Optimization of a Prototype Electric Power System: Legacy Assets and New Investments

by

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1. Introduction

We have developed a new model that has unique features needed to adequately represent operations and cost assessments of regional electric power systems. The *Electricity Supply and Investment Model* (ESIM) represents the interactions among types of generating units with different characteristics and vintages. These interactions have cumulative effects on unit performance characteristics and on the unit's useful lifetime due to accumulated "wear-and tear." This topic involving baseload power plant "cycling" is an important topic that is developed in this paper. The ESIM model is designed to explore the implications for the electric power grid of cycling baseload power plants.

Regional electric power systems are large, complex dynamic systems. Most of their focus has been on operating the grid in real time, typically dispatching units based on their short-run marginal cost (SRMC), also known as merit order. Although some compensation for investment and fixed operating costs exists in capacity markets, these markets are inadequate to bring forth an optimized mix of generating assets with quite different characteristics, all of which can have important roles to play, i.e., market shares, within an optimized system.

Electricity is a unique phenomenon. Demand must be met in real time. Circuits, including generation, transmission, and end-use loads, obey Kirchhoff's laws. Traditional power generation involves electro-mechanical systems with heavy rotating equipment which also helps to stabilize frequency and voltage in alternating current (AC) systems.

Maxwell's partial differential equations describe complex electro-magnetic behavior. Hence electric processes are not described by neoclassical linear homogenous production functions that are generally assumed when analyzing economic systems.

A key question is whether these complex nonlinearities negate the applicability of a fundamental theorem in economics which states that competitive markets with neoclassical production functions are efficient. "Efficiency" here is an economics concept in which ideal competitive markets supply economic goods and services at least cost. See Baumol and Oates.

Baumol and Oates discuss cases where markets deviate from efficiency due to external interactions among producers. Given the unique characteristics of electricity production, transmission, and use, it is an empirical question whether an electricity market design based on short-run marginal costs leads to the least cost for customers over time, or whether additional features, incentives, regulations, or constraints could improve electricity market efficiency.

Given the complexity of electrical systems, the question of market efficiency becomes an empirical question, requiring analysis and modeling of key features of the electric power system. The ESIM model has been designed to explore these questions and to suggest interventions that could be further examined.

Electric power generators are expensive, long-lived, capital-intensive assets. Careful system planning can potentially impact large amounts of money in the economy.

Another concern is the stability of the price of natural gas. The shale gas resource is very large, but technology must continue to progress to access new, more difficult reservoir conditions. ESIM contains a gas supply scenario model calibrated to earlier EIA AEO high, low, and mid resource extraction costs. Exploring the implications of higher and lower gas supply function scenarios is an important capability of the ESIM model.

For policy analysis and technology development planning, ESIM calculates the discounted present value of fuel costs, operating and maintenance costs, and relevant capital investment expenditures.

2. Overview: The Emergence of an Expensive Circular Process

The accelerated retirements of baseload power plants is the result of a "circular process." We use the figure below to explain this process. The figure is constructed first by dispatching units in the US in their respective regions. All the power plants are then sorted in order of variable cost (vc) and their variable cost is then shown with the blue line and their resulting capacity factor (CF) is shown with the orange line. Cumulative capacity in gigawatts is shown on the X-axis.

The major differences in variable costs among units arise due to differences in delivered fuel prices (gas prices vs coal prices, transportation and delivery costs, contractual differences) and differences in efficiency (i.e. "heat rates"). Efficiency differences are correlated with the age of the unit.

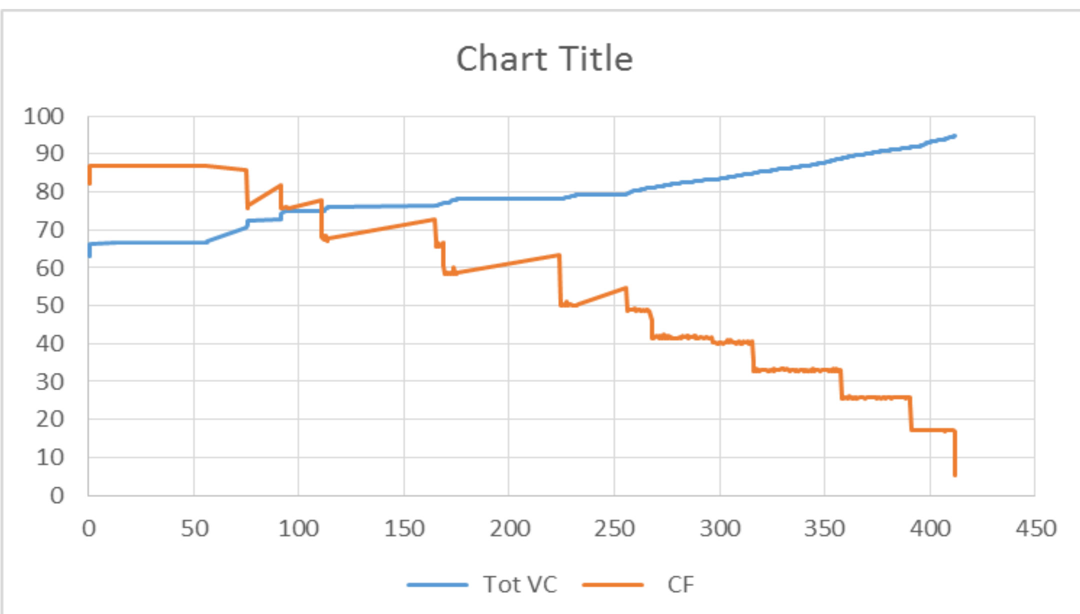

Figure 2.1: Model dispatched coal and gas power plants in the US showing increasing variable costs and decreasing capacity factors (CF)

The chart shows that the *vc* curve is relatively flat. Therefore small differences in a dispatched unit's variable cost (the blue line) can make a large difference in its relative loading order and hence in its capacity factor (the orange line) and resulting generation.

A major change in electricity markets over the last decade has been the availability of cheap natural gas, resulting in new natural gas combined cycle (NGCC) units being operated with high capacity utilization as they are dispatched before the units that were designed for baseload operation.

Note that an effective tax on emissions, such as the requirement to hold allowances per ton of SO2 emissions or a carbon tax on CO2 emissions would have dramatic results on unit dispatch order with lower emitting plants operating at higher capacity factors and vice versa.

In the economics literature this is known as a Pigouvian tax and in a textbook perfectly competitive market it leads to efficient outcomes. Probably the most significant contribution of this paper is to discuss whether or not Pigouvian taxes lead to greater efficiency or instead increased social costs due to the special nature of electricity markets and their reliance on SRMC dispatch.

With the high NGCC efficiency and low gas prices, many of those units are dispatched higher in the loading order than coal units. Coal units were designed historically for running baseload and were only designed to tolerate a specified amount of load-following and on-off cycling. When they exceed these design tolerances, a combination of metallurgic creep and fatigue lead to component failures, and if severe enough, result in closure of the unit.

Figure 2.2 traces through the capacity factor changes over time for a set of diverse coal-fired power plants. Some units with higher heat rates slide so far down the loading order that the deep cycling and on-off shutdowns result in various types of efficiency losses, equipment failures, and other types of forced outages and increased operating costs.

Note the circular retirement pattern that Figure 2.2 illustrates: The units furthest down the loading order retire quickly. This loss of capacity is made up in some way, most likely the construction of a new efficient NGCC units which will be dispatched before older coal units. The coal units now pushed down to the end of the loading order end up with an intolerably low capacity factor and soon retire. More efficient NGCC capacity is added; more older coal units are pushed to retire and the circular process plays out rapidly over time.

A takeaway message here is that relatively small shifts in variable cost (e.g., change in fuel price; imposing a Pigouvian tax) can cause a major re-ordering of unit merit order with potentially large changes in capacity factors of units.

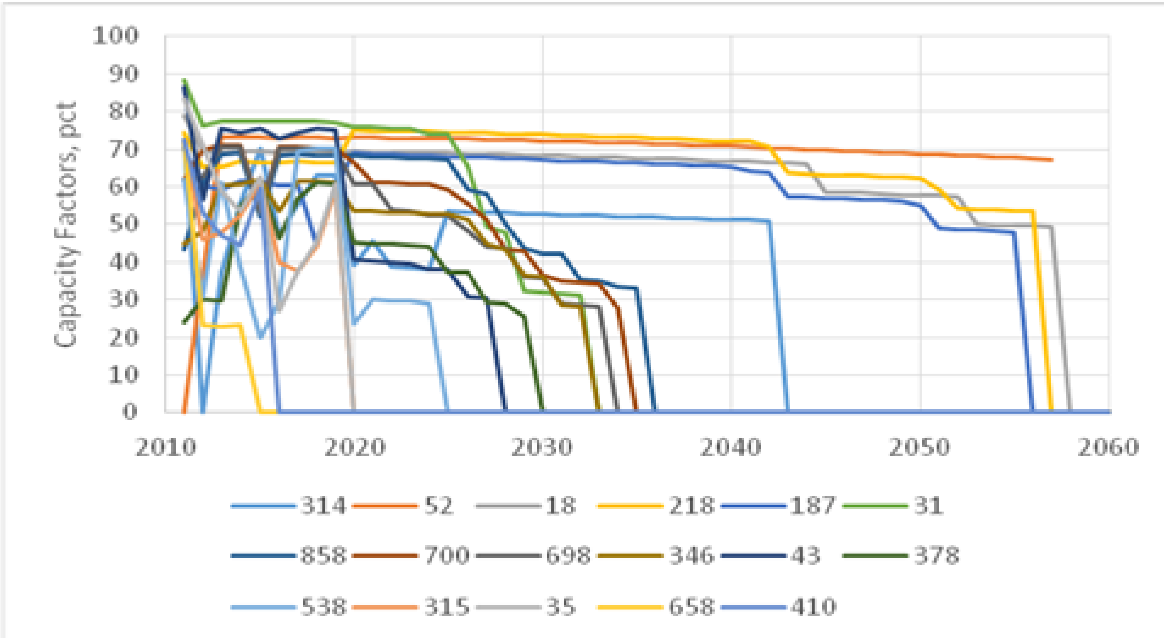

Figure 2.2: Capacity factor decreases for coal-fired units as wind, solar, and gas capacity grows

As a result of this dynamic process we get a reference case projection of generation from coal-fired power plants (CFPPs) that is lower than EIA's Reference case as shown in figure 2.3.

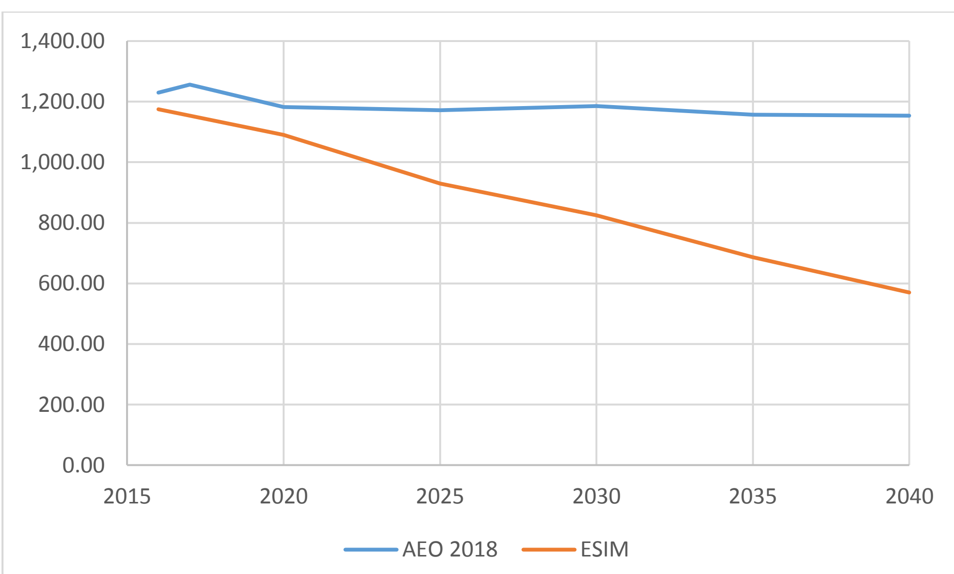

Figure 2.3: Alternative Reference Case projections of generation from coal-fired power plants

In this paper we begin to explore the question of whether this circular retirement and replacement process is consistent with maintaining an efficient electric grid, or if it is a more expensive way forward than other alternatives.

3. Overview of the ESIM Model

The Electricity Supply and Investment Model (ESIM) calculates generation for individual coal units and natural gas capacity by vintage for each of seven U.S. regions based on the merit order dispatch criterion or other policy options. The model contains a long-term electric power planning module covering the 50-year period 2020-2070 (Shelby, 2008; Hanson, 2016).

Table 1 and Figures (a) and (b) show the ESIM unit inventory distribution for coal units exceeding 50 MW capacity.

Table. 1. Distribution of coal-fired power plants by vintage and region within ESIM.

Number of units, and Nameplate Capacity:

	pre 1960	post 1960	post 1970	post 1980	post 1990	SuperCrit	Tot Regn
N East	28	23	0	3	0	0	54
OVDPJM	113	76	39	9	24	5	266
S East	121	65	55	31	19	3	294
N Cent	141	154	70	32	4	10	411
SPP pls	6	10	13	22	5	2	58
Texas	0	0	15	14	5	7	41
West	8	29	32	26	12	1	108
US Total	417	357	224	137	69	28	1232
	pre 1960	post 1960	post 1970	post 1980	post 1990	SuperCrit	Tot Regn
N East	2.8	3.3	0	1	0	0	7.1
OVDPJM	15.8	21.5	27.5	2.2	5	5.1	77.1
S East	16.9	18.7	30.1	19.1	6.6	2.2	93.7
N Cent	17.3	24.2	33.4	15.8	0.7	8.9	100.3
SPP pls	0.4	1	7	13	2.1	1.1	24.6
Texas	0	0	9	8.7	2.5	5.3	25.4
West	0.7	4.1	15.5	12.8	2.7	0.9	36.6
US Total	53.9	72.9	122.5	72.6	19.6	23.4	364.9

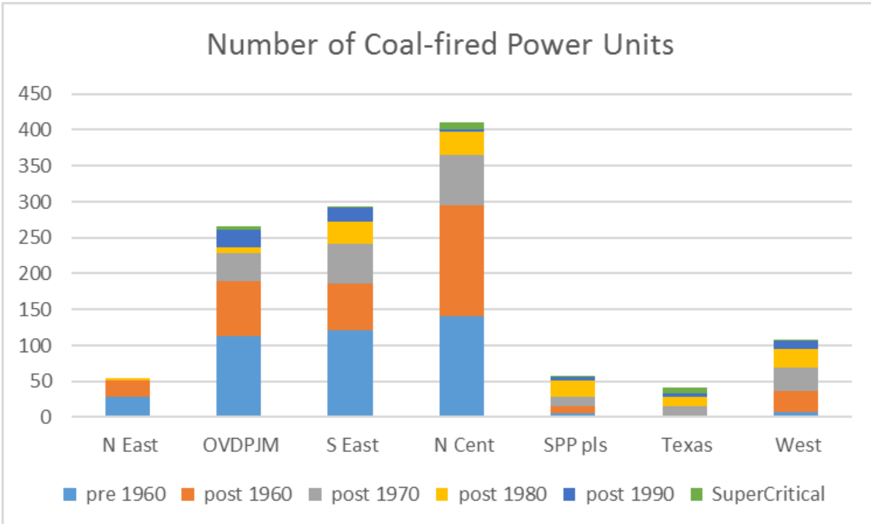

Figure 3.1 Number of units

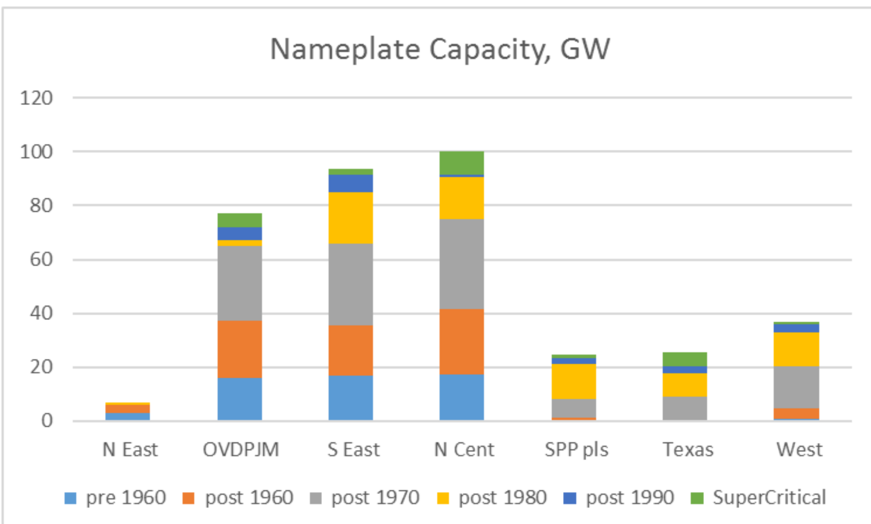

Figure 3.2 Nameplate capacity distribution

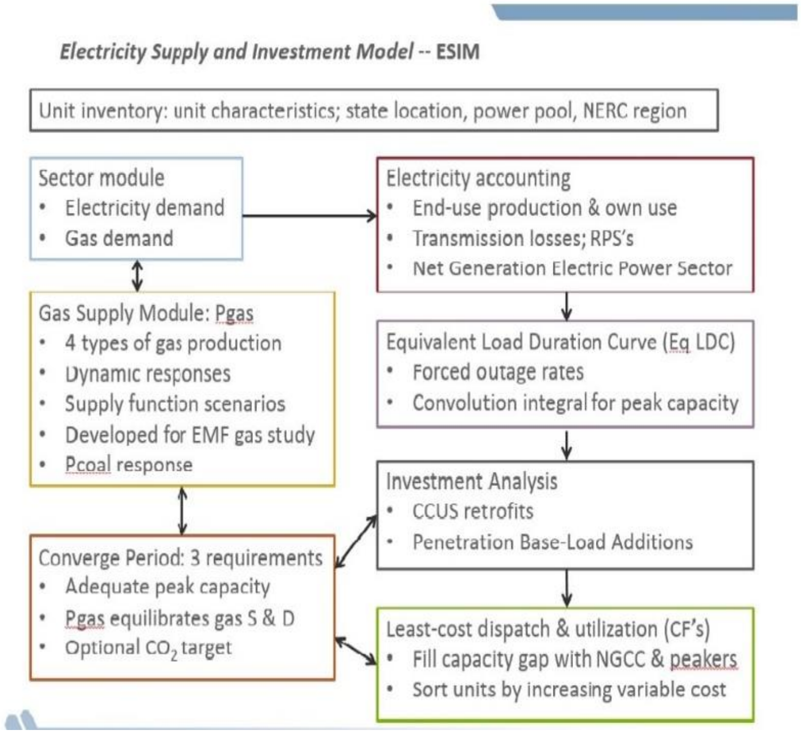

Figure 3.3: Electricity Supply and Investment Model

In addition to the existing unit inventory, ESIM includes 20 technologies including CCS retrofits, new state-of-the-art coal units, biomass units, existing and new nuclear capacity, Natural Gas Combined Cycle (NGCC) capacity by vintage, peaking turbines, oil/gas steam units, wind generators, utility solar, photovoltaic solar, geothermal, hydropower, pumped storage, and battery storage. These are considered to be electric power system technologies. In addition ESIM includes end-use electricity generating technologies by fuel type.

There are advanced technology concepts currently being developed. One focus here is how best to plan for a low-carbon future for electric power generation taking into account the best use of current generating assets, and the option to deploy advanced, more efficient, lower carbon baseload technologies within the planning horizon.

Baseload technologies with heavy rotating equipment provide important voltage and frequency regulation for the electric grid (NERC, May 2017). There is concern that the existing fleet of coal and nuclear baseload units will be retired before advanced fossil fuel and nuclear baseload technogies will be available and widely deployed.

A concern is that if existing baseload power plants retire too rapidly they will be replaced with too much gas-fired and other capacity, locking out advanced nuclear technologies and advanced fossil fuel technologies with CCS.

A problem is that for many regions, the baseload portion of the load duration curve is limited and available only for a portion of the units that were designed to run in baseload mode.

Below we briefly discuss what future technology configurations might look like. These future technologies play a key role in our long-term modeling.

A typical load duration curve (LDC), illustrated in Figure 3.4, represents the demand for electricity on the vertical axis sorted from highest to lowest by hour during the period of time being analyzed, e.g., during the summer months of the year. Figure 3.4 shows the general shape. The minimum load in the period is the height of the LDC on the far right. The minimum load establishes the amount of baseload generating capacity, typically coal and nuclear units, which can operate at their full available capacity. Units with higher variable costs are stacked higher on the LDC and hence their generation is limited by the number of hours in the period for which their capacity is needed to meet load.

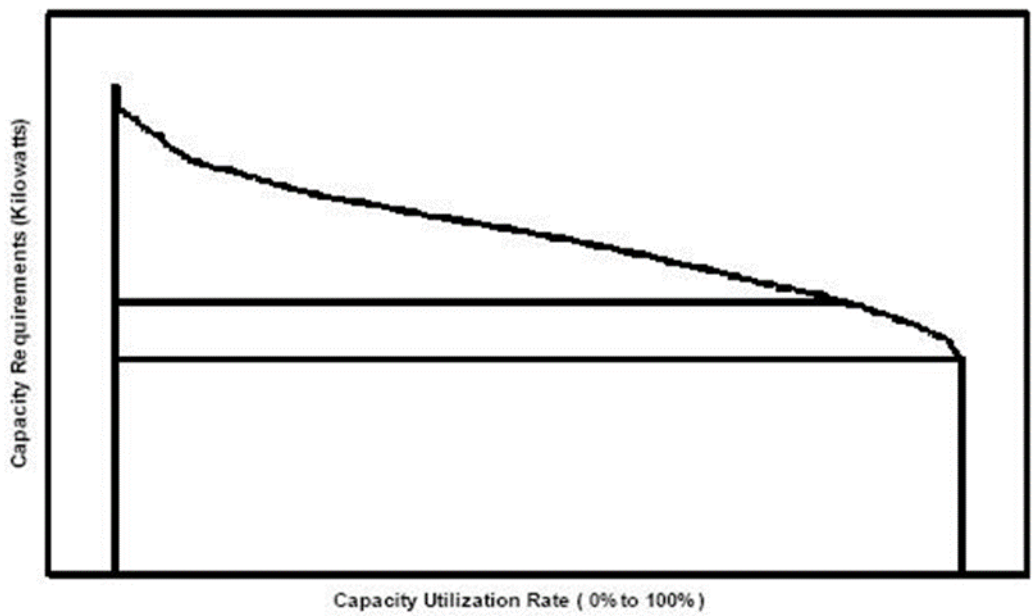

Figure 3.4. Typical shape of the Load Duration Curve representing electricity demand in the period.

Adequate capacity is required to meet peak demand shown on the vertical axis. Capacity meeting peak demands will have a low utilization rate, or low capacity factor, and are typically gas-fired combustion turbines.

With some probability a particular generating unit may be down for repair and not available, so reliability considerations require that the power system contains excess capacity to prevent power outages. NERC requires a very low loss-of-load-probability (LOLP). The LOLP is calculated by a convolution integral taking into account the probability that multiple units may be out of service at the same time. An “equivalent load duration curve” can be derived from the convolution integral calculation. An equivalent load duration curve has the effect of adjusting upward the system total capacity requirement to guarantee reliability. The 2018 version of the

ESIM model dispatches units against equivalent load duration curves for four seasons per year with separate load duration curves for weekdays and weekends for each of seven US regions.

Some types of generation tend to be put at the base ("must-run") part of the load curve. These generators include some end-use generation sold to the grid, and may include wind and solar generation. Below we show the size of the dispatchable load (after subtracting must-run at the base and peaking capacity that serves peak-load). In the figures below, the dispatchable load areas by season and by weekday and weekend are rotated 90 degrees from Figure 3.4. These load areas are taken from the NorthEast region, largely PJM.

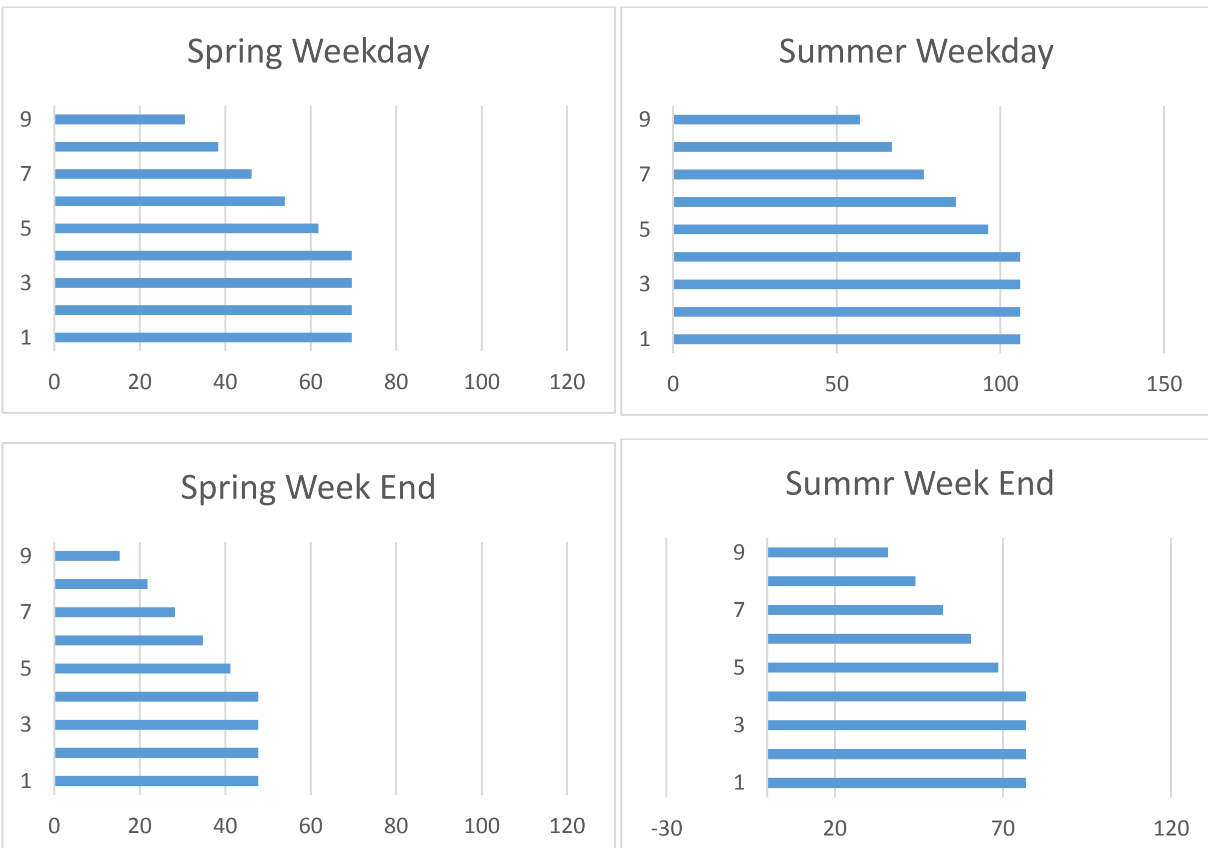

Figure 3.5. Comparison of the portion of the load curve available for dispatchable units

The summer season needs more disputable capacity than the spring season. Weekends use less electricity than week days. These seasonal differences contribute to baseload power plant load-following and weekend powering down of some older baseload units.

Existing CFPPs were not designed to switch on and off to follow load. 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 in this documentation 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.

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 3.6a shows the heat rate (Btu/kWh) rising very gradually as the unit ages and then noticeably faster as a result of increased cycling damages. Cycling also increases outage rates, lowering availability over time, as shown in Figure 3.6b. 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).

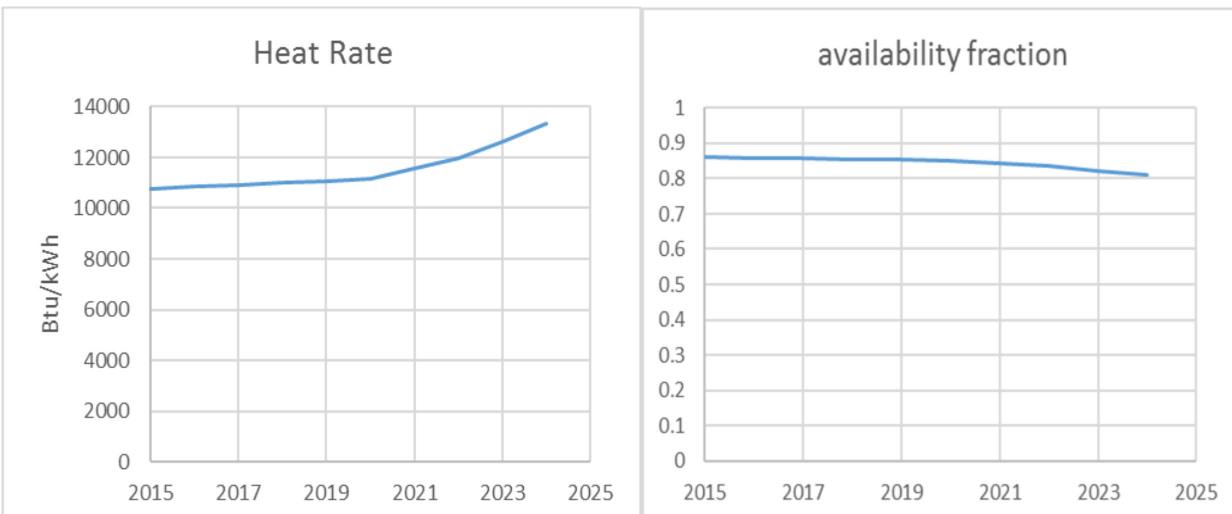

Figure 3.6. Typical coal-fired power plant loss of performance with aging and cycling

Figure 3.7a shows the evolution of the capacity factor for CFPP with an internal ESIM model #233. The declining capacity factor implies that the unit is operating in an increasingly severe cycling mode. Figure 3.7b shows the index of cumulative damage for unit #233 over time. The rate of increase in damage is initially slow, rising sharply in 2020. Unit #233 retires in 2023 after reaching threshold value as shown in Figure 3.6b.

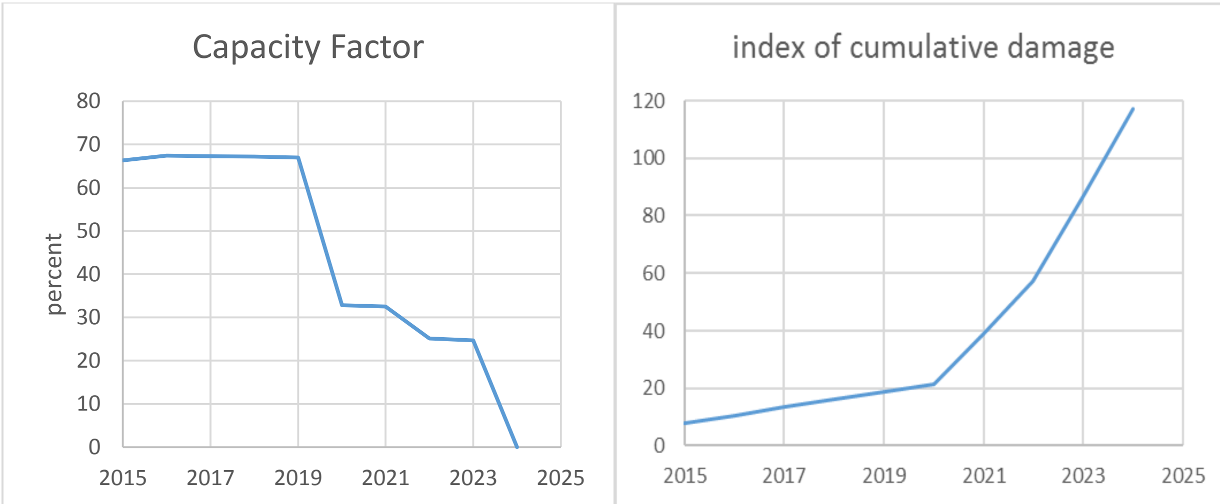

Figure 3.7. The typical CFPP capacity factor reduction and cumulative cycling damage measure

Below are known physical processes that increase unit forced outages and heat rates, resulting in reduced unit capacity factors:

- Wear of seals and turbine blades
- Fouling and deposition on heat transfer surfaces and steam turbine blades
- Aging of refractories and structural shells, particularly boilers
- Component failure from corrosion, fatigue, and creep
- Interaction of fatigue and creep under cycling and temperature swings

Metallurgical creep is a slow deformation process below the material's tensile yield. Fatigue is defect growth due to cycling changes in stress. Example results are illustrated in Figure 3.8.

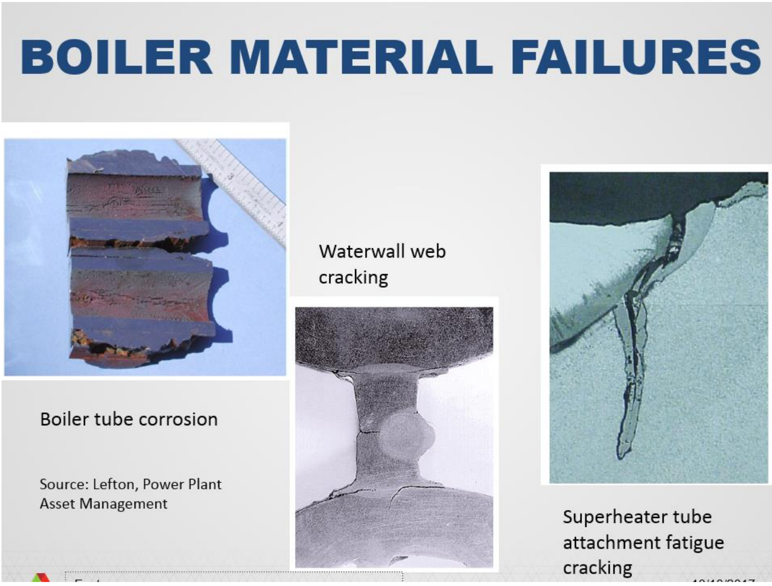

Figure 3.8: Examples of Fatigue Cracking, Waterwall Cracking, and Boiler Tube Corrosion

Existing coal-fired power plants built in the 1960's were designed for baseload (24/7) operation. These units have limited tolerance for swings in operations (see Appendix for further discussion).

The 2018 version of ESIM has changed from dispatching units once every year to dispatching units eight times per year. Demand is provided by region for each of four seasons. Within a season weekends with lower demand are dispatched separately from weekdays. The model runs sequentially through a given year staring with winter (January, February, March), then spring (April, May), summer (June July, August), and autumn (September, November, December). The number of days in a season are 90.25 average days for winter (includes the effect of leap year), 61 days for spring, 92 days for summer, and 122 days for autumn. The table below shows the resulting fraction of days in a year for each of the eight dispatches.

		season share	day type share	combined
winter	week day	0.2471	0.7143	0.1765
winter	weekend	0.2471	0.2857	0.0706
spring	week day	0.167	0.7143	0.1193
spring	weekend	0.167	0.2857	0.0477
summer	week day	0.2519	0.7143	0.1799
summer	weekend	0.2519	0.2857	0.0719
autumn	week day	0.334	0.7143	0.2386
autumn	weekend	0.334	0.2857	0.0954

The regions in the ESIM model are currently configured for a Stanford University Energy Modeling Forum (EMF) study as illustrated in Figure 3.9. In ESIM, however, we included Texas as a separate region from the rest of the South Central region.

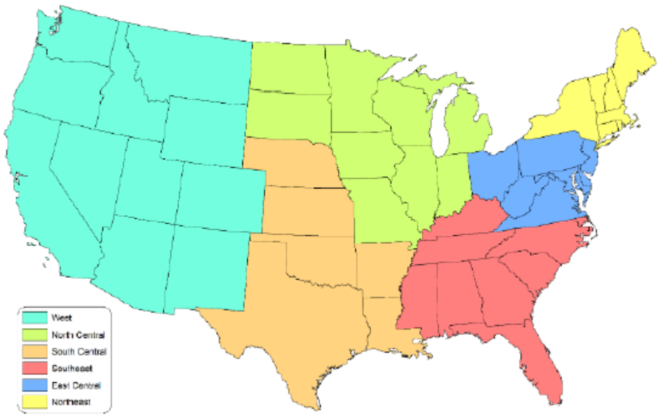

Figure 3.9: Regions Represented in ESIM, but with Texas Split from the rest of South Central Region

4. The Representation of Advanced Fossil Energy Technologies

It is important for overall system planning to prepare for a transition to low carbon baseload units. Some impressive designs are being developed both for fourth generation nuclear power and for fossil fuel combustion with CCS (see Figure 4.1). Further description of these more efficient and cleaner baseload technologies is available on the NETL website and in a Duke Energy presentation to the United States Energy Association (USEA).

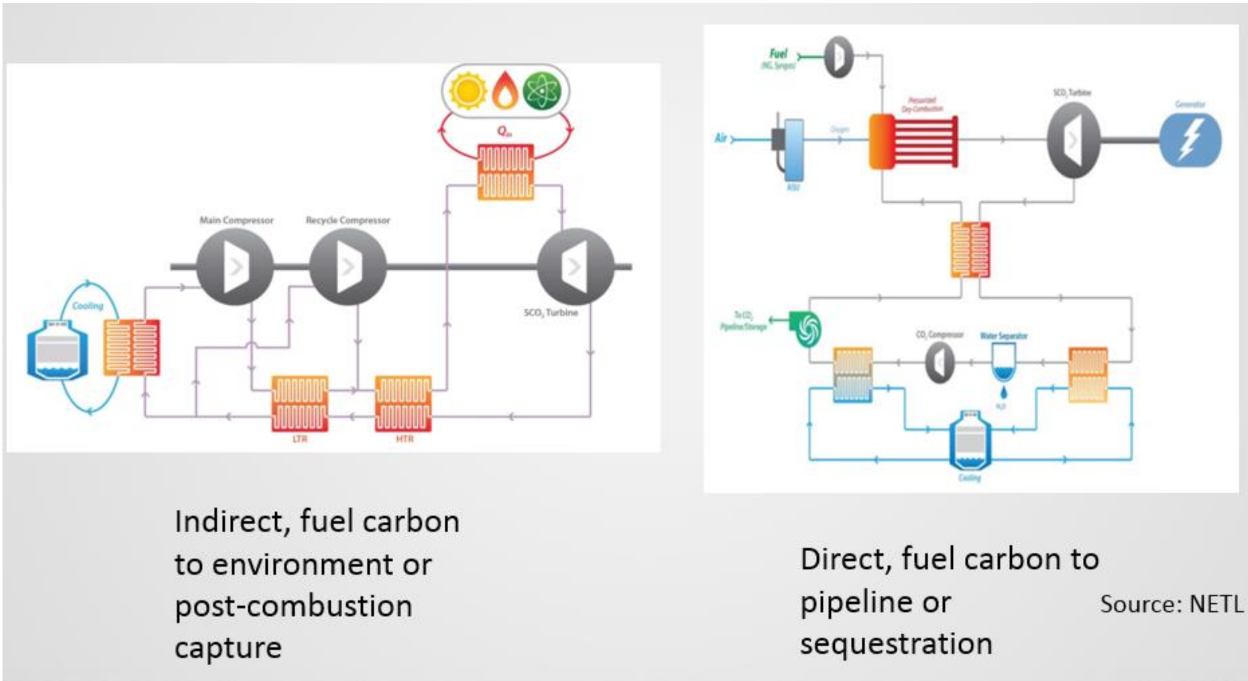

Figure 4.1: Supercritical Electricity Generation either with Indirect Heat from Coal, Biomass, or Nuclear Energy, or with Direct Oxycombustion of Natural Gas, or SynGas, both with CO_2 Separation

5. The Gas Supply Model

The natural gas supply scenario model allows sensitivity analyses for alternative gas supplies at a given price (i.e., shifting the supply function). We exercised this capability for the Stanford University Energy Modeling Forum study (EMF-31) under business-as-usual (BAU) scenarios with higher, mid, and lower gas supply functions, giving rise to lower-to-higher gas prices. The integrated model solves for a gas supply and demand equilibrium path.

The gas supply functions were originally calibrated to the *Annual Energy Outlook* (AEO) 2013, but key parameters are annually updated. 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 5.1 shows how much the gas supply curves shift in the different supply cases.

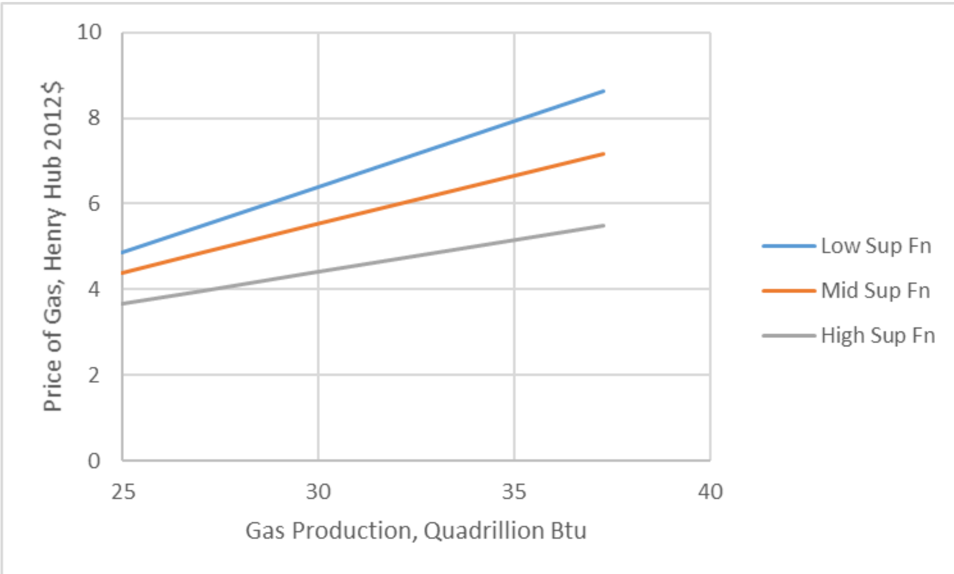

Figure 5.1. Linear approximation to shifts in the gas supply function for year 2030

Gas supply functions are important components of the ESIM model in order to obtain general equilibrium results in for the connected gas and electricity markets.

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 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.

We have simulated this gas price volatility by exogenously 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.

6 Expenditures and Present Value Costs for the Future Electric Power System

If SRMC dispatching of baseload units results in significant cycling damage and early retirements, can we design operational rules for electricity systems which are lower in cost, hence serving customers better and benefitting the economy. We compared two scenarios, a reference cast based on SRMC dispatch and a “test case” in which some of the better baseload units are giving a preference in loading order. The results are shown in Figure 6.1.

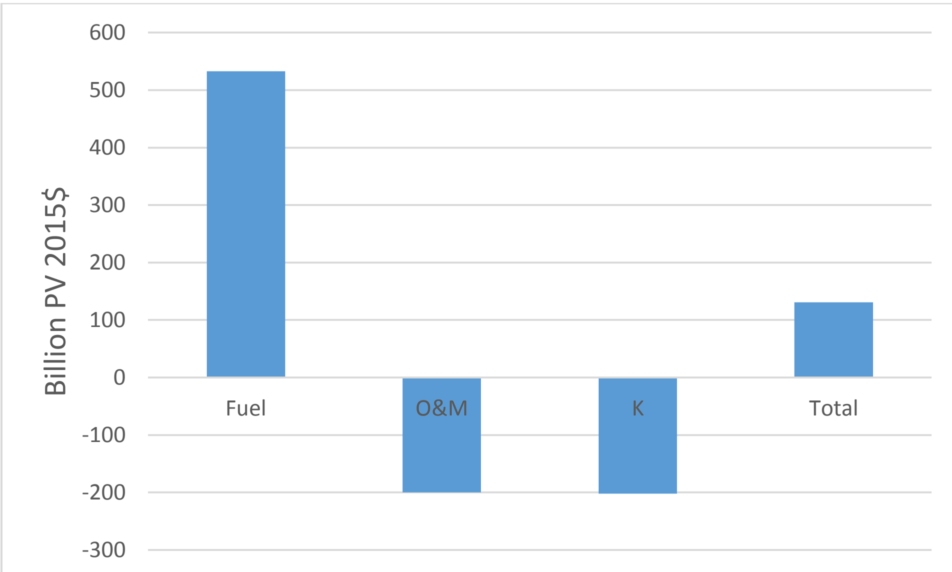

Figure 6.1: PV Cost Comparison at 5% Real Discount Rate: High cycling cost case - Baseload preference case

NGCC units are pushed down the loading order somewhat. This saves expensive gas fuel. Also not a much new gas capacity needs to be built saving capital costs and preventing a future “lock-in” of gas capacity. The life-extension of existing baseload units allows time to develop and deploy advanced baseload technologies, so these technologies play a bigger role in a resilient low-carbon future. Because the advanced technologies are designed to be low carbon, cumulative CO2 emissions are no different over a fifty-year time horizon of 2020-2070 comparing the two cases.

In calculating present values, we don’t include that portion of capital outlays that provide electricity to customers post-2070. This is done using Capital Recovery Factors common in finance. We have used a 5% real discount rate in this analysis.

Another feature is that the expenditure savings on electricity generation in the 2020-2030 phase by not retiring as much existing capacity could be used to help finance the development of advanced low carbon technologies.

Further, the advanced technology development and adoption positions the world for a lower carbon future post 2040.

7 Could SRMC Dispatch Be Inefficient for the Electric Power Grid?

Baumol and Oates (1988) define a neoclassical production process in the absence of externalities as one in which none of the inputs to a firm's production are chosen by others without particular attention to the effects on this firm. A production externality exists if this condition does not hold.

Does the modern electricity grid provide an avenue through which a production technology such as wind turbines impact the production of other generators such as existing baseload coal and nuclear plants? If so, this would appear to satisfy the definition of an externality as defined by Baumol and Oates.

It is difficult to think of electricity generation as a neoclassical production function. Most electricity is produced by an electro-mechanical process combining Newtonian mechanics with electro-magnetic forces. And if driven by steam, there is a boiler needing to be maintained at temperature, pressure and with specified water chemistry. So what happens on the "grid" (that is the associated electric power system) will impact all of the above conditions.

So clearly the grid is sending external forces to a particular power plant without regard to the impact of those forces on that power plant. We can think of the effects as being those discussed in the Appendix:

- Increased forced outage rates
- Increased fuel use per kWh generated when operating at partial capacity
- Degradation of the heat rate over time
- Increased maintenance costs
- Increased wear and tear on equipment leading to sooner replacements or plant retirements.

A more formal discussion with a comparison to urban congestion which is a well-recognized externality follows.

We paraphrase from William J. Baumol and Wallace E. Oates, *The Theory of Environmental Policy*, Second edition, Cambridge University Press, 1988, p. 17:

Condition 1. An externality is present whenever firm A's production function (or person A's utility function) is impacted by a decision made by another firm B (or person B) without regard to A's welfare.

Condition 2. The decision maker, whose activity affects others' utility levels or enters their production functions, does not receive (pay) in compensation for this activity an amount equal in value to the resulting benefits (or costs) to others.

We now describe two situations. The first is the case of congested urban transportation; a situation generally accepted to be an externality in the urban economics literature.

Congested Urban Transportation Example: Individual A has a choice of commuting to work in the city by taking the train, and leaving the family car at home for his/her spouse, or buying a second car for commuting on an already congested roadway. Individual A does not take into account the resulting incremental increase in congestion affecting traffic generally.

Electric Power Market Example: Firm A obtains a permit to develop a wind farm (having near-zero Short-Run Marginal Cost) where, according to market dispatch rules, the wind generation will displace generation from baseload power plants, impacting their downtime, revenue streams, maintenance costs, and expected useful lifetimes.

The conceptual similarities between the urban congestion externality and electric power description imply that the latter is also an externality.

A second test for the existence of an externality is whether it results in a failure to achieve least-cost production. Our modeling and simulation work of electric power markets indicates that cycling and other interactions among electric power generators based on merit order dispatch rules and other requirements increase the long-run cost of electricity relative to feasible alternatives.

Note: For simplicity textbook examples of externalities are usually framed in terms of "flows" such as smoke flowing from a stack. However real world externalities usually also involve durable goods such as equipment choices and infrastructure investments. In the urban congestion case the choice to buy a car rather than take the commuter train to the city will impact the freeway congestion situation. In the electric power case, the least-cost path forward make involve somewhat less near-term accumulation of wind and NCGG capacity because the presence of this capacity leads to operations which impose cycling costs on other units. That is, a longer term horizon can be cost-effective.

There may exist a number of regulatory measures and incentives which could mitigate the external effects of cycling impacts propagated through the grid. One such measure would be to substitute gas-fired combustion turbine capacity for a portion of the large amount of NGCC capacity projected to be built. Combustion turbines are designed to cycle and could be used to reduce the amount of coal unit cycling. Current policy could lock-in expanding NGCC capacity for many years, thus slowing the penetration of advanced technologies.

Following Baumol and Oates, we suggest that the reason for this is that the electricity grid system transmits the effects of production from one power plant onto the production of other power plants in ways that impose load following and cycling costs on units designed to tolerate only limited amounts of load following and on and off switching.

Also of note, there may exist a number of regulatory measures and incentives which could mitigate the external effects of cycling impacts propagated through the grid. One such measure would be to substituting gas-fired combustion turbine capacity for a portion of the huge amount of NGCC capacity projected to be built. Combustion turbines are designed to cycle and could be used to reduce the amount of coal unit cycling. A near-term carbon tax would lock-in expanding NGCC capacity for many years.

Finally, the development of sensors and controls to monitor power plant operating conditions and material impacts can cost-effectively reduce the effects from the load-following nature of the electric power grid (NETL 2013; Schmalzer 2017). Reducing the cycling of newer coal-fired power plants would preserve the option to retrofit them with CO_2 capture in the future.

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Appendix: Aging and Cycling Effects on Existing Power Plants

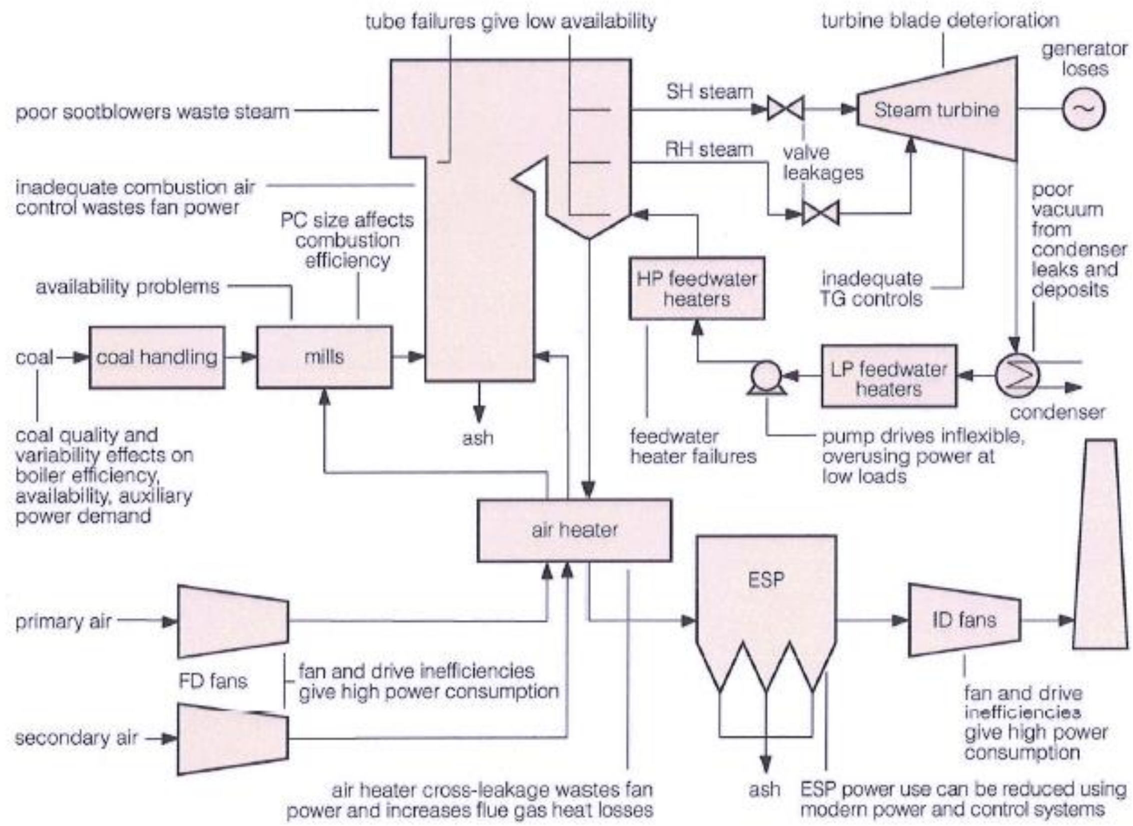
In the following, we discuss the physical issues impacting CFPP from aging, from cycling, and from the interaction of aging and cycling.

Aging

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 a principal source of unit heat rate increases. In summary, the physical effects can be described in 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 reduce unit availability and effective capacity factor through forced outages and planned maintenance outages.

There is an extensive literature on plant aging and heat rate improvement. Reports and papers from the International Energy Agency (IEA)[i][ii][iii], EPRI[iv], NETL[v], and Honeycheck[vi] provide considerable detail. Technical descriptions fill hundreds of pages of documentation and analysis.

The following schematic from Campbell[vii] illustrates the range of sources within a coal-fired generating unit where efficiency can decrease (heat rate increase)



Source: Congressional Research Service, Report R43343, Increasing the Efficiency of Existing Coal-Fired Power Plants, December 20, 2013

Notes: ID=induced draft fans are used to create a vacuum or negative air pressure in a system or stack; ESP= an electrostatic precipitator is a particulate collection device that removes particles from a flowing gas (such as air)using the force of an induced electrostatic charge ; FD=a forced draft fan is used to provide a positive pressure to a system ; LP=low pressure; HP=high pressure; PC=pulverized coal; RH=reheated ; SH=superheated; TG=turbine generator.

It is well established that, at the generation unit level, performance decreases (heat rate increases) with service, and that much, but not all, of the change can be recaptured in a major maintenance effort. Unit upgrades can actually reduce heat rate below the original design but have rarely been done due to economic considerations and regulatory concerns with the New Source Performance Standards.

Temporal trends of generation heat rates have not been routinely publicly reported so there is limited empirical data on the subject. EPA (2012)[viii] estimated flat heat rates through their MARKAL projection period while EPA (2014)[ix] estimated annual growth of heat rates of 0.1% for existing coal units, but used, for new supercritical coal, a rate of 0.01%. Kumar[x] describes a typical track of 4 – 5% increase in heat rate over a 4 – 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 is consistent with a 0.2% -0.25% per year fleet average increase in heat rate. Probasco and Ruhlman[xi] found a subcritical fleet average heat rate increase of about 0.06%/y over the 2005 -2009 period. Their discussion attributes some of this to increasing unit cycling during the period due to the recession, reduced electrical demand, and increases in intermittent power on the grid.

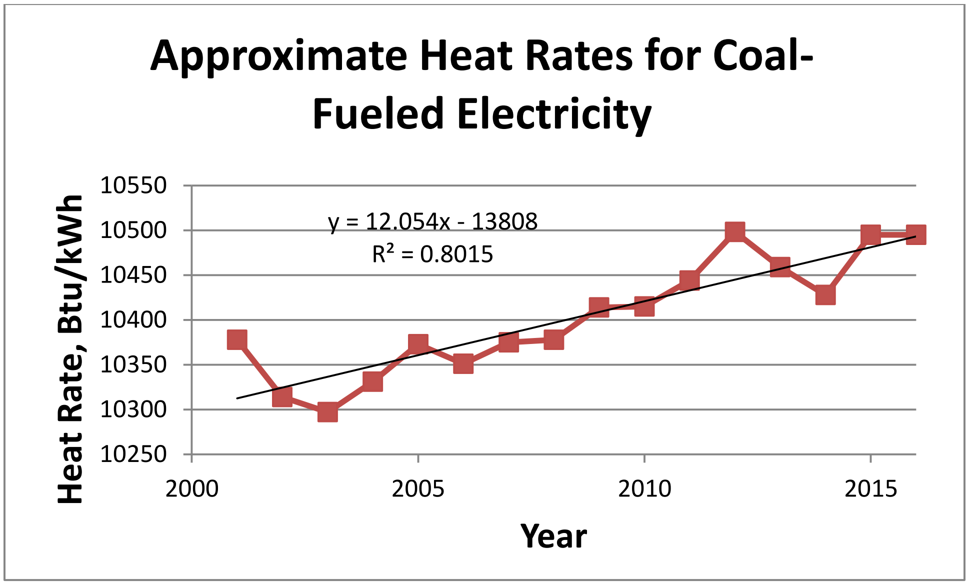
EIA does not appear to explicitly link heat rates to unit or fleet age in their NEMS modeling and Annual Energy Outlook publications. EIA[xii] did impose a 3%/y increase in operation and maintenance expenses in a case study of accelerated retirement of coal-fired generation units. It is unclear whether this O&M surcharge is roughly equivalent, economically, to a growth in heat rate with unit age. As it may appear as a fixed charge in the NEMS modeling rather than a variable charge it could impact unit dispatch differently than an explicit heat rate increase.

Probasco and Ruhlman[xiii] reported the operating (not design) heat rates, over the period 2005 – 2009, for 458 units comprised of 308 subcritical units < 500 MW, averaging 190 MW, 75 subcritical units > 500 MW, averaging 621 MW, and 75 supercritical units, averaging 802 MW capacity. Group efficiencies ranged from 32.5 to 34.7 percent and Equivalent Availability Factors (EAF) ranged from 86.4 to 84.1 percent, being highest for large subcritical units and lowest for supercritical units.

Probasco and Ruhlman[xiv] provided updated information on 378 units from the Navigant Generation Knowledge Service (GKS) data set. The units comprised 228 ‘small’ subcritical units averaging 218 MW capacity, 65 ‘large’ subcritical units averaging 619 MW capacity, and 85 supercritical units averaging 782 MW capacity.

Notably across these five year group averages, EAF, a standardized measure of unit availability, and average unit operating efficiency decreased from the five-year 2005 – 2009 period to the five-year 2010 – 2014 period in all unit classes. EAF, for the supercritical units, decreased about 4.5% between the periods, a marked reduction.

EIA does not appear to directly link fleet age with heat rate but their published table, “Approximate Heat Rates for Electricity and Heat Content of Electricity”[xv], contains data from 2001 through 2014. The graph below shows the heat rate trend.



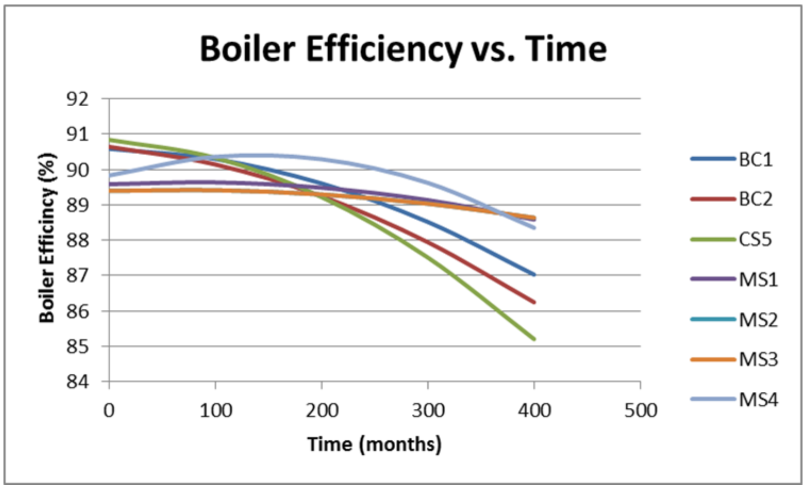
(**Data source**: EIA Monthly Energy Review, Table A6. Approximate Heat Rates for Electricity, and Heat Content of Electricity, Published May 25, 2017)

The reported data is consistent with a heat rate increase of about 0.15%/y. This is based on fuel consumption and net generation 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.

Honeycheck[xvi] obtained data from 117 power plants operated by 19 utilities for his dissertation. Confidentiality agreements precluded him explicitly naming either the utilities or plants. More than 162,000 data points were acquired covering nearly 40 operating years. Plant size ranged from 40 MW to 1300 MW though most fell in the range of 350 MW to 800 MW. 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.

Individual data points in the above figure were not published but least squares curve fits were presented for each of the seven boilers. All of the fits had negative quadratic coefficients, consistent with accelerating losses with advancing age of the boilers. Results of these fits are shown below. Boiler capacity, operating pressure, and other details were not included in the published data.



Honeycheck found decreasing efficiency with age in HP, IP, and LP steam turbines. Rather than the long slow decline observed for boilers he observed a periodicity of roughly five years, which he attributed to maintenance of turbines. Turbine efficiency improved after a maintenance outage but did not fully rebound to the 'new' turbine level.

Steam condenser backpressure, which directly affects the efficiency of the LP turbine, was seen to have a six to nine month periodicity; partly this is attributable to seasonality of cooling water temperature, partly to routine periodic cleaning of tube bundles, and partly from aging.

Feedwater heater data had substantial scatter but no clear trend. Data was available for eight feedwater pumps. Fits of the data all had negative quadratic time coefficients. Limited data was available on generator, induced draft fans, and electrostatic precipitator efficiencies. Negative quadratic time coefficients were found for all of these units.

Cycling

Electrical supply systems are experiencing increasing cycling[xvii] of their fossil thermal generating units to accommodate intermittency in generation from renewable resources, particularly wind and solar. As the penetration of intermittent capacity in a system increases, thermal unit cycling pushes further into the dispatch order, beyond simple cycle gas turbine generators, into NGCC and coal-steam (CFPP) units. Here we focus on impacts of increased cycling of coal-fired units in a system.

Cycling coal-fired units creates three major impacts:[xviii]

- Lower net generation, consequently a lower capacity factor (CF) and, generally, less revenue.
- Lower total fuel consumption, but higher heat rate, from fuel consumed during non-productive periods and lower efficiency during off-design periods of operation.
- Equipment damage and wear and tear resulting from the thermal and pressure transients inherent in the cycling and upsets in water chemistry, also inherent in cycling.

Operators capture net generation and heat rate information essentially immediately as they are quickly monetized. Equipment damage and accelerated wear and tear are cumulative and appear over time in unit forced outage rate, maintenance expenses, and capital expenses. Consequently, the level and quality of information available on the direct, immediate impacts of cycling is much better than that on the accelerated deterioration of the physical plant.

There are direct and readily identifiable impacts[xix] [xx] [xxi] [xxii] that are proportional, though not necessarily linearly, to the affected unit capacity factor (CF) and unit startups. Major items are fixed operating and maintenance costs (FOM) and fuel consumption per unit generation, typically expressed as heat rate (Btu/kWh).

Cycling plant operations whether by load following or periodic shutdowns and startups reduces the CF from what could have been achieved in base load operation. Consequently, FOM cost is amortized over a smaller net generation (MWh) so the FOM/MWh is larger than at base load operation. Similarly, the cycling unit will have lower net generation and, generally, lower revenue than if it were operated in a base load mode.

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 shutdown 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, together with reduced efficiency during part-load operation, is an increase in the unit average heat rate[xxiii] and fuel consumption per unit generation.

Korellis[xxiv] found that operation at low load results in high heat rates compared to operation at full load and that load transients result in heat rate transients as well as elevated heat rates. Additionally, load transients cause temperature, and sometimes pressure transients in the system.

EPRI[xxv] in a study of damages from cyclic operation noted that most plant operations had high-level cost allocation systems; typically, only plant wide O&M costs were tracked. INTERTEK AIM (formerly APTECH)[xxvi] has noted wide variation in reported costs.

Lefton[xxvii] estimated costs of various operating modes for a large coal unit. He found that forced outage costs and the combination of maintenance and capital costs dominate the cost of hot, warm, and cold startups.

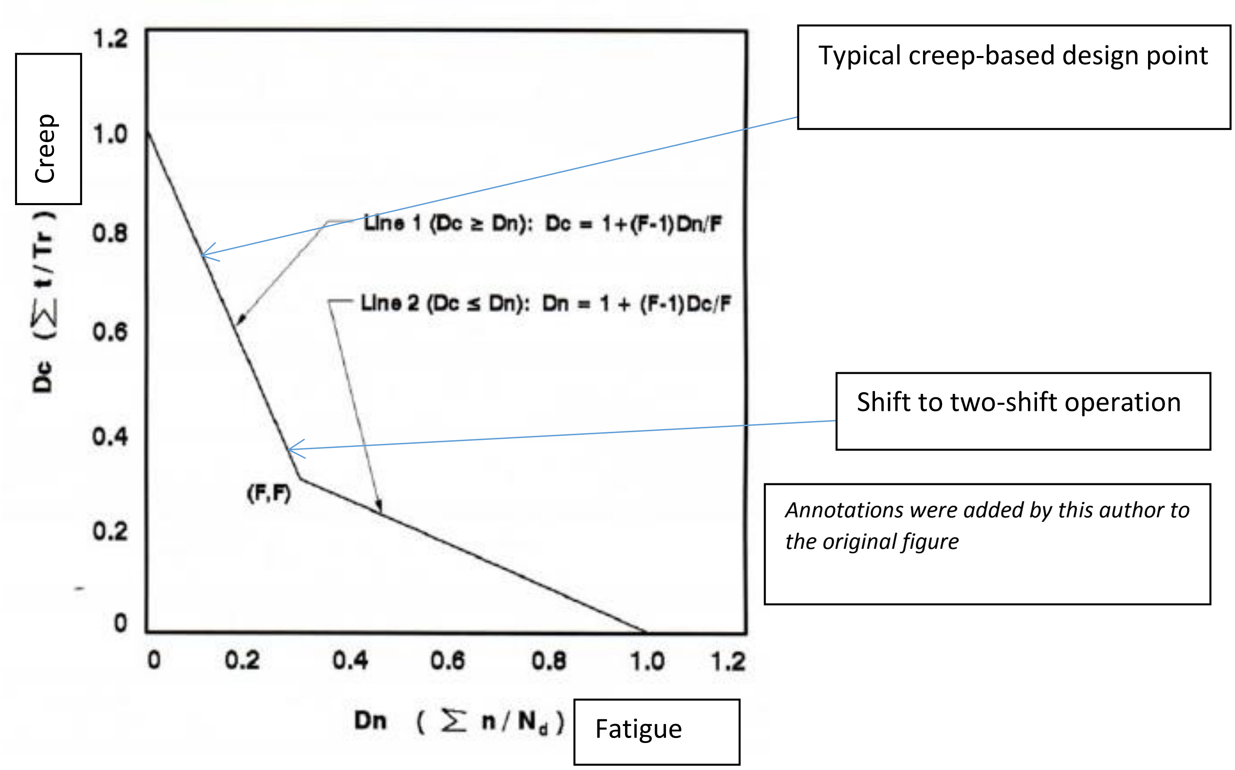
Oates and Jaramillo[xxviii] also estimated cold, warm, and hot start costs for coal plants, finding a large variance in available data.

Interaction of Aging and Cycling

Cycling CFPP units involves temperature, pressure, and flow changes. Studies by EPRI[xxix], INTERTEK AIM (formerly APTECH)[xxx], and others have identified temperature transients and non-uniform temperatures as the major source of reduced component lifetimes and accelerated failure rates. Changes and instability in water chemistry is also seen as a source of increased water-side corrosion.

Repetitive cycling and resulting temperature changes create stress in components leading to creep and fatigue failures[xxxi]. There is a material-dependent interaction of creep damage and fatigue damage in high temperature, high pressure components. The 2 ¼ Cr – 1 Mo steel, a widely used material in pressure and structural components in CFPP construction is notably more susceptible to combined creep and fatigue damage than more expensive materials like stainless steel and Inconel.

In the Mise failure model, the normalized damage from creep and from fatigue are linearly additive which would give a 45 degree slope in the plot but many materials, including the commonly used power plant steel do not behave in such a linear manner. This interaction is illustrated in the following graphic[xxxii]. The introduction of significant fatigue (via cycling) degrades the material life markedly more than linearly.



Huddleston[xxxiii] notes that under ASME Code Case N47 Rules, the design point for a material must lie on or below the bilinear line connecting the normalized creep and fatigue damage lines.

Fleming and Foster[xxxiv] describe how the rate of temperature change in a high temperature component constructed of the typical 2 ¼ Cr - 1 Mo steel has to be kept below 8 degrees C per minute to avoid fatigue failure.

Lefton[xxxv] describes low cycle fatigue damage to the inner and outer casing of a steam turbine.

EPRI notes[xxxvi], "*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*."

Koripelli[xxxvii] recently reviewed metallurgical issues in units pushed into cycling operation and described some strategies for mitigating damage. Impacts included: creep fatigue, thermal fatigue, ligament cracking, and condensate collection. He made a series of recommendations including lowering ramp rates (more gradual startup and shutdowns) and careful tracking and management of water chemistry. He also made recommendations for improved welding techniques, improved design and welding of heavy-wall penetrations, and approaches to give longer and more symmetric ligaments on tube penetrations. These latter recommendations may be more applicable in new unit design and major maintenance, e.g., steam header replacement, on existing units than in routine maintenance efforts.

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