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operating but that can be brought online quickly (non-spinning reserves). This is particularly important as more intermittent generators are added to the grid, because technologies like wind and solar have uncertain availability that can be difficult to predict. Since AEO2014, the capacity and dispatch submodules of the EMM have been updated to include explicit constraints requiring spinning reserves in each load slice. The amount of spinning reserves required is computed as a percentage of the load height of the slice plus a percentage of the distance between the load of the slice and the seasonal peak. An additional requirement is calculated that is a percentage of the intermittent capacity available in that time period to reflect the greater uncertainty associated with the availability of intermittent resources. All technologies except for storage, intermittents, and distributed generation can be used to meet spinning reserves. Different operating modes are developed for each technology type to allow the model to choose between operating a plant to maximize generation versus contributing to spinning reserves, or a combination of both. Minimum levels of generation are required if a plant is contributing to spinning reserves, and vary by plant type, with plant types typically associated with baseload operation having higher minimums than those that can operate more flexibly to meet intermediate or peak demand.

Variable heat rates for coal-fired power plants

Low natural gas prices and rising shares of intermittent generation have led to a shift in coal plant operations from baseload to greater cycling. The efficiency of coal plants can vary based on their output level, with reduced efficiency when plants are run in a cycling mode or to provide operating reserves. The AEO2017 code introduced variable heat rates for coal plants based on the operating mode chosen by the EMM to better reflect actual fuel consumption and costs.

A relationship between operating levels and efficiencies was constructed from data available for 2013-2015 in the EPA continuous emission monitoring system (CEMS) and other EMM plant data. A statistical analysis was used to estimate piece-wise linear equations that estimate the efficiency as a function of the generating unit's output. The equations were estimated by coal plant type, taking into account the configuration of existing environmental controls, and by the geographic coal demand region for the plant, based on the plant level data. Equations were developed for up to 10 different coal plant configurations across the 16 coal regions used in the EMM. The form of the piecewise linear equations for each plant type and region combination can vary, and has between 3 and 11 steps.

Within the EMM, these equations are used to calculate heat rate adjustment factors to "normalize" the average heat rate in the input plant database (which is based on historical data, and associated with an historical output level), and to adjust the heat rate under different operating modes. The EMM currently allows six different modes within each season for coal plants. They are based on combinations of maximizing generation, maximizing spinning reserves or load following, and can be invoked for the full season (all three time slices) or approximately half the season (only peak and intermediate slice). Each of these are associated with different output levels, and the heat rate adjustment factor is calculated based on the capacity factor implied by the operating mode.

Fossil fuel-fired and nuclear steam plant retirement

Fossil-fired steam plant retirements and nuclear retirements are calculated endogenously within the model. Generating units are assumed to retire when it is no longer economical to continue running them. Each year, the model determines whether the market price of electricity is sufficient to support the continued operation of existing plant generators. A generating unit is assumed to retire if the expected revenues from the generator are not sufficient to cover the annual going-forward costs and if the overall cost of producing electricity can be lowered by building new replacement capacity. The going-forward costs include fuel, operations and maintenance costs, and annual capital additions, which are unit-specific and based on historical data. The average annual capital additions for existing plants are $9 per kilowatt (kW) for oil and gas steam plants, $17 per kW for coal plants, and $23 per kW for nuclear plants (in 2016 dollars). These costs are added to the estimated costs at existing plants regardless of their age. Beyond 30 years of age an additional $7 per kW capital charge for fossil plants and $35 per kW charge for nuclear plants is included in the retirement decision to reflect further investment to address the impacts of aging. Age-related cost increases are attributed to capital expenditures for major repairs or retrofits, decreases in plant performance, and/or increases in maintenance costs to mitigate the effects of aging.

EIA assumes that all retirements reported as planned during the next ten years on the Form EIA-860, Annual Electric Generator Report, will occur as well as some others that have been announced but not yet reported to EIA. This includes 6.4 GW of nuclear capacity retirements after 2016. Additionally, the AEO2017 nuclear projection assumes a decrease of 3.0 GW by 2020 to reflect existing nuclear units that appear at risk of early closure due to near-term market uncertainty.

Nuclear plants receive fixed licenses from the U.S. Nuclear Regulatory Commission (NRC) that require renewal at 40 and 60 years for continued operation. The majority of plants have received their first license renewal to operate until 60 years, but only two utilities have announced plans to request a subsequent license renewal (SLR), as most have not reached the age when a decision is required. There is considerable uncertainty surrounding the ability of all reactors to obtain an SLR and operate to 80 years, which will have implications on the requirements for other generation sources through 2050. The AEO2017 Reference case assumes a decrease of 22 GW between 2030 and 2050 to reflect the retirement of some existing reactors after 60 years of operation. This is implemented as a regional derate factor, with the timing and location of the derates based on the distribution and age of the existing fleet, as well as the regulatory status of the plant owner.

Biomass co-firing

Coal-fired power plants are assumed to co-fire with biomass fuel if it is economical. Co-firing requires a capital investment for boiler modifications and fuel handling. This expenditure is assumed to be $534 per kW of biomass capacity. A coal-fired unit modified to allow co-firing can generate up to 15% of the total output using biomass fuel, assuming sufficient residue supplies are available.

Nuclear uprates

The AEO2017 nuclear power projection assumes capacity increases at existing units. Nuclear plant operators can increase the rated capacity at plants through power uprates, which are license amendments that must be approved by the U.S. Nuclear Regulatory Commission. Uprates can vary from small (less than 2%) increases in capacity, which require very little capital investment or plant modification, to extended uprates of 15-20%, requiring significant modifications. AEO2017 assumes that uprates reported to EIA as planned modifications on the Form EIA-860 will take place in the Reference case, representing 0.1 GW of additional capacity. EIA also analyzed the remaining uprate potential by reactor, based on the reactor design and