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The Impacts of Meeting a Tight CO₂ Performance Standard on the Electric Power Sector

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Abstract

This paper presents innovative modeling of complex interactions among gas-fired generators, coal-fired power plants, and renewables (wind and solar) when pushed hard to reduce CO₂ emissions. A hypothetical CO₂ technology performance standard, giving rise to a shadow price on CO₂ emissions, was specified as part of the study design. In this work we see gas generation rapidly replacing coal generation. To understand the fate of coal-based generation, it is important to examine trends at a granular level. An important feature of our model, the Electricity Supply and Investment Model (ESIM) is that it contains a unit inventory with unit characteristics and a memory of how each unit is operated over time. Cycling damages that individual coal units incur are a function of cumulative wear and tear over time. The expected remaining life of a cycled coal unit will depend on the severity of the cycling and for how many years. Deteriorating

operating characteristics of a cycled unit over time results in higher operating costs, slipping down the dispatch loading order, and hence an acceleration of cycling damage, that is, a viscous circle of decline. The rate of CFPP retirements will increase for lower gas prices, higher price on CO₂ emissions, and greater penetration of variable and intermittent renewables.

Keywords

Electricity analysis

Energy modeling

Gas demand

Intermittent renewables

Power plant dispatch

Power plant retirements

JEL classifications

Q21, Q28, Q41, Q42, Q47, Q54

1. Introduction

This paper presents innovative modeling of complex interactions among gas-fired generators, coal-fired power plants (CFPP), and renewables (wind and solar) when pushed hard to reduce CO₂ emissions. This is an interesting topic for the EMF31 natural gas study because CO₂ reductions may be the major driver for increased gas demand, with effects on its market price and gas production. A hypothetical CO₂ technology performance standard, giving rise to a shadow price on CO₂ emissions, was specified as part of the EMF31 study design.

In this work we see gas generation rapidly replacing coal generation. To understand the fate of coal-based generation, it is important to examine trends at a granular level. An important feature

of our model, the Electricity Supply and Investment Model (ESIM) (Hanson, 2013; Hanson, 2010; Shelby, 2008) is that it contains a unit inventory with unit characteristics and a memory of how each unit is operated going forward. This is important because low price gas and renewable penetration (encouraged by subsidies and mandates) have already been shifting generation from coal-based to gas and renewables, resulting in load-following for many of the coal units. The costs that individual coal units incur are a function, not of just their current dispatch, but rather of cumulative wear and tear over time. These impacts are called cycling damages in the literature (EPRI, 2001; Kumar, 2012). The expected remaining life of a cycled coal unit will depend on the severity of the cycling and for how many years. Deteriorating operating characteristics of a cycled unit over time results in higher operating costs, slipping down the dispatch loading order, and hence an acceleration of cycling damage, that is, a viscous circle of decline.

The rate of CFPP retirements will increase for lower gas prices, higher price on CO₂ emissions, and greater penetration of variable and intermittent renewables. Hence, the ESIM model is a useful tool to be able to better understand and mitigate forces transforming the electric power sector. The ESIM model uses a residual Load Duration Curve approach (Ueckerdt, 2015) and provides a representation of the impacts of the growing share of renewables on the electric grid (Edenhofer, 2013; EPRI, 2015; Hirth, 2016; James, 2015; Mount, 2012).

2. Model Description

The ESIM model is the electric power sector component of the AMIGA modeling system (Shelby 2008, Hanson 2010, Hanson 2013). The AMIGA system also includes an inter-industry input-output model with nested constant elasticity of substitution (CES) production functions for

capital, labor, materials, and energy (gas, liquids, electricity) by production sectors and household sectors. Hence, the AMIGA model provides price-sensitive demands for sector workers, energy carriers, and investment. The AMIGA system is modular including sector models for vehicles, transportation, liquid fuels production, and gas supply.

2.1 The Gas Supply Model and Sensitivities

The natural gas supply scenario model allows sensitivity analyses for alternative gas supplies at a given price (i.e., shifting the supply function). We exercise this capability for EMF31 under business-as-usual (BAU) scenarios with higher, mid, and lower gas supply functions, giving rise to lower-to-higher gas prices. For the Technology Performance Standard, we run mid and lower gas supply functions. The integrated model solves for a gas supply and demand equilibrium path. We view these model runs as sensitivity analyses, rather than attempts to capture the full scope of gas market uncertainties.

The gas supply functions were originally calibrated to the *Annual Energy Outlook* (AEO) 2013 Reference Case and several high- and low-resource sensitivity cases. The gas supply functions are nonlinear and dynamic with simple representations of resource depletion effects which somewhat offset technical progress. To illustrate gas supply function differences, we did some off-line runs of the gas supply model and plotted results for the year 2030 with linear interpolation. Figure 1 shows how much the gas supply curves shift in the different supply cases.

Figure 1. Linear approximation to shifts in the gas supply function for year 2030

Under Business-As-Usual (BAU) conditions (i.e., no CO₂ standards imposed), Figure 2 shows market clearing price paths for gas under the three gas supply cases.

Figure 2. BAU price paths for gas under three gas supply conditions

The shifts in the gas supply function have an interesting effect on the resulting CO₂ emission paths, as shown in Figure 3.

Figure 3. CO₂ emission projections under Business-As-Usual scenarios

In early years, more gas implies lower CO₂ emissions as gas displaces some coal generation. However post-2030, more gas starts to displace new low-carbon technologies, resulting in higher CO₂ emissions.

2.2 The ESIM Model

The ESIM model features a unit inventory of existing coal-fired power plants, the construction of a load duration curve yielding both peak capacity requirements and hourly generation requirements, estimates of end-use generation (industrial, commercial, residential) which are included here as a component of total generation, a rank ordering of dispatchable units, resulting utilization for each generating unit, endogenous retirements, and replacement capacity additions.

The shape of the “equivalent” load duration curve (LDC) is fitted to historical data. An extended peak reflects a reserve margin needed to accommodate peak loads and generator outages. The equivalent LDC is consistent with the convolution integral approach for estimating the loss-of-load probability (LOLP) under uncertain generating unit outage rates or lack of renewable

generation. As we model it, the x-axis of the LDC is in units of available or “effective capacity” in thousands of megawatts (MW), and the height on the y-axis represents the distribution of hours (h) for an 8760-hour year, but normalized to 1.0. The capacity factor of a unit is a function of both the height of the eq. LDC at the point where the unit is dispatched and the probability that the unit is available when needed.

In the ESIM model, the area under the eq. LDC is a function of electricity demand scaled up to reflect transmission and distribution (T&D) losses. This area must also equal total net generation from electric power plants. So we can think of the area under the eq. LDC as total net generation. When end users, such as oil refineries, generate their own power, thereby avoiding T&D losses, the savings on displaced net generation is credited. Industrial combined heat and power (CHP) units are placed at the beginning of the loading order and run as baseload to provide industrial steam requirements.

Wind and solar facilities are subject to intermittent and variable output depending on wind and solar conditions, which typically vary over morning, afternoon, and nighttime hours.

Representing intermittent renewable electricity output as a distribution function over hours of the year can provide some useful analysis, but such an approach does not fully account for the uncertainty of output from intermittent sources in any given hour, making it difficult to assign a capacity credit to intermittent resources.

Figure 4 shows an eq. LDC in the ESIM model for 2025. The area to the left of the slanted line represents certain baseload capacity and renewable energy and reflects an assumption about the distribution of variable renewable sources over hours of the year.

Next in order are coal and gas units that are dispatched on the basis of their short-run variable costs, including fuel costs, variable operating and maintenance (VOM) costs, and a CO₂ emissions charge. The CO₂ emissions charge emerges from the shadow price on the emissions constraint due to the rate standard.

The x-axis represents a peak available capacity requirement and therefore includes an effective capacity credit given to intermittent generators.

Figure 4. Equivalent Load Duration Curve shape and peak load, year 2025

In the remainder of the paper, we show the effects of constraining CO₂ emissions.

3. Derivation of the Implicit CO₂ Emissions Constraint

In the Acid Precipitation allowance trading program under Title IV of the 1990 Clean Air Act Amendments, fixed quantities of allowances were given away to utilities free, and some were sold at auction, implying a revenue stream for the government.

Imposing a CO₂ rate standard (i.e., lb CO₂/MWh) on a set of covered units can also result in a market-based CO₂ permit trading program (regional or national), but with an important difference: all permits are allocated free to covered units at rates proportional to their actual generation (i.e., the rate standard times the powerplant's generation); the government does not receive a revenue stream in this case. Effectively, the scheme sets up a cross-subsidy arrangement in which revenue flows from generating units that have an emissions rate greater than the standard (e.g. CFPPs that do not have carbon capture and storage) to units that have an emissions rate lower than the standard (e.g., wind and solar). The extra revenue from wind and solar generation increases the attractiveness of investing in those technologies.

A mathematical representation of this CO₂ permit trading program can be specified. The ratio of the sum of CO₂ and the sum of generation over covered units j must equal (or be less than) the standard R :

$$\frac{\sum CO2_j}{\sum MWh_j} \leq R.$$

By multiplying through by the denominator, a linear constraint can be derived as follows:

$$\sum_j [CO2rate_j * MWh_j - R * MWh_j] \leq 0$$

A price on CO₂ emission permits arises as a shadow price on the above constraint.

The first term would result in a tax rate on coal generation that is about three times the tax rate on gas generation. The CO₂ emission factor on gas is about half of the emission factor on coal. Further, new NGCC units are much more efficient than existing CFPPs. The second term is a subsidy, which is equivalent to a powerplant receiving a higher wholesale electricity price for its generation.

The EMF31 study specified three compliance periods with progressively lower values for the rate standard, R:

- 2020–2029, averaging the reduction over the 10-year period,
- 2030, as a single-year target,
- 1% declining path after 2030, allowing borrowing and banking of permits.

We mentioned earlier that we found the EMF31 performance standard to be quite stringent. Here, we find that it is very hard to achieve the first-period reduction, but if this reduction is achieved, the second and third targets will tend to be automatically achieved, implying an inequality that holds in later years in the constraint above.

4. Results for CO₂ Performance Standard Cases

4.1 CO₂ and Gas Prices for Mid and Low Supply Cases

The charge for CO₂ emissions, shown in Figure 5, is the lever used to achieve the rate standard.

Figure 5. CO₂ emissions charge under two gas supply cases

The initial CO₂ price spike in 2020, shown in Figure 5, immediately reduces the use of CFPPs, putting them on trajectories toward retirements due to cycling. Their reduced use ensures that the first phase of the standard (from 2020–2029) is met. Coal generation is replaced with gas (and some near-zero generation sources). After the coal plants are gone, no further CO₂ tax is needed to allow generators to meet the second and third phase standards.

Another interesting finding is that the required CO₂ price needed to achieve the standard is higher under the lower gas supply scenario, as shown in Figure 5. The CO₂ standard is identical under both gas supply scenarios. When the gas price is higher under the lower gas supply scenario, coal use will replace gas, increasing CO₂ emissions. To offset this effect, the CO₂ penalty must increase (i.e., to penalize coal more than gas). The equilibrium gas price paths for the two gas supply cases are shown in Figure 6.

Figure 6. Price paths for gas under mid and lower supply cases with a CO₂ standard

We now examine the fuel price and associated CO₂ charge, both in units of \$/MBtu, for the mid gas supply case. We do this for both gas and coal which affects their relative competitiveness.

(Gas technologies are generally more efficient than coal generators, which offsets the fuel price advantage of coal over gas.) Figures 7 shows the combined effects of delivered prices for gas and coal and their respective CO₂ charges on an equivalent Btu basis. Figure 7 shows that the CO₂ charge on gas is less than the charge on coal because of their different fuel carbon contents.

Figure 8 combines these into a single effective price for gas and coal. Even with the large CO₂ charges, effective coal prices are still lower. The reason that NGCC units in and after year 2020 tend to be dispatched before coal units is that these new gas units are highly efficient.

Figure 7. Coal and gas prices and CO₂ charges under the mid gas supply case

Figure 8. Effective coal and gas prices including the CO₂ charge under the mid gas supply case

An important determinant of how much coal demand will be displaced with gas is the coal supply price response. It turns out that, in equilibrium, the variable costs on a \$/MWh basis of gas and coal generation are almost equal, implying a near-knife-edge coal versus gas dispatch decision. So, if coal prices drop more as coal demand decreases, coal would regain some market share.

Now consider a downward shift in the gas supply curve. Because a gas supply curve is upward sloping, there are two modes of adjustment if there were a downward shift in the gas supply curve: gas prices can rise to achieve the same level of gas production, or gas production can decrease while maintaining close to the original gas price. In these ESIM model runs, both modes are at work (i.e., market clearing gas prices are somewhat higher, and gas use for electric power generation is lower because it is being replaced with new baseload power plants and renewable facilities). Of course, the shifts are constrained to meet the same CO₂ intensity standard. A third adjustment channel plays a small role as well: higher gas prices result in

slightly lower electricity demand. Clearly, the general equilibrium response to a shift in the gas supply function involves numerous adjustments.

Figure 9. Gas Production and Gas End Uses (with difference being electric power gas use)

Figure 9 provides one kind of summary to the adjustments at work. The top lines show gas production shifting down under the lower gas supply scenario. So although the gas price is higher, that is not enough to offset the downward shift in the gas supply curve. Furthermore, gas demand by end-use sectors (residential, commercial, industrial, and transportation) plus net gas exports are relatively inelastic. The lower lines in Figure 9 show end-use gas demand plus net gas exports changing very little in response to slightly higher gas prices. Figure 9 is constructed to show the amount of gas supplied for electric power production (the vertical difference between production and non-generation uses) — that is, the difference between total domestic gas production and uses of gas other than for power generation. Figure 9 shows that gas demand for electricity production is reduced under the lower gas supply scenario.

4.2 Sources of Electricity Generation: Switching from Coal to Gas

In the remainder of this section, we focus mainly on the mid-gas supply scenario. Differences between this scenario and the lower gas supply scenario are interesting, but not particularly surprising. A somewhat small downward shift in the gas supply function results in relatively small adjustments.

Figure 10. Electric power generation by category under the mid gas supply

Figure 10 shows how the area under the LDC in Figure 4 is filled for each year by technology category. The bottom two areas represent renewable sources: intermittent wind and solar and hydro and gethermal. We show a slow retirement of the existing fleet of nuclear power plants and the slow replacement by new, next-generation nuclear plants. Generation from the existing fleet of CFPP decreases sharply due to the initially high shadow price on CO₂ emissions, followed by rapid retirements due to low capacity factors and wear-and-tear due to cycling. Over time, as gas prices rise, there is some replacement by advanced coal technologies, with partial

biomass co-firing. Most of the reduction in coal generation is replaced with NGCC generation. Gas combustion turbines are needed to meet peak loads, but only represent a small portion of electricity generation. The top area represents self-generation by the end-use sectors, as well as large combined heat and power (CHP) plants serving gulf coast refineries and partially owned by electric power companies. This generation is almost entirely gas-fired, although a small amount of end-use coal generation is included here.

The dispatch order of CFPP and NGCC units is very sensitive to the carbon price. When the CO₂ performance standard, as specified for phase 1, goes into effect in 2020, there is a dramatic decrease in generation by the existing fleet of CFPPs and a corresponding huge increase in generation by NGCC units. Over time, existing CFPPs are retired and replaced by new NGCC capacity. This replacement is partly attributable to the aging of the existing fleet of CFPPs, but the immediate effects over the first 5 years after the standard goes into effect (2020–2024) are mostly attributable to gas and renewable generation pushing CFPP generation down the dispatch loading order, resulting in low utilization rates and imposing severe cycling damage, as discussed further in the next section and in the Appendix.

5. Dispatch of Gas and Coal Units

5.1 CFPP Cycling Modes and Ultimate Retirements

Notice that the slanted line in Figure 4 results in the displacement of some CFPP baseload operation. The NGCC units are designed to run at lower capacity factors, making the displacement less problematic. However, existing CFPPs were not designed to switch on and off to follow load. The CFPP cycling causes component wear, fouling on heat transfer surfaces, and metal creep and fatigue (EPRI, 2001; Kumar, 2012; EIA, 2015). Such degradation processes can

only be tolerated for a limited amount of cycling operation. The Appendix provides a literature review of aging and cycling damage and describes the technical basis for the effects of cycling that we assume in this study.

Three operating modes for CFPPs, with mild to severe cycling assumptions, were constructed and modeled, and are assumed to apply to CFPP with 30+ years of service at the beginning of cycling. Average annual capacity factors (CF) are based on an 85% availability.

Mode 1 — Runs 24 hours on weekdays but does some load following, averaging 85% “effective capacity” (i.e., 85% of full power) while running. One warm shutdown and startup per week. Average annual CF 51.6%.

Mode 2 — Runs 16 hours per weekday, averaging 85% effective capacity. Six warm shutdowns and startups per week. Average annual CF 34.4%.

Mode 3 — Runs 12 hours per weekday in two 6-hour periods, averaging 92–95% effective capacity during those peak periods. Eleven warm shutdowns and startups per week. Average annual CF 28.8%.

Effective Capacity here means the ratio (%) of the MWh generated in a period of operation divided by the nominal or nameplate generation during the same period. For example, in Mode 1, the unit may run at 100% of capacity for 12 hours and for 70% of capacity the other 12 hours, averaging 85% of potential generation during that operating period. This kind of load swing is consistent with a unit operating in load-following mode.

A typical CFPP generating unit will initially be in base load operation, followed by operation according to the conditions described for mode 1. The unit will continue to have lower utilization over time, eventually ending up operating under the conditions described for mode 3. The unit

moves sequentially through these modes as its increasing age, reduced availability, heat rate in (Btu/kWh) increases, and other operating costs cause it to move down the loading order.

The ESIM model translates unit operations in each of these three modes into an index of cumulative cycling damage for each dispatched unit. When the cumulative index reaches q value of 100, the unit is retired. We assign an interpolated score to units that operate in between modes in a given year.

To illustrate a unit's behavior, we choose an example plant in the unit inventory built in 1964 (with an internal unit number of 233). For this representative unit, Figure 11a shows the heat rate (Btu/kWh) rising very gradually as the unit ages and then noticeable faster as a result of increased cycling damages. Cycling also increases outage rates, lowering availability over time, as shown in Figure 11b. The deterioration of its operating characteristics pushes the unit down the dispatch loading order based on variable running costs, thereby reducing its capacity factor (percent of maximum generation).

Figure 11. Typical coal-fired power plant loss of performance with aging and cycling

Figure 12a shows the evolution of the capacity factor for CFPP #233. The declining capacity factor implies that the unit is operating in an increasingly severe cycling mode. Figure 12b shows the index of cumulative damage for unit #233 over time. The rate of increase in damage is initially slow, rising sharply in 2020, the first year that the CO₂ performance standard is implemented. Unit #233 retires in 2023 after reaching the threshold of 100 points as shown in Figure 12b.

Figure 12. The typical CFPP capacity factor reduction and cumulative cycling damage measure

5.2 Dispatch of Gas and Coal Units

CFPP and NGCC units are dispatched in order of variable costs (vc). Figure 13 shows the ESIM dispatch model results for 2020, the year of biggest impact.

Figure 13. Total variable costs (2012\$/MWh) of gas and coal units dispatched in Year 2020 and their resulting capacity factors (percent)

The units are categorized on the basis of variable costs, but Figure 13 illustrates that the resulting variable cost curve is relatively flat. The CO₂ charge in 2020 is just enough to put most of the gas capacity in front of the coal units to achieve high gas capacity factors and low coal capacity factors, thereby reducing CO₂ emissions. In Figure 13, note that variable costs are monotonically increasing, and capacity factors tend to decrease as you move down the load curve, but occasionally a capacity factor may increase if a unit has particularly high availability. The x-axis in Figure 13 represents cumulative effective capacity (in GW) of all units dispatched. Simple gas turbine peaking capacity meets remaining the peak load requirements.

Figure 14. The three components of variable cost for a selected CFPP in year 2020

Based on the large CO₂ charge in 2020, Figure 14 shows why a new and efficient NGCC unit has a lower variable cost than a typical CFPP unit. Without the CO₂ charge, the coal unit would have been dispatched at a high capacity factor.

After the large number of CFPP retirements during 2020–2024, coal and gas capacity factors return to more normal ranges, as shown in Figure 15. At this point, the CO₂ price returns to zero (i.e., the CO₂ rate constraint is no longer binding). Enough coal has been eliminated to meet the CO₂ emission rate requirements. The best CFPPs that remain are cycled less at this point, and gas returns to intermediate load following.

Figure 15. Average capacity factors over time for CFPP, NGCC units, and gas peakers under the mid gas supply

6. Achieving the CO₂ Target

Figure 16 shows the resulting CO₂ per MWh intensity, which meets the target for the 2020–2029 period but actually exceeds the targeted reduction in 2030 and has a greater-than-1% decline past 2030.

Figure 16. Resulting CO₂ intensity over time

Figure 17 shows the resulting CO₂ reduction compared with the BAU case. Note that actual CO₂ emissions decline more slowly than the intensity standard because electricity demand is growing.

Figure 17. CO₂ reduction compared with the BAU case

7. Volatility Scenarios

So far, we have shown gas market equilibrium results that are relatively smooth year by year, but we have not eliminated the possibility of volatility at shorter time scales. The time scales have become amazingly short. Shale gas producers can vary production rates to respond to market signals in a matter of months. Demand fluctuations can be much faster — hours or days — as changes in fuel prices can switch variable cost comparisons almost to a knife's edge in determining whether to dispatch gas- versus coal-fired units.

As a modeler's choice run, we simulated this gas price volatility, fluctuating gas prices by plus or minus \$2/MBtu around the mean equilibrium gas price. Supplies and demands could both be met with gas storage injection and withdrawal. However, there were larger swings in CFPP and NGCC capacity factors, leading to faster cycling damage for coal plants and earlier retirements compared with a case not involving gas price volatility. The early retirement of existing power plants puts additional strain on gas production and results in higher gas prices.

8. Conclusions

The analysis described here raises some concerns. If a market-based, tradeable Technology Performance Standard were implemented in 2020, would gas suppliers and delivery infrastructure be able to adjust to an increase in gas demand of about 70% by the electric power sector?

Also, although the Technology Performance Standard can be implemented as a market-based system involving charges for CO₂ emissions, it may not support a least-cost solution to obtaining the CO₂ reduction. This is because the cycling damage to existing CFPPs, caused by expanded renewable and gas generation, may be a form of externality. A regional utility that owned both

coal and gas units, thus internalizing any externality, would probably operate its system so as to reduce cycling of the coal units, although coal units might run for periods of time in which their short-run variable costs were higher than those of gas. Over the planning horizon, discounted present values costs could be lower.

The complex interaction among components of the future electric power grid indicate the need for sophisticated modeling of these interactions. Simple measures like the Levelized Cost of Energy (LCOE) are unlikely to provide helpful guidance, as has been pointed out elsewhere (EIA, 2013).

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Appendix: Aging and Cycling of Coal-Fired Power Plants: Technical Summary

Both heat rate and forced outage rate, on average, increase with the age of a generating unit for various reasons. Physical changes that reduce the efficiency of the generation cycle are the principal source of unit heat rate increases. The physical effects can be described in terms of three categories: wear of rotating components such as seals and turbine blades, fouling and deposition on heat transfer surfaces and turbine blades, and metal failure from corrosion and fatigue. Metal failures do not primarily impact heat rates, but they reduce unit availability and capacity factor through forced outages and planned maintenance outages.

Aging

Extensive literature is available on plant aging and heat rate improvement. Reports and papers from the International Energy Agency (IEA),^{1,2,3} Electric Power Research Institute (EPRI),⁴ National Energy Technology Laboratory (NETL),⁵ and Honeycheck⁶ provide considerable detail. Technical descriptions and analyses literally fill hundreds of pages.

Researchers have established that, at a generation unit level, performance decreases (heat rate increases) with service and that much, but not all, of the decrease can be reversed by means of a major maintenance effort. Unit upgrades can actually reduce the heat rate below the original design rate, but they have rarely been undertaken because of economic considerations and regulatory concerns about triggering the U.S. Environmental Protection Agency (EPA) New Source Performance Standards.

Temporal trends for heat rates have not been routinely publicly reported so there are limited empirical data on the subject. EPA (2012)⁷ estimated flat heat rates through its MARKAL projection period, while EPA (2014)⁸ estimated annual growth in heat rates of 0.1% for existing coal units, but used, for new supercritical coal, a rate of 0.01%. Kumar et al.⁹ describe a typical track of 4–5% increase in heat rate over a 4- to 5-year period followed by about a 75% recovery upon a major unit turnaround (maintenance), which often occurs on a 4- to 5-year time cycle. This would be consistent with a 0.2%–0.25% per year fleet average increase in heat rate. Probasco and Ruhlman¹⁰ find a subcritical fleet average heat rate increase of about 0.06%/y over the 2005–2009 period. Their discussion attributes some of this increase to increasing unit cycling during the period due to the recession, reduced electrical demand, and increases in intermittent power on the grid.

Probasco and Ruhlman¹¹ also reported the operating (not design) heat rates for 458 units divided into 308 subcritical units of <500 MW, averaging 190 MW; 75 subcritical units of >500 MW, averaging 621 MW; and 75 supercritical units, averaging 802 MW capacity. All classes of units showed roughly a 0.5% decrease in efficiency (~50 Btu/KWh increase in heat rate) over the 2005–2009 period.

EIA does not appear to directly link fleet age with heat rate but its published table, “Table A6 Approximate Heat Rates for Electricity and Heat Content of Electricity, Net Generation, Coal Plants Heat Rate (Btu/kWh)”,¹² contains data from 2001 through 2014.

The reported data are consistent with a heat rate increase of about 0.15%/y. This increase is based on fuel consumption and net generation rates (as reported to EIA), so it does not explicitly capture units added to or removed from the generation fleet or other changes in composition or utilization of the coal-fired fleet.

Honeycheck¹³ obtained data from 117 power plants operated by 19 utilities. Plant size ranged from 40 MW to 1300 MW although most fell in the range of 350 MW to 800 MW. The data covered nearly 40 operating years. He identified boiler, turbine, and condenser efficiencies as major elements in determining overall plant heat rate.

Boiler data indicated a long slow decrease in efficiency from about 90% to about 88% over a 30+-year period with no obvious periodicity. Honeycheck found decreasing efficiency with age in high-pressure, intermediate-pressure, and low-pressure steam turbines. Rather than the long slow decline observed for boilers, he observed a periodicity of roughly 5 years, which he attributed to maintenance of turbines. The plots in Honeycheck's dissertation also show that turbine efficiency improved after an outage but did not rebound to the 'new' turbine level.

Steam condenser backpressure, which directly affects the efficiency of the LP turbine, was shown to have a 6- to 9-month periodicity; this is partly attributable to the variability of cooling water temperature with the seasons, partly to routine cleaning of tube bundles, and partly to aging.

Cycling

Electrical supply systems are experiencing increasing cycling of their fossil thermal generating units to accommodate intermittency in mandated and/or economically attractive generation from renewable resources, particularly wind and solar.

Cycling coal-fired units creates three major impacts:

- Lower net generation, resulting in a lower capacity factor (CF) and, generally, less revenue;
- Lower total fuel consumption, but higher heat rate, from fuel used during non-productive periods; and
- Lower efficiency when operating in off-design periods.

Equipment damage and wear and tear result from the thermal and pressure transients inherent in the cycling and from upsets in water chemistry, which are also inherent in cycling.

There are direct and readily identifiable impacts^{14,15} that are proportional, although not necessarily linearly, to the affected unit's CF and unit startups. Major impacted items are fixed O&M costs and fuel consumption per unit generation, typically expressed as heat rate (Btu/kWh).

Total fuel consumption in cyclic operation will decrease less than proportionally to the decrease in CF. This is a consequence of fuel being burned to bring the unit to the online state, fuel being burned during an orderly or output ramp, and fuel being burned during an offline period to maintain unit temperatures and allow for relatively rapid return to online generation from standby status. The net effect of this, aside from reduced efficiency during part-load operation, is an increase in the unit's average heat rate¹⁶ and fuel consumption per unit generation.

Interaction of Aging and Cycling

Cycling PC units involves temperature, pressure, and flow changes. Studies by EPRI,¹⁷ APTECH,¹⁸ and others have identified temperature transients and non-uniform temperatures as the major sources of reduced component lifetimes and accelerated failure rates. Changes and instability in water chemistry are also seen as sources of increased water-side corrosion.

Repetitive cycling and resulting temperature changes create stress in components, leading to creep and fatigue failures.¹⁹ Material-dependent interaction of creep damage and fatigue damage also occurs in high-temperature, high-pressure components.

EPRI notes,²⁰ “Where operational cycling is introduced on a former baseload unit, *the residual life can be greatly reduced to between 40% and 60% of the original design life because of the combined effects of creep and fatigue.*”

Fleming and Foster²¹ report that the rate of temperature change in a high-temperature component constructed of typical steel (2 ¼ Cr, 1 Mo) had to be kept below 8 degrees C per minute to avoid fatigue failure. This limitation can severely limit rapid unit ramping to follow load changes.

¹ Adams, D., “Efficiency Upgrades for Existing Coal-Fired Power Plants,” Gliwice, Poland, IEA, September 2009.

² Fleming, A., and D. Foster, “Aging of Coal-Fired Power Plants,” IEA Coal Research, April 2001.

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- ³ Henderson, C., “Upgrading and Efficiency Improvements in Coal-Fired Power Plants,” IEA Clean Coal Centre, August 2013.
- ⁴ EPRI, *Advances in Life Assessment and Optimization of Fossil Power Plants – Proceedings*, Palo Alto, CA, Report No. 1006965, 2002.
- ⁵ NETL, *Opportunities to Improve the Efficiency of Existing Coal-Fired Power Plants – Workshop Report*, July 15–16, 2009.
- ⁶ Honeycheck, T., *The Effect of Age on Heat Rates in Central Station Power Plants*, Dissertation, Lamar University, Beaumont, TX, October 2005
- ⁷ Victor, N., Personal Communication, data abstracted from EPA9RUS 2012 MARKAL dataset, October 2014.
- ⁸ Victor, N., Personal Communication, data abstracted from EPA9RUS 2014 MARKAL dataset, October 2014.
- ⁹ Kumar, N. et al., *Power Plant Cycling Costs*, Intertek APTECH, Subcontract Report No. NREL/SR-5500-55433, NREL, Golden, CO, July 2012.
- ¹⁰ Probasco, D., and B. Ruhlman, “Coal Fired Generation Cost and Performance Trends,” *Power Magazine*, May 1, 2011.
- ¹¹ Probasco and Ruhlman, op. cit.
- ¹² DOE/EIA, Monthly Energy Review, Table A6, October 28, 2014.
- ¹³ Honeycheck, op. cit.
- ¹⁴ Kumar et al., op. cit., page 2.
- ¹⁵ EPRI, *Damage to Power Plants Due to Cycling*, Palo Alto, CA, 2001 No. 1001507, page ix.
- ¹⁶ Kumar et al., op. cit., page 35.
- ¹⁷ EPRI, op. cit. (2001), page 3-1.
- ¹⁸ Kumar et al., op. cit., page 2.
- ¹⁹ EPRI, op. cit. (2001) page 3-1.
- ²⁰ EPRI, op. cit. (2001), page 3-3.
- ²¹ Fleming and Foster, op. cit., page 53.