is an alternative to collecting commitments customer by customer. For instance, under a program offered in Massachusetts, the natural gas LDC would practice such a mechanism to evaluate the level of interest from prospective distribution customers. The natural gas LDC would be able to proceed with reasonable guarantee of cost recovery to make a system expansion economic, if adequate number of promises were gathered during the open-season period.

The discussed measures will help entice and educate customers about the basic economics of natural gas conversion. These measures are consistent with basic principles of regulatory fairness as they will boost natural gas LDCs’ opportunities for system expansions without involving cross-subsidization and without giving natural gas any advantage over alternative fuels other than the benefits of its inherent characteristics and cost.

13.3 Reliability through Infrastructure Expansion

In contrast to the power system that is built with, out of necessity, reserve capacity, natural gas infrastructure planning is done at the pipeline level by private natural gas pipeline companies after customer (i.e., shippers) commitments are clear. Based on their self-assessed needs, individual customers execute firm natural gas pipeline capacity contracts. Long-term firm contracts serve as indication of market need for pipeline expansion. Natural gas LDC customers build reliability into the system through the amount and type of capacity they buy- although there is no explicit obligation that natural gas pipelines sustain reserve capacity- for instance, they preserve a portfolio of natural gas supply contracts and pipeline/storage capacity contracts to address the projected peak needs of their aggregated customers.

The market for pipeline services, or transportation, involves a primary and secondary market. Primary transportation consists of two broad types of service – firm and interruptible – with contracts signed by the pipeline and shipper. The effective cost of firm pipeline service is generally more expensive than interruptible pipeline service. Firm service gives the shipper priority service for a set quantity of natural gas delivery between specific receipt and delivery points. Interruptible pipeline service is also based on a specific quantity of natural gas delivery between two points. Nevertheless, interruptible service conveys a lower priority than firm service in that the shipper approves to delivery only when capacity is accessible on the pipeline. As such interruptible shippers encounter plausible service disruptions during periods of high natural gas demand or pipeline system interruptions.

The appetite of power plants for firm pipeline transportation contracts differs across power markets. In general, natural gas- fired merchant generators in restructured power markets depend on lower cost interruptible pipeline service as cost recovery is far from certain for these power generators. In regulated power markets, the situation is different. Electric utilities incline more toward firm service contracts, because public utility commissions often permit the costs to be imposed on consumers through retail electric rates. However, growing harmonization between the natural gas and power markets suggests that novel solutions are necessary in regulated power markets. Regulators and public policy makers should consider a variety of innovative cost recovery mechanisms that meet multiple needs locally in a different fashion; each state must decide what innovative structure is best for its citizens.

For instance, while power capacity markets in the northeast are intended to compensate generators for reliability, the payments propose only short-term revenue certainty of one to three years in contrast to firm natural gas pipeline service contracts that are typically ten years or longer in duration, as such holding a higher risk for a merchant generator if it subscribes to firm pipeline capacity. Additionally, clearing prices and locations differ from auction to auction and market rules are often silent on any requirement for firm fuel supply, consequently natural gas-fired generators may not be incented to sign firm natural gas pipeline transportation contracts.

At the leading edge of this issue is ISONE ; given ISONE's traditional position at the end of the long haul interstate natural gas pipeline system from the US Gulf, and as natural gas becomes a greater part of its total generation mix. Projected changes to its power capacity market are intended to incentivize reliability investments. ISONE's proposal would put in place a "pay-for-performance" structure that consists of both penalties and incentives for power capacity resources throughout power system reserve shortage incidents. Such structure results in a transfer of payments between performing and non-performing resources. Penalties and incentives would reflect both the resource's performance in relation to its capacity commitment and the rigorousness of the system shortage. As an alternative some groups argue for federal or state regulations or directives to resolve conflicting viewpoints between the natural gas and power industries, and in lieu of the current system that centers on evolving power market rules with extensive stakeholder input. Several different types of investments could result in from the proposed structure , including natural gas pipelines, dual fuel power generation capability - often natural gas-fired generation with fuel oil, often distillate, as a back-up fuel-, demand response, and imported power from adjacent markets. ISONE's proposal will take time to implement as adjustments involve an extended stakeholder development and authorization process. With some of the highest electric rates in the country, the New England market is inspired to search for solutions that balance reliability with cost.

13.4 Conclusions

Regulators should also develop guidelines as part of their policy statements which can act as safe harbor rules for reducing uncertain conditions for utilities and ease hindsight reviews. They can help steer utilities' proposals for facility extensions in line with what the regulators consider essential requirements. Regulatory guidelines should provide (1) standards for satisfactory investments in pipeline expansion, (2) commission procedures for assessing proposed expansions, (3) cost allocation, (4) ratemaking treatment of costs, and (5) conditions under which regulators would approve system expansions and allow full recovery of costs. A utility is more likely to expand its distribution system as potentials for cost recovery increase.

14. Summary and Recommendations for Future Actions

Scope of work:

Task 15: Provide a set of recommendations on improving the coordination of natural gas and electricity industries.

Deliverable: Recommendations on future actions in natural gas and electricity industries

In this section, we provide several recommendations for future actions to improve natural gas and electricity industry coordination based on the discussions in the previous chapters.

Recommendation 1: Harmonize Natural Gas and Electricity Infrastructures

The coordination between natural gas suppliers and power generators is a major focus of electric system regional transmission operators and FERC. Two challenges stand out in current discussions surrounding natural gas/electric harmonization – boosting the coordination of daily operations between the two industries and assuring that pipeline infrastructure can service a growing fleet of natural gas-fired generators.

Recommendation 2: Align Daily Market Schedules

Natural gas market day and the power market day are not synchronized. This scheduling inconsistency implies that natural gas-fired generators either purchase and schedule fuel delivery without knowing their power market energy dispatch status, or they bid into the energy market without knowing whether they will be able to successfully purchase and schedule natural gas. The misalliance in scheduling is manageable most of the time, but the situation can become challenging with potential reliability implications during peak natural gas demand and during pipeline maintenance or emergencies.

Recommendation 3: Create a coordinator (ISO) in the Natural Gas Industry

The electricity industry's concept of an ISO/ reliability coordinator does not have a parallel entity in the pipeline industry. The public domain Information, however, is generally shared between pipeline operators and ISOs. Accordingly, establishing a coordinator in the natural gas industry that could be directly communicate with ISOs through appropriate protocols could be an option to solve the confidentiality problem and enhance the information sharing in natural gas-electric system planning

Recommendation 4: Expand inter-industry communication protocols under extreme system conditions

Timely information sharing is most important when natural gas suppliers and pipeline operators can determine that a potential shortages or interruptions may occur due to usage and transportation outages. Operational procedures should include formalized coordination with the gas supply and pipeline industry, as well as emergency procedures during extreme events. It is thus imperative to re-examine inter-industry communication protocols that apply during periods of stress and use formal communication between industries to increase coordination.

Recommendation 5: Ensure sufficient flexibility in the electricity system to mitigate the added uncertainties pertaining to natural gas availability

Power system operators should increase their awareness of fuel arrangements in their areas. Power system operators will need to have access to sufficient flexible generating resources to mitigate the added uncertainty associated with natural gas fuel risks, including those introduced by interruptible natural gas transportation services. Policymakers and regulators should consider developing solutions that provide the right balance between electricity reliability and the increased costs associated with such provisions. In the long-term operation, dual-fuel capability and a variety of storage facilities may provide options to mitigate the risk with fuel availability.

Recommendation 6: Integrate the natural gas availability into national and regional reliability valuations

Because natural gas is largely delivered on a just-in-time basis, vulnerabilities in gas supply and transportation from a planning perspective must be sufficiently evaluated to inform system operators about credible contingencies and flexibility options. As the number of natural gas-fired generation units increases, it is imperative to integrate fuel availability into national and regional reliability valuations, and develop a uniform seasonal and long-term reliability assessment tool for the natural gas-electric planning. In particular, the natural gas fuel availability or natural gas-fired generation availability should be incorporated into NERC's Long-Term Reliability Assessment and Seasonal Reliability Assessments.

Recommendation 7: Improve the generator availability data system to identify issues related to natural gas availability

The electricity industry's growing reliance on natural gas has raised concerns by ISOs, RTOs, market participants, national and regional regulatory bodies and other government officials regarding the ability to maintain electric system reliability when natural gas supplies to power generators are constrained. To increase the effectiveness of trending gas-fired generator outages and causes related to fuel issues, it is imperative to improve the NERC Generator Availability Data System.

Recommendation 8: Investigate cyber security issues in the coordinated systems

The interdependency of electricity and natural gas systems has greatly increased because of the significant emergence of natural gas-fired generators. In the meantime, lack of coordination remains to be a major concern, and there is a growing anxiety in both industries that the interdependency could heighten the potential impact of malicious cyber attacks. It is thus imperative to investigate cyber security issues and to detect and address any vulnerability that may result from integrating natural gas and electricity systems.

Recommendation 9: Reinforce education and workforce training

Compared to other industries, the workforce in the electricity and natural gas industries has an older average age. A large gap exists between the number of retiring technical professionals and the number of graduates coming out of junior college, college, and graduate school with the knowledge and skills required to work in the industry. Electricity and natural gas companies should review and consider increasing their financial support for educational or training activities to support the development of the next generation of professionals with knowledge and skills in the fields necessary for prudent development of the nation's electricity and natural gas resource base. Congress should provide financial support for higher-education programs, including research programs in areas of national interest related to energy resources.

Natural gas has the potential to increase the overall efficiency of energy use, to shrink air emissions, to cut energy costs, and to boost local economic development. Earning potential benefits from the revolutionized natural gas market could be stimulated by evaluation of existing PUC and natural gas LDC policies and practices. Further, substantial regional diversity across U.S. energy markets impedes a one-size-fits-all approach to energy policy, regulation, and business models. As such opportunities to increase the natural gas market share will vary by region and by state. Challenges include recovering the often high up-front costs of investments by natural gas LDCs and consumers, contradictory federal, state, and local policy objectives, regulations based on outdated assumptions regarding natural gas supply and cost, and promoting a consensus as to the new realities of the natural gas market. While the regional experiences are unique, the common threads of discussion include the need to raise awareness and share information between the two industries, the need to address when communications are permitted between the industries, and to consider changing rules of the markets to simplify coordination.

Growing interdependency in the electricity and natural gas industries is here and both sides are learning how to adapt and mitigate as the events unveil. Regions, already saturated with natural gas-fired generation, turn out to be more prepared for adaptation to this trend. They even insist that no nation-wide coordination or interference from FERC would be required or productive, and their claims could be decisive in certain regions. Providing a coordinated scheduling practice and adding more flexibility to the two systems seems to be a project of monumental proportions; however, it does not seem to bring in as much debate as the issue of sharing information between industries. The need for expanding data sharing across the markets is not being contested by either party. The repeatedly raised argument is: How far beyond what is already being publicly posted should the two entities unveil to their counterparties? This will likely mean the industries will have to post more data in the public domain. Most entities in the two industries, however, try to mitigate the problem by sharing data under confidentiality agreements. Finally, to better understand the coordination, planning tools should add more features as we discussed earlier. But the basic idea remains to be the data exchange as much as possible between natural gas system and electricity systems for enhancing the reliability and the economics of the coordinated systems. Also because of the uncertainty represented by the no-firm supply of natural gas, it is hard to apply planning tools to a practical simulation of the coordinated electricity and natural gas systems. In the future, it is envisioned that the additional cooperation between the two industries, which is shaped by the myriad of natural gas-fired generating units, will reduce operation risks, improve reliability, and enhance the resilience of the two industries in extreme circumstances.

15. Glossary of Terms

Scope of work:

Task 16: Glossary of terms, bibliography, and a discussion of contracting concepts.

Deliverable: Provide a glossary of terms, bibliography and discussion of contracting concepts

15.1 Electric Power

Alternating current (ac)	An electric current that reverses direction at regular intervals and is the dominant form of electric power in transmission and distribution systems worldwide.
Balancing authority	An entity responsible for balancing generation and load (with specified imports and exports) within a specified geographic region
Bulk power system	That part of the electric grid comprised of generators and high-voltage transmission lines
Capacitance	A parameter relating the charge stored in an electric field to the voltage producing the field. Transmission lines have capacitance because their voltage creates electric fields between conductors and between conductors and the ground
Capacitor	An element exhibiting capacitance.
Capacity market	A wholesale forward market for resources to supply energy. These capacity resources are usually, but not always, generators.
Congestion	A condition that occurs when lack of transmission capacity prevents the least-cost set of generators from serving load, causing an increase in the wholesale price of electricity or cost of service at one or more locations in the system.
Contingency	An abnormal event in the power system, such as the tripping of a generator or a transmission line.
Converter	A generic term referring to a system employing power electronics to convert electric energy from one form to another, e.g., from direct current at one voltage to direct current at another voltage or alternating current at one frequency to direct current or to alternating current at another frequency.
Current	The amount of electric charge flowing past a specified circuit point per unit of time.
Demand response	Customer loads that are responsive to conditions in the electric power system, particularly at peak times.
Direct current (dc)	An electric current that flows in one direction and is used selectively in

	electric power systems, primarily for point-to-point applications.
Distributed generation (DG)	Small-scale, on-site generation systems owned by entities that are primarily consumers of electricity.
Distribution system	The part of the power system that delivers electricity to customers, operating at lower voltages than the transmission system.
Eastern Interconnection	One of the two major synchronized alternating current power grids in North America, reaching from Central Canada eastward to the Atlantic coast (excluding Québec), south to Florida, and back west to the foot of the Rockies (excluding most of Texas).
Economic dispatch	The assignment of generating units' production in order to minimize overall costs.
Electric Reliability Council of Texas (ERCOT)	Synchronized alternating current power grid that occupies nearly all the state of Texas.
Extra-high voltage	Transmission voltages between about 345 kilovolts and 765 kilovolts.
Federal Energy Regulatory Commission (FERC)	U.S. independent agency that: regulates the interstate transmission of electricity, natural gas, and oil; reviews proposals to build liquefied natural gas terminals and interstate natural gas pipelines; licenses hydropower projects; and performs some other related activities.
Generation	The process of converting energy from some other form into electricity, usually in power plants, but also via distributed generators, such as solar photovoltaic arrays.
Generator	A device that transforms some other form of energy (typically mechanical energy) into electric energy.
Grid	The physical components of the electric power system that link generating units to the loads they serve, as well as the associated operational, regulatory, and governance structures.
High-voltage direct current (HVDC)	Technologies for transmitting bulk power via direct current at transmission-level voltages.
Impedance	The opposition of a conducting device to the flow of alternating current through it; the inverse of adminttance. The impedance of an element depends on its reactance in addition to its resistance.
Independent power producer	An entity that is not a public utility and that owns facilities to generate electricity for sale to utilities and/or end users.
Independent system operator (ISO)	A regulated entity without generation or distribution assets that oversees the wholesale electricity market and operates the bulk power system in a particular region.
Inductance	A parameter relating energy stored in a magnetic field to the current producing the field. Transmission lines have inductance because their current creates magnetic fields around their conductors.

Inertia	The resistance of any physical object to a change in its state of motion (or rest). Inertia is proportional to mass; inertia in generators and loads enhances the stability of an electric power system.
Inverter	A power electronic system whose function is to convert electric power from direct current to alternating current.
Line rating	Maximum steady-state power that can be safely carried in a transmission line of a given length under standard ambient conditions.
Load	The aggregate demand for electricity consumed by devices connected to the electric grid; sometimes also used to include the customers who own and operate those devices.
Load duration curve	The distribution function for electrical demand in a particular region, typically formed using hourly load data for a year (8,760 points) ordered from highest to lowest, each showing the electrical power required by the load in a different hour of the year.
Load factor	The ratio between average and peak power.
Locational marginal price	For any economic dispatch, the marginal cost of meeting a small increment of load at a particular location; the spot price of electricity at that location.
Loop flow	An undesirable flow of power over a secondary transmission path, potentially causing congestion and unfavorable economic operation.
Losses	The difference between generated power and power delivered to the load, typically caused by resistance in transmission lines and transformers and converted to waste heat.
Power	The rate at which energy is flowing.
Power electronics	Electronic circuits, employing switching electronic semiconductor devices, whose function is to control electric energy and convert it from one form to another, e.g., from alternating current to direct current, or alternating current at one frequency to alternating current at another frequency.
Power factor	The ratio of real power to apparent power. Reflects the degree to which a given amount of current is producing useful work.
Power quality	The extent to which the voltage waveform at a load conforms to the ideal sinusoidal shape and nominal value. Poor power quality is generally the result of loads that draw current that is not sinusoidal (a particular problem with electronically controlled loads) or weak distribution networks producing frequent outages or voltage sags.
Price responsive demand	Load that responds to prices that vary with system supply-and-demand conditions.
Public utility commission	A state agency typically responsible for regulating retail electric rates and other utility prices.
Reactive power	Power that exists in ac power systems when reactance is present. Reactive power charges and discharges the energy stored in reactive elements. It

	does no time-average work, but its presence still contributes to electrical losses and voltage drops.
Regional transmission organization (RTO)	An independent system operator (ISO) that the Federal Energy Regulatory Commission has certified to have satisfied a specified set of requirements and that has slightly greater responsibilities for system reliability than ISOs that have not been so certified.
Regulation	In electric power systems, a control scheme that attempts to maintain some quantity at a nominal value or within a nominal range. This term is often applied to the concept of maintaining voltage and frequency within certain bounds. Also refers to the activity of a government agency charged with controlling the behavior of a public utility or other entity.
Renewable portfolio standard	A state-level requirement that a minimum fraction of in-state electricity consumption correspond to generation from specified renewable technologies, such as wind, solar, or geothermal.
Resistance	The property of a conducting device to resist the flow of current through it.
Supervisory control and data acquisition (SCADA)	Specialized computer systems that monitor and control industrial processes, including the operation of components of the electric grid, by gathering and analyzing sensor data in near real time.
Transformer	A device used to connect two alternating current circuits operating at different voltages.
Transmission network	The part of the power system that carries electric power over moderate to long distance, usually at high voltage.
Transmission overlay	A network of transmission lines to be superimposed on the existing transmission network. Usually refers to lines that are longer and have higher voltage and capacity than existing lines.
Unit commitment	The process of scheduling a generator (unit) to provide energy during a specific time period.
Variable energy resource (VER)	A generator for which output varies over time and is imperfectly predictable, e.g., wind- and solar-powered generators.
Vertical integration	In the electric power sector, a situation in which an entity that distributes electricity to retail customers also owns generation and transmission facilities that are connected to its distribution system.
Volt (V)	Unit of electric potential and electromotive force, equal to the difference of electric potential between two points on a conducting wire carrying a constant current of one ampere when the power dissipated between the points is one watt; roughly analogous to water pressure in a pipe.
Volt ampere (VA)	A measure of apparent power that defines the capacity of equipment, such as transformers or generators, that is limited in voltage and current. It combines both real (time average) and reactive power components.
Watt (W)	The standard unit of electric power, the rate at which work is done when

	one ampere of current flows through an electrical potential difference of one volt.
Watt-hour	A unit of electric energy equal to 3,600 joules.
Western Interconnection	One of the two major synchronized alternating current power grids in North America. It stretches from Western Canada south to Baja California in Mexico, reaching eastward to just over the Rockies into the Great Plains.

15.2 Natural Gas

Aquifer Storage Field	A subsurface facility for storing natural gas consisting of water-bearing sands topped by an impermeable cap rock.
Base natural gas	The quantity of natural gas needed to maintain adequate reservoir pressures and deliverability rates throughout the withdrawal season. Base natural gas usually is not withdrawn and remains in the reservoir. All natural gas native to a depleted reservoir is included in the base natural gas volume.
Biomass natural gas	A medium Btu natural gas containing methane and carbon dioxide, resulting from the action of microorganisms on organic materials such as a landfill.
British thermal unit	The quantity of heat required to raise the temperature of 1 pound of liquid water by 1 degree Fahrenheit at the temperature at which water has its greatest density (approximately 39 degrees Fahrenheit).
Citygate	A point or measuring station at which a distributing natural gas utility receives natural gas from a natural gas pipeline company or transmission system.
Condensate (lease condensate)	Light liquid hydrocarbons recovered from lease separators or field facilities at associated and non-associated natural gas wells. Mostly pentanes and heavier hydrocarbons. Normally enters the crude oil stream after production.
Coke Oven Natural Gas	The mixture of permanent natural gases produced by the carbonization of coal in a coke oven at temperatures in excess of 1,000 degrees Celsius.
Commercial Consumption	Natural gas used by nonmanufacturing establishments or agencies primarily engaged in the sale of goods or services. Included are such establishments as hotels, restaurants, wholesale and retail stores and other service enterprises; natural gas used by local, State, and Federal agencies engaged in nonmanufacturing activities.
Consumption	Natural gas used as lease fuel, plant fuel, for use by pipeline and distribution systems, and by end users (including residential, commercial, industrial, electric power, and vehicle fuel).

Customer Choice	The right of customers to purchase energy from a supplier other than their traditional supplier or from more than one seller in the retail market.
Delivered(natural gas)	The physical transfer of natural, synthetic, and/or supplemental natural gas from facilities operated by the responding company to facilities operated by others or to consumers.
Depleted storage field	A sub-surface natural geological reservoir, usually a depleted natural gas or oil field, used for storing natural gas.
Dry natural gas	Natural gas which remains after: 1) the liquefiable hydrocarbon portion has been removed from the natural gas stream (i.e., natural gas after lease, field, and/or plant separation); and 2) any volumes of nonhydrocarbon natural gases have been removed where they occur in sufficient quantity to render the natural gas unmarketable. Note: Dry natural gas is also known as consumer-grade natural gas. The parameters for measurement are cubic feet at 60 degrees Fahrenheit and 14.73 pounds per square inch absolute.
Electric power sector	An energy-consuming sector that consists of electricity only and combined heat and power(CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public
Electric utility	A corporation, person, agency, authority, or other legal entity or instrumentality aligned with distribution facilities for delivery of electric energy for use primarily by the public. Included are investor-owned electric utilities, municipal and State utilities, Federal electric utilities, and rural electric cooperatives. A few entities that are tariff based and corporately aligned with companies that own distribution facilities are also included.
Exports	Shipments of goods from within the 50 States and the District of Columbia to U.S. possessions and territories or to foreign countries.
Flared	Natural gas disposed of by burning in flares usually at the production sites or at natural gas processing plants.
Natural Gas Condensate Well	A natural gas well that produces from a natural gas reservoir containing considerable quantities of liquid hydrocarbons in the pentane and heavier range generally described as "condensate."
Natural Gas Well	A well completed for production of natural gas from one or more natural gas zones or reservoirs. Such wells contain no completions for the production of crude oil.
Gross Withdrawals	Full well stream volume, including all natural gas plant liquid and nonhydrocarbon natural gases, but excluding lease condensate. Also includes amounts delivered as royalty payments or consumed in field operations.
Heating Season	Typically begins in October and runs through the end of March.
Heating Value	The average number of British thermal units per cubic foot of natural gas as determined from tests of fuel samples.

Imports	Receipts of goods into the 50 States and the District of Columbia from U.S. possessions and territories or from foreign countries.
Industrial Consumption	Natural gas used for heat, power, or chemical feedstock by manufacturing establishments or those engaged in mining or other mineral extraction as well as consumers in agriculture, forestry, and fisheries. Also included in industrial consumption are generators that produce electricity and/or useful thermal output primarily to support the above-mentioned industrial activities.
Intransit Deliveries	Redeliveries to a foreign country of foreign natural gas received for transportation across U.S. Territory and deliveries of U.S. natural gas to a foreign country for transportation across its territory and redelivery to the United States.
Intransit Receipts	Receipts of foreign natural gas for transportation across U.S. territory and redelivery to a foreign country and redeliveries to the United States of U.S. natural gas transported across foreign territory.
Lease Fuel	Natural gas used in well, field, and lease operations, such as natural gas used in drilling operations, heaters dehydrators, and field compressors.
Liquefied Natural Gas (LNG)	Natural gas (primarily methane) that has been liquefied by reducing its temperature to -260 degrees Fahrenheit at atmospheric pressure.
Local Distribution Company (LDC)	A legal entity engaged primarily in the retail sale and/or delivery of natural gas through a distribution system that includes mainlines (that is, pipelines designed to carry large volumes of natural gas, usually located under roads or other major right-of ways) and laterals (that is, pipelines of smaller diameter that connect the end user to the mainline). Since the restructuring of the natural gas industry, the sale of natural gas and/or delivery arrangements may be handled by other agents, such as producers, brokers, and marketers that are referred to as "non-LDC."
Manufactured Natural Gas	A natural gas obtained by destructive distillation of coal, or by the thermal decomposition of oil, or by the reaction of steam passing through a bed of heated coal or coke. Examples are coal natural gases, coke oven natural gases, producer natural gas, blast furnace natural gas, blue (water) natural gas, carbureted water natural gas. Btu content varies widely.
Marketed Production	Gross withdrawals less natural gas used for repressuring quantities vented and flared, and nonhydrocarbon natural gases removed in treating or processing operations. Includes all quantities of natural gas used in field and processing plant operations.
Natural Gas	A natural gaseous mixture of hydrocarbon compounds, the primary one being methane. Note: The Energy Information Administration measures wet natural gas and its two sources of production, associated/dissolved natural gas and nonassociated natural gas and dry natural gas, which is produced from wet

	natural gas.
Natural Gas Marketer	A company that arranges purchases and sales of natural gas. Unlike pipeline companies or local distribution companies, a marketer does not own physical assets commonly used in the supply of natural gas, such as pipelines or storage fields. A marketer may be an affiliate of another company, such as a local distribution company, natural gas pipeline, or producer, but it operates independently of other segments of the company. In States with residential choice programs, marketers serve as alternative suppliers to residential users of natural gas, which is delivered by a local distribution company.
Natural Gas Field Facility	A field facility designed to process natural gas produced from more than one lease for the purpose of recovering condensate from a stream of natural gas; however, some field facilities are designed to recover propane, normal butane, pentanes plus, etc., and to control the quality of natural gas to be marketed.
Natural Gas Liquids (NGL)	A group of hydrocarbons including ethane, propane, normal butane, isobutane, and natural gasoline. Generally include natural gas plant liquids and all liquefied refinery natural gases except olefins.
Natural Gas Plant Liquids (NGPL)	Those hydrocarbons in natural gas that are separated as liquids at natural gas processing, fractionating, and cycling plants. Products obtained include ethane, liquefied petroleum natural gases (propane, normal butane, and isobutane), and natural gasoline. Component products may be fractionated or mixed. Lease condensate and plant condensate are excluded. Note: Some EIA publications categorize NGPL production as field production, in accordance with definitions used prior to January 2014.
Natural Gas Marketed Production	Gross withdrawals of natural gas from production reservoirs, less natural gas used for reservoir repressuring, nonhydrocarbon natural gases removed in treating and processing operations, and quantities vented and flared.
Natural Gas Processing Plant	Facilities designed to recover natural gas liquids from a stream of natural gas that may or may not have passed through lease separators and/or field separation facilities. These facilities control the quality of the natural gas to be marketed. Cycling plants are classified as natural gas processing plants.
Nominal Dollars	A measure used to express nominal price.
Nominal Price	The price paid for a product or service at the time of the transaction. Nominal prices are those that have not been adjusted to remove the effect of changes in the purchasing power of the dollar; they reflect buying power in the year in which the transaction occurred.
Nonhydrocarbon Natural Gases	Typical nonhydrocarbon natural gases that may be present in reservoir natural gas, such as carbon dioxide, helium, hydrogen sulfide, and nitrogen.
Nonutility Power Producers	A corporation, person, agency, authority, or other legal entity or instrumentality that owns or operates facilities for electric generation and is not an electric utility. Nonutility power producers include qualifying

	cogenerators, qualifying small power producers, and other nonutility generators (including independent power producers). Nonutility power producers are without a designated franchised service area and do not file forms listed in the Code of Federal Regulations, Title 18, Part 141
Outer Continental Shelf	Offshore Federal domain.
Offshore Reserves and Production	Unless otherwise indicated, reserves and production that are in either State or Federal domains, located seaward of the coastline.
Oil Well (Casinghead) Natural Gas	Natural gas produced along with crude oil from oil wells. It contains either dissolved or associated natural gas or both.
Onsystem Sales	Sales to customers where the delivery point is a point on, or directly interconnected with, a transportation, storage and/or distribution system operated by the reporting company
Pipeline	A continuous pipe conduit, complete with such equipment as valves, compressor stations, communications systems, and meters for transporting natural and/or supplemental natural gas from one point to another, usually from a point in or beyond the producing field or processing plant to another pipeline or to points of utilization. Also refers to a company operating such facilities.
Pipeline Fuel	Natural gas consumed in the operation of pipelines, primarily in compressors.
Plant Fuel	Natural gas used as fuel in natural gas processing plants.
Receipts	Deliveries of fuel to an electric plant; purchases of fuel; all revenues received by an exporter for the reported quantity exported.
Refill Season	Typically begins in April and lasts through the end of September.
Refinery Natural Gas	Noncondensate natural gas collected in petroleum refineries.
Repressuring	The injection of natural gas into oil or natural gas formations to effect greater ultimate recovery.
Residential Consumption	Natural gas used in private dwellings, including apartments, for heating, air-conditioning, cooking, water heating, and other household uses.
Salt Cavern Storage Field	A subsurface storage facility that is a cavern hollowed out in either a salt "bed" or "dome" formation.
Shale Natural Gas	Natural gas produced from wells that are open to shale formations. Shale is a fine-grained, sedimentary rock composed of mud from flakes of clay minerals and tiny fragments (silt-sized particles) of other materials. The shale acts as both the source and the reservoir for the natural gas.
Storage Additions/Injections	Volumes of natural gas injected or otherwise added to underground natural gas reservoirs or liquefied natural gas storage.
Storage Withdrawals	Total volume of natural gas withdrawn from underground storage or from liquefied natural gas storage over a specified amount of time.

Supplemental Natural Gaseous Fuels Supplies	Synthetic natural gas, propane-air, coke oven natural gas, refinery natural gas, biomass natural gas, air injected for Btu stabilization, and manufactured natural gas commingled and distributed with natural gas.
Synthetic Natural Gas (SNG)	(Also referred to as substitute natural gas) A manufactured product, chemically similar in most respects to natural gas, resulting from the conversion or reforming of hydrocarbons that may easily be substituted for or interchanged with pipeline-quality natural gas.
Therm	One hundred thousand (100,000) Btu.
Total Storage Field Capacity	The maximum volume of base and working natural gas that can be stored in an underground storage facility in accordance with its design, which comprises the physical characteristics of the reservoir, installed equipment, and operating procedures particular to the site.
Transmission (of natural gas)	Natural gas physically transferred and delivered from a source or sources of supply to one or more delivery points.
Transported Natural Gas	Natural gas physically delivered to a building by a local utility, but not purchased from that utility. A separate transaction is made to purchase the volume of natural gas, and the utility is paid for the use of its pipeline to deliver the natural gas.
Underground Natural Gas Storage	The use of sub-surface facilities for storing natural gas for use at a later time. The facilities are usually hollowed-out salt domes, geological reservoirs (depleted oil or natural gas fields) or water-bearing sands (called aquifers) topped by an impermeable cap rock.
Unit Value, Consumption	Total price per specified unit, including all taxes, at the point of consumption.
Vehicle Fuel Consumption	Natural gas (compressed or liquefied) used as vehicle fuel.
Vented Natural Gas	Natural gas released into the air on the production site or at processing plants.
Wellhead	The point at which the crude (and/or natural gas) exits the ground. Following historical precedent, the volume and price for crude oil production are labeled as "wellhead, "even though the cost and volume are now generally measured at the lease boundary. In the context of domestic crude price data, the term "wellhead" is the generic term used to reference the production site or lease property.
Wellhead price	The value at the mouth of the well. In general, the wellhead price is considered to be the sales price obtainable from a third party in an arm's length transaction. Posted prices, requested prices, or prices as defined by lease agreements, contracts, or tax regulations should be used where applicable.
Working natural gas	The quantity of natural gas in the reservoir that is in addition to the cushion or base natural gas. It may or may not be completely withdrawn during any

	particular withdrawal season. Conditions permitting, the total working capacity could be used more than once during any season. Volumes of working natural gas are reported in thousand cubic feet at standard temperature and pressure.

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