Natural Gas-fired Generation:
International Experience in Wind Integration

Prepared by
The Regulatory Assistance Project, Exeter Associates, and The Center for Resource Solutions[1]
September 1, 2010

Introduction

China's National Energy Agency (NEA) asked the Energy Research Institute (ERI) to prepare a study of the role that increased natural gas-fired generation can play in integrating large amounts of wind generation. The Regulatory Assistance Project (RAP) has been asked to provide relevant international experience and studies with a focus on the US, EU, India, and Vietnam.

Summary of Key Points

1. Natural gas-fired generation is a preferred technology, used not solely because it is more flexible than coal or nuclear generation. The dominant factor leading to investment in natural gas-fired generation has been the basic economics of generation. In particular, the mix of baseload, cycling and peaking power plants has been the result of the basic economics of minimizing total power plant capital and operating cost to meet a particular load duration curve. A secondary factor has been environmental concerns, and more recently carbon regulation. Other factors include faster construction time, easier licensing, and reduced exposure to market risk in areas that rely on competitive generation.
2. Worldwide, natural gas is used to generate about 20% of the electricity produced. This fraction is expected to remain steady though 2035 while electricity doubles. In China, natural gas-fired generating capacity accounts for about 2.5% of total generating capacity.
3. Many wind integration studies have been completed. Many lessons and general conclusions can be drawn, a few of which relate to natural gas-fired generation. Countries or regions with large amounts of flexible generation (hydro and natural gas) are better able to integrate large amounts of wind.
4. Natural gas-fired generation in China can help address wind integration, carbon intensity, and air pollution goals.
5. Natural gas-fired generation in China will benefit from investment strategies aimed at reducing the cost of generation and reformed generation pricing policies for non-baseload flexible generation.

Discussion

1. Mix of Generation Resources from Selected Countries/Regions

Of the approximately 4,000 GW of installed electricity capacity globally, more than two-thirds of generation from this capacity is fossil-fuel sourced. Natural gas provides more than 20% of global generation services.[2] In the US, EU, India and Vietnam, natural gas is generally growing as a share of installed capacity and

---

[1] David Moskovitz, Riley Allen, Ajith Rao, Lisa Schwartz, Rebecca Schultz at The Regulatory Assistance Project; Kevin Porter at Exeter Associates; and Ryan Wiser at The Center for Resource Solutions.

[2] Energy Information Administration, International Energy Annual, 2010, Exh. 6., available at http://www.eia.gov/oiaf/ieo/index.html.

generation. Looking forward through 2030, after renewable resources, natural gas capacity is projected to grow faster than any category of generation globally.

Worldwide, both pipeline and liquefied natural gas (LNG) are expected to increase in the future. Most of the increase in LNG supply comes from the Middle East and Australia.

Almost 75% of the world's natural gas reserves are located in the Middle East and Eurasia. Russia, Iran, and Qatar combined currently account for about 60% of the world's natural gas reserves.

Russia is the world's single largest exporter of natural gas, with net exports of 245 bcf in 2008, all of it by pipeline. Iran, despite having the second largest reserves after Russia, lags behind with exports of only 4.2 bcf in 2008.[3]

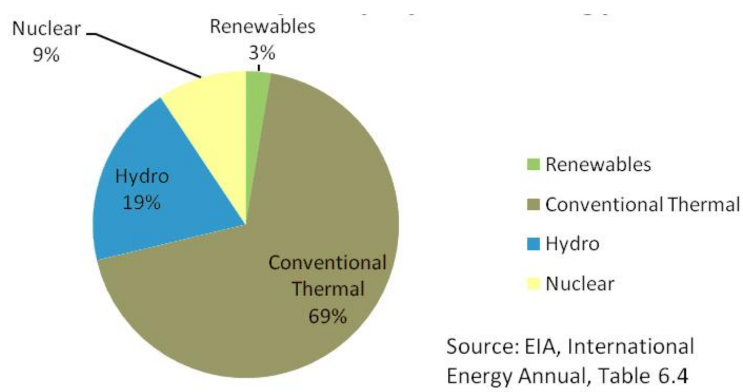

Figure 1: Global Capacity by Technology

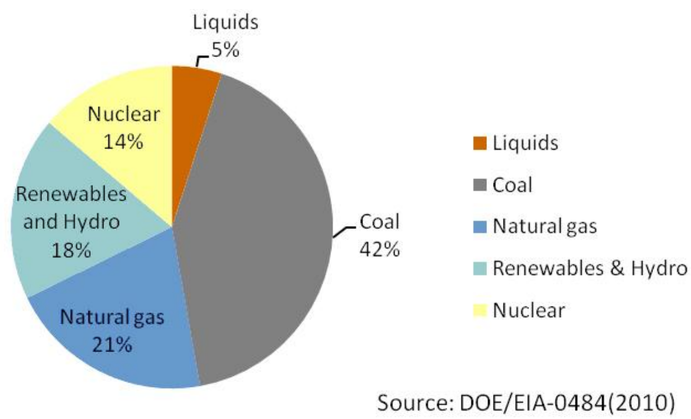

Figure 2: Global Electricity Generation by Fuel

[3] CIA World Factbook, Natural Gas Exports Country Rank, 2010, available online at http://www.photius.com/rankings/economy/natural_gas_exports_2010_0.html

United States

In the US, natural gas accounts for the largest share of generation capacity, followed by coal and then nuclear. In 2007, 384 GW, or roughly 40% of the 965 GW of US summer rated generation capacity came from natural gas. While coal generation represents a smaller share of capacity, it represented more baseload capacity and typically operates a greater share of the time. Coal represents 32% of US capacity and provides roughly 50% of US electricity generation. Similar to coal, nuclear, as baseload capacity, represents a much larger share of generation than capacity. In 2007 nuclear represented 10% of US capacity and roughly 20% of electricity generation. Conventional hydro-electric generation represents only about 8% of capacity and 6% of electricity generation. Wind, solar, and geothermal generation still account for less than 2% of generation and capacity.[4] Petroleum accounts for roughly 6% of the generation, but functions largely as a peaking resource and accounts for only about 1% of electricity generation.

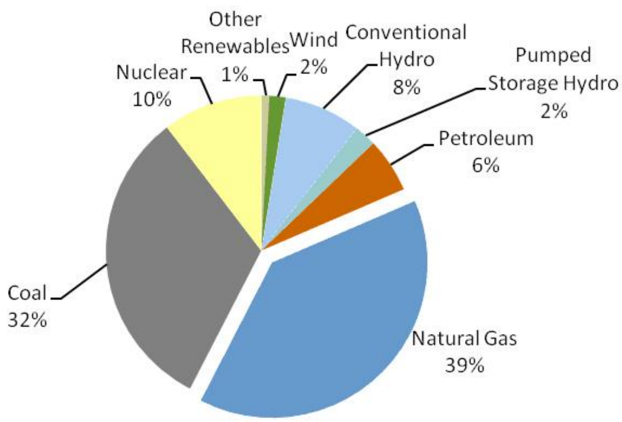

Figure 3: 2007 US Generation Capacity by Fuel

Recent Investment Trends

Most recent investment in generating capacity in the US is in natural gas and wind. From 1998 to 2008, natural gas-fired generation has increased its share of the capacity base from roughly 167 GW to 397 GW, or by 138%.

Natural gas combined-cycle generation in the US operates as a cycling resource with an average annual capacity factor of 40%. This compares with 91% for nuclear and 72% for coal, which typically operate as baseload sources of generation.[5] Other natural gas- and petroleum fired generation typically operate as peaking resources with capacity factors in 2008 of roughly 11% and 9% respectively.

Investment in renewable energy, specifically wind, is the fastest growing category of generation, but from a small base. From 2005 to 2007, wind capacity almost doubled, from 8.7 GW to 16.2 GW. These figures more than doubled again between 2007 and 2009 as cumulative capacity additions of wind grew to 35 MW in

[4] Unless indicated otherwise, all statistics for US generation and generation capacity are from the Annual Energy Review, Long Term Historical Statistics, available at http://www.eia.doe.gov/emeu/aer/elect.html.

[5] US Energy Information Administration, Form EIA-860, "Annual Electric Generator Report;" Form EIA-923, "Power Plant Operations Report."

2009.[6] The significant growth during the last two years amidst the financial crisis surprised many, but can be explained by a variety of drivers, including the American Recovery and Reinvestment Act of 2009, carryover from projects planned for 2008, state renewable portfolio standards, and other federal programs and initiatives.[7] At the same time, the recession and lower wholesale prices are dampening expectations for wind in the near future.

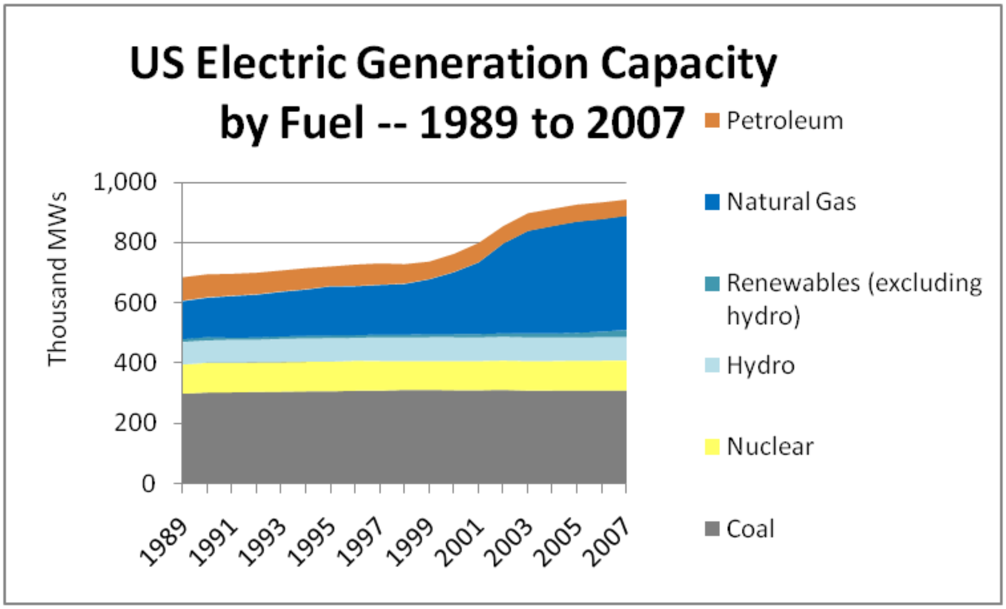

Figure 4: US Electric Generation Capacity by Fuel, 1989 to 2007

Sector reforms, combined with low capital costs of natural gas capacity and low natural gas prices in the late 1990s through 2003, led to substantial investment in natural gas generation. Wellhead prices in North America remained below $5/Mcf prior to 2004. After the run-up in prices from 2004 through 2008, natural gas price trends have declined in recent years following improvements in extraction of natural gas from unconventional sources.[8] Increasing estimates of shale gas resources have helped to increase US natural gas reserves by almost 50% over the past decade.[9] Consequently, the US has become significantly less dependent on LNG imports. Since the mid-1990s, the electricity sector has provided the fastest growth in natural gas demand.[10]

Since its peak in 1990 of 112 nuclear generation licenses, there are now only 104 operating nuclear facilities. DOE reference case projections show nuclear declining as a share of total capacity in the electricity sector.[11] Coal generation continues to grow under a reference case, but its share of capacity declines and its future remains clouded by risks associated with regulatory uncertainties.[12]

Looking forward, the US government projections suggest natural gas will continue as the preferred choice for new generation. The EIA projects that natural gas will by far account for the most significant investment in

[6] Wiser, Bolinger, 2009 Wind Technologies Market Report, LBNL-3716E, August 2010.
[7] See *supra* note 2.
[8] EIA, Natural Gas Navigator, available at http://www.eia.gov/dnav/ng/hist/n9190us3A.htm.
[9] EIA, International Energy Outlook, Report DOE/EIA-0484, 2010, available at http://www.eia.doe.gov/oiaf/ieo/highlights.html.
[10] EIA, Annual Energy Review, 2008, at Exhibit 35, available at http://www.eia.doe.gov/emeu/aer/pdf/aer.pdf.
[11] EIA, Annual Energy Outlook, 2010, at 65, available at http://www.eia.doe.gov/oiaf/aeo/pdf/trend_3.pdf.
[12] *Id.*, at 66.

new generation capacity from 2009 to 2014.[13] The Department of Energy projects that roughly 45 GW of retirements over the next 20 years, together with expected load growth, will create the need for significant additional generation. Natural gas generation and investments in renewable energy are projected to continue as the preferred categories of investment. DOE expects that 46% of new generation capacity will come from natural gas.[14] Economic drivers fostered in part by state and federal actions continue to improve the outlook for natural gas and renewable resources. However, future investments depend in large part on the future of environmental regulations including carbon and other pollutants that are currently under review.

The predominant drivers for wind generation include a combination of factors that serve to improve the financial performance of wind generation. Among these factors are improvements in the technology, combined with favorable tax incentives and initiatives in many US states to implement aggressive goals for renewable portfolio standards. In most states, wind is the least expensive renewable resource eligible to meet these standards.

Europe

In the EU-27, conventional thermal generation accounts for about half of generation. Significant growth in combined-cycle generation has occurred over the last 11 years and accounts for roughly half the growth in new capacity. Within the EU-27, more than 67 GW of new combined-cycle generation has come on line. Almost 80% of this investment has occurred within just four countries in Europe (Italy, Spain, UK, and Netherlands). Europe depends heavily on imports for its natural gas supply. As an example, Germany relies on domestic supplies for only 15% of its needs; the remainder is from Russia and northern European countries.[15]

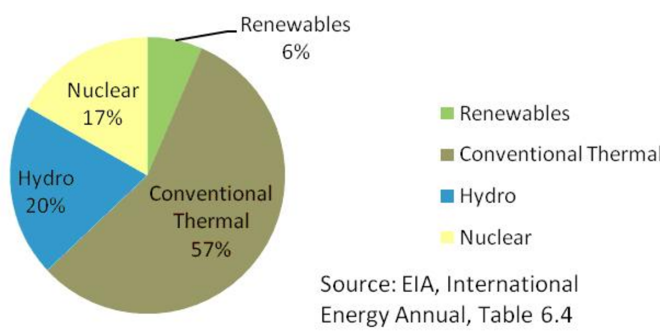

Figure 5: Europe Installed Capacity by Technology, 2008

[13] EIA, "Planned Generating Capacity Additions from New Generators by Energy Source," January 21, 2010, available at http://www.eia.doe.gov/cneaf/electricity/epa/epat1p4.html.

[14] EIA, Annual Energy Outlook, 2010, at 66, available at http://www.eia.doe.gov/oiaf/aeo/pdf/trend_3.pdf.

[15] RWE, Facts and Figures, October 2008, available at http://rwecom.online-report.eu/factbook/en/servicepages/welcome.html.

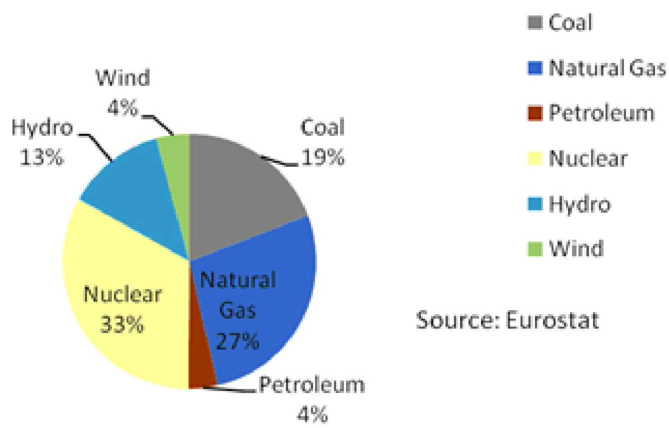

Figure 6: EU-27 Generation by Fuel, 2008

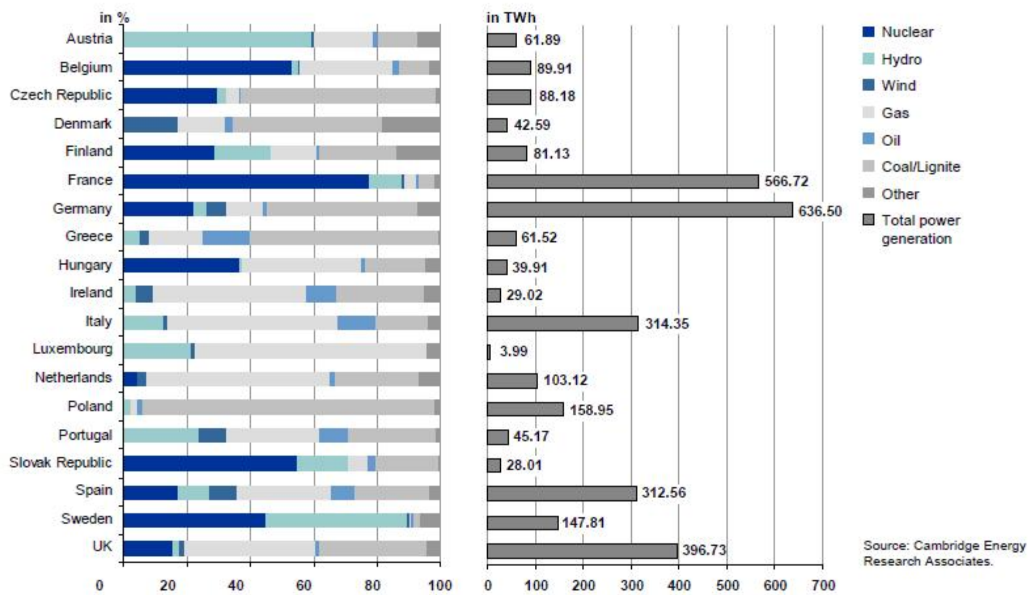

Figure 7: Shares of Primary Energy Sources in Total Electricity Generation in Europe, 2007

France and Germany are the largest electricity producers. Among the largest producer nations in Europe, Italy, UK, Spain, and Germany, natural gas accounts for a significant share.[16]

Recent Investment Trends

Most of the recent investment in Europe is in renewable energy and natural gas, especially combined-cycle generation. Similar to the US, low natural gas prices combined with sector reforms and the efficiency advantages and short construction cycle of natural gas generation combined to spur the development of natural gas-fired generation. However, the recent period of higher natural gas prices, combined with long standing concerns over dependence on imports of natural gas from other regions, may temper its continued expansion at this level.

[16] *Id*.

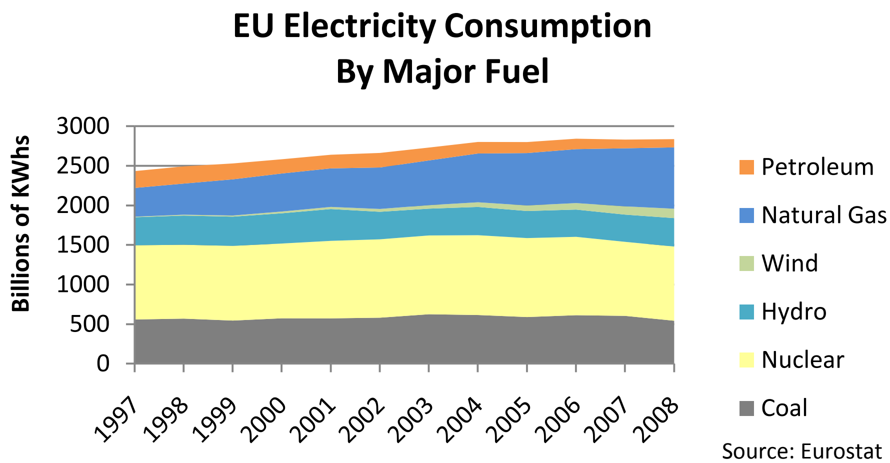

Figure 8: EU Electricity Generation by Major Fuel, 1997-2008

Similar to the US, Europe has challenges with the aging of its fleet of generators. RWE reported in 2008 that 60% of the coal plants were more than 25 years old and would need to be replaced by 2030. The last boom in plant construction was in the 1980s, and 40% of the thermal and nuclear plants are older than 25 years.[17]

India

The installed power generation capacity of India is approximately 164 GW (June 2010).[18] The Indian government set an ambitious target to add approximately 78,000 MW of installed generation capacity by 2012.[19] Given India's vast coal reserves and its large untapped hydroelectric potential, these two resource categories are likely to provide the bulk of additional generation capacity in future. About 63% of the electricity consumed in India is generated by thermal power plants (in which coal supplies about 52% and natural gas approximately 10%), 3% by nuclear plants, 25% by hydroelectric power plants, and 9% by other renewable energy sources such as biomass and wind.[20]

India has committed a massive amount of funds for the construction of nuclear reactors which would generate at least 40 GW by 2030.[21] In recent years India has also invested heavily in renewable sources of energy, such as wind energy.[22] The total commercially exploitable potential of renewable resources in India is estimated at about 47 GW – 20 GW for wind, 10 GW from small hydro and 17 GW from biomass.[23] The government is promoting renewable resources and is increasing their allocations in its five-year plans. Renewable resources currently account for only a minor share of total commercial primary energy in India. Nonetheless, their share is rapidly growing. Installed wind-power capacity in India is among the highest in the world. Wind power increased rapidly in the 1990s, boosted by subsidies and financial incentives. As of 2008, India's installed wind power generation capacity stood at 9.65 GW.[24] In July 2009, India unveiled a $19

---

[17] *Id*.
[18] Central Electricity Authority of India, available at http://cea.nic.in/.
[19] KWR International, "Indian Electricity: Miles to Go," available at http://www.kwrintl.com/library/2007/indianelectricity.htm.
[20] Government of Indian, Ministry of Power, available at http://www.powermin.nic.in/.
[21] See *supra* note 19.
[22] World Wind Energy Association, World Wind Energy Report 2008, available at http://www.wwindea.org/home/images/stories/worldwindenergyreport2008_s.pdf.
[23] McKinsey & Company, Renewable Energy: Bridging India's Power Gap, Winter 2008, available at http://www.mckinsey.com/clientservice/sustainability/pdf/renewables_india.pdf.
[24] See *supra* note 22.

billion plan to produce 20 GW of solar power by 2020.[25]

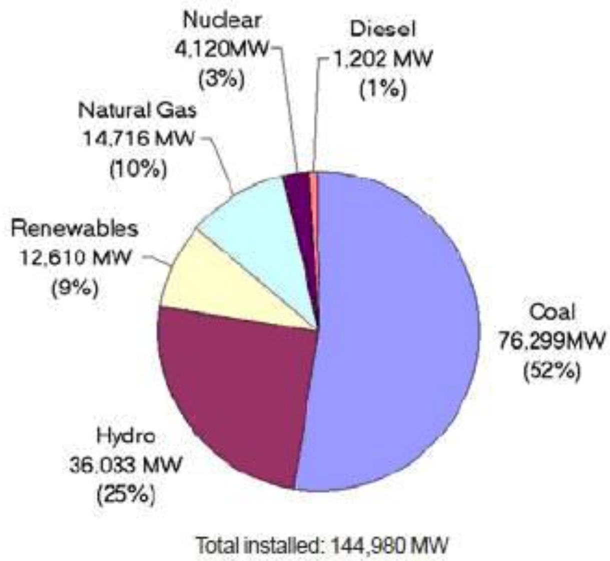

Figure 9: India Generation by Fuel, 2008. Source: EIA

India's electricity supply is mainly based on coal. Power plant manufacturers in India are more familiar with coal-boiler and steam-turbine technology than with combustion-turbine technology.[26]

In 2009, India consumed roughly 1.8 Tcf of natural gas, almost 300 Bcf more than in 2008.[27] The largest share is consumed by power generation (38.1% in 2006-07), followed by the fertilizer industry (27.1%). Natural gas is expected to be an increasingly important component of energy consumption as the country pursues energy resource diversification and security. Despite the steady increase in India's natural gas production, demand has outstripped supply and the country has been a net importer of natural gas since 2004. Natural gas demand is expected to grow considerably, largely driven by demand in the power sector.

According to the *Oil & Gas Journal*, India had approximately 38 Tcf of proven natural gas reserves as of January 2010.[28] The EIA estimates that India produced approximately 1.4 Tcf of natural gas in 2009, a 20% increase over 2008 production levels. The bulk of India's natural gas production comes from the western offshore regions, especially the Mumbai High complex, though the Bay of Bengal and its Krishna-Godavari fields are proving quite productive. Onshore fields in Assam, Andhra Pradesh, and Gujarat states are also significant sources of natural gas production.[29]

Recent Investment Trends

The Indian natural gas market is in the midst of a major shift from a centrally managed system to one with a greater role on market forces. Since the first major gas supplies began flowing in the mid-1980s, natural gas has been produced entirely by the national oil company, Oil and Natural Gas Corporation (ONGC), and

[25] Shukla, P. R., et. al., "Natural Gas in India: An Assessment of Demand from the Electricity Sector," Program on Energy and Sustainable Development, Stanford University, 2007, available at http://pesd.stanford.edu/publications/india_electricity/.
[26] See *supra* note 25.
[27] See *supra* note 25.
[28] Oil & Gas Journal, available at http://www.ogj.com/index.html.
[29] See *supra* note 28.

transported and marketed by the state-owned Gas Authority India Limited. Gas provided by these entities was sold at low prices set by the central government which, at the time, had a large surplus and sought to stimulate consumption.

ONGC's main interest is in oil. India has historically had little interest in natural gas, and private oil and gas companies had little access to the Indian market, this hindered investment in new gas production and infrastructure. A gas shortage quickly emerged by the end of the 1990s. In response to this supply shortfall, the Indian government passed a series of broad reforms designed to increase the production and availability of gas. Prominent among these was the enactment of the New Exploration Licensing Policy, which allowed private companies to bid for oil and gas exploration blocks and to construct LNG import terminals. These reforms have quickly yielded fruit. In 2002, Reliance Industries Limited announced a 14 Tcf gas field off the east coast of India, increasing India's available gas reserves by nearly 50%. Other large reserves have since been announced by the Gujarat State Petroleum Corporation and ONGC as well.

India's existing installed generation capacity still has a deficit of generating capability that is estimated to be about 13.5% below peak demand and 8.7% below energy demand.[30] Under the *"Power for All"* initiative,[31] a projected installed generation capacity of 200 GW is required to meet demand in 2010. According to *"Hydrocarbon Vision 2025,"* [32] natural gas-fired generation is projected to double from the current level of 13.4 GW to about 26.8 GW by 2012. This growth suggests an increase in natural gas demand of 153 to 208 MMSCMD from the current consumption of 38 MMSCMD.[33]

India currently has around 7000 km of gas pipeline with capacity to transport 160 MMSCMD of natural gas.[34] The government policy of open access and private participation to ensure enough pipeline capacity is slowly being realized. Major investors are building pipelines that will ultimately connect supply centers to demand regions. Although India's natural gas market is evolving rapidly, at present there is no competitive gas market in the country where multi-sourcing and multi-buying options are available.

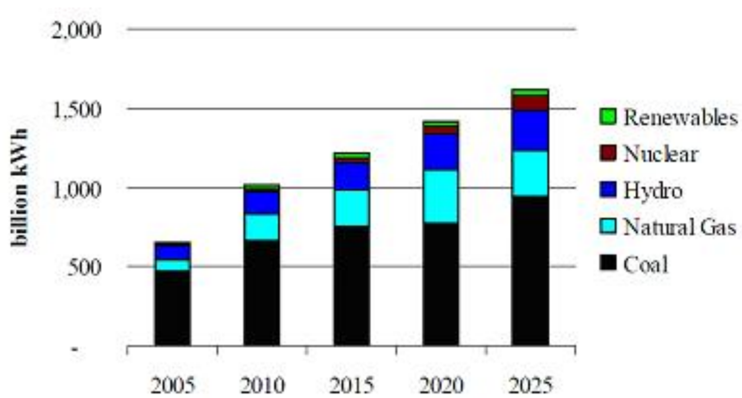

Figure 10: India Projected Electricity Generation Mix, 2005-2025. Source: Jackson, 2007

[30] ICF International, "The Practical Insight to Gas Pricing in India", available at http://www.icfi.com/Docs/india-gas-price.pdf
[31] Government of India, Ministry of Power, Power for All by 2012 Initiative, available at http://www.powermin.nic.in/indian_electricity_scenario/power_for_all_target.htm.
[32] Government of India, Hydrocarbon Vision 2025, available at http://petroleum.nic.in/vision.doc.
[33] Jackson, Mike, "The Future of Natural Gas in India: A Study of Major Consuming Sectors," Program on Energy and Sustainable Development, Stanford University, 2007, available at http://pesd.stanford.edu/publications/india_gas_synth/.
[34] *Id*.

Despite the projected growth in natural gas-fired generation, coal is expected to maintain its dominant position in the Indian electricity mix although there are competing interests.[35] On the one hand, liberalization of the Indian coal sector currently underway is expected to make it more competitive and slow the rise of natural gas. New gas-fired plants will be forced to compete with regulated coal-fired generation. A competitive coal sector seems likely to out-compete gas for most electric power applications. On the other hand, regional air pollution controls could provide a strong advantage to natural gas over coal. A plausible tightening of sulfur emission rules could nearly double demand for gas in the power sector by 2025.[36] Lastly, the expected reform of the Indian electricity grid could also provide an opportunity for natural gas to play a larger role in meeting loads during peak seasons. Capacity limitations currently constrain delivery of electricity, especially in the summer season. At a minimum, natural gas is expected to play an important role in generating peaking power, as the load curve will shift from the baseload-dominated power of today to a load curve with greater daily variability.

Vietnam

In 2007, Vietnam had 12.6 GW of capacity and produced approximately 66.8 billion kWh of electricity. Natural gas generation capacity has risen sharply since the late 1990s.[37]

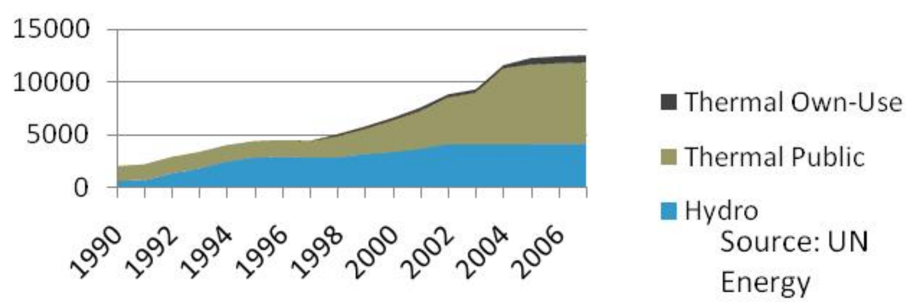

Figure 11: Vietnam Electric Generating Capacity by Technology and Ownership

The State-owned Electricité de Vietnam (EVN) dominates generation of electricity in Vietnam. Foreign and private company participation has been permitted since 2001 with some expansion in capacity.[38]

In 2004, a little more than half of Vietnam's generation capacity was from conventional thermal sources and the remainder came from hydroelectric sources. Since then, new thermal capacity has substantially increased. Natural gas-fired power plants have emerged as a major new source of electricity supply. EVN reported that 29% of its generating capacity came from natural gas-fired power stations. The rise of natural gas-fired electricity is mostly due to the development of a single power complex, which consists of five natural gas-fired generating units providing 3,900 MW of new capacity.[39]

[35] See *supra* note 32.
[36] See *supra* note 32.
[37] Energy Information Administration, Vietnam Country Profile, June 30, 2010, available at http://tonto.eia.doe.gov/country/country_energy_data.cfm?fips=VM.
[38] ASEAN Center for Energy, Vietnam, Power Development Plan, available at http://www.aseanenergy.org/energy_sector/electricity/vietnam/power_dev_vietnam.htm.
[39] Id.

2. The Role of Gas-fired Generation in Integrating Wind and Other Variable Energy Resources

Maintaining a reliable power system has historically depended on several types of reserve capacity and on system operators adjusting generation up and down to match changing levels of demand and unexpected generation or transmission outages. The term "ancillary services" broadly encompasses the range of actions generators and some types of demand-side resources may be asked to perform to ensure electric system reliability.

Ancillary services have traditionally been provided by flexible natural gas and hydroelectric power plants with the capability of adjusting output rapidly. Increasingly, ancillary services are provided through non-generation resources, such as demand response and energy storage resources.[40] These services are an important part of balancing supply and demand and maintaining power system reliability. The integration of large amounts of wind, solar and other variable energy resources into the grid may increase the need for balancing and other ancillary services.

Although there is no universal agreement on the number and definitions of ancillary services, the "regulation" and "load following" services shown in the chart below are considered necessary to maintain reliable grid operation.[41]

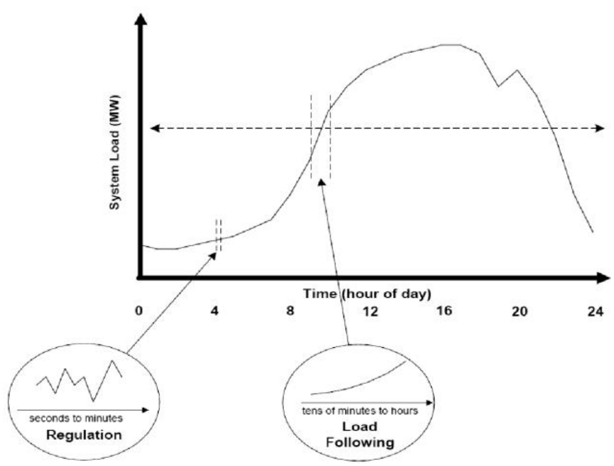

Figure 12: Regulation and Load Following Time Frames. Source: Milligan, 2006

- *Regulation* - Regulation is maintaining system frequency on a second-by-second basis for system balancing by resources equipped with automatic controls. While this is currently provided only by thermal generators and hydro systems, regulation also could be supplied by demand response and storage technologies.

Fast, unpredictable variations in load occur in very short (i.e., seconds to minutes) time frames. Regulation services allow for rapid increases or decreases in energy generation to meet the changes. Since variations in

[40] North American Electric Reliability Corporation (NERC), "Accommodating High Levels of Variable Generation," 2009, available at http://www.nerc.com/files/IVGTF_Report_041609.pdf.

[41] Exeter Associates, "Review of International Experience Integrating Variable Renewable Energy Generation," 2007, available at http://www.energy.ca.gov/2007publications/CEC-500-2007-029/CEC-500-2007-029.PDF.

wind energy generally take place over longer time periods, wind power requires only minimal regulation. Automatic generation control systems monitor load and generation and balance the two by providing a signal to increase or decrease generator output. The cost of regulation related to wind energy variability is fairly low – less than 0.1 cent per kWh of wind energy. [42] Because regulation is designed to respond to random, moment-to-moment variations of loads and generators, it is expensive to use it to respond to variations in loads over larger time scales.

- *Load Following* - Load following is implemented on time scales of minutes to hours, and involves ramping generation up or down to react to the change in expected load patterns, such as increasing loads in the morning and decreasing loads late in the day.

Large penetrations of wind energy can have a significant impact on system ramping requirements in this time scale, varying by time of day and time of year. This impact can be calculated explicitly. Wind generation that is installed across a broad geographic area will typically have a smaller impact on load following requirements than if all or most of the wind capacity is concentrated in a small area.

<u>Ancillary Services</u>

Ancillary services may be offered through a market, as is the case for many (although not all) of the liberalized markets in the US. Or they may be provided internally by large generating firms or arranged through bilateral contracts, as is typically the situation for the Western and Southern US. Such bilateral arrangements are more representative of what happens in China.

In nearly all instances, ancillary services are paid for by all customers – i.e., the costs are aggregated and are charged to load, not to generators. More recently, some transmission providers have imposed wind integration charges to wind generators to reflect wind integration costs. The Bonneville Power Administration includes a wind energy balancing charge in its transmission tariff that is about $5.70/MWh. Westar Energy charges wind generators higher generator regulation and frequency response charges of about $0.80/MWh. Idaho Power, PacifiCorp and Avista all reduce their payments to wind power generators by an integration rate that ranges up to $6.50/MWh.

Current ancillary service levels and types may change at higher levels of wind penetration, and it is important to recognize what is needed and to take steps to secure it. Load following may need to be a required ancillary service, with generators compensated for providing the service. Premiums may need to be offered for faster ramping. Multi-hour wind ramping events are too slow for expensive spinning and non-spinning reserves that must respond within 10 to 30 minutes, depending on the type of reserve. System operators are also supposed to restore reserves within 30 minutes and no later than 105 minutes (i.e., 90 minutes after the events), although they are often restored much quicker than that. Because of the restrictions on using spinning and non-spinning reserves, the lack of such restrictions on using regulation and the comparative lack of a long-term reserve, it is easy, but perhaps costly, for system operators to rely on regulation to follow wind's variability. Regulation can be relatively expensive in the US, because generators that provide this service are paid a capacity price plus their opportunity costs for not participating in the energy market. Providers of other reserves are paid strictly for energy. Therefore, a new ancillary service that lasts for multiple hours may be needed to handle wind ramps.

Ancillary service levels may also need to vary by season and time of day rather than an annual flat amount to account for varying seasonal and daily levels of wind output. Some grid operators in the US are moving in this direction. The California ISO is considering buying higher levels of regulation in the spring and fall when wind output is higher, and ERCOT varies its monthly purchase of non-spinning reserves depending on its wind forecast. ERCOT's non-spinning reserves must respond within 30 minutes and can be used to respond to loss-of-resource contingencies, wind and load forecast errors when limited reserves are on-line or when 95% or more of the Balancing Energy Up bids are projected to be used.

[42] ISO/RTO Council, Increasing Renewable Resources, 2007, available at http://www.isorto.org/atf/cf/{5B4E85C6-7EAC-40A0-8DC3-003829518EBD}/IRC_Renewables_Report_101607_final.pdf.

Regulation and load following reserves are used for normal system conditions, while spinning and supplemental reserves are relied on for outages and other contingency conditions that produce unexpected changes in loads over very short timeframes.

- *Frequency-Responding Spinning Reserve* - Frequency-responding spinning reserves refer to generating capacity that is typically synchronized to the grid and can maintain reliability if a generating unit or transmission line is tripped off-line.

- *Supplemental Reserves* - Supplemental reserves perform a similar function to spinning reserves – i.e., maintaining reliability in case of the loss of a major generating unit or transmission line, but the generators providing this service are generally not synchronized (i.e., non-spinning) to the grid and may need additional start-up time to contribute.[43]

In the US, the Federal Energy Regulatory Commission (FERC) requires transmission providers under its jurisdiction to offer six ancillary services, including regulation, spinning reserve, and supplemental (sometimes called non-spinning reserve).[44] FERC does not yet recognize load following as an ancillary service.

Several US wind integration studies have found that load following requirements will likely increase at higher levels of wind penetration. As China considers the role of natural gas in helping to increase the use of wind energy, load following capability and related issues of minimum operating capacity and rapid start-up and shut-down times and costs may be the most important power plant characteristics to evaluate. International experience with natural gas-fired generation provides useful technical, economic, and policy information.

Technical

The ability of power plants to rapidly increase or decrease their output in response to changing conditions varies greatly based on fuel type, size, and design. Coal plants generally have limited ability to ramp output quickly due to significant thermal inertia in their large boilers. Coal plants have typically been designed to operate as baseload power plants. They generally operate at relatively high and constant load levels. They also tend to have high minimum load levels of 45% to 50% of their design capacities and are much slower and more costly than natural gas-fired power plants to bring back on line once they have been shut down.

Modern natural gas- fired combined-cycle combustion turbine plants can be ramped up or down more rapidly and cycled more frequently with less impact on their long-term economic viability than other thermal generation sources.. The key factors limiting the plant's ability to rapidly vary its output are the allowed pressure and temperature transients of the steam turbine, the waiting times of the heat recovery steam generator to reach proper steam conditions, and the warm-up times for the main piping system and other plant components.

The need for more flexibility has caused power plant designers and vendors to offer improved designs that increase ramp rates and start-up times.[45]

[43] Parsons, et. al., "Grid Impacts of Wind Power Variability," 2006, available at http://www.nrel.gov/docs/fy06osti/39955.pdf.
[44] The three other required ancillary services are (1) scheduling, system control and dispatch for coordinating transmission and generation transactions; (2) reactive supply and voltage control; and (3) energy imbalance for correcting hourly mismatches been energy supply and load. Transmission providers are the only parties that can offer scheduling and reactive supply. Where markets exist, market participants can procure the other four ancillary services from transmission providers or from other market participants.
[45] "The Importance of Combined Cycle Generating Plants in Integrating Large Levels of Wind Power Generation," J. Nicolas Puga, Electricity Journal, Vol. 23, Issue 7, Aug/Sept 2010.

Economic

Basic power sector economics focus on finding the optimum mix of power plants to meet demand. Each generation technology has capital cost and operating cost characteristics that determine if it will be cost-effective to meet baseload needs, peaking needs, or something in between. The economics of natural gas-fired generation has changed over time. But in the US and the EU, its capital cost has been consistently well below the capital cost of coal-fired or nuclear generation. Competitive markets and the shift from conventional steam to turbine-based technology have driven innovation, cost reduction, and efficiency in natural gas-fired generation technology.[46]

Operating costs for thermal plants mostly consist of volatile fuel prices. Natural gas plant operating costs have generally been high relative to coal, but improving generation efficiency and natural gas price reductions brought about by increased supply has occasionally reduced operating costs of natural gas plants below coal plants.

The combination of capital and operating costs has made natural gas a cost-effective resource for power generation, especially cycling and peaking use with, or without, consideration of its superior ability to ramp up or down.

Increased use of wind energy will likely lead to increased use of peaking and intermediate power plants that operate at lower capacity factors and decreased use of baseload generation. Baseload plants including nuclear and coal assets typically have high fixed costs and low variable costs. Such units are most economic to build when there is an expectation that they will be operated as a baseload plant. But with high levels of wind or solar generation, such assurances cannot be provided.

The economics of new power plant construction will therefore shift. Power plants with lower up-front fixed costs (and higher variable fuel costs) will tend to become more economically competitive. As a result, an electric system with large amounts of wind energy will therefore increasingly shift towards peaking resources and away from baseload resources.[47] In the US and Europe, simple-cycle and combined cycle combustion turbines are ideally suited to meet these needs, as they typically have lower capital (but higher operating) costs.

Policy

Two policies have been instrumental in supporting the development of natural gas-fired generation in the US and the EU. First was the repeal of laws that prohibited, or discouraged, the use of natural gas for power generation as concerns about long-term shortages of natural gas faded with discoveries of abundant supplies.

Second was the widespread adoption of pricing policies that encourage investment in cost-effective generation. These policies include separately pricing the capacity, energy, and more recently ancillary services that generation can provide.

[46] Massachusetts Institute of Technology, Energy Laboratory, Comparative Study on Energy R&D Performance: Gas Turbine Case Study, Final Report, August 1998, available at http://web.mit.edu/energylab/www/pubs/el98-003a.pdf.

[47] Lamont, A.D., "Assessing the long-term system value of intermittent electric generation technologies," *Energy Economics*, 30(3): 1208-1231, 2008; Milborrow, D., "Quantifying the impacts of wind variability," Proceedings of the Institution of Civil Engineers. *Energy*, 162(3): 105-111, 2009; Boccard, N., "Economic properties of wind power: A European assessment," *Energy Policy*, 38(7): 3232-3244, 2010.

In areas of the US and EU that do not have liberalized markets, the standard practice is to price capacity and energy separately. The capacity price is paid on a per-kilowatt per-period basis and allows each power plant to recover its fixed capital cost no matter how many hours it operates. It is paid for whether or not the unit produces any energy (although there are often penalties for non-performance when the unit is called on). The energy price is paid on a kilowatt-hour basis. The kilowatt-hour charge is set to cover the variable (or marginal) costs of operation (predominantly the fuel cost plus variable operating and maintenance costs). This pricing system allows full cost recovery for all types of power plants without regard to the number of hours a power plant runs. This is especially helpful for natural gas-fired peaking plants that are the most cost-effective generation for meeting demand during a relatively few number of hours.

Pricing policies are more complex in areas with competitive generation markets, but in both the US and EU the goal has been the same: design market rules to assure the market delivers the right amount and mix of generation.

In the US, there have been several reforms to early competitive generation markets to address the issue of sufficient capacity to address future needs. The first was the addition of capacity markets in several liberalized markets in the US. Capacity markets help support investment in generation that does not operate often and due to other aspects of energy markets would be unable to recover capital costs through higher energy prices. Second, FERC has created defined requirements for ancillary services that support natural gas and other flexible generation. Third, FERC is considering reforms to put demand-side resources on a more equal footing with supply-side resources.

Finally, FERC has recently commenced a proceeding to examine a wide range of issues including use of sub-hour scheduling and increasing the size of balancing areas aimed at market and pricing reforms to help integrate wind.[48] FERC also has instituted a proceeding to require regional transmission planning, including a requirement that transmission planning reflect public policies such as renewable portfolio standards.

In the EU, current market rules vary from country to country. Spain and Ireland have adopted capacity markets, while England and Wales have not. OFGEM, the electricity regulatory body in England, has recently completed a year-long review of electricity market reforms that may be needed to meet the UK's climate and renewable energy goals. Many reforms, including creating capacity markets, have been identified.[49]

The Council of European Energy Regulators (CEER) the association of Europe's independent national electricity regulators, recently recognized that increased wind generation will lead to more volatile market prices and this will have a fundamental impact on the incentives the market has to invest in conventional generation including needed, flexible natural gas-fired generation. CEER also recognizes the impact that increased wind generation is having on existing conventional generation. Some power plants operators state that their operating costs are rising with increasingly lower operating hours and higher start-up costs. CEER is now considering market reforms needed to address these issues.

[48] FERC, Notice of Inquiry - Integration of Variable Energy Resources, FERC Docket No. RM10-11-000, January 21, 2010, available at http://www.ferc.gov/whats-new/comm-meet/2010/012110/E-4.pdf.

[49] OFGEM, "Project Discovery: Options for delivering secure and sustainable energy Supplies," February 2010, available at http://www.ofgem.gov.uk/MARKETS/WHLMKTS/DISCOVERY/Documents1/Project_Discovery_FebConDoc_FINAL.pdf.

3. Lessons Relating to Gas-Fired Generation from Large-scale Wind Integration Studies

A number of sophisticated wind integration studies have been conducted in the US and EU looking at long-term operational and investment changes. The fundamental design of wind integration studies conducted in the US to date takes the perspective that wind affects the "net load" (load minus wind) on a utility grid, and that wind's potential impacts on the electric system should therefore be assessed as a whole. As a result, few wind energy integration studies have specifically considered the impact of wind, or benefit to wind, of natural gas-fired generation in particular. Some of these wind integration studies attempt to estimate a "wind integration cost" at different levels of wind penetration. The wind integration costs represents estimates of costs from increased fuel consumption, increased O&M costs and costs of increased reserves as power systems incorporate the wind generation.

A 2006 wind integration study for Xcel Energy looked at the potential effects of 10% and 15% wind energy penetration on natural gas purchases, consumption, and storage for the utility's Colorado operations. [50] Xcel Energy is a large electric utility that purchases natural gas on a day-ahead basis, using load forecasts and commitment plans for natural gas plants. Higher levels of wind generation contribute to increased day-ahead uncertainty, thereby adding uncertainty to how much natural gas should be purchased. Because natural gas storage is limited in the US, under-predicting fuel needs could lead to potentially more costly short-term power purchases of natural gas or electricity, whereas over-predicting fuel needs could result in more expensive electric generation supply. The study compared the projected wind integration cost impacts of higher levels of wind with – and without – additional gas storage, with the hedging benefits of the additional gas storage credited to wind generation.

The study found that, with increasing wind generation, integration costs due to natural gas fuel supply might increase (by $2.17/MWh or $2.52/MWh, depending on the level of wind generation). At the same time, the study found that there is an additional benefit to increased natural gas storage under higher penetrations of wind energy. Importantly, the study found that the *benefits* of using natural gas to help balance the higher variability of wind energy must be weighed against the *costs* of using natural gas-plants in this way, including wind energy's impact on natural gas consumption forecasts and storage needs.

A 2008 update to the Xcel study assessed the specific effect on wind integration costs of adding a 500 MW flexible combined-cycle natural gas plant to the utility system in Colorado. Because Xcel's Colorado operations already had plentiful flexible conventional generation at the time, however, the study found that the reduction in projected wind integration costs was relatively small, ranging from $0.10/MWh to $0.33/MWh. Xcel expects that the cost benefits of more flexible generation would be greater if it had less pre-existing flexible generation, and that the benefits will grow with higher levels of wind generation.

A Utility Wind Integration Group (UWIG) report in 2003 summarized the results of many wind integration studies. It concluded that existing ancillary services are sufficient to address a significant part of the variable wind energy production and could do so more economically than using dedicated energy storage. The report included steps that can be taken to reduce the need for ancillary services including the following:[51]

- Improved wind forecasts can reduce ancillary service costs by allowing the commitment and dispatch of other types of generators more accurately to account for wind variability.

[50] R.M. Zavadil, et. al., "Wind Integration Study for Public Service Company of Colorado," May 2006, available at http://www.nrel.gov/wind/systemsintegration/pdfs/colorado_public_service_windintegstudy.pdf.

[51] Utility Wind Integration Group, "Utility Wind Integration: State of the Art," 2003, available at http://www.windonthewires.org/documents/UWIGWindIntegration052006.pdf.

- Large balancing areas with robust transmission tend to reduce wind's variability impact and ancillary service costs and also provides access to a deeper stack of potential resources to provide ancillary services.
- The use of sub-hour scheduling significantly reduces the need and costs for ancillary services.

Six major wind integration studies are summarized in this paper: the Eastern Wind Integration and Transmission Study, the Western Wind and Solar Integration Study, Texas Wind Generation study, Nebraska Statewide Wind Integration Study, the Southwest Power Pool Wind Integration Study (all for the US) and the Roadmap 2050 Study for Europe. Most of these studies do not contain explicit references to using natural gas for accommodating the variability of wind. However, useful information can be gleaned on the effects of increased wind levels on the use of natural gas. In most of these studies, gas is typically displaced as wind penetration increases, in part because gas is maneuverable, but also because gas in on the margin. Not unless gas prices get very low (as in the Western Wind and Solar Integration Study) or carbon prices very high (as in the Eastern Wind Integration and Transmission Study) does wind displace coal.

Additionally, the studies offer important insights into other aspects of large-scale wind integration and strategies for improving the scale of integration. Some of the notable conclusions from these studies are:

- Systems with significant amounts of flexible generation, such as that could be provided from natural gas generation, will more easily be able to integrate wind generation and at lower costs than systems with less flexible generation.
- The cost for integrating wind increases as the proportion of wind generation to conventional generating resources or peak load increases.
- Reserve costs attributed to wind integration are relatively small at wind penetration levels of less than 20% (generally up to $5/MWh up to wind penetrations by energy of up to 20%). How the variability and uncertainty of wind generation interacts with variations in load and load forecasting uncertainty has a large impact on the level of wind integration costs.
- Reserve costs for wind generation are dependent on the characteristics of the grid that is integrating wind, the adequacy and characteristics of the existing reserves, and the specific reserve requirements for each grid.

Large-scale US Studies

The *Eastern Wind Integration and Transmission Study* (EWITS) was completed in January 2010. This study expanded on the work of previous integration studies, which had looked at considerably smaller geographic footprints and did not include transmission. EWITS expanded the study area to include the entire Eastern Interconnection and included conceptual transmission overlays in its analysis models.

The EWITS study constructed four high-penetration scenarios to represent several wind generation development possibilities in the Eastern Interconnection. Three of these scenarios delivered wind energy equivalent to 20% of the projected annual electrical energy requirements in 2024, while the fourth scenario increased the amount of wind energy to 30%.[52]

[52] EnerNex Corporation, "Eastern Wind Integration and Transmission Study," 2010, available at http://www.nrel.gov/wind/systemsintegration/pdfs/2010/ewits_final_report.pdf.

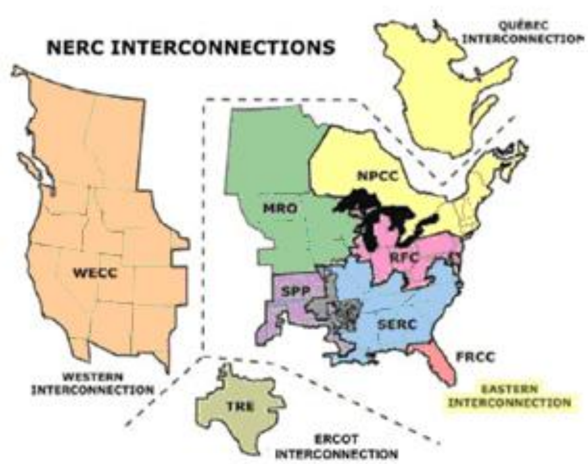

Figure 13: EWITS Area of Study

- *Scenario 1, 20% penetration* - Utilized high-quality wind resources in the Great Plains, with other development in the eastern United States where good wind resources exist
- *Scenario 2, 20% penetration* - Some wind generation in the Great Plains is moved east; some East Coast offshore development is included
- *Scenario 3, 20% penetration* - More wind generation is moved east toward load centers, necessitating broader use of offshore resources
- *Scenario 4, 30% penetration* - More use of offshore resources
- *Reference Scenario* with 6% wind penetration, approximating the current state of wind development plus an expected level of near-term development based on generator interconnection queues and state renewable portfolio standards

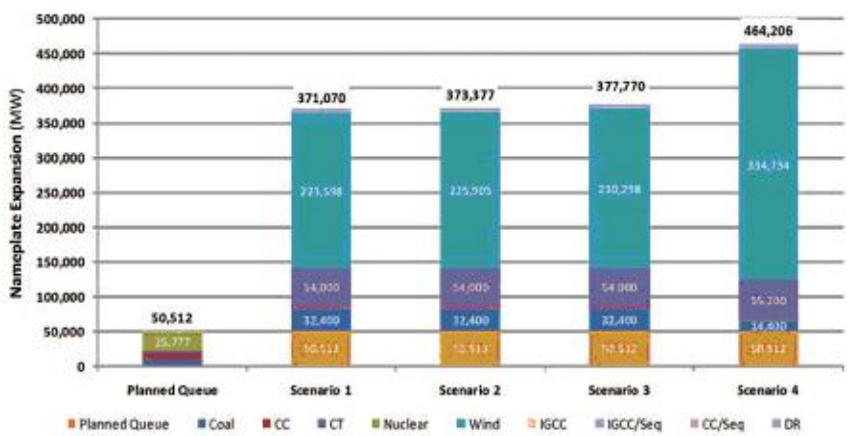

Figure 14: Generation Expansion by Scenario. Source: EWITS, 2010

The assumed range of average costs of natural gas in the study were $8.55/MBtu in 2008 to $15.85/MBtu in 2024. Carbon dioxide costs were assumed to be $100/metric ton of CO_2. With a carbon cost penalty, modeling results for projected capacity expansions shifted from coal-fired resources to nuclear and less carbon-intensive, natural gas-fired combined-cycle resources.

The EWITS study concluded the following:[53]

- High penetrations of wind generation, up to 30% of the electrical energy requirements of the Eastern Interconnection, are technically feasible with significant expansion of the transmission infrastructure.
- New transmission would be required for all the future wind scenarios in the Eastern Interconnection, including the Reference Case. Without transmission enhancements, substantial curtailment of wind generation would be required for all of the scenarios.
- Increased transmission helps reduce the impacts of the variability of the wind, which reduces wind integration costs, increases reliability of the electrical grid, and helps make more efficient use of generation resources. Although costs for aggressive expansions of the existing grid are significant, they make up a relatively small portion of the total annualized costs in all of the scenarios studied.
- Interconnection-wide costs for integrating large amounts of wind generation were moderate with large regional operating pools and significant market, tariff, and operational changes.
- Carbon emission reductions in the three 20% wind scenarios were similar, and carbon emissions are further reduced in the 30% wind scenario as more natural gas generation is used to accommodate wind variability. In general, emissions decline as more wind is added to the supply picture.

The *Western Wind and Solar Integration Study* (WWSIS) was completed in May 2010. WWSIS was initiated in 2007 to examine the operational impact of up to 35% energy penetration of wind, photovoltaics, and concentrating solar power on the power system (30% wind and 5% solar) providing power to the WestConnect group of utilities in Arizona, Colorado, Nevada, New Mexico and Wyoming, and 20% wind/3% solar for the rest of WECC outside of WestConnect. The study modeled the entire Western Interconnection (WECC region) for the year 2017.[54]

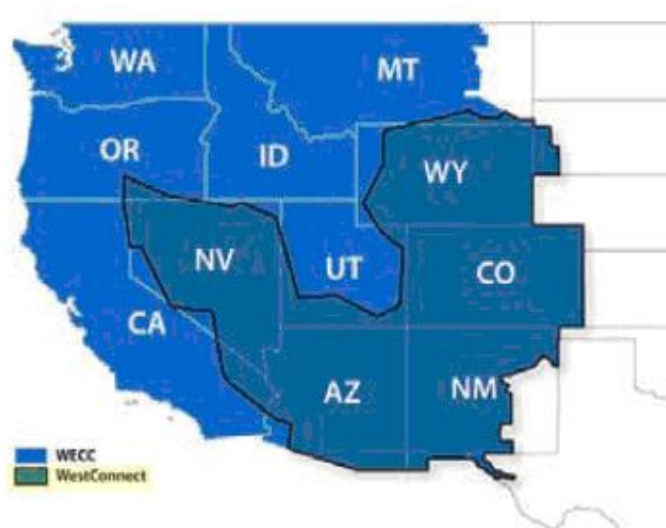

Figure 15: WWSIS Area of Study

[53] See *supra* note 45.
[54] GE Energy, "Western Wind and Solar Integration Study," 2010, available at http://www.nrel.gov/wind/systemsintegration/pdfs/2010/wwsis_final_report.pdf.

	In Footprint			Rest of WECC		
Case Name	Wind + Solar	Wind	Solar	Wind + Solar	Wind	Solar
PreSelected	3%*	3%	*	2%*	2%	*
10%	11%	10%	1%	11%	10%	1%
20%	23%	20%	3%	11%	10%	1%
20/20%	23%	20%	3%	23%	20%	3%
30%	35%	30%	5%	23%	20%	3%

* *Existing solar generation embedded in load*

Figure 16: Wind and Solar Energy Penetrations for WWSIS Scenarios

The average costs assumed were $2/MBtu of coal and $9.50/MBtu of natural gas. Carbon dioxide costs were assumed to be $30/metric ton. All study results were in 2017 nominal dollars with a 2% escalation per year.

The study report states that it is operationally feasible in 2017 to accommodate 30% wind and 5% solar energy penetration, with resources located in WestConnect and the rest of the Western Interconnection (see Figure 16), assuming the following changes to current practice could be made:[55]

- Substantially increase balancing area cooperation or consolidation, real or virtual;
- Increase the use of sub-hourly scheduling for generation and interchanges;
- Increase utilization of transmission;
- Enable coordinated commitment and economic dispatch of generation over wider regions;
- Incorporate state-of-the-art wind and solar forecasts in unit commitment and grid operations;
- Increase the flexibility of dispatchable generation where appropriate (e.g., reduce minimum generation levels, increase ramp rates, reduce start/stop costs or minimum down time);
- Commit additional operating reserves as appropriate;
- Build transmission as appropriate to accommodate renewable energy expansion;
- Target new or existing demand response programs (load participation) to accommodate increased variability and uncertainty;
- Require wind plants to provide down reserves.

The study also found that instead of committing additional generation for operating reserves, using demand response – reducing customer loads in response to pricing or incentive payments – would save up to $600 million in operating costs per year.

The base assumption of $9.50/MBtu for natural gas resulted in the displacement of natural gas-fired generation, leaving less-flexible coal plants to accommodate the variability of the wind and solar resources. Because natural gas-fired generation is typically more flexible than coal generation, the economic displacement of natural gas plants by wind and solar generation reduced the flexibility of the remaining dispatchable generation. When the price of natural gas was set at $3.50/MBtu instead of $9.50/MBtu, wind and solar generation primarily displaced coal generation. With this lower gas price assumption, operating cost savings from wind and solar generation were 40% lower, but emissions reductions were higher because more coal generation is displaced.

[55] See *supra* note 49.

A study on *Texas Wind Generation* was carried out in 2009.[56] Wind capacity in Texas was approximately 8,000 MW that year, representing about 10% of capacity and 5% of the total electricity generated. The study examined the effects of adding another 10,500 MW of wind generating capacity by 2013, representing approximately 20% of capacity and 15% of electricity produced. The simulated growth was mainly facilitated by subsidies and construction of transmission lines. An average price of $8/MCF of gas was assumed.

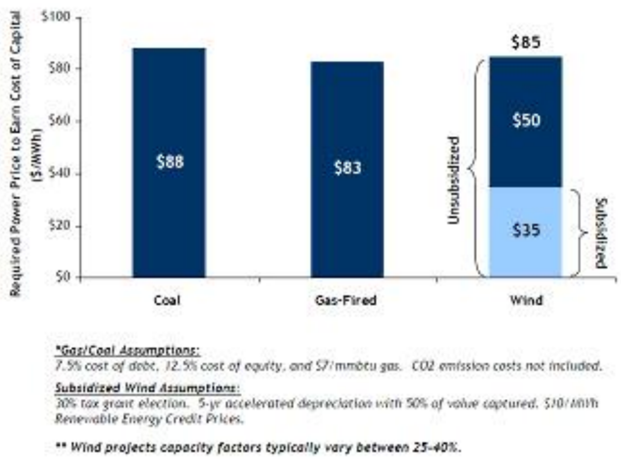

Figure 17: Economics of Coal, Gas-Fired and Wind Generation, Texas Wind Generation Study
Source: Tudor Holt Pickering, 2009

With no transmission constraints, the study found that marginal off-peak power prices would fall by $25/MWh (42%) and on-peak prices would fall by $30/MWh (33%) (Figure 18). However, taking into consideration that average wind production is 20% of total capacity on-peak and 40% off-peak, the on-peak impact would be $7/MWh and off-peak impact $15/MWh. From this perspective, the pricing of intermediate and peaking generation would be impacted less than baseload generation (Figure 19).[57]

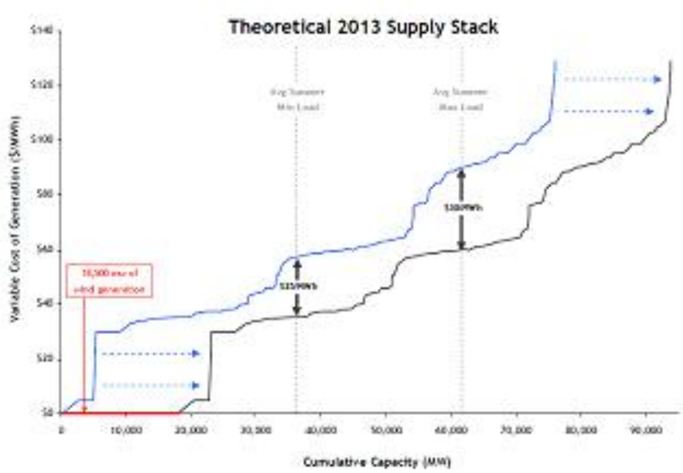

Figure 18: Theoretical 2013 Supply Stack from the Texas Study.

[56] Tudor Holt Pickering & Co, "Texas Wind Generation," 2009, available at http://www.tudorpickering.com/pdfs/TPH.Texas.Wind.Generation.Report.August.2009.pdf.
[57] See *supra* note 49.

Source: Tudor Holt Pickering, 2009

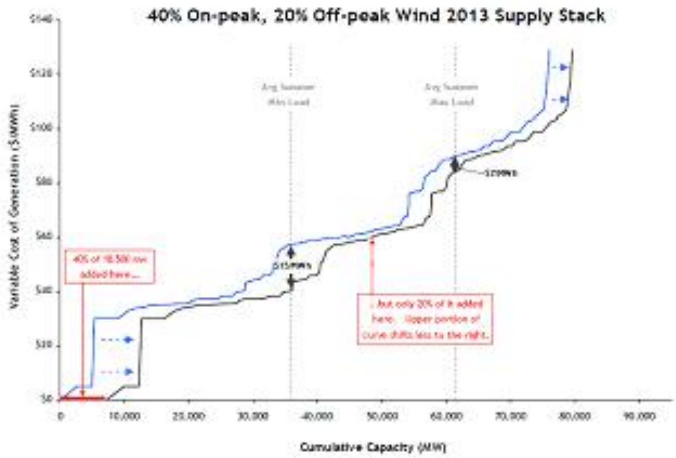

Figure 19: Theoretical 2013 Supply Stack from the Texas Study, modeling the effects of on-peak and off-peak supply. Source: Tudor Holt Pickering, 2009

The *Nebraska Statewide Wind Integration* study was completed in January 2010. Wind generation penetration levels equivalent to 10%, 20%, and 40% of the projected Nebraska retail electric energy sales in 2018 were defined as the targets for the study.[58]

The results showed that increased price penalties on CO_2 result in decreased wind integration costs as more gas resources were committed due to CO_2 penalties. In all the cases, these penalties diminished the cost difference between coal and gas. Significant carbon reductions through dispatch penalties or emissions caps also resulted in huge increases in the use of natural gas for electricity.

The base penetration scenarios also show a consistent increase in use of natural gas-fired resources (especially combined-cycle plants) to deal with wind forecast error and increased reserve requirements when comparing actual wind to ideal wind runs. (The "actual" wind case simulations included the effects of forecast error, incremental reserves and wind variability, and therefore resulted in higher production costs than the "ideal" wind cases, which had no forecast error, incremental wind reserves or wind variability). Natural-gas fired resources are called upon more in response to wind forecast errors, displacing coal that cannot respond as quickly as natural gas. If coal is less expensive than gas, the greater use of natural-gas fired resources will naturally increase wind integration costs.

[58] National Renewable Energy Laboratory, "Nebraska Statewide Wind Integration Study," 2010, available at www.neo.ne.gov/reports/NebraskaWindIntegrationStudy.pdf.

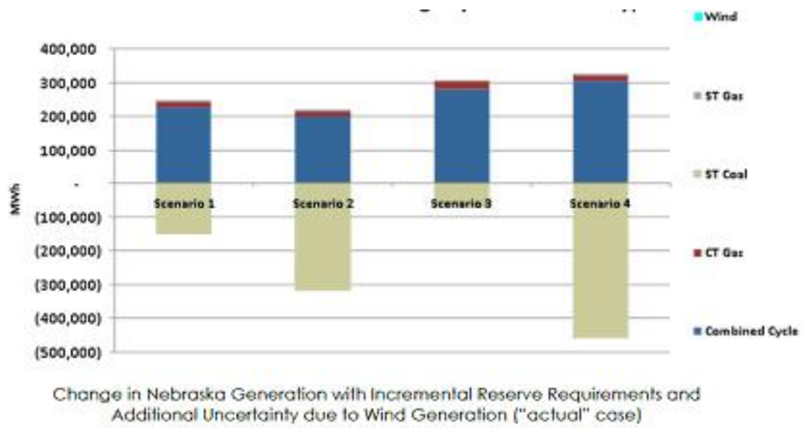

Figure 20: Nebraska Study: Generation Change by Fuel and Unit Type. Source: EnerNex, 2010

The *Southwest Power Pool (SPP)* conducted a study in 2009 to determine the operational and reliability impacts of integrating wind generation into the SPP transmission system and energy markets.[59] The study assessed the impacts of wind generation on transmission, operation, and markets. Four wind cases were analyzed: the power system as it currently exists (a base case with about 4% wind penetration) and three levels of higher wind energy generated in SPP – 10%, 20%, and 40%. Detailed analysis was done for the base, 10%, and 20% cases. A partial analysis was done for the 40% case.

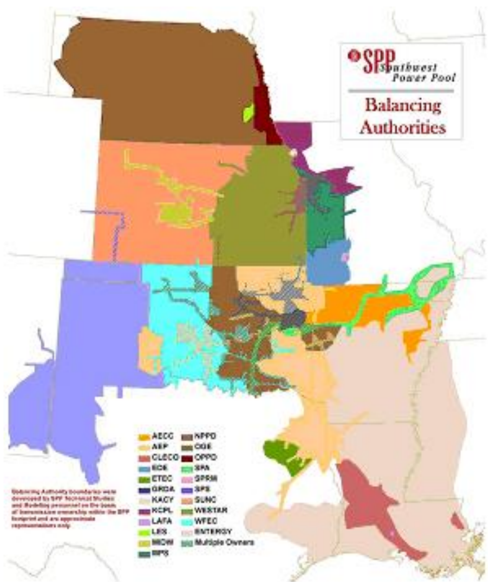

Figure 21: SPP WITF Area of Study. Source: CRA, 2010

[59] Charles River Associates, SPP WITF Wind Integration Study, 2010., available at http://www.spp.org/publications/2010.zip.

Penetration Scenario	Base Case	10% Case	20% Case	40% Case
Number of farms	40	69	100	142
Installed Nameplate Wind Capacity (MW)	2,877	6,840	13,674	25,003
Wind/Non-Wind Nameplate Capacity	0.046	0.109	0.217	0.397

Figure 22: SPP WITF Wind Generation Capacity by Penetration Level. Source: CRA, 2010

The following recommendations were made to enable high levels of wind integration in the SPP transmission system:[60]

- Major transmission reinforcements are needed to accommodate high levels of wind penetration, starting as low as 10%.
- The addition of high voltage lines requires the installation of voltage control to prevent over-voltages under low flow conditions due to contingencies or low availability of wind.
- Dynamic voltage support becomes increasingly important for the higher wind penetration cases, in which several conventional generators may become displaced in the dispatch order by wind generators. Therefore, it is recommended that new wind plants be required to provide reactive support of the same type and quantity as the displaced thermal units – i.e., continuously and instantaneously controllable reactive support. [61]

10% case results: With the introduction of wind, baseload units (coal-burning steam cycle units) and intermediate load units (natural gas-fired combined-cycle units) generated less and cycled more, compared to the base case. Therefore, the average number of hours up decreased for these unit types. Peaking plants (natural gas-fired simple-cycle units) were less affected in general and had higher capacity factors while up. The decrease in generation by baseload and intermediate load generators was assumed to be caused by wind generation displacing baseload plants, because the marginal cost of wind was lower. Along with the fluctuation of wind output, this led to more cycling of these units as well. Peaking plants compensated for the fluctuation of wind output and therefore ran more, especially in areas where more wind was introduced.

20% case results: With 20% wind penetration, most non-wind units generated less and cycled more. This was particularly true for baseload and intermediate load, as well as for peaking units. Consequently, the average hours running per start went down for most units.

Roadmap 2050

The Roadmap 2050 study is significant in the scale of wind and solar generation under analysis, as well as the breadth of analysis and review.[62] It also is significant in taking a distant view (the year 2050) of resources necessary to deliver on the targeted scenarios. There are many valuable insights from the report, but among those relevant to the role of natural gas generation in integrating wind and other variable energy resources is that some combination of grid expansion and backup capacity can balance a system with high levels of wind and solar, along with some baseload generation.

[60] See *supra* note 52.
[61] These findings are more severe than other wind integration studies, in part because wind was not as geographically diversified as in other wind integration studies and also because it was not assumed that wind projects would be state-of-the-art.
[62] European Climate Foundation, Roadmap 2050, available at http://www.roadmap2050.eu/.

In the analysis, solar and wind energy sources provide valuable complementary resources. However, in periods such as winter when there is less solar production and demand is higher, roughly 10% to 15% of the total generation capacity would be needed to act in a backup arrangement and operate with low load factors. The preferred technologies for such backup service remain an open issue. Likely options include expansions of existing flexible plants, new natural gas-fired plants (e.g., open-cycle natural gas turbine plants without carbon capture and sequestration), biomass/biogas fired plants. and hydrogen-fueled plants.

The study was conservative in relying on established technologies. Notably, the study did not rely on new, large-scale energy storage capable of shifting large amounts of energy between seasons or electric vehicle-to-grid applications.

The analysis revealed that for every 7 MW to 8 MW of wind and solar photovoltaic capacity, about one additional MW of additional backup capacity would be required. This backup forms an important part of the system balancing and is required especially at times in winter, with little solar power available and demand from heat pumps at its highest. The load factor of these backup resources is expected to be below 5% for the 40%/60%/80% renewable energy pathways and up to 8% in the scenario that approaches a near-zero carbon emissions path.

Demand response was demonstrated to be an important means of balancing the grid and avoiding curtailment of low-carbon, low marginal-cost resources, particularly renewable energy generation.[63]

Significantly, increasing transmission capacity between regions was effective at lowering the need for backup generation capacity and reducing balancing costs by 35-40%.

4. Increased Gas-fired Generation Can Help China Meet Multiple Objectives

At the current pace of renewable energy development, balancing variable energy resources will become a challenge for China's power sector. And the existing low-carbon policy framework may exacerbate the challenge in two ways. First, China's energy plans involve adding new nuclear plants – 70 GW by 2020 – and large efficient coal-fired plants, both of which have a limited ability to ramp up and down effectively to accommodate changes in demand or changes in wind and solar generation. Second, smaller coal-fired plants, which do have modest ramping ability, are being shut down as part of a strategy to improve the environment and the overall thermal efficiency of the coal fleet.

Current integration plans focus on using coal and hydro to balance wind, but looking forward other resources with greater operational flexibility, like pumped storage, demand response and natural gas, will likely play a role in integrating renewable energy into the system.

In the US and the EU, the capital and operating costs of natural gas-fired generation has made it a cost-effective resource with, or without, consideration of its superior ability to ramp up or down and start up quickly. Even where the basic economics favored coal, the environmental benefits and risk characteristics of natural gas have made it a popular for investors in both the US and EU.

A number of factors indicate that China's experience will be different from that of the EU and US:

[63] The Western Wind and Solar Integration Study stated that demand response would be a more cost-effective way of meeting the need for reserves than adding new generation.

- By the end of 2006, natural gas-fired plants accounted for only 15.6 GW, or 2.5% of generating capacity.
- Given current exploration efforts and technology, China has limited domestic gas supplies.
- The regulatory structure assigns priority fuel-use to other sectors (residential, chemical fertilizer industry, etc.).[64]
- High efficiency natural gas-fired generating equipment is largely imported, meaning China has relatively high plant capital costs.[65]

If integrating renewable energy were the only objective, building flexible coal plants might be a more cost-effective solution. However, China is simultaneously harmonizing power sector plans with carbon intensity and air pollution goals, which collectively may justify increasing the share of natural gas-fired generation in China's power supply beyond the 70 GW planned by 2020.[66]

Carbon Intensity Goal

China's carbon intensity reduction target of 40% to 45% below 2005 levels by 2020 will lead to more interest in natural gas-fired generation. As is widely recognized, natural gas-fired plants can produce electricity with substantially less energy input per kilowatt-hour than a typical coal plant. In the US, the CO_2 content of natural gas is 46% lower than that of coal.[67] On average, a natural gas plant produces half as much carbon dioxide per kilowatt-hour as a coal plant.[68]

Combined cycle plants in the US have an average heat rate of 7,500 Btu/kWh, better performing than the most state-of-the-art coal turbines.[69] In California, the Best Available Control Technology (BACT) standard for combined-cycle gas turbines – a standard which is guiding national greenhouse gas policy development at the US Environmental Protection Agency – is 7,730 Btu/kWh, and a CO_2 emissions rate of 800 lb/MWh is

[64] National Development and Reform Commission, No. 2155 [2007], 国家发展改革委关于印发天然气利用政策的通知, available at http://www.sdpc.gov.cn/zcfb/zcfbtz/2007tongzhi/t20070904_157244.htm. International Energy Agency, "Natural Gas in China: Market Evolution and Strategy," June 2009, available at http://www.europeanenergyreview.eu/data/docs/natural%20gas%20in%20china%20(market%20evolution%20&%20strategy).pdf.

[65] In China, the most efficient combined cycle gas generation technology is imported and thus costly. In contrast to the US and EU, gas-fired generation capital costs in China are on par with, or only slightly more expensive than, those of coal, so the economics are not as favorable. Average cost of gas plants built between the years of 2002-2005 was 3385yuan/kW; while the average cost of coal plants with FGD built within the same time frame was 4285 yuan/kW, or 26% more expensive than gas. But the average cost of large gas plants (300-390 MW) was more expensive than coal plants in the same capacity range, 4354 yuan/kW vs. 3823yuan/kW, or 14% more expensive. China State Electricity Regulatory Commission, "十五"期间投产部分电工程项目单位造价排序, July 2006.

[66] By the end of 2006, gas-fired plants provided 15.6GW, or 2.5% of generating capacity, up from 1.7% in 2005. Government plans have aimed to increase gas-fired capacity to 70GW by 2020 and 36GW by 2010. Estimates from Energy Research Institute of NDRC are slightly less optimistic, putting total installed capacity by 2020 at 60GW. Energy Research Institute, "Policy Study: Gas-fired Power Generation in China," 2006.

[67] Calculated from EIA's CO_2 emissions coefficient of coal and gas. In 2008 in the US, the CO_2 emissions coefficient of coal for electric power generation was 94.7 million metric tons CO_2 per quadrillion Btu, as compared to that for pipeline natural gas which was 53.06 million metric tons CO_2 per quadrillion Btu, representing a 46 percent higher CO_2 content. *See:* US DOE, Energy Information Administration, US Emissions Data, Carbon Dioxide Emissions Factors, available at http://www.eia.doe.gov/environment.html.

[68] Average coal-fired generation produces 2,249 lbs/MWh of carbon dioxide, where as average natural gas generation produces 1135 lbs/MWh of carbon dioxide. *See* US Environmental Protection Agency, Climate Change>Clean Energy, available at http://epa.gov/cleanenergy/energy-and-you/affect/natural-gas.html.

[69] MIT, *The Future of Natural Gas*, Interim Report, June 2010.

considered achievable for new plants.[70] Ultra-supercritical coal generators, of the sort that China is currently building, can have an efficiency of 42% to 43%, whereas combined-cycle gas turbine technologies range from 51%, to as high as 60% efficient (see Figures 23 and 24).[71,72]

Performance	Subcritical	PC/Supercritical	PC/Ultra-supercritical
Heat Rate Btu/kWe-h	9950	8870	7880
Generation Efficiency (HHV)	34.3%	38.5%	43.3%
Coal Use (10^6 t/y)	1.548	1.378	1.221
CO_2 Emitted (g/kWe-h)	931	830	738
Assumptions: 500 MW net plant output; Illinois #6 coal; 85% Capacity Factor			

Figure 23. Coal Consumption and Emissions of Coal-fired Generation Technologies[73]

For the US and EU, natural gas-fired generation offers the most realistic solution for near-term reductions in greenhouse gases. Fuel-switching from coal to natural gas, in response to declining natural gas prices, was partly responsible for a 4% reduction in CO_2 emissions from the US power sector from 2008 to 2009.[74] A recent study estimates that, with the existing fleet, dispatching gas before coal would force more than a 10% reduction in CO_2 emissions from the power sector nationwide, without additional capital costs or risk to system reliability.[75]

Air Pollution Goal

China's SO_2 and NO_X emissions reduction ambitions are also at the top of the list of government priorities for the 12th Five Year Plan period and beyond – and gas would serve this purpose as well.

A natural gas-fired plant in the US has an average NO_X emissions rate of less than one-third that of coal, and

[70] CALPINE, "GHG BACT Analysis Case Study," February 2010, Slide #7 and #9, available at http://www.epa.gov/oar/caaac/climate/2010_02_GHGBACTCalpine.pdf.

[71] US DOE, National Energy Technology Laboratory, Natural Gas Combined Cycle Plant F-Class, available at http://www.netl.doe.gov/KMD/cds/disk50/NGCC%20Plant%20Case_FClass_051607.pdf.

[72] The Regulatory Assistance Project, "Emissions Rates for Power Generation Technologies," 2001, available at http://www.raponline.org/docs/RAP_DGEmissions_2001_05.pdf. US DOE, NETL, Natural Gas Combined Cycle Plant with and without CCS, 2007, available at http://www.netl.doe.gov/KMD/cds/disk50/NGCC%20Technology_051507.pdf. G-type gas turbine combined plant has an efficiency exceeding 53% (HHV base). Mitsubishi Heavy Industries, Technical Review, Vol. 45 No. 1, March 2008, available at http://www.mhi.co.jp/technology/review/pdf/e451/e451015.pdf. GE H-class has an efficiency of 60%. GE Heavy Duty Gas Turbines and Combined Cycle, available at http://www.gepower.com/prod_serv/products/gas_turbines_cc/en/index.htm.

[73] "Higher Efficiency Power Generation Reduced Emissions," Janos Beer, MIT, National Coal Council Issue Paper 2009, available at, http://web.mit.edu/mitei/docs/reports/beer-emissions.pdf.

[74] US DOE, Energy Information Administration, US Carbon Dioxide Emissions in 2009: A Retrospective Review, May 5, 2010, available at http://www.eia.doe.gov/oiaf/environment/emissions/carbon/.

[75] "The current fleet of natural gas combined cycle (NGCC) units has an average capacity factor of 41 percent, relative to a design capacity factor of up to 85 percent. However, with no carbon constraints, coal generation is generally dispatched to meet demand before NGCC generation because of its lower fuel price. Modeling of the ERCOT region (largely Texas) suggests that CO2 emissions could be reduced by as much as 22 percent with no additional capital investment and without impacting system reliability by requiring a dispatch order that favors NGCC generation over inefficient coal generation; preliminary modeling suggests that nationwide CO2 emissions would be reduced by over 10 percent. *See:* MIT, *The Future of Natural Gas*, Interim Report, June 2010.

the average emission rate for SO_X is roughly 1% that of coal.[76] New natural gas plants have even superior performance, emitting a negligible amount of SO_2, PM and mercury. Compared to advanced coal technology, they stand out as the cleaner option, emitting only one-tenth as much NO_X (see Figure 24 below).

Pollutant	Natural Gas Combined Cycle	Pulverized Coal Supercritical
CO_2		
tons/year	1,661,720	3,632,123
lb/MMBtu	119	203
SO_2		
tons/year	Negligible	1,514
lb/MMBtu	Negligible	0.085
NO_X		
tons/year	127	1,250
lb/MMBtu	0.009	0.070
PM (filterable)		
tons/year	Negligible	232
lb/MMBtu	Negligible	0.013
Hg		
tons/year	Negligible	0.020
lb/MMBtu	Negligible	1.140

Figure 24. Emissions Summary for Natural Gas Combined Cycle and Pulverized Coal Supercritical Plants (assuming 85% capacity factor)[77]

Pollution reduction achieved through building gas generation as a substitute for new coal would support China meeting its 11th and 12th Five Year Plan targets for SO_2 and NO_X emissions control. More critical perhaps is the role for natural gas-fired generation in improving air quality and complying with new emissions regulations in key population centers along the eastern seaboard, as laid out in the State Council's Regional Air Quality Management (RAQM) rule issued in May 2010.

The RAQM rule identifies the three major inter-jurisdictional regions – Beijing-Hebei-Tianjin, Shanghai-Jiangsu-Zhejiang, and the Pearl River Delta – for aggressive air pollution prevention and control. Among measures required by the new regulation are the following of particular relevance:

- Apply strict limits on new construction and expansions to coal-fired power plants.
- Set emissions standards for coal-fired power generators that are more stringent than national standards.
- Aggressively reduce NO_X and PM emissions.
- Ramp up deployment of clean energy resources in urban areas, specifically natural gas.
- Pilot a cap on total coal consumption.

[76] US EPA, Climate Change, Clean Energy, How does electricity affect the environment?, available at http://www.epa.gov/cleanrgy/energy-and-you/affect/coal.html.

[77] This study assumes the operation of pollution control equipment according to the US Best Available Control Technology (BACT) standards for emission requirements of the 2006 New Source Performance Standard for criteria pollutants. US DOE, National Energy Technology Laboratory, Cost and Performance Baseline for Fossil Energy Plants, Volume I, May 2007, available at http://www.netl.doe.gov/KMD/cds/disk50/index.html.

In recent years, partly for the benefits to air quality, natural gas plants have been built in and around the coastal cities, such as Guangzhou and Shanghai – though exposure to high global LNG prices and an unfavorable domestic policy structure have reportedly caused these plants to lie idle on more than one occasion.[78,79] Now, though, particularly to comply with these new environmental restrictions on coal, additional natural gas generation will likely be needed to keep supply on pace with demand in these fast-growing urban areas.

It is broadly understood that natural gas performs better environmentally than coal. Less well understood is the effect on conventional plants of more frequent cycling to accommodate the fluctuations of variable generation such as wind. The problem is two-fold. Running a plant at a lower capacity factor and with more up and down cycling than what it was designed for reduces plant efficiency, and thus increases emissions and fuel costs, and potentially reduces the plant life and plant reliability.[80] At the same time, running the plant at variable, sub-optimal temperatures causes complications with the pollution control equipment, resulting in increased emissions rates. These two factors may lead to greater amounts of SO_2, NO_X and CO_2 than if the plant had been operated consistently at a higher load factor.[81]

In light of China's carbon and environmental goals, the emissions impact of cycling coal plants – even those designed with greater operational flexibility – should be duly analyzed and incorporated into strategies to integrate renewable energy and planning for natural gas generation.

In addition, consideration should be given to flexibility and the ability of generating plants to tolerate frequent cycling, as newer gas turbines from GE and Siemens are able to do. For a coal plant, there are significant financial costs associated with the damage caused by routine cycling and by running below optimal capacity levels. These include increased maintenance costs, equipment repair and replacement expenses, as well as an potential shortened plant life. As with emissions, the precise cost of cycling damage will vary according to the age, type and other specifications of the plant. And while some coal plants have better ramping capabilities than others, these costs are estimated to be significant enough at a high rate of renewable energy penetration to change the bottom line for marginal coal plants in the US.[82]

[78] Existing gas plants are concentrated in Shanghai, Zhejiang, Fujian, Guangzhou, and Jiangsu. Energy Research Institute, "Policy Study: Gas-fired Power Generation in China," 2006; DOE's Energy Information Administration, http://www.eia.doe.gov/cabs/China/NaturalGas.html. "China's Natural Gas Industry and Gas to Power Generation," Chun Chuni, Institute of Energy Economics, Japan (EEIJ), 2007. "Fuel oil power plants wethering away in China with increasing gas utilization," *Reuters*, June 6, 2010, http://www.glgroup.com/News/Fuel-oil-power-plants-wethering-away-in-China-with-increasing-gas-utilization-48804.html/. "China in 'great leap forward' for gas," *Reuters*, March 17, 2010, http://www.reuters.com/article/idUSTRE62G0UM20100317.

[79] Because users in Guangdong are tied to import prices, they seem to be especially vulnerable to the global market. "NG-fired generators in Guangdong suffer from lasting fuel shortages," *CBI China*, April 24, 2008, http://en.cbichina.com/Common/1530301,0,0,0,1.htm. In 2007-2008, residential and industrial sector were willing to pay high prices, whereas the power sector was reluctant. International Energy Agency, "Natural Gas in China: Market Evolution and Strategy," June 2009, http://www.europeanenergyreview.eu/data/docs/natural%20gas%20in%20china%20(market%20evolution%20&%20strategy).pdf.

[80] Danneman, Gene, Xcel Energy, "Baseload Unit Cycling Costs," Presentation before the Utility Wind Integration Group Workshop on Wind Integration Studies: Models and Methods, June 25, 2010.

[81] "How Less Became More: Wind, Power and Unintended Consequences in the Colorado Energy Market," Bentek Energy, April 2010, available at http://www.wind-watch.org/documents/wp-content/uploads/BENTEK-How-Less-Became-More.pdf; "The impact of wind generated electricity on fossil fuel consumption," C. le Pair & K. de Groot, April 2010, available at http://www.clepair.net/windefficiency.html.

[82] Puga, J. Nicolas, "The Importance of Combined Cycle Generating Plants in Integrating Large Levels of Wind Power Generation," Electricity Journal, Vol. 23, Issue 7, Aug/Sept 2010.

By contrast, modern combined-cycle natural gas plants can ramp quickly and frequently, without affecting the economics of the plants, and retrofit modifications can be made to increase the operational flexibility of older combined-cycle plants.[83]

Obstacles remain to natural gas-fired generation in China. Even with new estimates of China's unconventional reserves bulging domestic supply figures, China's share of global reserves is still very limited. Other obstacles are easier to address. Plant construction costs, for example, are not prohibitively higher than coal plant costs – average capital costs are actually 26% lower than coal, but larger 300 MW to 390 MW-sized plants are 14% more expensive – and costs are coming down.[84] What is not known is how a concerted effort to develop the domestic capability to build high efficiency natural gas-fired power plants can drive the capital cost down as China has done for other sources of generation.

One economic disadvantage that can be overcome deserves special attention here: China's generation pricing practice. China issues generation prices based on a combined energy-and-capacity scheme that assumes 5,000 or so annual operating hours – the typical hours of a baseload coal plant. This encourages investment in such facilities, but discourages investment in peaking or cycling generation that would be expected to operate only during peak hours or when needed to firm up wind. That is because if a generator does not operate the 5,000 or so hours over the course of the year, it will not fully recover its capital costs.

This pricing scheme has also proven a hurdle in implementing China's innovative dispatch policies that prioritize renewable energy and other clean generation – known as renewable priority dispatch and environment dispatch policies. Under these dispatch rules, dirty coal plants may be operated less than 5,000 hours, and so require some mechanism to be compensated for their capital costs. Relatively straightforward pricing reform, which would separate the recovery of energy and capacity costs, could remove the disincentive for flexible generation like natural gas, and help address these other related problems as well.

[83] Id.
[84] National Development and Reform Commission, No. 2155 [2007], 国家发展改革委关于印发天然气利用政策的通知, http://www.sdpc.gov.cn/zcfb/zcfbtz/2007tongzhi/t20070904_157244.htm.