# Coal to Natural Gas Electric Utilities Repowering: Consequences for valve usage and replacement

**Presented by:** **Roger S. Turley,**

**CRANE ChemPharma & Energy**

Academic Education and Degrees:

BSME – Brigham Young University

MSME – Brigham Young University

Professional Position:

Global Business Line Manager

CRANE ChemPharma & Energy

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## Introduction:

In any industry, and indeed, in any productive endeavor, changes in technology (or method of production) are ordinarily driven by one or more of the following factors: cost of inputs used in production; efficiency (quantity of output relative to input); external factors (such as regulatory dictates, or changes in the nature of demand).

Enduring trends in repowering (of coal-fired boilers) used by electrical utilities have been motivated by all three of these factors. Despite recent spikes in natural gas prices causing temporary increases in coal power generation, over the long term its use as fuel to produce steam to power electricity-generating turbines is forecast to gradually decline in step with declining cost advantages relative to other fuels, such as natural gas. Such fuel cost developments, in combination with recent, pending, and anticipated new environmental protection legislation authored by the EPA, will make the cost of producing electricity using coal increasingly prohibitive compared to other fuels.[1]

Power plant efficiencies are typically defined as the amount of heat content in (Btu) per the amount of electric energy out (kWh) generated, commonly called a heat rate (Btu/kWh – the lower the heat rate, the more energy efficient the process is). Although the technology exists to make the heat rate of coal roughly equal to gas, this is not realized at existing coal-fired plants where the standard heat rate of coal is between 30-50% higher than that of gas.

Perhaps the most persistent and intensifying factor contributing to the relative diseconomy of coal is in the form of regulations aimed at curbing pollutants. This factor alone has been the primary driver behind the widespread adoption of gas-fired technology for new power generating plants, and impacts all overhauling decisions at existing plants.

Whatever the reasons, changes in the means of powering utility plants are ongoing, with important ramifications for valve demand, as well as for valve use and selection. It is the aim of this paper to examine some of these issues.

## Abstract:

The US power industry is subject to increasingly stringent Environmental Protection Agency (EPA) regulations, including mandated compliance by all power generating plants.

In conjunction with economies associated with natural gas as fuel for power generation, environmental regulations can make repowering (conversion from one fuel type to another) the preferred alternative rather than retrofitting coal-powered electricity generating plants with emission control equipment.

As a consequence, US power generating plants are converting from coal to other fuels in large numbers. In some cases the existing infrastructure is (to the extent possible) retained, with only the combustible material being altered. In the "middle" are plants that retrofit certain aspects of their infrastructure while converting to gas as fuel. A common version of this type of change involves using an existing turbine to run on steam from a heat recovery steam generator (HRSG) that draws (recycles) exhaust heat from a new gas turbine, together forming a combined cycle. This is also called "partial repowering," since the existing turbine and generator are conserved. At the other end of the scale are newly constructed power plants, which are predominantly gas-fueled. Each of these three repowering alternatives requires a different quantity of new valves, often of varying types.

While the long-term outlook is fairly certain, the picture is not so clear for the near-term.

EPA's Proposed Carbon Pollution Standard for New Power Plants would require that new fossil fuel-fired power plants meet an output-based standard of 1,000 pounds of carbon dioxide per megawatt hour of electricity generated. That standard would effectively prohibit the construction of new coal-fired power plants without carbon capture and storage. The EPA has been evaluating comments and expects to issue a final rule in 2013 (which could be extended). Because the rule is not yet final, it is not assumed to take effect in any of the AEO2013 cases. New power generating plants approved prior to the imposition of this rule would have 12 months (from the date when the rule becomes valid) to begin construction in order to be exempted from the 1,000 pound limit. According to the Energy Information Administration, there are 13 proposed coal projects planned for completion over the next four years, accounting for 8,336 megawatts of capacity.

A recent development with regards to this rule is that the EPA intends to review and revise it before making it valid, putatively in order to make it enforceable. The concern is that according to the Clean Air Act, any rule governing air pollution must be able to be adhered to by using best available technology. Several utilities have challenged this assumption, motivating the EPA to revise its rule to accommodate this objection. The net effect of all this is that even if the EPA enacts the rule within the next 18 months (as it says it intends to do), it will mean that there is a window of up to 2½ years during which coal-fired power generation facilities may continue to be started – all exempt from the new emission rules.

Power generating activities that are not subject to this proposed rule are as follows:

-Existing units, including modifications such as changes needed to meet other air

pollution standards;
-New power plant units that have permits and start construction within 12 months of this proposal, or units looking to renew permits that are part of a Department of Energy demonstration project, provided that these units start construction within 12months of this proposal. These units are called “transitional” units.;
-New units located in non-continental areas, which include Hawaii and the Territories;
-New units that do not burn fossil fuels (e.g., burn biomass only).

However, there is a growing roster of other EPA rules and standards that will impact existing power plants, making coal-fired electricity generation increasingly less viable. The impact on valve demand will be significant, and prudent valve manufacturers and distributors will continue to adapt their market strategies accordingly.

## Overview:

The fact that U.S. energy industry is steadily migrating away from coal is acknowledged by both industry and the EPA.

According to U.S. Energy Information Administration, current trends in the electric power market put many coal-fired generators in the United States at risk for retirement. In the Annual Energy Outlook 2012 (AEO2012) Reference case, 49 gigawatts of coal-fired capacity are expected to retire through 2020, representing roughly one-sixth of the existing coal capacity in the U.S. and less than 5% of total electricity generation nationwide. Most of the generators projected to retire are older, inefficient units primarily concentrated in the Mid-Atlantic, Ohio River Valley, and Southeastern U.S. where excess electricity generation capacity currently exists. Lower natural gas prices, higher coal prices, slower economic growth, and the implementation of environmental rules all play a role in the retirements. AEO2012 features several alternative cases that examine how changing assumptions about natural gas prices and economic growth rates influence the electric power sector, including projected retirements of coal-fired generators.

Correspondingly, speaking on behalf of the coal industry, the American Coalition for Clean Coal Electricity (ACCCE) released a study in early May 2013, listing 32 states with coal plant closures (over a similar period) that have been attributed, at least in part, to EPA policies. These closures are said to total 285 units and represent more than 41 gigawatts of electric generating capacity. Most of the coal units listed are closing, but a few are converting to either biomass or natural gas.

**Table 1 - Coal Units Closing Because of EPA Policies**[3]

| | MW Closing | # of Units Closing |
|---|---|---|
| Ohio | 6,852 | 38 |
| Pennsylvania | 3,298 | 22 |
| Georgia | 3,094 | 14 |
| West Virginia | 2,737 | 18 |
| Indiana | 2,473 | 20 |
| Virginia | 2,349 | 16 |
| North Carolina | 2,198 | 17 |
| Kentucky | 1,981 | 9 |
| South Carolina | 1,759 | 14 |
| Alabama | 1,686 | 10 |
| Tennessee | 1,558 | 12 |
| Texas | 1,399 | 3 |
| Illinois | 1,395 | 9 |
| New Mexico | 1,375 | 5 |
| Colorado | 1,172 | 11 |
| Florida | 961 | 4 |
| Wisconsin | 635 | 11 |
| Oregon | 585 | 1 |
| Louisiana | 575 | 1 |
| Minnesota | 569 | 9 |
| Oklahoma | 460 | 1 |
| New York | 367 | 2 |
| Iowa | 323 | 17 |
| Massachusetts | 308 | 3 |
| New Jersey | 268 | 2 |
| Utah | 172 | 2 |
| Michigan | 162 | 4 |
| Montana | 154 | 1 |
| Maryland | 115 | 2 |
| Missouri | 67 | 2 |
| Wyoming | 45 | 4 |
| South Dakota | 22 | 1 |
| 32 States | 41,114 MW | 285 Units |

[3] This list is current as of May 2, 2013. Most of the coal units listed in the table are closing; a few are converting to either biomass or natural gas.

*Source: American Coalition for Clean Coal Electricity (ACCCE)*

The establishment and enforceability of the various EPA rules and policies relating to the US power industry specifically affecting coal-fired electricity generation is not without some delays and compromise.

The CSAPR (Cross-State Air Pollution Rule) requires states to significantly improve air quality by reducing power plant emissions that contribute to ozone and/or fine particle pollution in other states. The rule has been vacated by The U.S. Court of Appeals for the D.C. Circuit in August 2012. On January 24, 2013, the United States Court of Appeals for the D.C. Circuit denied EPA's petition for rehearing en banc of the Court's August 2012 decision to vacate the CSAPR. Then, on March 29, 2013, the U.S. Solicitor General has petitioned the Supreme Court to review the D.C. Circuit Court's decision.

Airborne release of mercury is regulated in the US under the Clean Air Act. Mercury is classified (under the Act) as a hazardous air pollutant, and is controlled under the National Emissions Standards for Hazardous Air Pollutants (NESHAP). Performance standards derived from a principle of maximum achievable control technology standards (MACT), set the required emission reductions to equal those achieved by the average of the top 12% best controlled plants categorized by type of pollution being emitted. EPA’s proposed Mercury and Air Toxic Standards (MATS rule) will set the first nationwide limits on coal-fired power plant emissions of mercury, designed to reduce mercury emissions from new and existing coal (and oil) fired electricity generating utilities by 91%.

In many cases concerning enforcement of existing rules and legislation, environmental groups are seen to be “forcing the hand” of EPA by filing lawsuits against it on the basis that it is itself not acting in accordance with law when it occasionally is slow to exercise its authority.

An example is the case of the New Steam Electric Power Generating Effluent Guidelines (Section 301/304 of the Clean Water Act). On March 18, 2012, the EPA entered into a consent decree with environmental groups, committing to update effluent guidelines for fossil fuel and nuclear electric generating plants by July 23, 2012. Under the original consent decree, the EPA was required to publish new effluent guidelines for the industry sector every even year, and it had not done so since 1982. In December 2012, the EPA and environmental groups agreed to give the EPA until April 19, 2013, to issue a proposal, and May 22, 2014, to issue a final rule.

On Jan. 14, 2013, the EPA transmitted a draft proposed rule to the Office of Management and Budget for interagency review. The proposed rule could be issued soon after this review is complete, and is projected to affect approximately 500 existing coal-fired power plants. The new effluent limits will not affect any individual existing plant until the plant renews its National Pollutant Discharge Elimination System wastewater discharge permit, at which time, the limits will be incorporated into the plant’s new permit. For the first time, federal limits would be placed on toxic metals discharges from existing and new power plants, as well as new or additional requirements for discharges from wastewater streams related to flue-gas desulfurization, fly ash, bottom ash, combustion residual leachate, flue-gas mercury control, nonchemical metal cleaning wastes, and gasification of fuels such as coal and petroleum coke. For existing power plants the new rules would be phased in between 2017 and 2022.

Cooling Water Intake Structure Regulations under Section 316(b) of the Clean Water Act is a proposed rule setting up standards for water use and discharge. In November 2010, the EPA entered into an agreement with environmental groups to promulgate standards for existing cooling water intake structures intended to protect aquatic organisms. The EPA issued a proposed rule in April 2011, which would require facilities that withdraw more than 2 million gallons of surface water per day to meet a maximum allowable fish kill standard or reduce intake velocity to 0.5 feet per second or less. Facilities withdrawing more than 125 million gallons per day would be required to conduct studies and work with their state permitting authority to develop custom standards. A closed-loop cooling water system or other equivalent technology would have to be installed if an existing facility planned to increase generating capacity.

In July 2012, the EPA and the environmental groups agreed to extend the EPA's deadline to finalize the rules until July 27, 2013. The EPA has indicated that it is working to meet this deadline. The final rule will include a schedule for existing facilities to come into compliance with the new requirements. This proposed scheduled period will be not more than eight years after the final rule becomes effective.

EPA's Proposed Carbon Pollution Standard for New Power Plants (requiring new fossil fuel-fired power plants to meet an output-based standard, currently proposed at 1,000 pounds of carbon dioxide per megawatt hour of electricity generated) may take effect over the next year or two. With a global tendency toward stricter environmental protection, it is difficult to envision valid reasons for expecting a reversal in the increasingly restrictive trend in emission and pollution standards over the long term.

Energy fuel prices are a key influencer of fuel use strategies. With the development of shale gas at least temporarily producing ample supply, natural gas is available at historically low prices. Since it offers certain operational, environmental, and economic advantages, it is expected to remain the favored fuel option for new power generating facilities under foreseeable conditions.[1]

Power generating utilities with large capacity coal-fired plants may consider investing in emission control equipment to comply with regulatory standards. Smaller coal-fired operations are more likely to switch to natural gas as fuel rather than invest in more expensive emission control equipment. In many cases, the cost of converting a coal-fired plant to combined cycle natural gas alternative are lower than installing the required pollution controls that could enable continued use of coal.

The combined effect of environmental (and other) regulations and the anticipated cost of gas (relative to coal) is what drives the ultimate repowering decisions made by utilities. As both the regulatory landscape and market realities of energy pricing aren't predictable with certainty, valve manufacturers will find it difficult to reliably forecast demand for valves based on the types of repowering options that various utilities may adopt in the coming years, with decreasing predictability over time.

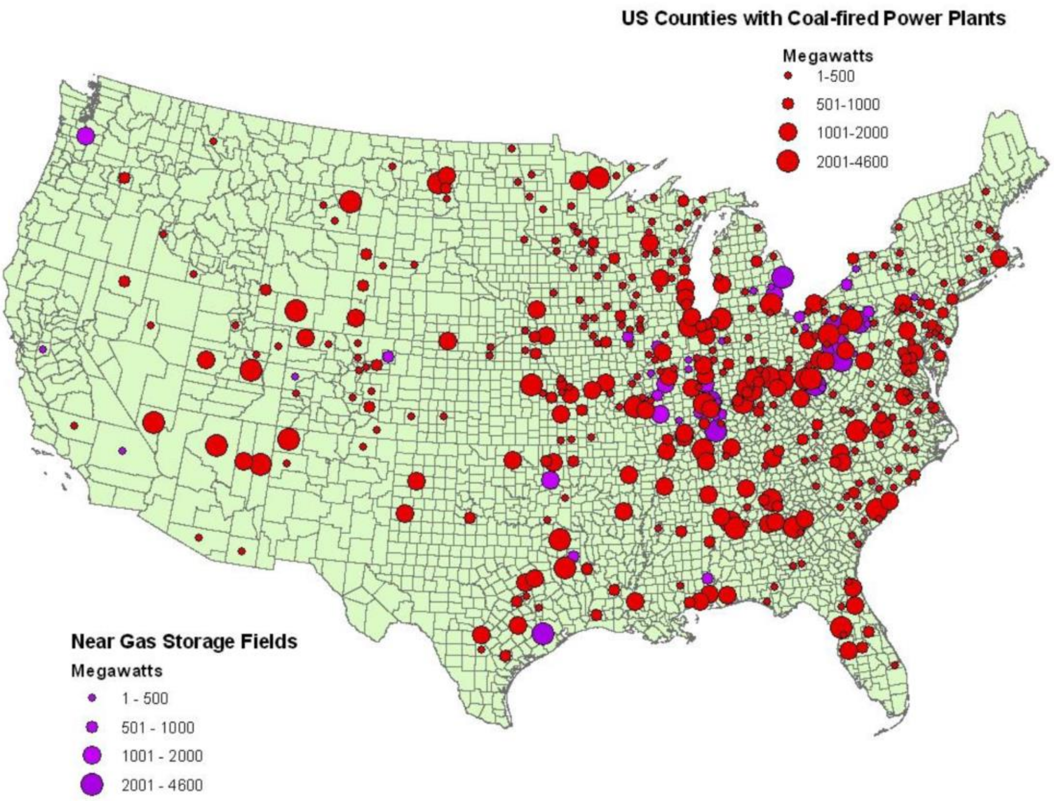
Adding to the uncertainty inherent in making optimal repowering decisions, the Aspen study voices questions about the dependability of gas supply, as well as about its price. Expanding production of shale-deposited gas is attracting environmental concern and in some cases local opposition to gas drilling due to its use of a technique known as hydraulic fracturing. Fracturing injects large amounts of water and chemicals into a well to crack open rock formations and then hold the cracks open so that natural gas can flow up the well. EPA and others are studying the potential adverse impacts of hydraulic fracturing. Even if fracturing continues, serving a much larger market will require even more drilling that is already at record levels. The implied supply curve reflecting the cost of new reserve additions developed herein suggests natural gas prices in the range of $10 per MMBtu to replace the reserves consumed last year. The Energy Information Administration's AEO 2010 projects a gas price in 2036 of $8 per MMBtu with production not much higher than in 2000; a study for the Interstate Natural Gas Association of America includes a Base Case that projects $6.96 per MMBtu ($ 2008) with production in 2030 of roughly 27 Tcf. In other words, these studies show relatively high natural gas prices at demand levels generally more modest than reviewed herein. With these observations in mind, it seems unwise to expect to serve demand levels that are potentially very much higher than today without sending prices to much higher levels.

Transmission infrastructure is not in place in some US states. Estimates of new pipeline capacity required range from $106 Billion to $163 Billion in one industry study. This study escalates those estimates to $348 Billion should all coal-fired generation need to be replaced with natural gas-fired generation. In looking at existing capacity, 21 states would find the interstate pipeline capacity coming into their state insufficient to serve existing demand plus the demand that would result from converting existing coal-fired generation to gas.

Storage infrastructure is another element contributing to the difficulty with an orderly conversion from coal to gas. For the electricity industry to broadly switch its coal-fired units to natural gas, it will also need more gas storage capability. Geology limits opportunities to build storage where the market would prefer it. Because of that, the current 400 or so storage facilities are not distributed evenly across the country and many of those facilities are single season reservoirs—rather than higher deliverability salt cavern-based facilities. (*Source: Aspen Environmental Group)*

Lastly, there are operational considerations that are beyond the scope of this paper. Interested readers are referred to the original Aspen study (*Implications of Greater Reliance on Natural Gas for Electricity Generation*).

**Figure 17: Existing Coal-Fired Generation Located In Same County as Underground Gas Storage**




*Source: Aspen Environmental Group*

# Coal to Gas Repowering options:

There are three primary methods for fuel conversion at a power plant:

1. Modifications to existing boiler to use natural gas as fuel

2. Complete replacement of the existing coal-fired plant with a new combined cycle plant

3. Adding a new gas-fired turbine to power the generator drive shaft, and recovering its exhaust heat through a heat recovery steam generator (HRSG) to create steam used to power the steam turbine (which may have been previously powered by a coal-fired boiler, or it can be a new replacement steam turbine). The steam turbine delivers additional energy to the generator drive shaft. *(Please see Combined Cycle Repowering diagram below.)*

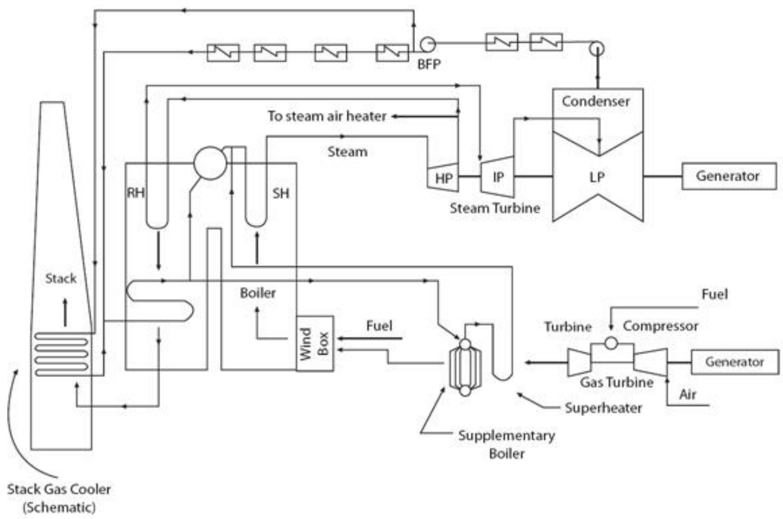
Each of these three options has well-understood costs and benefits, some of which are the following:

1) Option 1 is often found to be undesirable because of the usual inefficiencies inherent in the basic design. The BTU consumption per kWh of a dedicated coal-fired boiler converted to natural gas in most cases exceeds that of a system like that in option 3.

2) Building (in situ) a new gas powered plant can often be the preferred approach if obtaining necessary licensing and permits for a new location is not feasible, or where existing transmission infrastructure demands that generation continues in the same location.

3) Adding a new gas turbine frequently costs less than installing “new technology” environmental control systems on the original coal-fired system.

**Combined Cycle Repowering.** In this configuration, a gas turbine is added to an existing plant, and the exhaust from the turbine is ducted to the boiler windbox, where it is used as combustion air for the boiler. This configuration uses a supplemental heat exchanger (or partial HRSG) or mixes ambient air upstream of the boiler to cool the exhaust temperature to levels acceptable to existing windbox materials. The existing air heaters are typically retired, and new stack gas coolers (or partial HRSG) are added in parallel to the feedwater heaters to maximize cycle efficiency.




Option 3: combined cycle repowering. The advantages of this option are a power increase of up to 70%; plant efficiency improvement of up to 15%; retaining the current equipment and, if desired, current fuel; and reduced plant emissions. The disadvantages include more complex steam system interface and piping systems, possible boiler surface changes and/or derate, and special low-oxygen burners for the boiler. (Source: Coal Power Magazine)

Although some coal-fired power plants are reported to have been converted from coal to natural gas, a 2010 study by the Aspen Environmental Group for the American Public Power Association reports that such "conversions," when examined, are replacements rather than retrofits.

Theoretically, the electricity industry can switch to natural gas either by retrofitting existing coal-fired units to burn natural gas or by closing the coal plants and building new gas-fired plants. Aspen’s research uncovered no instances of coal plant retrofits to natural gas and, in fact, virtually all of the public references to conversion of coal to natural gas or repowering turn out instead to be replacements. The reason is economics. Even the U.S. Government Accountability Office (GAO), when it looked at this issue switching the Capitol Building power plant to natural gas, noted that not only was switching all U.S. coal-fired generation infeasible due the gas supply and infrastructure required, but that it would be more cost-effective to construct new gas-fired units than to retrofit existing coal-fired units to burn natural gas. Combined-cycle gas-fired generation costs roughly $1 million per MW, installed.

However, for some repowering projects, retrofitting may well be the optimal solution. This view is echoed in a Power Engineering article published in February 2013, which contends that while retrofitting an existing coal-fired (or oil-fired) plant to burn natural gas may not be the most energy-efficient use of natural gas, it may turn out to be the most economically feasible approach to help clean up an existing coal fleet while not having to invest in hundreds of millions, or even billions, of dollars for back-end pollution control equipment. This is especially true for any plants in the east which still burn high-sulfur hard coal, have NOx compliance issues and expect to have to invest heavily in order to me NISHAP and MACT compliance rules.

Power Engineering concludes that economic and grid-reliability analyses on a plant-by-plant basis reveal that there are coal-fired plants where a gas-based retrofit would be feasible and, in fact, a good investment, if gas remains below $5/mmBtu. It is claimed that state utility commissions are likely to be sympathetically inclined to approve such retrofits for a number of reasons, including what is essentially instantaneous clean-air compliance, reduced carbon footprint and the avoidance of massive capital spending for new construction of plants or back-end retrofits. Such projects typically come in $20 million to $50 million per unit, depending on size, proximity to gas supplies and site readiness (compared to the hundreds of millions to billion plus dollars for the potential alternatives).

## Valve utilization under the three Repowering Options:

- Retrofitting of existing turbine piping with a switch to natural gas results in low demand for additional valves (existing valves often suffice)
- Retaining an existing boiler and adding a gas turbine (with switch to natural gas) - requires replacement or addition of new valves
- A new Combined Cycle Plant will require new valves as would be the case for any new plant construction where piping is utilized

Valve requirements will vary from plant to plant, depending on the nature and extent of the plant modifications. Because of the substantial retrofitting needed in order to adapt an existing turbine to the new HRSG, significant piping work has to be done. While the old coal-fired boiler will have piping and valves of a type that could be used in the new configuration, such systems are in an incompatible configuration and are usually of an age at which replacement is recommended.

New gas turbines, HRSG systems, and steam interface sections also create demand for additional valves in related auxiliary (supporting) systems. Only steam turbine and boiler section valves are more likely to be redeployed in a new plant or modification.

## Valve Operating Conditions in power generation plants:

In a coal-fired power plant (steam system), typical temperatures and pressures range from 1058 to 1075 ºF, and from 2900 to 4100 psig, respectively. This compares to ranges of 1000 ºF to 1100 ºF, and 2200 to 3500 psig, respectively, in a combined cycle power plant.

Boiler sizes can vary with fuel type, as do operating cycle frequencies. Coal-fired plants are base loaded (units generally run 24/7 to provide for constant demand), but combined cycle can be base loaded or operated during peak demand times.

Here are some examples of actual pressure and temperature measurements taken at various points in a mid-sized power generating facility (at high pressure, HP and intermediate pressure, IP):

| | |
|---|---|
| HP steam drum Outlet | 2200 psig @ 1075ºF |
| IP steam drum Outlet | 560 psig @ 670ºF |
| HP feed water Inlet | 3765 psig @ 365ºF |
| IP feed water Inlet | 1800 psig @ 365ºF |
| LP drum boiler feed recirculation Pump | 3765 psig @ 365ºF |

## Factors affecting valve selection

As in most other applications, valve design and specifications are determined primarily by the operating pressure, temperature, process flow, and media.

As the range of types and particular specifications of valves that might be used in any repowering project is very broad, it is not the intent here to provide an exhaustive list. However, in anticipation of many (and perhaps most) repowering applications being versions of a combined cycle installation utilizing an HRSG, here is an example of valves a typical combined cycle steam section may require:

Pressure Seal (Class 900-Class 2500)
HP and IP sections
- Main Steam Stop Valve (Parallel Slide)
- Main Steam Non-Return Valve (NRV Globe)
- Check Valve (Feed Water, Desuperheater, Reheat, Bypass)
- Vent Valves (Boiler Drum, Deaerator, Header)
- Drain Valves (Boiler Drum, Deaerator, Header)
- Isolation Valves (Feed Water, Desuperheater, Economizer, Reheat)

Bolted Bonnet (Class 150-600)
LP sections
- Mainsteam Steam Stop Valve (Gate)
- Main Steam Non-Return Valve (NRV Globe)
- Check Valve (Feed Water, Desuperheater, Reheat, Bypass)
- Vent Valves (Boiler Drum, Deaerator, Header)
- Drain Valves (Boiler Drum, Deaerator, Header)
- Isolation Valves (Feed Water, Desuperheater, Economizer, Reheat)

Steel Alloy
- HP Drum Outlet Non Return Valve (Stop Check) C12A or F91
- HP Steam Outlet (Parallel Slide Gate) C12A or F91
- HP Steam Outlet Start-up Vent (Y-Globe) F91
- Hot Reheat Sky Valve Isolation (Gate) WC9

Other valves

Blow Down Valve
Continuous Blow Down Valve
Feed Water Control Valve
Fuel Flow Valve
Deaerator Level Control Valve
Spray Water Control Valve
Condensate Recirculation Control Valve
Turbine Bypass Control Valve
Deaerator Pegging Steam Control Valve

## Conclusion:

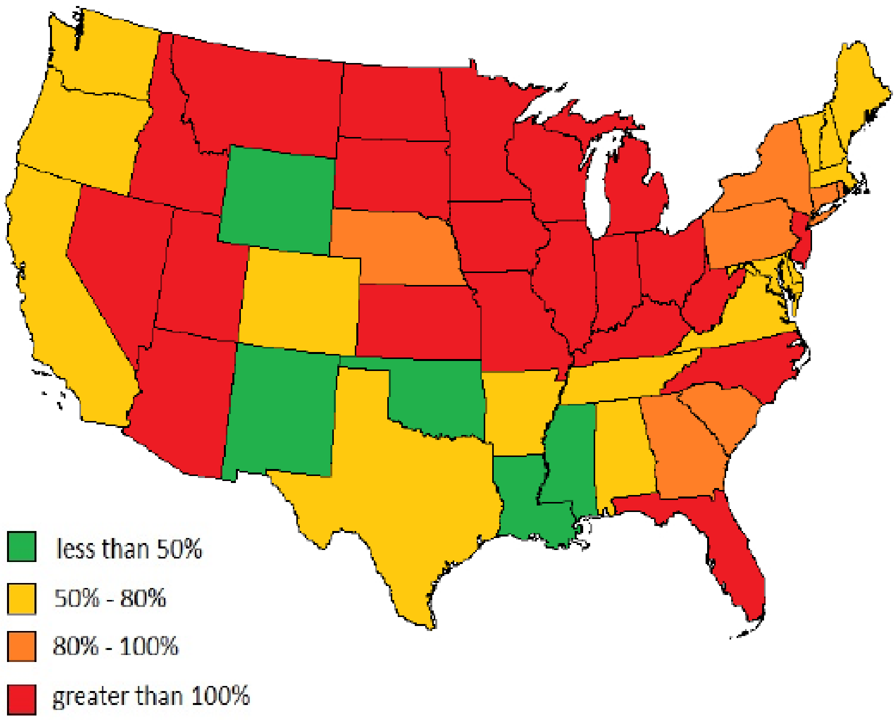
As environmental regulations continue to stipulate reductions in pollution tolerance, coal to natural gas conversion projects, of one type or another, are expected to increase. The extent and rate of this increase is impacted by the relative economy of (natural gas) conversions versus installation of pollution control equipment while continuing to use coal. Since every project is unique with its own set of constraints and requirements, there can be no standard projections as to the volume or types of valves that may be required for conversions. The best way that a valve manufacturer/supplier can benefit an electric utility that is considering repowering, is by offering and providing its expertise in valves and flow control in general – from inception to completion. Crane has the experience and expertise to help power generating customers evaluate options and considerations associated with any conversion from coal to natural gas, and can specify and supply the appropriate valves and related equipment where and when needed.

Sources: 1. Institute for Energy Research: "*Coal and Gas Fight Over Electric Generation Market.*" (May 6, 2013)

- Power Engineering, February 2013
- U.S. Energy Information Administration
- (US) EPA
- Coal Power Magazine
- Aspen Environmental Group

**Appendix A:** Infrastructure required to convert power plants from coal to gas will need to be developed. This includes both transportation and storage facilities.

**Figure 14: Interstate Pipeline Capacity Utilization if An Individual State Switched its Coal-Fired Generation to Natural Gas**




Source: Aspen and APPA

**Appendix B:** Comparison of electricity generation cost by plant type.

## Table 1. Estimated levelized cost of new generation resources, 2018

| Plant type | Capacity factor (%) | U.S. average levelized costs (2011 $/megawatthour) for plants entering service in 2018 | | | | |
|---|---|---|---|---|---|---|
| | | Levelized capital cost | Fixed O&M | Variable O&M (including fuel) | Transmission investment | Total system levelized cost |
| **Dispatchable Technologies** | | | | | | |
| Conventional Coal | 85 | 65.7 | 4.1 | 29.2 | 1.2 | 100.1 |
| Advanced Coal | 85 | 84.4 | 6.8 | 30.7 | 1.2 | 123.0 |
| Advanced Coal with CCS | 85 | 88.4 | 8.8 | 37.2 | 1.2 | 135.5 |
| Natural Gas-fired | | | | | | |
| Conventional Combined Cycle | 87 | 15.8 | 1.7 | 48.4 | 1.2 | 67.1 |
| Advanced Combined Cycle | 87 | 17.4 | 2.0 | 45.0 | 1.2 | 65.6 |
| Advanced CC with CCS | 87 | 34.0 | 4.1 | 54.1 | 1.2 | 93.4 |
| Conventional Combustion Turbine | 30 | 44.2 | 2.7 | 80.0 | 3.4 | 130.3 |
| Advanced Combustion Turbine | 30 | 30.4 | 2.6 | 68.2 | 3.4 | 104.6 |
| Advanced Nuclear | 90 | 83.4 | 11.6 | 12.3 | 1.1 | 108.4 |
| Geothermal | 92 | 76.2 | 12.0 | 0.0 | 1.4 | 89.6 |
| Biomass | 83 | 53.2 | 14.3 | 42.3 | 1.2 | 111.0 |
| **Non-Dispatchable Technologies** | | | | | | |
| Wind | 34 | 70.3 | 13.1 | 0.0 | 3.2 | 86.6 |
| Wind - Offshore | 37 | 193.4 | 22.4 | 0.0 | 5.7 | 221.5 |
| Solar PV[1] | 25 | 130.4 | 9.9 | 0.0 | 4.0 | 144.3 |
| Solar Thermal | 20 | 214.2 | 41.4 | 0.0 | 5.9 | 261.5 |
| Hydro[2] | 52 | 78.1 | 4.1 | 6.1 | 2.0 | 90.3 |

*[1] Costs are expressed in terms of net AC power available to the grid for the installed capacity.*
*[2] As modeled, hydro is assumed to have seasonal storage so that it can be dispatched within a season, but overall operation is limited by resources available by site and season.*
*Note: These results do not include targeted tax credits such as the production or investment tax credit available for some technologies, which could significantly affect the levelized cost estimate. For example,new solar thermal and PV plants are eligible to receive a 30-percent investment tax credit on capital expenditures if placed in service before the end of 2016, and 10 percent thereafter. New wind, geothermal, biomass, hydroelectric, and landfill gas plants are eligible to receive either: (1) a $22 per MWh ($11 per MWh for technologies other than wind, geothermal and closed-loop biomass) inflation-adjusted production tax credit over the plant's first ten years of service or (2) a 30-percent investment tax credit, if placed in service before the end of 2013 (or 2012, for wind only).*
*Source: U.S. Energy Information Administration, Annual Energy Outlook 2013,December 2012, DOE/EIA-0383(2012)*


### *Authors:*
Crane ChemPharma & Energy



**CRANE ChemPharma & Energy** (within Crane's Fluid Handling segment) designs and manufactures a variety of high performance products including: highly engineered check valves, sleeved plug valves, lined valves, process ball valves, high performance butterfly valves, bellows sealed globe valves, aseptic and industrial diaphragm valves, multi/quarter-turn valves, actuation, sight glasses, lined pipe, fittings and hoses, and air operated diaphragm and peristaltic pumps. Its trusted brands (in alphabetical order) ALOYCO®, CENTER LINE®, COMPAC-NOZ®, CRANE®, DEPA® & ELRO®, DUO-CHEK®, FLOWSEAL®, JENKINS®, KROMBACH®, NOZ-CHEK®, PACIFIC VALVES®, RESISTOFLEX®, REVO®, SAUNDERS®, STOCKHAM®, TRIANGLE®, UNI-CHEK®, WTA®, and XOMOX® offer customers complete and innovative product portfolio designed for the most demanding corrosive, erosive, and high purity applications. Among the industries served are the chemical processing, biotechnology, pharmaceutical, oil & gas, refining, and power generation.