NATIONAL ENERGY TECHNOLOGY LABORATORY

NETL

Impact of Load Following on Power Plant Cost and Performance: Literature Review and Industry Interviews

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Impact of Load Following on Power Plant Cost and Performance

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1. Executive Summary

The adoption of renewable energy laws or Renewable Portfolio Standards (RPS) requiring increased utilization of intermittent generation resources will require that fossil fuel-fired generators, originally designed to be base loaded, will have to operate on a load following or cyclic basis. The purpose of this research was to compile information on the impacts of load following on fossil-fueled generators and identify future areas of research to better understand these impacts and develop ways to mitigate adverse effects. This research was conducted through literature reviews and discussions with industry experts from utilities, engineering firms, and consultants.

The key findings of this report are:

There is a very limited understanding of how Carbon Capture and Storage (CCS) requirements will impact the ability of fossil fuel-fired power plants to load follow. Some preliminary modeling has been completed on amine scrubber systems, and there are several proposed load following scenarios involving venting, solvent storage, polyproducts, etc., but little in-depth study has been completed.

Boiler and turbine manufacturers have recognized that the power plant of the future will be required to load follow and cycle much more than in the past. Manufacturers are designing systems and components to better survive the cycling environment and developing controls and operating procedures to accommodate rapid load changes.

The impact of mandatory requirements to dispatch intermittent renewable generation resources on emissions is poorly understood. Rapidly reducing, and then increasing, fossil generation to follow renewable generation requires that fossil units operate in a non-optimized manner. The heat rate is degraded and the air quality control equipment is negatively impacted leading to increased emissions.

The actual costs of load following are poorly understood. Utilities know that thermal cycling does damage plant components, but the total cost impact is rarely fully understood in terms of increased forced outages and increased O&M costs.

Key recommendations for further research are:

1. Develop a comprehensive study to better understand the effect of load following on CCS systems. Although it can be argued that any plant with a CCS system would not be required to load follow, an understanding of the potential issues is required. Questions to be answered by further research could include:

   - Which type of capture system is capable of load following?

   - What is the impact on carbon capture efficiency when load following?

   - What is the potential impact on the cost of carbon capture when load following?

   - Are there issues with the CO_2 compression and storage when load following?

2. Evaluate the impact of equipment modifications and improvements on ramp rates and costs. This study would include a literature search to identify published results of plant modifications that improved load following capabilities. Vendors would be contacted to determine current and planned technological developments to improve load following capabilities. With that information, a detailed comparisons (costs, operations, forced outages, etc.) will be made of a typical non-load following plant and a current/near-future plant constructed for load following will be analyzed.

3. Conduct a study to understand the impact of load following on emissions and heat rate. This work will require a better understanding of emissions and heat rate variations from different boiler types at different firing rates, the effect of varying loads on emission control equipment (SCR, FGD, ESPs, etc.), and the time required for the plant to return to steady state operation.

4. Work with industry to quantify the true cost of cycling fossil generators. Because of the diverse nature of this country's fossil generation fleet, it is anticipated that the research will require a detailed analysis of which class of plant (type, size, age, location, etc.) is most likely to be required to load follow and/or cycle and then determine the impact on O&M costs, forced outages, and plant life.

5. Conduct a study to understand the impact of load following at a grid level. Balancing wind and solar with coal and natural gas to determine actual start/stop times, ramp rates, partial load requirements and how each type of plant affects the others on the grid. Key questions to be answered include:

    - Do current ramp rates of fossil plants limit the utilization of intermittent generation resources?

    - Is there enough "turn down" or partial load capacity to accept planned additional intermittent generation resources?

    - Is there enough distribution stability if significant fossil generation is idled?

Exhibit 1 is a summary of the information collected during this research. Where there is conflicting information, each value is listed and its source is identified. As can be seen, there is little information available on the impact of load following on emissions and systems with CCS.

Exhibit 1 Comparison of Fossil Power Technologies

	NGSC	NGCC	NGCC w/ capture	Subcritical PC	Subcritical PC w/ Capture	Super-critical PC	Super-critical PC w/capture	IGCC	IGCC w/ capture	Oxy-combustion
Minimum Partial Load	50%	60%[1] 40%[2]		50%[3] 10%[4,5] 30%[2]	80%[6]	40%[7]	40%[7]	80%[8] 60%[9]		50-70%[10]
Heat Rate Penalty at Minimum Partial Load (Btu/kWh)	1270	765[11] 1889[9]		464 @ 49% Load[9]		489[12]	1632[13]	1877 @ 37% Load[9]		
System that Dictates Partial Load Limit		Steam-side components	Steam- side components	Boiler Drum	Boiler Drum					ASU
Emissions Impact at Minimum Partial Load										
NOₓ		-240% to -600% (increased emissions from gas turbine during turn down)[14]		-10 to -20% (Increased emissions)[15]						50% to 70% (Decreased emissions) [16]
SO₂				Variable[17]						Increase compared to Subcritical PC[18]
Hg										Lower com-pared to Subcritical PC[10]

	NGSC	NGCC	NGCC w/ capture	Subcritical PC	Subcritical PC w/ Capture	Super-critical PC	Super-critical PC w/capture	IGCC	IGCC w/ capture	Oxy-combustion
Cold Start Time		150 to 250 min with new technology[19]		12 – 15 hrs[20]		90 min to turbine synch w/ bypass[21]		24 hrs[22]		10 hrs[23]
Warm Start Time		120 to 200 min with new *technology*[19]				45 min to turbine synch w/ bypass[21]				
Hot Start Time		45 to 90 min with new technology[19]		180 min[20]		90 min to full load[24] 30 min to turbine synch w/bypass [24, 21]		6 hrs[22]		17 hrs[25]
Maximum Ramp Rate (typical)–Increasing Load		5%/min[26]	5%/min[26]	5%/min[27]		2%/min[28, 29]		≥ 5%/min[30] 3.5% in 5 sec[22] 40% @ 3%/min[22]		3%/min for the ASU[31]
Maximum Ramp Rate (enhanced controls) – Increasing Load				5%/min[32]						
Design Cold Start Frequency		100 starts/yr[33]		200 starts[34]						
Design Hot Start Frequency				5,000 starts[34]		6,000 starts[35]				

[1] Based on Harvey Goldstein interview.

[2] From NETL "Internal Use Only" presentation "PC Performance @ Part Load"

[3] Based on Harvey Goldstein interview. Below 50% emissions control is lost and is usually intolerable.

[4] Xcel has some PC plants designed with "hibernation" mode capable of turning down from 250 MW t0 25 MW. (Gonzales 2010)

[5] Multiple subcritical PC minimum % of Maximum Continuous Ratings Table 3-1 of (EPRI 1998)

[6] Based on Harvey Goldstein interview.

[7] Estimated turn-down of a modeled 1100 MW Supercritical PC Plant (Linnenberg 2009)

[8] Based on Harvey Goldstein interview.

[9] Net Efficiency (%LHV) From NETL Internal use presentation "PC Performance @ Part Load"

[10] Based on finds from an ANL-EERC Study and IFRF Study (Santos 2005)

[11] Combined cycle net efficiency loss from 57.5%@100% to 51%@47% Combined cycle output for a GE9371B. From NETL Internal use presentation "PC Performance @ Part Load"

[12] Modeled efficiency loss of a 1100 MW Supercritical PC Plant with no CO_2 Capture at 40% Load (Linnenberg 2009)

[13] Modeled efficiency loss of a 1100 MW Supercritical PC Plant at 40% Load with retrofitted amine base 90% CO_2 capture system (Linnenberg 2009)

[14] 2 cases modeled with actual wind data and emission data for a Siemens-Westinghouse 501FD (200 MW) NGCC (Katzenstein 2008)

[15] Measured on a down-fired 100 MWe PC boiler during load following operation (NETL 2001)

[16] This is compared to air-fired coal boilers (Vitalis 2007)

[17] SO_2 scrubbing efficiency varies during load cycling based on equipment configuration and controls. Over 50 adjustments may be necessary to the SO_2 scrubber to maintain scrubber performance. (Bentek Energy LLC 2010)

[18] Oxycombustion can potentially increase the SO_2 and SO_3 in the flue gas which could reduce the SCR's performance. (Toftegaard 2010)

[19] Siemens 400 MW single shaft system reports decreased start times with application of new technologies (H. Emberger, Fast Cycling Capability for New Plants and Upgrade Opportunities 2005)

[20] Typical Rankin Boiler Start-up times (Commission for Energy Regulation, Utility Regulator 2010)

[21] From first fire to turbine synch with bypass system (Alstom 2007)

[22] Based on Nominal 250 MW plant with 1 Texaco Gasifier and a 1x1 combined cycle with a GE7FA CT. Cold plant start-up time assumes already operating ASU. Additional 24 hrs is required for ASU cool-down (Black & Veatch Corporation 2004)

[23] Dynamic Simulation of 1000 MW Class Oxyfuel System (Ueno 2009)

[24] Ultra Supercritical Siemens' turbine with "new" startup procedure Figure 11of (Quinkertz 2008)

[25] Required time for ASU hot start-up (Ueno 2009)

[26] IRP data for Mohave 994 MW and 846 MW NGCC Plants (Synapse Energy 2006)

[27] Based on Harvey Goldstein interview.

[28] Automatic boiler ramp up at 460 MWe CFB SC Lagisza plant (Utt 2009)

[29] 10 MW/min on 450 MW SC Benson type boiler (Peltier 2005)

[30] Based on Harvey Goldstein interview.

[31] Based on a study by Doosan Babcock Energy presented in (Toftegaard 2010)

[32] Simulate advanced controls on 600 MW PC plant with hybrid sliding controls (Leung 1995)

[33] *Design cold starts for 1020 MW NGCC with 4 - 159 MW7FA GT's and 2 – MWGE ST's (Kuehn 1995)*
[34] *Design number of starts based on standard adopted by Central Electricity Generating Board (CEGB), UK (Chow 2002)*
[35] *Number of designed total hot starts slightly lower than normal due to "fast start" routine which still negatively impacts design life*

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2. Background

The ambitious targets for renewable generation among the industrialized nations in the form of renewable energy law or Renewable Portfolio Standards (RPS) could transform the wholesale market of today in which power plants are expected to run according to the merit order (base load, intermediate load, and peaking load) from one load level to another. New rules, regulations and, designs could be required to meet the challenges of intermittency of renewable energy (wind and solar).

The integration of wind power creates unpredictable operational patterns, e.g. substantial difficulties of integrating intermittent wind power generation into the electric grid. It becomes inevitable that reliable technical solutions have to be found as fossil-fired power plants would be expected to flex in response to the intermittency of wind.

Consequently, in this liberalized market, the impact of load following fossil plants on costs of generating electricity and environmental emissions must be fully understood for different fossil fuel plant configurations because these plants will continue to be substantial contributors to a reliable large-scale electricity supply. However, as they are called upon to fulfill this new role, these plants are expected to cycle more than today and be exposed to damage of key components (shorter lifetime expectancy).

The Department of Energy/National Energy Technology (DOE/NETL) is conducting a Literature Review to address the future implications of load following to respond to this delicate "balancing power act" in terms of operational scheduling of existing and near-term new design fossil power plants in light of the integration of intermittent power sources.

This document is a compilation of information from research and interviews concerning load following and its impact on costs and performance. It is divided into three main sections:

Section 3 – "Impact on components," discusses how major power plant components are affected by load following. This section starts with a general discussion on creep and fatigue because those phenomena are a major factor in component failure.

Section 4 – "Impact on systems, highlights" issues pertaining to specific power plant configurations and discusses the effect load following has on forced outages and carbon capture.

Section 5 – "Cost and emissions impact of load following," presents the potential cost and environmental impacts of load following through actual case studies.

3. Impacts of load following on components

In general, cycling decreases component life through damage caused by fatigue, creep, and other stresses. Aptech has evaluated these costs and have found they account for some of the largest costs incurred by load following. They differentiate load following induced maintenance versus normal wear and tear by counting each time the plant cycles, determining the type of cycle (partial load, hot start, cold start, etc.) and time at each load condition. Steve Lefton, of Aptech, described the two methods used for this evaluation as follows:

" 1.Top-down multi-year regression (with delay terms as cycles cause delayed expenses and outages) of cost and cycles. Cycling related costs correlate with cycles and then we can explain all past years of cost with fixed cost, cost per cycle, and cost of base loading"

"2. Bottom up method: detailed review of all work orders for 7-10 years. These costs correlate well with top down results."

In simple terms, they look at the plant's maintenance history when the plant ran at base load and compare it to the maintenance history when the plant is load following. Detailed damage modeling is done with plant testing data. Examples of Aptech studies can be found in Section 5.1 Case Studies later in this document.

3.1.   Fatigue and creep

Fatigue and creep due to thermal stresses when cycling constitute the underlying problem with almost all equipment and system issues discussed below.

Fatigue is caused by components being cycled due to load following, restarts, shutdowns, etc. and can lead to cracking. Thick sections of material are areas of most concern because they are more frequently cycled and are more susceptible to damage due to thermal stresses. Creep damage, by definition, is caused by a prolonged exposure to high temperature and stress. In principle, since creep is both time- and temperature-dependent, plant cycling and low load operation should reduce the effects of creep. However, it is found that during low loads, there are circumstances where temperature overshoot occurs, thus causing localized overheating for extended periods of operation above the design temperature. Accumulated occurrences of operating at these temperatures causes, and often accelerates the creep damage.

These two issues are usually synergistic: creep strains can reduce fatigue life and fatigue strains can reduce creep life, causing accelerated failure. Exhibit 2 demonstrates the interaction of creep and fatigue for P22 (Shibli 2002). The exhibit illustrates that the largest fraction of damage during continuous operation (furthest point to the right) is due to creep. The black line represents material failure point. The brown line represents different material life scenarios. As the material is cycled due to two shift operation, a larger fraction of the damage is caused by fatigue (further to the left). Creep damage is known to occur and the design lifetime of the component includes this expected damage. Fatigue damage becomes more of a factor as the component is cycled and can lead to premature failure especially if the component is near the end of its creep life.

Exhibit 2 Creep Fatigue Interaction for P22 Nickel Alloy (Shibli 2002)
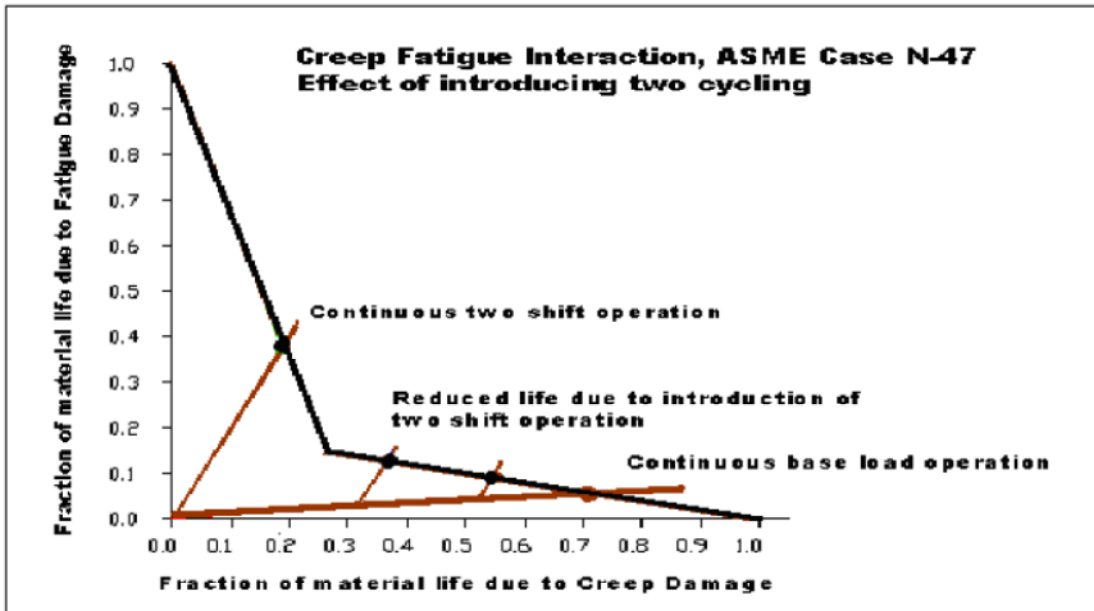
(Used with permission by ommi.co.uk and European Technology Development Ltd. UK)

New plants can have failures as early as 5 to 7 years into operation. For older plants it could be nine months to two-years after start of significant cycling. (S. A. Lefton 2006)

3.2. Coal handling and feeding

There are basically two arrangements for coal handing and feeding: direct fire or bin storage. With the direct fire arrangement, the coal is broken into manageable sizes and stored in a bunker. The raw coal is then fed to a pulverizer, which crushes the coal to the appropriate size for feeding into the boiler. The pulverizer is swept with hot air, which aids in removing moisture from the coal.

The pulverizer for direct-fire arrangements must be capable of turning down to match the turn-down of the boiler. In some plants, the pulverizer can be the limiting factor on ramp rate due to older controls and permissives that are in place to prevent explosion or fire in the pulverizer. (Gonzales 2010)

Several pulverizer manufacturers are beginning to design load following capabilities into their vertical mill designs. One design change is to provide variable loading on the pulverizer wheels based on coal feed rate. Exhibit 3 is an example of wheel load versus coal feed rate for one manufacturer's design. (Babcock and Wilcox n.d.)

Exhibit 3 Pulverizer Wheel Load versus Coal Feed Rate for a General Manufacturer's Design (Babcock and Wilcox n.d.)
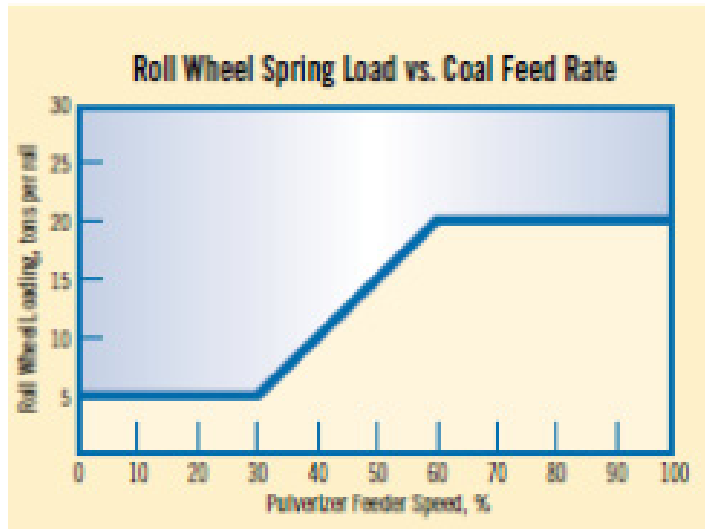
(Used with permission by B&W)

With the bin storage arrangement, the coal is crushed to the appropriate size and then stored prior to feeding into the boiler. This arrangement allows for greater turndown and the ability to continue boiler operation during short pulverizer outages. However, this arrangement requires proper venting of the storage bin to prevent fires or explosions.

3.3. Boiler/HRSG

Boiler issues not discussed in detail below include fatigue failures in the economizer and lower furnace tubes. Exhibit 4 shows the incremental growth of cycling-related tube leaks with a given number of starts.

Other general issues for boilers/HRSGs include structural damage to such areas as windbox supports, and large transient temperature differences of 200 °F to 400 °F accelerating thermal damage.

**Exhibit 4 Cumulative Tube Leaks versus Unit Starts for a 600 MW Coal-Fired Unit
(S. A. Lefton 2006)**
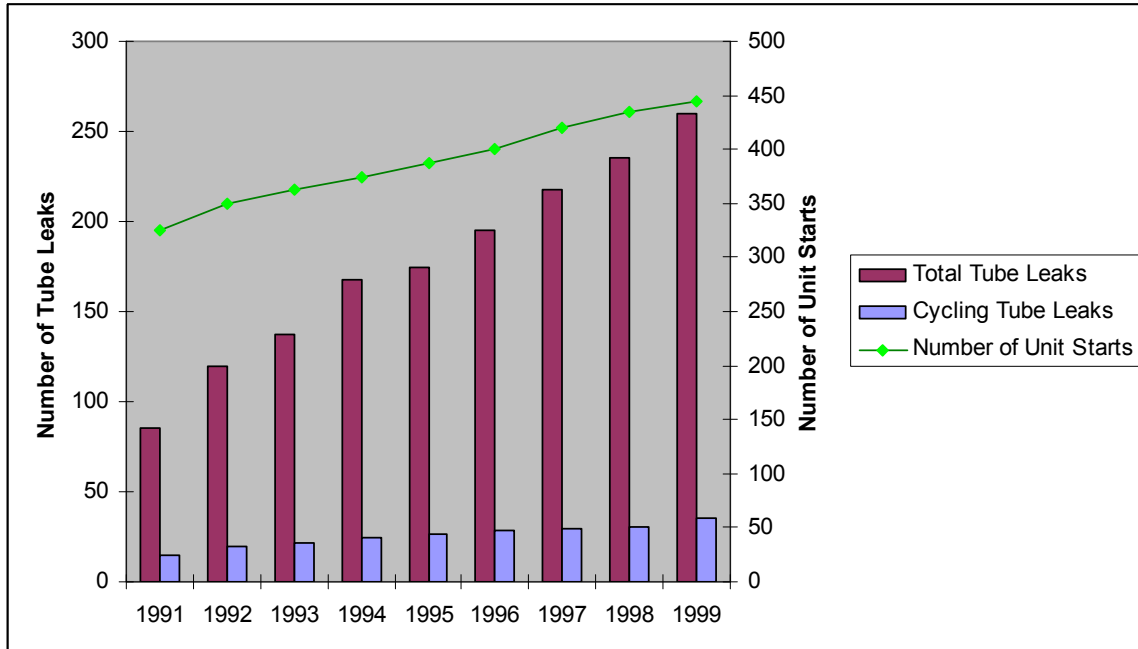
(Used with permission by Steven Lefton)

Superheater and Reheater Header Fatigue/Creep

Internal ligament cracking has become a common form of thermal fatigue and creep/fatigue damage affecting superheater headers. Cracking can propagate though the wall rapidly with adverse stub geometry. With the extended life of older plants, creep continues to accumulate in the superheater and reheater headers as well (Johnston n.d.).

**Exhibit 5 Superheater Outlet Header Showing
Ligament Crack Locations (Johnston n.d.)**
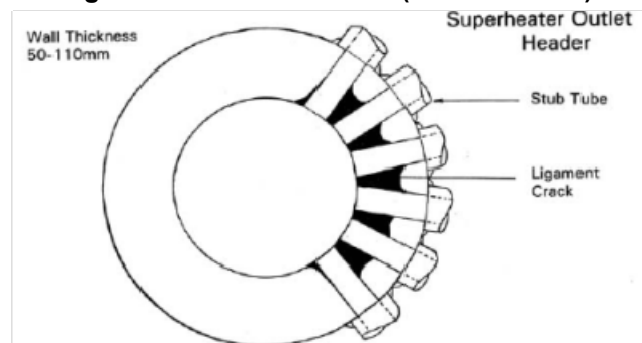
(Used with permission by RWE Innogy)

Other Superheater and Reheater problems include: (Pasha 2008)

- Thermal shock - Condensate in a superheater section or colder reheat steam in the hotter and dry reheater section results in thermal shock to the inner surfaces of the tubes and headers.

- Oxidation - Exposure of the metal to higher temperature than that which it was designed for, particularly during start-ups, can result in oxidation. Oxidation and exfoliation can happen both inside and outside the tubes and piping, caused by exhaust gas on one side or steam/water on the other. Dry reheater designs are particularly vulnerable.

- Differential expansion - Uneven heating of tubes—caused by uneven distribution of (1) exhaust-gas or steam/water flows or (2) exhaust-gas temperatures—can cause adjacent tubes to expand or contract differently. Both compressive and tensile loads are imposed.

- Deposits - Uneven or excessively fast ramp rates may result in the accumulation of condensate in the superheaters and, consequently, the formation of deposits.

Boiler Drum Nozzle Fatigue

The Electric Power Research Institute (EPRI) conducted a study of 51 drum units supplied by three U.S. boiler manufactures. Evaluations indicated that the temperature differential between the subcooled inlet feedwater (FW) and the saturation temperature of the steam-water mixture was the dominant thermal driver. This temperature differential is greatest at partial loads with magnitudes at one quarter load from 155 to 273°F (86 to 152°C), decreasing to 56 to 147 °F (31 to 82°C) at full load for the units in the database. Units without economizers had the highest temperature differentials because the drum supply comes directly from the last high-pressure FW heater. (Roberts 2004)

Damage to Superheater and Reheater Elements

Flexible operation often leads to tube temperatures transiently peaking above normal; these peaks arise typically prior to synchronization in radiant and platen surfaces and post-synchronization in pendants. A number of problems are associated with high peaking metal temperatures from which tube failure risk increases, for example (Johnston n.d.):

- Element distortion, itself leading to a higher degree of local overheating, long-term overheating, or fireside corrosion failures

- Occasional short-term overheating failures

- Degradation in tube material properties leading to lower tolerance of transients

- Disruption of protective oxide leading to enhanced metal loss rates (unlikely unless temperatures peak above 650℃

- Degradation of transition joint integrity

- Fatigue at slip ties leading to crack formation in tube walls and tube misalignment, seal boxes, and header stubs due to differential expansion

3.4. Steam Turbine

A number of issues with cycling can occur, including cracking caused by water induction, thermal fatigue from temperature changes, solid particle erosion in the blades and nozzles, and rotor defect growth.

Steam Admission

Full arc admission valves are used in most turbines to control steam entering the turbine. During load following and at partial loads, all the admission valves are throttled, reducing the efficiency and increasing the wear on the valve.

Partial arc admission allows the steam to enter through individual valves opening in a sequential manner; thus, as load is increased, more valves open to admit steam. The change reduces throttling losses through the valves. This upgrade would be beneficial and probably likely if the plant were to constantly operate in a load following manner. However, units with partial arc admission in which the lower arc valves open first are more susceptible to increased vibration at reduced minimum loads. This is due to unbalanced upward pressure forces that tend to lift the rotor and partially unload the HP-IP bearings (TG Advisers, Inc. n.d.).

Turbine Rotor Defects

Steam turbine rotors are among the most critical and highly stressed components in a power plant. The potential consequences of a rotor failure include blade loss, spindle fracture, and most significantly, but rarely occurring, fast fracture from a near-bore defect causing a catastrophic burst. These failures are generally caused by reducing start-up times to improve flexibility, which raises transient thermal stress levels at the rotor bore and surface. The problem is then compounded when utilities increase the number of annual start cycles, thereby substantially enhancing rotor material degradation (Johnston n.d.).

Higher Water Droplet Erosion

Boiler temperature droop at lower loads typically occurs in both reheat and main steam conditions. Lower steam temperatures will increase moisture levels and also move the saturation line further upstream (near Wilson line) of the last stages of the low pressure (LP) turbine. At the Wilson line, chlorides become concentrated and stress corrosion concerns are elevated. Impingement of droplets on rotating blades leads to accelerated damage of installed erosion shields and blade surfaces (TG Advisers, Inc. n.d.).

Last Stage Blade Stall Flutter Vibration

LP last stage blade stall flutter potential is greatest during conditions of low flow and high back-pressure. Stall flutter occurs when flow separation at the base of the blade forces steam flow towards the tip. This stalling of the flow around the blades excites the blades, producing vibrations and stress that result in cycle fatigue blade failure. Longer blades are more susceptible than shorter blades.

3.5. Gas Turbine

Gas turbines are robust and typically handle cycling and load following well. The issues involved with gas turbines are the emissions. When the engines are base loaded, the combustion system operates at high firing temperatures and most of the CO is oxidized to Carbon Dioxide (CO_2). But at partial loads, when the firing temperature is lower, the CO to CO_2 oxidation reaction is quenched by the cool regions near the walls of the combustion liner. This results in increased CO emissions at low loads (Nag 2008).

Exhibit 6 is a chart of Siemens' 501G's calculated turndown capability to 10 ppm CO emissions for an unnamed demonstration plant (Nag 2008).

Exhibit 6 Siemens' 501G Predicted Engine Turndown Capability (Nag 2008)
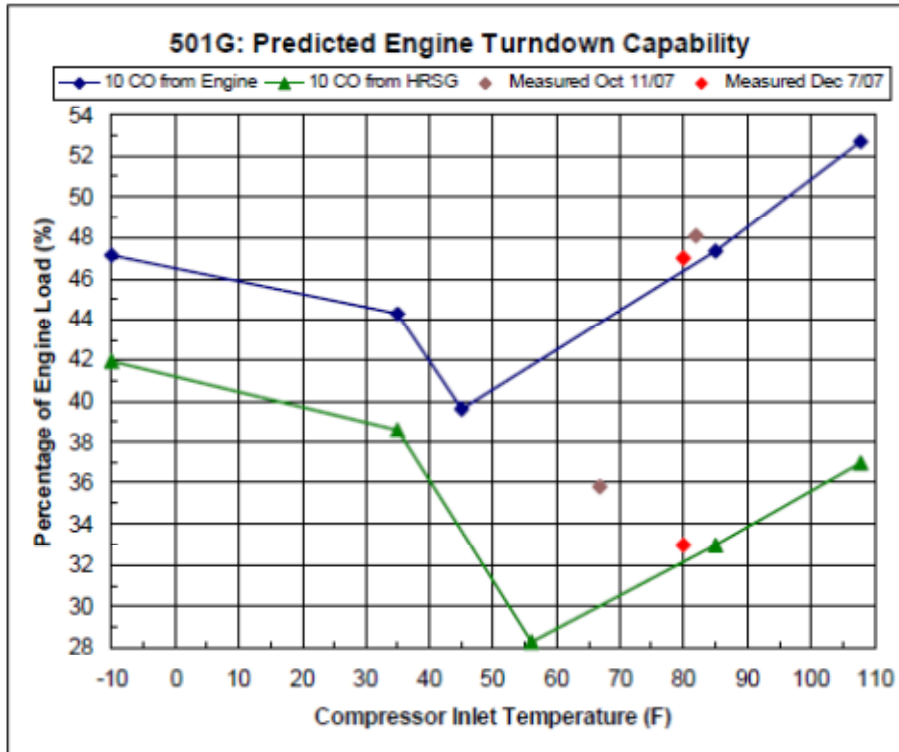
(Used with permission by Pennwell)

Siemens' 501G's maximum turndown maintaining 10 ppm CO out of the turbine is approximately 40 percent of full load and 28 percent of full load when maintaining 10 ppm out of the HRSG stack after using a CO catalyst.

3.6. Air Quality Control Systems (AQCS)

Flue Gas Desulfurizers (FGD)

The effects of cycling and partial loads on FGDs include fatigue/creep due to thermal cycling on the linings used in the FGD absorbers and the additional rotational loads on motors and pumps as they are accelerated to operating speed. (UK Department of Trade and Industry 2000). Limited data also suggest that fluctuations of flue gas to the FGD can cause controllability issues leading to increased emissions during periods of load following (Bentek Energy LLC 2010).

3.7.   Generator

Generators can have cycling-accelerated effects on the retaining ring and end-turn fatigue that can lead to failure and/or arcing.

3.8.   Recirculating Water/Cooling

Cooling water usage tends to be erratic as load following or cycling occurs where large amounts of cooling water can be used wastefully. A study conducted on 18 steam electric facilities in New York compared the relationship between the reductions in cooling water capacity used as a function of reducing electric generation.

Exhibit 7 Reduction in Cooling Water Capacity versus Generating Capacity for Steam Electric Facilities in New York (Nieder 2010)
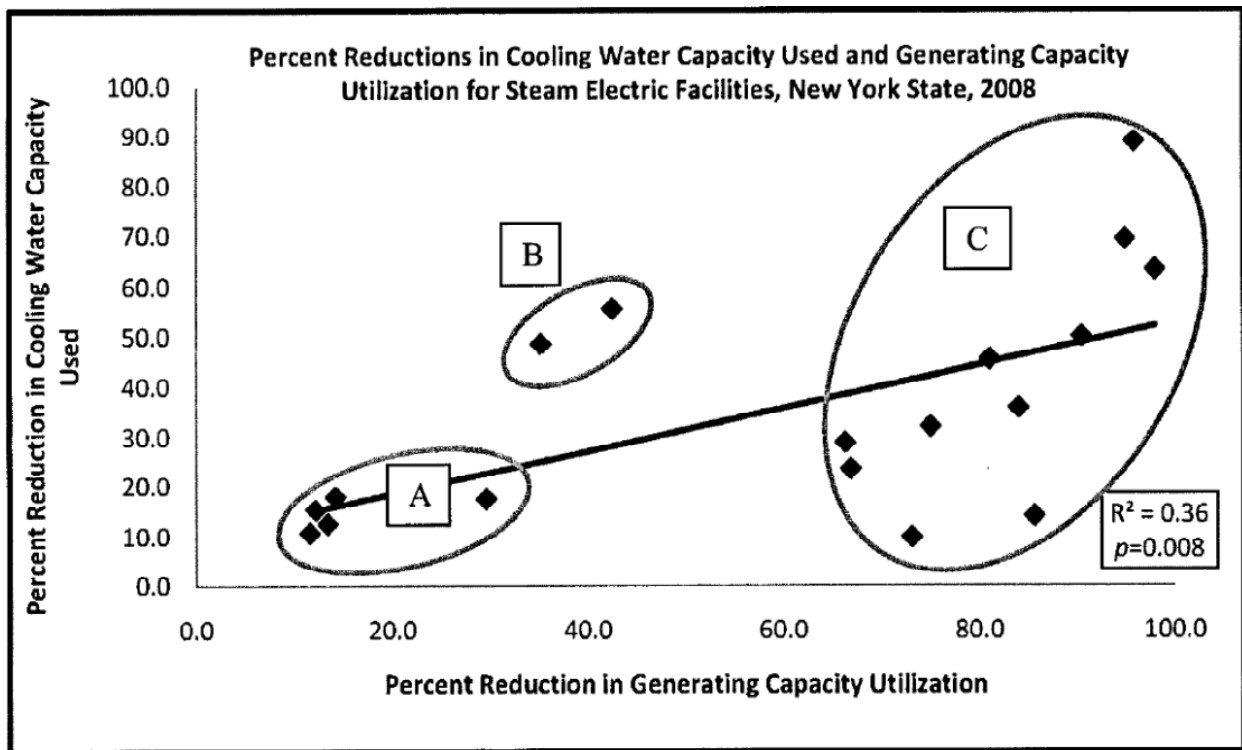
(Used with permission by NY Dept of Environmental Conservation)

 Exhibit 7 shows that the plants naturally grouped into A – base loaded plants, B – unique water use, and C – peaking and load-following plants. Group A is a tight grouping indicating consistent operational use of cooling water in relation to electric generation. Group C is very inconsistent, with some facilities using very little of their generating capacity but operating their cooling system at more than 70 percent their design capacity (Nieder 2010).

3.9. Air Separator Unit (ASU)

Typical ASU ramping rates are 1 percent per minute with 2 percent per minute capability with advanced controls. 3 percent per minute is possible if the unit is designed for rapid ramping. (White 2009)

3.10. Pumps

Motors

Most pump motors are constant speed requiring more oscillation of the control valves during load following and partial load. This will cause wear and tear on the valves and the motor.

Variable Frequency Drives (VFDs) allow control of the speed of the motor extending the life of the motor and control valves during load following and partial load. In some instances, incorporating variable speed drives can reduce energy use by up to 50 percent at partial loads (WesterKamp 2008).

3.11. Water/Steam Cycle

Water Chemistry

Upset conditions in the water chemistry can occur in cycling situations due to the inability of the chemical control system to rapidly respond to flow fluctuations. This can occur in all fossil-fuel generators but has the most detrimental effect on Supercritical PC plants due to the absence of boiler blowdown. Blowdown from the boiler/HRSG can be used to balance chemical upset situations and to help drum level control, but this comes at a high cost both in efficiency and water usage (Eisenbise 2010).

Corrosion fatigue and oxygen pitting can cause corrosion products to be transported to the boiler and turbine. Silica, iron, and copper can start to deposit on equipment. Phosphate hideout can occur leading to acid and caustic attacks.

Exhibit 8 Steam Temperature Variations of a Generic Coal Plant during Plant Load Off-and-On Cycling (S. A. Lefton 1997)
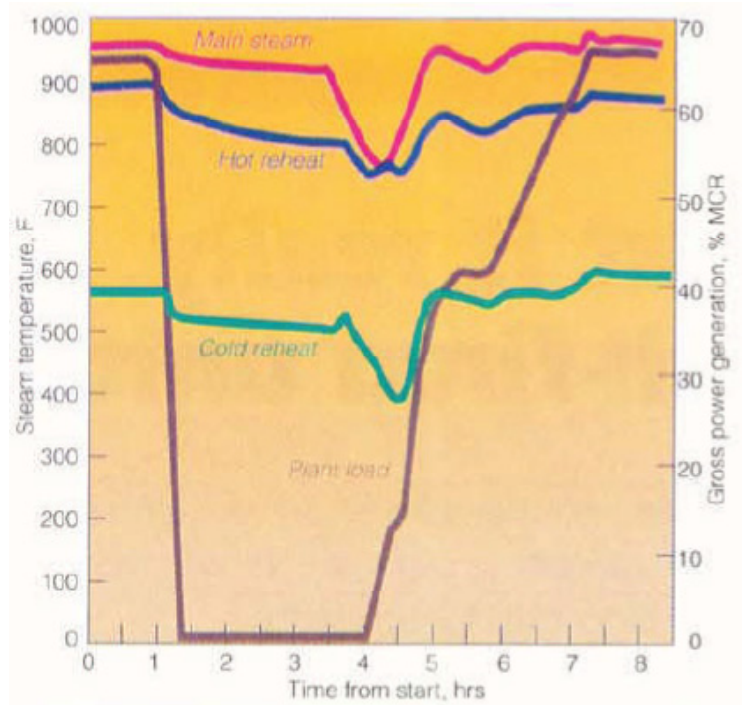
(Used with permission by Power Magazine)

Pipe

Pipe thermal stress and fatigue cracking are some of the most significant problems with load following. The chart to the right shows the temperature changes in the different steam systems compared to load (S. A. Lefton 1997).

Condenser

Condenser tube grooving at the support plates can occur due to poor water chemistry (S. A. Lefton 1997). Dissolved oxygen can increase at low loads, potentially reaching the limit of the vacuum pumps/ejectors, and could be the "bottle neck" when it comes to plant ramp rates (Eisenbise 2010).

Feedwater Heaters

Feedwater heater tube grooving at the support plates can occur due to poor water chemistry (S. A. Lefton 1997).

Attemperator Spray

Attemperating the main steam and hot reheat is a difficult task for most plants when base loaded. Once cycling occurs, attemperation spray cannot always keep up with temperature changes causing steam temperature swings leading to hot spots and sometimes water entrainment (Eisenbise 2010).

3.12. Fans

Motors

Most fan motors are constant speed, requiring more oscillation of the dampers during load following and partial load. This will cause wear and tear on the dampers and the motor.

VFDs allow control of the speed of the motor extending the life of the motor and dampers during load following and partial load. In some instances, incorporating variable speed drives can reduce energy use by up to 50 percent at partial loads (WesterKamp 2008).

4. Impacts of load following on systems (operational, maintenance, emissions)

4.1. Impact on Equivalent Forced Outages

Equivalent Forced Outage Rates (EFOR) tend to increase as a utility begins to cycle its units. EFOR is basically the percentage of forced outage hours plus the forced derated hours divided by the service hours. The chart below shows the EFOR percentages over the life of four large aging coal-fired units compared with a typical base-loaded plant (S. A. Lefton 1997).

As expected, base-loaded units had the lowest EFOR. EFOR generally increased in the following order, after base load: (1) units that were specially designed for load following, (2) base-loaded designs that were upgraded for load following, (3) cycling plants with periodic upgrades, and (4) cycling without plant upgrade. A cross-cutting factor not always associated

with cycling problems is human/machine interface. Operator error as a result of greater hands-on requirements increases the risk of potential explosion, implosion, and improper valve alignment and control.

Exhibit 9 Generation Loss from Cycling of Four Different Coal Plants Compared to Base-Loaded Operation The area in the pink is generation loss due to Cycling-Related Damage
(S. A. Lefton 1997)
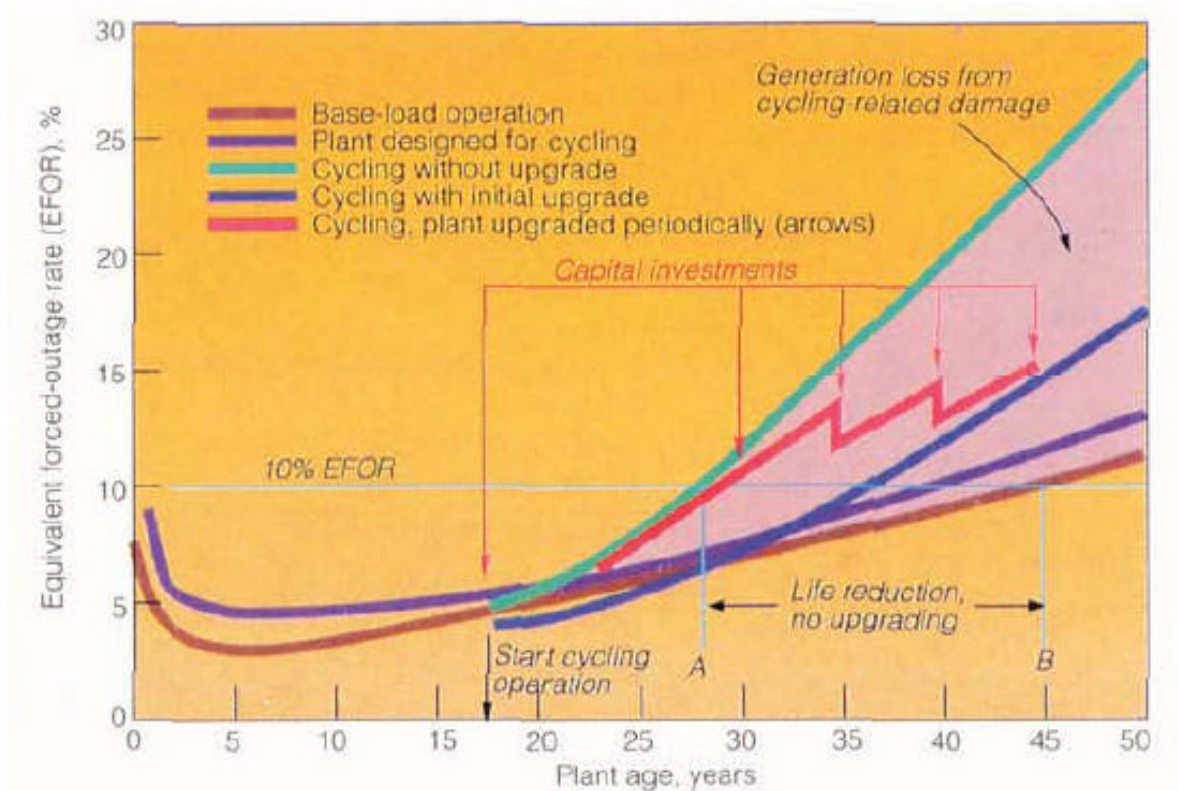
(Used with permission by Power Magazine)

4.2. Impact on Carbon Capture and Storage (CCS)

The impact of load following on CCS systems is not well understood at this time and little information has been published. The interaction of the generation plant with the carbon capture system may provide some opportunity to increase electricity generation during time of high demand by decreasing the amount of steam being extracted for re-boil in an amine-based capture system (Doosan Babcock Energy Ltd. 2007). Limiting steam extraction could be accomplished by venting some CO_2 to reduce regeneration demand, bypassing CO_2 scrubber completely, or storing CO_2-rich solvent to be regenerated later during low electricity demand periods.

NETL has conducted a study of "capture flexible" designs for supercritical PC and GE Energy (GEE) IGCC plants (NETL 2009). Additional details of this work are discussed in the supercritical PC and IGCC sections of this report.

Some work has been conducted at the University of Texas using Aspen Custom Modeler to develop a rate-based dynamic model of the amine stripper. This model simulated the effect of ramping the reboiler heat duty and rich solvent from 100 percent to 20 percent in 15 minutes

(turn-off scenario) and ramping the reboiler heat duty and rich solvent from 20 percent to 100 percent in 15 minutes (turn-on scenario).

Exhibit 10 illustrates the modeled dynamic response of reboiler temperature and Exhibit 11 shows the modeled lean loading response.

Exhibit 10 Dynamic Responses of Reboiler Temperature to Turn-On and Turn-Off Operations (Sepideh Ziaii 2009)
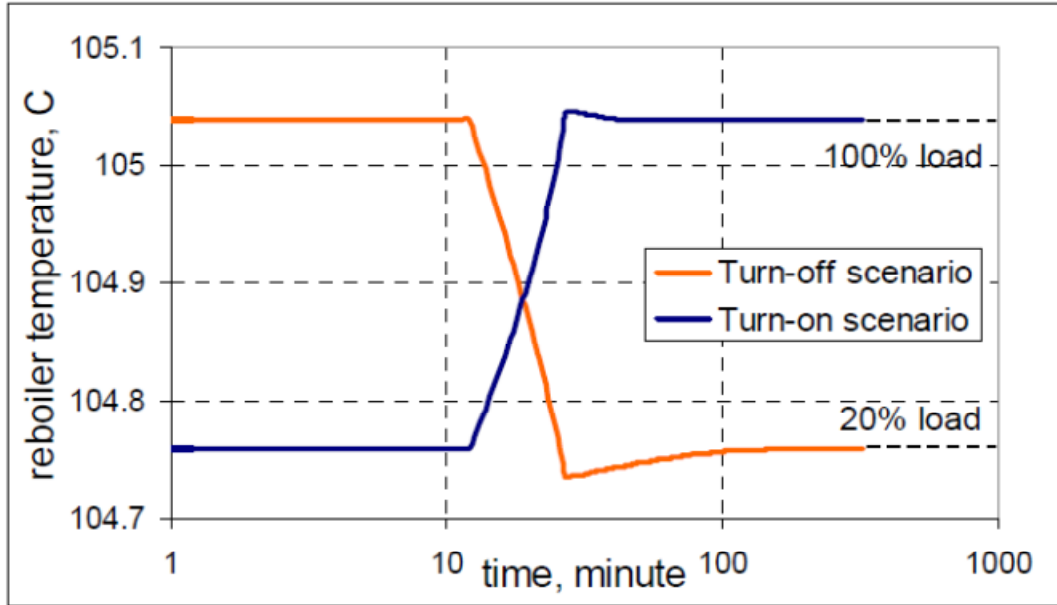
(Used with permission by Copyright Clearance Center)

**Exhibit 11 Dynamic Responses of the Lead Loading to Turn-On and Turn-Off Operations
(Sepideh Ziaii 2009)**
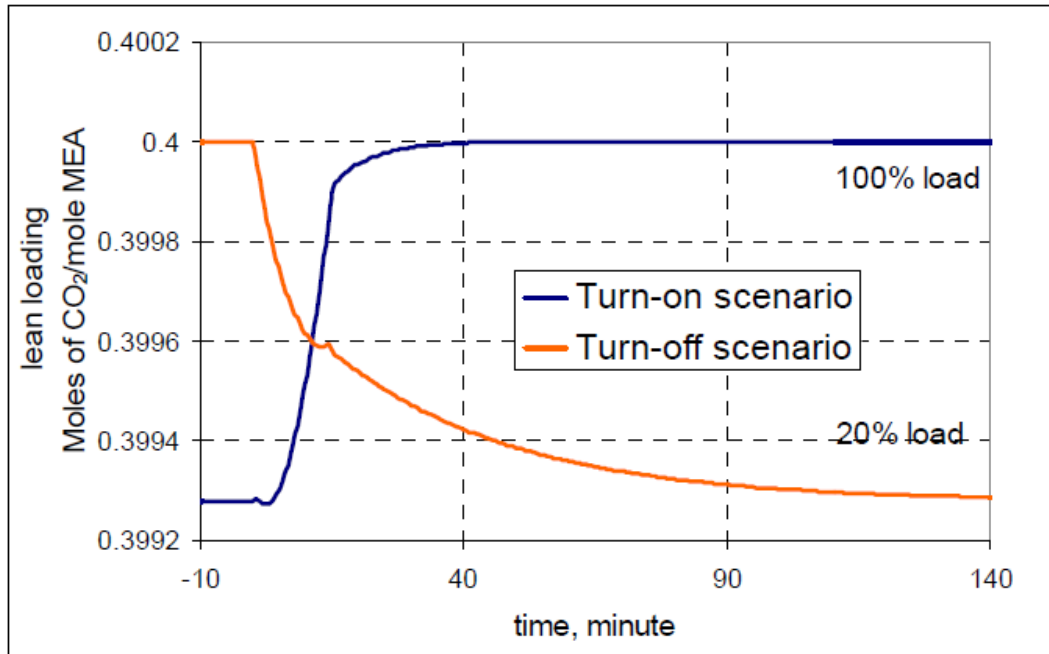
(Used with permission by Copyright Clearance Center)

4.3. IGCC without CO_2 capture

There are many different gasifier types; however, commercial utility scale gasifiers manufactured by the major vendors—GE, Shell, ConocoPhillips, or Siemens—are typically entrained flow slagging gasifiers. All of these are oxygen blown and not air blown, so the focus of this discussion is on oxygen blown systems. There are exceptions such as the TRIG/Southern Company air blown/non-slagging unit currently under construction; however, due to limited load following information, they will not be addressed in this paper.

A typical utility IGCC plant turndown of 20 percent can be achieved (80 percent of load); however, turndown and load following are typically not performed by IGCC plants (Goldstein 2010).

The reason that IGCC typically does not load follow is that the IGCC process is very complex, highly integrated, and has a high capital cost. The integration requires a complex control system that is sensitive to process changes making load following difficult. The high capital cost of the system requires that the utility operate the plant as much as possible to recoup the cost.

Configurations that consist of multiple gasifiers and combustion turbines can do some load following by reducing the firing rate of one or more of the combustion turbines or by shutting down one of the flow trains. The turndown of the gas turbine is typically approximately 60 percent with heat rate deteriorating at lower loads; however, cycling of the gasifier is difficult (Appendix 12 Top-down Commercial Evaluation of IGCC n.d.).

IGCC ramping is significantly more complicated than PC ramping. Ramp rate when decreasing load is different than when increasing load. The gas turbines are the "controller" devices in the system for the ramp rate. Gas turbines can ramp down quickly but the excess gas from the

gasifier would have to be flared off. This is technically easy to do, but the emission from flaring the gas has the potential to contain too much NO_x emissions to meet the plant's air permit. Ramping up is slow due to the nature of the gasification process. This ramp rate is generally the same as PC boilers: 5 percent per minute after initial warmed up. However, some ramp rates can be as poor as 2–3 percent per minute.

Major component life issues with cycling have to do with the gasifier; in particular, the refractory in the gasifier is very sensitive to thermal transients which limit life span. Because of this, several IGCC configurations have been proposed to allow co-production of a variety of products, which would allow the continuous operation of the gasifier while providing electrical load following capability. Exhibit 12 below illustrates the potential products from the gasifier (O'Brien 2004).

Exhibit 12 Potential Product from an IGCC Gasifier
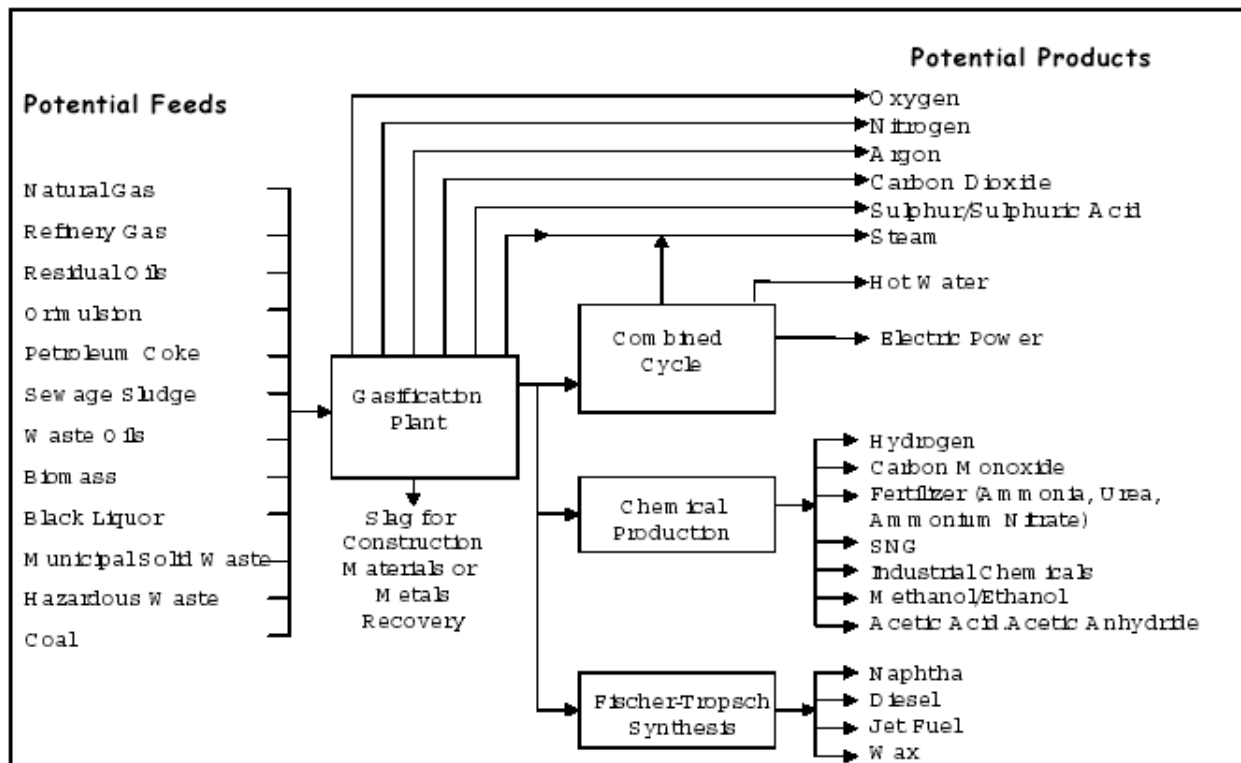
Any of these co-production concepts would improve the load following capability of the gasifier but require significant additional equipments such as:

- A syngas storage system to provide tanks to store the syngas from the gasifier during low electricity demand periods to be used for production of other products or to supply the gas turbine with additional gas during periods of high electricity demand.

- A gas-to-liquid system would require the addition of a Fischer-Tropsch synthesis or similar process to produce liquid fuels from the syngas when the electrical demand is low

or if the gas/steam turbines need to come off-line. The liquid fuel could then be vaporized later and used to fire the gas turbine or sold as a liquid fuel (Eskin, et al. 2007).

Another load following option for IGCC is to oversize the ASU and provides storage of the excess air products. This configuration allows the utility to overproduce and store air products during low electricity demand and shut down the ASU during periods of high electricity demand to produce more net electricity by eliminating ASU parasitic load.

ASU integration is another important factor in determining the operational flexibility of an IGCC plant. The degree of integration refers to the amount of compressed air coming from the gas turbine compressor and not from an ASU compressor. Within limits, the larger amount of integration (larger amount of compressed air from the turbine) leads to more efficient electricity generation and lower ASU compressor costs. However, this efficiency gain comes at the cost of decreased operational flexibility, longer start-up times, and decreased load following capability (Maurstad 2005).

4.4. IGCC with CO_2 capture

IGCC with CO_2 capture *and* load following/steady partial load is unprecedented. The same issues exist as with IGCC without CO_2 capture; the capital cost and complexity of the plant would negate any incentive to load follow.

An NETL study examined the potential of a "capture flexible" GEE IGCC plant equipped with two Water Gas Shift (WGS) reactors and a bypass around the WGS reactors to allow 0 percent CO_2 capture. The study considered three cases for the capture-flexible IGGC:

- 0 percent CO_2 capture

- Plant emissions equal to 1,100 lb CO_2/MWh_{net}, which occurs at 39 percent CO_2 capture

- 85 percent CO_2 capture

The results of this modeling effort indicated that this configuration could provide a net power output load following capability from approximately 616 MWe to 554 MWe by varying the CO_2 capture from 0 percent to 85 percent (NETL 2009).

4.5. Subcritical PC without CO_2 capture

Depending on efficiency of the PC plant, they typically are not designed to load follow. Maximum turn down is in the range of 50 percent. Below 50 percent, most plants increase their emissions to the point that they violate their air permit (Goldstein 2010). Another emissions issue below 50 percent load is the velocity in the stack. It can decrease to the point that proper dispersion cannot be achieved. Steady partial load can be obtained with little boiler and steam turbine problems or controllability issues. Most boilers can handle a 10 percent step change and 5 percent per minute ramp rate (Goldstein 2010).

In terms of large versus small PC configurations, the smaller units tend to be older and less efficient so they lend themselves to load following compared to larger and generally newer plants. However, most smaller plants are so old and inefficient that they often will be taken offline first rather than load followed.

The World Energy Council performed a study on subcritical coal-fired plants to determine the correlation between cycling and plant reliability. The study established an Output Factor (OF) for each plant in the given plant subgroup from data obtained by the North American Electric Reliability Council (NERC)'s Generating Availability Data System (GADS). The OF is the ratio of the plant's actual generation divided by the possible generation if the plant had been dispatched at 100 percent load during every hour that it was actually in service. It was found that plants with lower OF, that is, plants that are ramped more frequently, had failure rates 2.5 times greater than plants with higher OF(Richwine 2004).

4.6.   Subcritical PC with CO_2 capture

This configuration has most of the same concerns with load following, ramp rate, and steady partial load as the subcritical PC without CO_2 capture. Like IGCC, subcritical with CO_2 capture will now make the plant very expensive to run and its electricity very expensive to sell. Therefore, its owners would want to run it at full load or not run it at all. There is not much practical knowledge of plants load following or reducing steady partial load below 80 percent with CO_2 capture (Goldstein 2010).

Slipstream testing (equivalent to 1000 kg/hr of CO_2) on a 400 MW bituminous PC plant using an amine pilot scale scrubbing system indicated that the scrubbing system could maintain approximately 90 percent CO_2 capture while following the power plant load from 100 percent to 40 percent (Dong Energy 2009).

4.7.   Supercritical PC without CO_2 capture

Supercritical PC plants have few differences from their subcritical counter parts in the areas of load following, ramp rate, and steady partial load. The only major differences are the importance of water chemistry control, and generally supercritical PC plants tend to be more efficient, lending them to a better LCOE versus a subcritical.

Some supercritical boilers can be operated in a sliding pressure mode in which pressure follows load while maintaining constant temperature. This allows a relatively constant first stage turbine temperature reducing thermal fatigue.(Alstom 2007)

Modeling by the Technische Universitat Hamburgh-Harburg of an 1100 MW (gross) supercritical PC plant showed a decrease of 2.8 percent in net efficiency (45.6 percent to 42.8 percent) when the plant is turned down from 100 percent to 40 percent (Linnenberg 2009).

The cost of cycling a supercritical PC plant is higher than the cost of cycling a subcritical (S. Lefton 2010). The primary reason is that the change in temperature, especially during startup and shutdown, is much greater for a supercritical plant, thus creating a potential for greater damage.

Steam turbine manufacturers have begun to design ultra supercritical steam turbines that can start up more quickly and have better load following capabilities. HP stage bypass allows for better load following with minimum throttling loss while design and control features allow faster startup. Siemens reports that Ultra Super Critical (USC) turbine startup time can be reduced by 15 minutes by allowing the turbine to operate as the boiler comes up to temperature(Quinkertz 2008).

4.8. Supercritical PC with CO_2 capture

A supercritical PC plant with CO_2 capture would be one of the last plants to be subject to load following due to their efficiency and high capital costs. In a situation where CO_2 has a cost, the plant may be operated in a mode whereby CO_2 is captured when the CO_2 cost is high and/or electricity price is low, and is vented when the CO_2 cost is low and/or the electricity price is high.

NETL completed a model of a "capture flexible" supercritical PC plant that included a bypass around an Econamine FG Plus^{SM} process that allowed for evaluation of variable levels of CO_2 capture. The three capture levels modeled were:

- 0 percent CO_2 capture

- 48 percent CO_2 capture or total plant emissions equal to 1,100 lb CO_2/MWh$_{net}$

- 95 percent CO_2 capture

The model indicated that the plant would have a net load following capability from approximately 773 MWe at 0 percent capture down to 550 MWe at 95 percent capture (NETL 2009).

Modeling by the Technische Universitat Hamburgh-Harburg of a 1100 MW (gross) supercritical PC plant retrofitted with an amine-based 90 percent CO_2 capture system showed a decrease of 5.1 percent in net efficiency (35.3 percent to 30.2 percent) when the plant is turned down from 100 percent to 40 percent(Linnenberg 2009).

4.9. NGCC without CO_2 Capture

The startup and ramping of the typical NGCC plant is limited by the by the steam cycle side of the system. Approximately 50 percent of a typical NGCC start-up time is for the warm-up of the steam turbine and turbine valves, the waiting for the turbine to accelerate to nominal speed (H. Emberger, Fast Cycling Capability for New Plants and Upgrade Opportunities 2005).

Typical start-up times for an NGCC plant without CO_2 capture are presented below:

Exhibit 13 Typical NGCC Start-Up Times (H. Emberger, Fast Cycling Capability for New Plants and Upgrade Opportunities n.d.)

Shut Down Time	Start Time
Hot Start (8 hours)	90 Minutes
Warm Start (64 hours)	200 Minutes
Cold Start (>120 hours)	250 Minutes

Many NGCC plants typically do not run below 70 percent because the heat rate becomes so poor that utilities would find other more efficient sources to use for load following (Gonzales 2010). If the plant is configured with multiple single shaft gas turbines or a multi-shaft gas turbine, then

the plant can load follow more efficiently by sequentially loading the gas turbines. The chart below illustrates that a GE gas turbine can operate at 80 percent load with little heat rate degradation by using inlet guide vanes (IGV) to control flow and maintain gas turbine temperature. Below 80 percent load, the flow remains constant and the temperature is decreased, lowering efficiency (D.L.Chase n.d.).

Exhibit 14 GE STAG 200 Partial Load Performance (D.L.Chase n.d.)
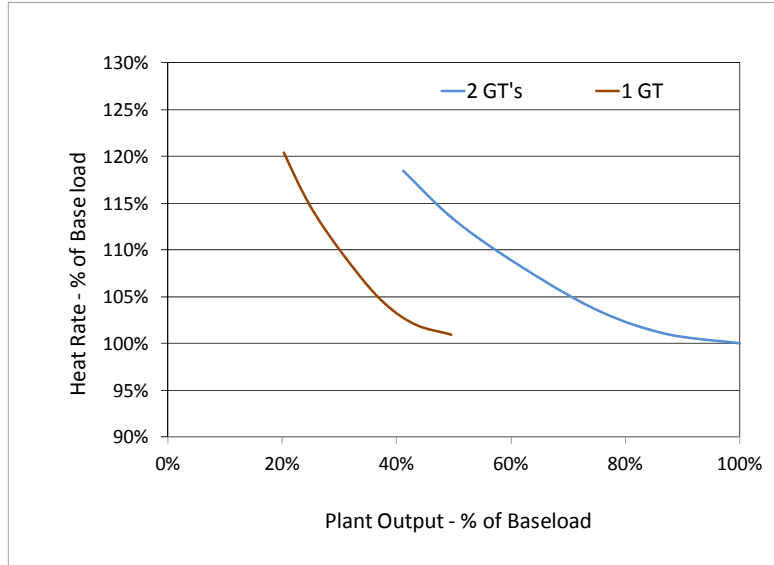
(Used with permission by GE Energy (GE Energy 2000))

Exhibit 15 illustrates the dramatic decrease in electrical efficiency and output as the gross natural gas input is decreased. Additionally, NO_x and CO emissions significantly increase when loads are decreased below 50 percent to 65 percent (Programme 2008).

Exhibit 15 NGCC Electric Efficiency and Output as a Function of Gross Input
(Miroslav Variny 2008)

Output linearization:
$$y = 0,6364x - 22,892$$
$$R^2 = 0,9966$$

Heat input in natural gas, MW
(Used with permission by Science Direct)
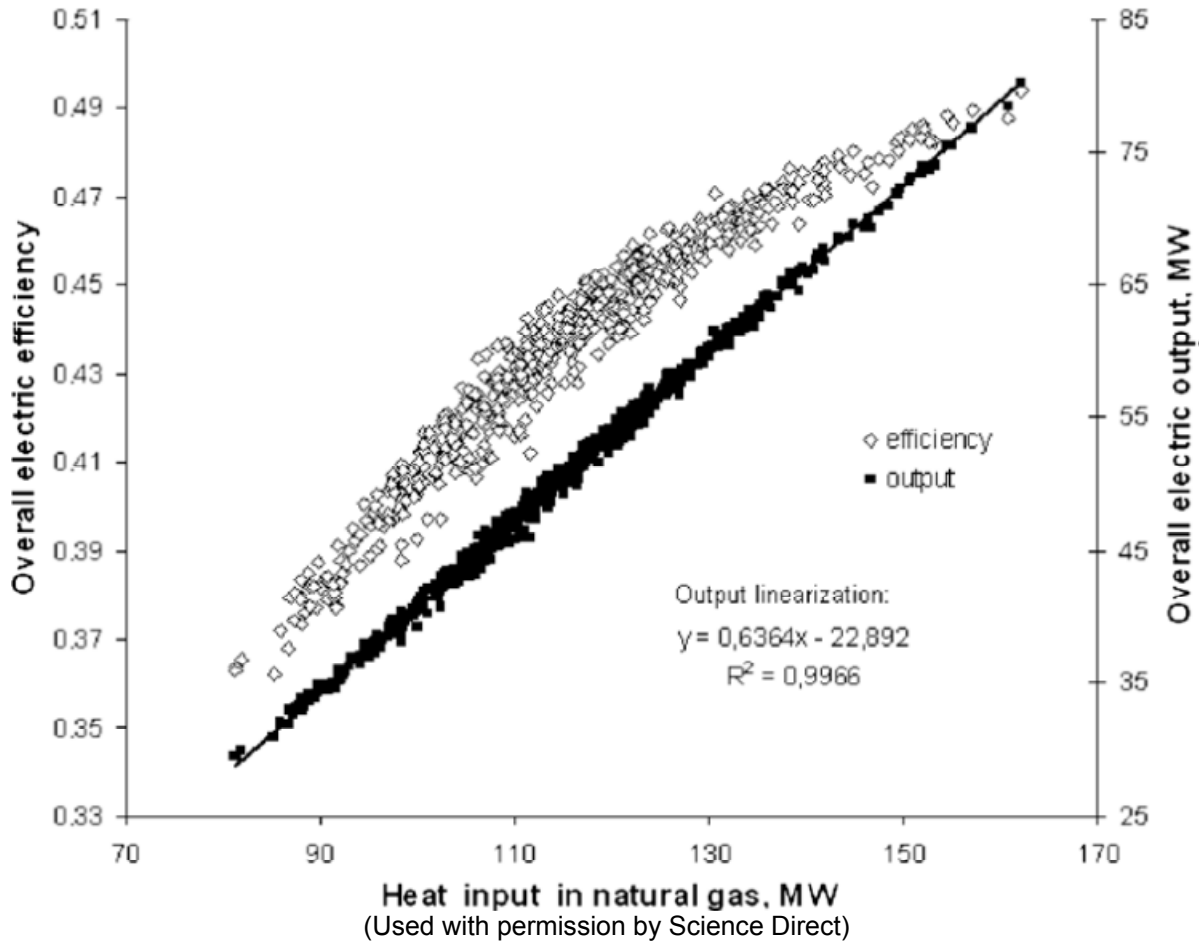
The gas turbine is the more flexible part of the system because it can be controlled directly to match the demand while the steam generation and steam turbine output follow the output of the gas turbine. Exhibit 16 shows the operations limits of the gas turbines (two units) and steam turbine for a nominal 80 MW NGCC at various ambient temperatures. The figure shows that the two gas turbines (GT) can operate from approximately 12 MW to 32 MW at an ambient temperature of 20 °C while the steam turbine has a narrower operational band from approximately 6 to 20 MW. This allows the plant to have a relatively large operational band of approximately 30MW to 80MW at 20 °C.

**Exhibit 16 Operation Limits of Nominal 80 MW NGCC Gas and Steam Turbines
(Miroslav Variny 2008)**
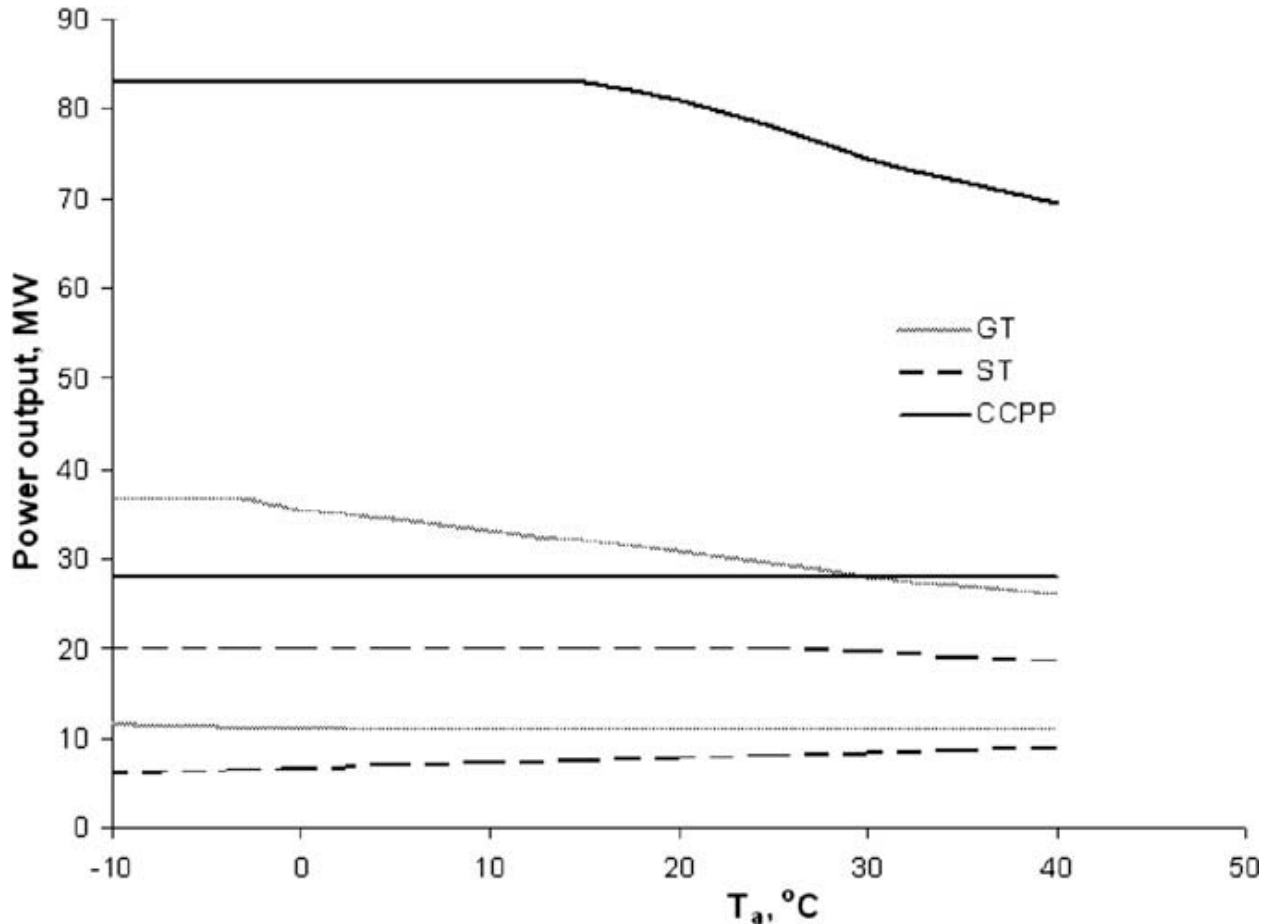
(Used with permission by Science Direct)

There are several NGCC design configurations or modifications that improve start-up and ramp/load following rates. These configurations/modifications include:

Duct Firing – Gas-fired burners in duct leading to HRSG allow for better load following by providing some control of steam generation independent of gas turbine exhaust flow. NGCC with duct firing is considered the best technology for load following out of all the fossil plants evaluated in this report (Goldstein 2010). Combination of regulating duct firing and fuel controls to follow load gives it the edge of non-duct firing. Duct firing also allows faster startup due to better control of heat to the HRSG which limits thermal fatigue.

HRSG Modifications to improve load following capabilities include:

Design HRSGs with thin-wall components to reduce thermal fatigue (H. Emberger, Fast Cycling Capability for New Plants and Upgrade Opportunities n.d.).

Design tubes and headers for thermal expansion cycling (Fontaine 2003)

Increase drain size to prevent condensation buildup (Fontaine 2003)

Steam Bypass – Enlarging steam bypass piping allows: (Ram G. Narula 2002)

The gas turbine to start-up faster without damaging HRSG tubing

Steam piping to be warmed earlier, lowering thermal stresses

Faster steam turbine startup by matching the steam and metal temperatures

Continued gas turbine operation after a sudden steam turbine shutdown.

4.10. NGCC with CO_2 capture

There is little information available about NGCC with CO_2 capture because it is a low priority in terms of CO_2 capture when compared to coal plants expelling a CO_2 footprint twice the size of an NGCC.

5. Cost and Emissions Impacts of Load Following

A study done by Aptech Engineering found that cost of cycling for a typical 600 MW coal-fired plant in a 4000 MW utility system can be as high as $10 million to $200 million over the life of the unit (S. A. Lefton 1997).

5.1. Case Studies

The following case studies are real examples of cycling and load following issues encounter by power generating units and how they corrected them or were advised to correct them.

Harrington Unit 3 – Xcel Energy
Full plant cycling evaluation

Harrington unit 3, a 360 MW PRB coal-fired plant, went through an extensive cycling cost evaluation by Aptech. They compared the plant at baseload high capacity factor (80 percent+ for close to 24 hours per day, 7 days per week) to forecasted costs resulting from significant increases in wind power through the grid by 2020 due to state renewable energy portfolio requirements enacted where Xcel Energy operates . Nine different cost factors were evaluated, and it was determined that of the nine, wear and tear costs were the highest. For example, the largest element, cold shutdown-start cycles, had a cost of maintenance at $120.1K (thousand) per start. The second highest cost was start-up fuel at $15.6K. This is equivalent to 2580 million Btu of extra fuel energy burned in a hot start up. Total estimated costs per each type of cycle at Harrington Unit 3 are listed below in Exhibit 17 (Aptech n.d.).

Exhibit 17 Cycling Costs of Harrington Unit 3 during the Year 2000 (Aptech n.d.)

(Used with permission by Steven Lefton)
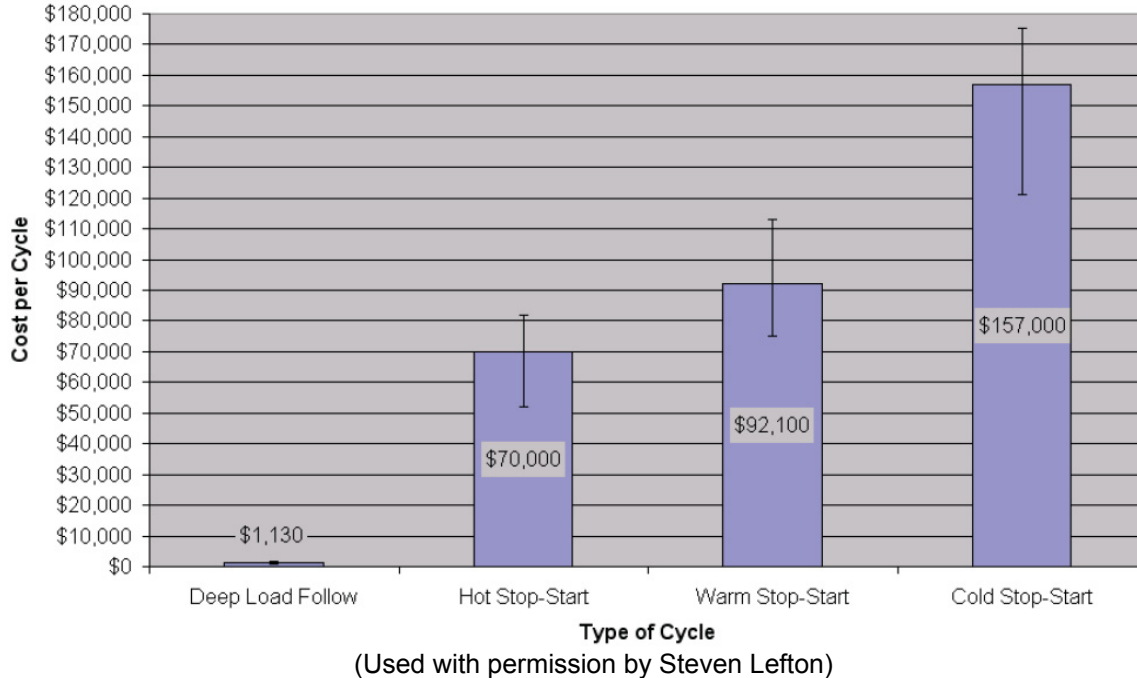
Pawnee Unit 1 – Xcel Energy
Full plant cycling evaluation

505 MW Pawnee Unit 1 went through an extensive cycling cost evaluation by Aptech. They compared the plant at baseload high capacity factor (80 percent+ for close to 24 hours per day, 7 days per week) to forecasted costs resulting from significant increases in wind power through the grid by 2020 due to state renewable energy portfolio requirements enacted where Xcel Energy operates. Nine different cost factors were evaluated and it was determined that of the nine, wear and tear costs were the highest. Of these the largest elements was the cost of maintenance at $54K per start, followed by forced outage and derate impacts at $23K per cycle (Aptech 2008).

Florida Power Corporation
Utility cycling evaluation

Florida Power Corporation went through an extensive cycling cost evaluation by Aptech of their fleet. They applied proprietary software called Cycling Advisor, developed and produced by Aptech and Intertek, which evaluates dispatch modeling and costs associated with hot and cold starts and their effects on wear and tear. Evaluation of the history of Crystal River Unit 2, a 500 MW coal fired unit, found that the unit incurred total cycling costs ranging from $30,000 to $110,000 for incremental hot-start/stop cycle. The corresponding range for a cold start was $70,000 to $240,000. Knowing these results, analyzing them across the entire fleet, and taking

the proper measures, the resulting potential savings were in the range of $10- to $25 million a year (S. A. Lefton 1997).

Delimara Power Station
Plant flexibility example

Delimara Power Station is Malta's first combined cycle plant. The Maltese national electrical grid is totally isolated and so is subject to wide load fluctuations, primarily between night and day. This can be managed with difficulty by the existing conventional steam cycle power plants, which have low load flexibility. Therefore, an essential design requirement for Delimara was the ability to respond to the needs of the Maltese grid, demonstrate a high degree of load flexibility, and maintain a high efficiency. The power station went commercial in September 1999. Since then, it has been operating as a load following plant with typical daily load demand fluctuating between 66 percent and 96 percent of plant baseload and with plant efficiency varying between 36.4 per cent (at 40 per cent load) and 46.9 per cent (at 100 per cent load). Delimara is a good example of combined cycle technology successfully applied for cycling duty operation mode (Galli n.d.).

Gerald Gentleman Station
Cycling equipment retrofit

The Gerald Gentleman Station consists of two 680-MW PRB coal-fired units. The stations went through an evaluation to determine what controls equipment was necessary to increase ramp rate capability to assist in cycling application. Unit 2 was addressed first, having a ramp rate capability limited to 3 MW/min., or about 0.50percent per minute. Operations staff preferred to sustain low loads on three of the eight pulverizers, which meant a minimum load of about 210 MW. This was in contrast to the daily load cycle, which zoomed from 180 MW at night to over 500 MW each day, per unit (Exothermic Engineering, LLC n.d.).

The controls evaluation targeted fuel flow, air flow, furnace draft, feed water control, and steam temperature. Through considerable performance testing, the unit is now capable of a 25 MW/min ramp rate. Very short load changes of about 10 MW can be handled much more rapidly. One test ran the unit up 10 MW at 75 MW/min. The maximum dispatchable ramp rate is now 15 MW/min. Prior to this work it, was 3 MW/min. Low load in automatic is now about 185 MW (Exothermic Engineering, LLC n.d.).

Milton R. Young Unit 1
Cycling equipment retrofit

Young Unit 1 is one of two 250 MW lignite coal-fired power generating units located near the town of Center, North Dakota. Recently the station joined the Midwest Independent Transmission System Operators (MISO), which required the station to quickly respond to market demand offset by the addition of wind farms on the grid. The plant was typically asked to ramp up or down roughly 10 MW swings; however, the unit's response to load setpoint changes often resulted in over/undershoot and lagging load response, both of which contributed to revenue lost and increased equipment maintenance (Stumpf 2009).

Minnkota Power Cooperative, the operator, enlisted the help of Emerson to implement their Smart Process Unit Response Optimization (URO). The system uses nonlinear, feed-forward and model predictive control to optimize boiler and turbine response for overall control. The results included 70 percent improvement in ramp rate from 2 MW/min to 7 MW/min, a 2 MW reduction in over/undershoot, and a 4 psi average decrease in throttle pressure, contributing to overall machinery health (Stumpf 2009).

Public Service Company of Colorado (PSCO)

Impact of Cycling on Emissions

A study was completed by Bentek Energy, LLC, on the impact of load following on emissions using data collected on July 2, 2008, and September 29, 2008 (Bentek Energy LLC 2010). These dates were used because hourly wind generation data were available.

Exhibit 18 shows the impact of a rapid increase of wind generation and the resulting rapid decrease in coal generation. During this event, coal generation was decreased from 2,500 MW to 1,800 MW and back to 2,500 MW over a period of 180 minutes.

Exhibit 18 Impact of Wind Generation on PSCO System July 2, 2008 (Bentek Energy LLC 2010)

4:00 AM   8:00 AM
(Used with permission by Bentek)
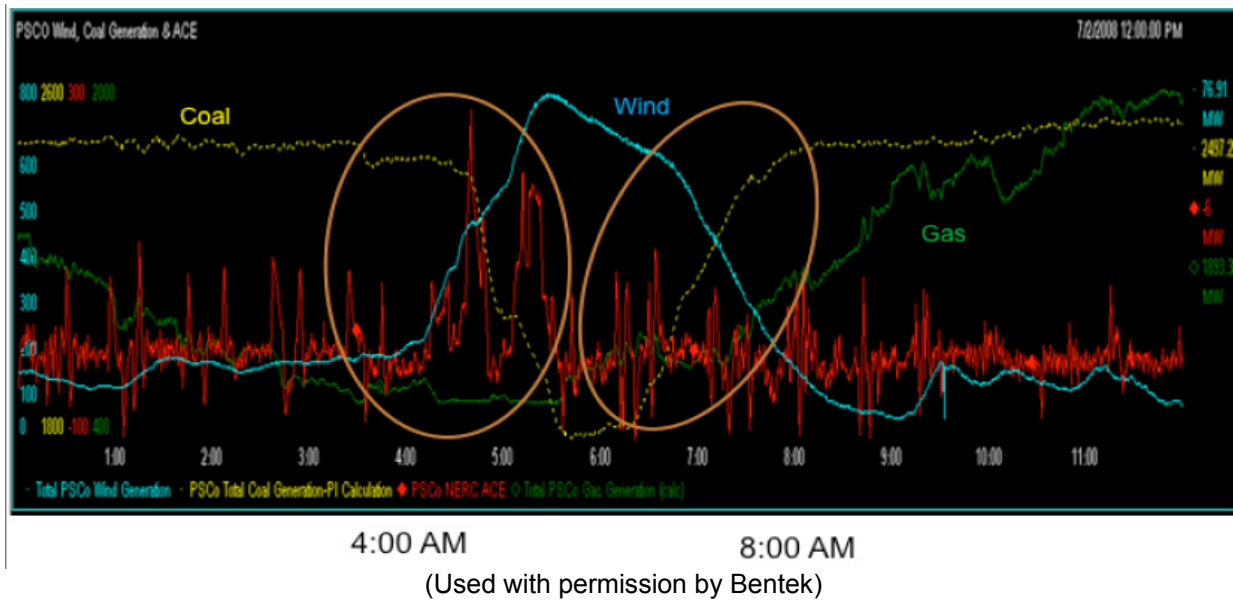
Eight coal-fired plants experience some amount of cycling due to this "wind event." An analysis of one plant in the affected system was completed to determine the effect of cycling on emission rates. The plant selected, Cherokee, has four boilers with nameplate capacities of 107 MW, 107 MW, 152 MW, and 352 MW and utilization rates of 75 percent, 72 percent, 75 percent, and 83 percent, respectively. The analysis was done by comparing actual emissions during the 3:00 am to 7:00 am "wind event" period to a stable operation period on July 29, 2008. Exhibit 19 shows that this analysis indicates that an additional 6,340 lbs of SO_2 and 10,826 lbs of NO_x were released while 246 fewer tons of CO_2 were released.

Exhibit 19 Estimated Emissions Impact from Cherokee Plant during "Wind Event" on July 2, 2008 (Bentek Energy LLC 2010)

	SO_2 (lbs)	NO_x (lbs)	CO_2 (tons)
Est. Stable Emission Rates based on July 29 (per MWh)	2.01	3.82	1.08
Actual July 2 Emission Rates (per MWh)	4.37	7.89	1.13
Stable Emissions, Est. No Wind Gen (3:00 am – 7:00 am, Total Gen 3,360 MWh)	6,754	12,829	3,628
Actual Emissions, Actual Gen on July 2 (3:00 am – 7:00 am, Total Gen 2,997 MWh)	13,103	23,655	3,383
Saved (Additional) Emissions	(6,348)	(10,826)	246

(Used with permission by Bentek)

Additional analysis of the emission data indicated that cycling caused instabilities in the emission control equipment operations resulting in increased emissions for several hours after the cycling event.

Additional wind generation data were available from the night of September 28, 2008, until the morning of September 29, 2008. During this "wind event," coal generation dropped from approximately 2,000 MW to approximately 1,500 MW in about 60 minutes. Approximately 4 hours later, coal generation was ramped back up to 1,900 MW in about 60 minutes as shown in Exhibit 20.

Exhibit 20 Impact of Wind Generation on PSCO System September 28-29, 2008 (Bentek Energy LLC 2010)
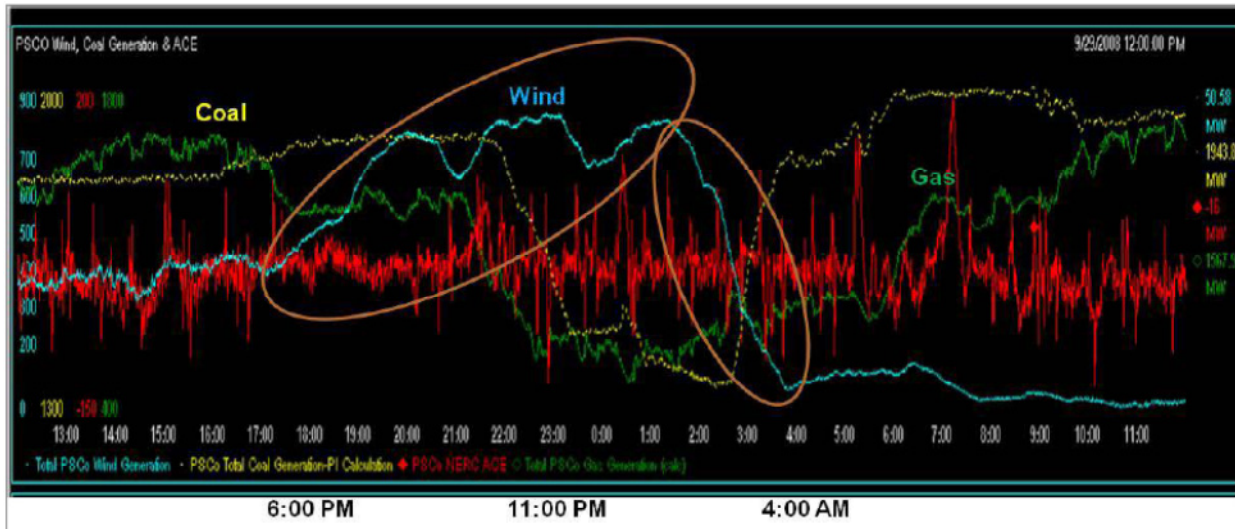
(Used with permission by Bentek)

A similar analysis of the September 28-29, 2008, data using the same methodology described above for the July 2 data indicated that the fleet emissions were reduced by 940 lbs of SO_2, 1,198 lbs of NO_x and 2,101 tons CO_2. However, detailed analysis of individual plant data indicated that two of the plants experienced an increase in NO_x and SO_x emissions due the cycling.

The conclusion of this report is that there can be significant negative impact on emissions when cycling coal plants to follow wind generation. The level of impact varies and should be calculated for a longer duration than just the "wind event" itself due to the negative impact on air quality control equipment operation.

6. Conclusions

The utility industry has long understood that there is a cost associated with cycling fossil-fuel fired power plants to follow the load demand. As an increasing amount of intermittent renewable load generation comes on-line, the utilities will be required to cycle more of their fossil units. What are not well understood at this time are the true impacts of increased cycling on costs, plant life, emissions, and reliability.

The key findings of this research are as follows:

There is a very limited understanding of how Carbon Capture and Storage (CCS) requirements will impact the ability of fossil fuel-fired power plants to load follow. Some preliminary modeling has been completed on amine scrubber systems, and there are several proposed load following scenarios involving venting, solvent storage, polyproducts, etc., but little in-depth study has been completed.

Boiler and turbine manufacturers have recognized that the power plant of the future will be required to load follow and cycle much more than in the past. Manufacturers are designing systems and components to better survive the cycling environment and developing controls and operating procedures to accommodate rapid load changes.

The impact of mandatory requirements to dispatch intermittent renewable generation resources on emissions is poorly understood. Rapidly reducing, and then increasing, fossil generation to follow renewable generation requires that fossil units operate in a non-optimized manner. The heat rate is degraded and the air quality control equipment is negatively impacted leading to increased emissions.

The actual costs of load following are poorly understood. Utilities know that thermal cycling does damage plant components, but the total cost impact is rarely fully understood in terms of increased forced outages and increased O&M costs.

7. Recommendations for Future Work

Five major recommendations for potential follow-on research were found:

7.1. Impact of CCS Systems on Plant Load Following Ability

Develop a comprehensive study to better understand the effect of load following on CCS systems. Although it can be argued that any plant with a CCS system would not be required to load follow, an understanding of the potential issues is required. Questions to be answered by this study could include:

1. Which type of capture system is capable of load following?

2. What is the impact on carbon capture efficiency of the various CCS systems when load following occurs?

3. What is the potential impact on the cost of carbon capture when load following occurs?

4. Are there issues with the CO_2 compression and storage when load following?

7.2. Impact of Equipment Modifications on Ramp Rate and Costs

Evaluate the impact of equipment modifications and improvements on ramp rates and costs. This study would include a literature search to identify published results of plant modifications that improved load following capabilities. Vendors would be contacted to determine current and planned technological developments to improve load following capabilities. With that information, a detailed comparisons (costs, operations, forced outages, etc.) will be made of a typical non-load following plant and a current/near-future plant constructed for load following will be analyzed.

7.3. Impact of Load Following on Emissions and Heat Rate

Conduct a study to understand the impact of load following on emissions and heat rate. This work will require a better understanding of emissions and heat rate variations from different boiler types at different firing rates, the effect of varying loads on emission control equipment (SCR, FGD, ESPs, etc.), and the time required for the plant to return to steady state operation. Included in this work is identifying a region that has significant intermittent generation assets and can provide historical electrical generation data from all assets. Within this region of intermittent generation, evaluate heat rate changes and actual versus steady state emissions.

7.4. Impact of Load Following on Costs

Work with industry to quantify the true cost of cycling fossil generators. Because of the diverse nature of this country's fossil generation fleet, it is anticipated that the research will require a detailed analysis of which class of plant (type, size, age, location, etc.) is most likely to be required to load follow and/or cycle and then determine the impact on O&M costs, forced outages, and plant life.

7.5. Impact of Load Following on Electric Grid

Conduct a study to understand the impact of load following at a grid level. Balancing wind and solar with coal and natural gas to determine actual start/stop times, ramp rates, partial load requirements and how each type of plant affects the others on the grid. Key questions to be answered include:

- Do current ramp rates of fossil plants limit the utilization of intermittent generation resources?

- Is there enough "turn down" or partial load capacity to accept planned additional intermittent generation resources?

- Is there enough distribution stability if significant fossil generation is idled?

Details of recommended research will be provided in a separate Statement of Work to be submitted at a later date.

8. Expert interviews

Eisenbise, Harry

Harry Eisenbise is a Senior Supervising Engineer for WorleyParsons. He has 30 years experience as a mechanical and chemical engineer.

Goldstein, Harvey

Harvey Goldstein is a Senior Project Manager for WorleyParsons. He has 39 years of experience working in the Power Select group, where he is responsible for power generation alternatives, including fossil, nuclear, solar, and coal gasification.

Gonzales, Ed

Ed Gonzales is Director, Power Plant Performance, Xcel Energy Inc. He has been responsible for monitoring the performance of Xcel's fossil-fired generation plants and conducting power plant performance testing at each plant every two years.

Lefton, Steven A.

Steven A. Lefton is Vice President of Aptech Engineering Services, Inc. In this position, he has provided expert testimony, managed and engineered power plant/ boiler/HRSG/gas turbine equipment design reviews, heat rate testing, combustion testing, cost/life assessment/damage/reliability analysis, and plant modification projects. He is currently involved in analysis of the costs of cycling and load regulation at some 200 fossil, hydro/pumped hydro, and combustion turbine/combined cycle power plants in the US, Canada, Europe, and Australia.

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