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| Prepared For: |
| Southern Company Services |
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Scenario Fuel Forecast Documentation – Budget 2019

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Disclaimer

All references to views of Charles River Associates and CRA represent views of the authors and do not necessarily represent views of all representatives of CRA.

# INTRODUCTION

This report describes Charles River Associates’ (CRA’s) development of fuel price forecasts for Southern Company’s Budget 2019 planning scenarios. CRA has produced similar reports supporting Southern's fuel price forecasts over the past nine years.

The Budget 2019 scenarios prepared by CRA are differentiated by varying views on the evolution of natural gas cost and supply, future greenhouse gas (GHG) emissions control policies, and clean technology advances.

CRA deploys its national MRN-NEEM model to generate integrated scenario results for natural gas and coal prices for the period from 2023 through 2058 in five-year increments. MRN-NEEM is multi-sector energy-economy model that solves for fuel prices and fuel demand across U.S. regions.

The integrated modeling approach makes it possible to develop forecasts for natural gas, petroleum, and coal prices that use a consistent set of underlying assumptions and accounts for fuel price impacts on economic growth, electricity consumption, and output across many sectors and regions. The integrated scenario approach takes a set of assumptions about market fundamentals and then solves for the prices that make the quantity supplied equal to the quantity demanded in all markets. In addition, the integrated approach simulates interactions among different markets and thereby reveals how such things as environmental regulations and natural gas supply outlooks shape the disposition of economic output across sectors, as well as the competition between generation fuels such as coal and natural gas.

The modeling process began with a calibration of the MRN-NEEM model to the most recent Energy Information Agency (EIA) Annual Energy Outlook (AEO) that was available at the time of the analysis, in this case the AEO 2018 Reference case. The AEO 2018 Reference case assumes a continuation of the environmental policies in place at the time of the forecast and does not include any nationwide domestic programs to address greenhouse gases. CRA chose this case based on the March 2017 Executive Order issued by the Trump administration to initiate a review and overhaul the rule. CRA analyses assume that other proposed rules that the United States Environmental Protection Agency (EPA) has yet to finalize (or has finalized since EIA performed its Reference case forecast) will come into effect and incorporates scenarios that include a tax on CO2 emissions. The combination of environmental pressure and lower gas prices causes many Budget 2019 scenarios to forecast a large decrease in the size of the coal fleet.

## Utilizing the Results of this Report

The models used in this analysis are focused on long-term results. Southern Company also uses near-term data from futures markets and similar sources to inform the initial years (current year plus next two years) of their internal modeling efforts. To account for this, and to ensure high-quality data is used for near-term expected prices, Southern Company utilizes a blending approach that trends from futures data to the CRA forecast. Under this blending approach, Southern Company interpolates between near-term data and long-term forecasts, with the results of this report being utilized for 2023 and all subsequent years for natural gas and 2021 and all subsequent years for coal.

Short-term forecasts are overseen by Southern Company’s Fuel Services department and updated monthly as part of Southern Company’s fuel budgeting process and marginal pricing dispatch procedures. The long-term forecasts described in this report are developed each year for use in system planning activities, business case analyses, and decision making. The development and documentation of the long-term forecasts is a collaborative effort between CRA and Southern Company and occurs as a part of the planning scenario development process under the guidance and direction of the Southern Company’s Planning Coordination Team. Once the updated long-term forecasts are developed, they are integrated with the short-term forecasts.

The short-term and long-term forecasts are separated for two reasons. The first is that the short-term forecasts are used for company activities such as regulatory fuel filings and operational budgets, which must reflect current laws that are in place. The long-term forecasts reflect a range of projections that take into account probable laws and regulations that are not yet in effect, yet represent Southern Company's expectation of a reasonable range of those future potential laws. Second, the short-term forecasts are based on actual market prices, which reflect current market conditions and market assumptions of the near future but which do not always reflect regulatory, legislative, or other impacts assumed in the modeling of the multiple long-term scenario forecasts.

This report describes the models and methods used to develop the long term fuel forecasts as well as the major underlying assumptions and justifications for these scenarios.

# Overview of Key Drivers: Views on Natural Gas Prices and Environmental Regulations

No model can predict specific future outcomes. Thus, it is important to consider a range of scenarios that encompass the uncertainty around key factors, such as fuel supply and emissions regulation, which materially affect the optimal long-term planning strategy.

For purposes of these forecasts, three fuel views were selected, in order of decreasing natural gas prices: High, Moderate, and Low. These views were developed to encompass what CRA believes is the range of reasonably likely natural gas price outcomes over the modeling horizon.

These natural gas views were each then paired with three CO2 policy views to create 9 unique scenarios:

* $0/tonne CO2: Current on-the-books regulations affecting CO2 emissions and CO2 emitters, but no additional carbon cost. Like Budget 2018, Budget 2019 imposes the EPA-promulgated new source performance standards (NSPS) for CO2 emissions from both coal- and gas/oil-fired new generating technologies.
* $10/tonne CO2: Starting in 2026, a carbon cost of $10 per metric ton CO2 (in **REDACTED** dollars) is applied, increasing at **REDACTED**% annually in real dollar terms.
* $20/tonne CO2: Starting in 2026, a carbon cost of $20 per metric ton CO2 (in **REDACTED** dollars) is applied, increasing at **REDACTED**% annually in real dollar terms.

In summary, CRA has analyzed nine scenarios, seen below in Figure 1, and named the scenarios based on their combination of fuel price outlook and CO2 pressure.

Figure 1: Budget 2019 Planning Scenarios

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
|  | | **CO2 Views** | | |
| **$0 CO2** | **$10 CO2** | **$20 CO2** |
| **Fuel Views** | **High Fuel** | HG0 | HG10 | HG20 |
| **Moderate Fuel** | MG0 | MG10 | MG20 |
| **Low Fuel** | LG0 | LG10 | LG20 |

## 

## Fuel

### Natural Gas

The most important factors in developing natural gas views are the cost, magnitude, and accessibility of shale resources and the magnitude and timing of demand growth.

The volume and cost of producible shale gas resources is critically important, and assumptions about the access to and cost of unconventional gas plays are key drivers in the Budget 2019 fuel scenarios. Since the Budget 2015 analysis, there has been further confirmation of the size of the shale gas resource, and shale gas production has continued to prove plentiful and relatively inexpensive, particularly from “liquids-rich” plays. CRA has observed growth in the estimates of recoverable reserves and improvements in drilling techniques in recent years. These trends drive scenarios where the U.S. is self-sufficient with regard to natural gas supply and becomes a net gas exporter. Under these scenarios, prices are set by the interplay of shale gas production economics and demand in the electric power, industrial sector, and demand for gas exports.

Budget 2019 also devotes considerable attention to what are seen as pivotal drivers of natural gas demand:

* **Power Generation**, increased coal-to-gas switching as a result of natural gas prices and the decision whether or not to extend the life of the existing nuclear fleet; and
* **Environmental Policies**, recent actions by the EPA increased pressure to reduce generation from coal-fired power plants in favor of natural gas and zero-emitting sources; and
* **LNG Exports**, abundant gas supply and low gas prices in many regions of the country have led to significant proposed investments in LNG export capacity as companies seek to take advantage of international gas prices; further, the federal government has signaled increasing openness to LNG exports.

Section 3 addresses these demand drivers and the different views on the gas resource in greater detail.

### Oil

At the commencement of modeling in early 2018, CRA observed a wide spread of recent international oil price forecasts. CRA assessed certain forecasts (e.g. AEO 2018 High Oil Price and Low Oil Price) as unsustainable over the long term, because market demand and supply respond to extended periods of high or low market prices, driving prices back towards the central trend. Still, the forecasts that remained represented radically different views of the global oil markets over the next 40 years. CRA attributes these discrepancies to different but reasonably probable perspectives on the direction and timing of key market drivers. It is extremely difficult to predict with any confidence the geopolitical developments that will shape OPEC’s market strategy, for instance. Given this uncertainty, it is best to view the Budget 2019 oil price forecast as a central tendency to which a range of possible forecasts revert. Through this lens, CRA determined that the EIA’s AEO 2018 Reference case was most consistent with CRA’s crude oil outlook.

Just as with natural gas, supply and demand assumptions are the key drivers of the oil price forecast. However, international drivers currently play a much larger role in setting long-term oil prices. In particular, Asian economic growth has long been a driver for international crude oil demand. CRA assumes that Asia will continue this trend, and expect the expansion of the personal transport sector in both India, China and smaller Asian countries to contribute to increased oil demand over the modeling horizon. Domestically, the Trump administration has announced its intention to freeze stringent fuel economy standards for passenger vehicles proposed by the Obama administration, which could put upwards pressure on demand over the next decade. Although certain pockets of the country may see increased penetration of alternative-fuel vehicles, our scenario set does not include a high level of penetration by 2nd and 3rd generation biofuels or electric vehicles.

On the supply side, CRA believes that OPEC countries will continue to sustain some production discipline, with Saudi Arabia particularly interested in firm oil prices if and when it initiates the planned IPO of a portion of Saudi Aramco. CRA sees some growth in non-OPEC production both domestically and internationally due to the exploitation of tight oil plays, other non-conventional sources and a resumption of deep water exploration to compensate for declining production from mature fields.

The AEO 2018 Reference case projects modest recovery in international oil prices through 2018. This trend is attributable to a more moderate near-term outlook for low-cost tight oil production due to Permian basin infrastructure bottlenecks. CRA concurs with this outlook, and believes that the renewed increase in tight oil exploration and production from 2020 through 2027 will buy time before traditional demand destruction economics again set global prices.

Section 4 discusses the outlook and drivers for the oil markets in greater detail.

### Coal

Because the U.S. power sector has historically consumed the vast majority of U.S. coal, the key drivers of our coal demand forecast are (1) how the relationship between natural gas and coal commodity prices influences fuel-switching between coal and natural gas in the power sector, and (2) environmental regulations targeting coal-fired power plants.

In response to stringent EPA requirements on air emissions, water intake and wastewater discharges, and coal ash disposal, the costs of coal-fired generation are assumed to increase. CRA assumes that existing plants will need to retrofit with environmental controls, reduce dispatch, or retire as they face new requirements. Furthermore, NSPS prevents the construction of new coal-fired generation without carbon capture and storage (CCS).

In Budget 2019, like Budget 2018, certain scenarios impose more proscriptive assumptions around natural gas-fired combined-cycle (NGCC) and nuclear capacity. These limits make new CCS-equipped plants a more viable option for meeting long term demand growth in the moderate and high gas price cases that also include carbon pricing. Budget 2019 had full CCS (90% capture) versions of integrated coal-gasification combined cycle (IGCC w/ CCS) and natural gas-fired CCs (NGCC w/ CCS) units.

Under the natural gas and CO2 prices considered in Budget 2019 scenarios, new coal-fired plants with CCS prove economic only in years featuring high natural gas prices and CO2 price pressure, and not in any significant amount until around 2053.

A small number of CCS retrofits on existing coal units were selected in the $10 and $20 CO2 cases across all gas price views. Some of these units are taking advantage of the 45Q tax credit and enhanced oil recovery revenue available in oil producing regions of the U.S. In the MG20 and HG20 cases, the model constructs additional retrofits beginning in late 2040’s and early 2050’s. However, the overall level of CCS activity is limited in scope and CRA’s results show that new CCS-equipped coal cannot come close to replacing the retirement of existing coal units particularly vulnerable to near-term environmental regulations. In turn, electric-sector coal demand falls from current levels across all Budget 2019 scenarios with CO2 pressure as more stringent environmental regulations take effect.

On the other hand, production cost increases in the majority of U.S. coal basins are putting upward pressure on mine mouth coal prices. Thus, CRA sees some growth in long-term coal prices even in the scenarios with the most pessimistic views on electric-sector coal demand.

In turn, coal prices generally increase slightly over time in the views lacking a CO2 price, while, in the CO2 price views, prices initially decline and then either flatten out or slowly recover to levels near or slightly above current prices.

Section 5 discusses the key market drivers and outlooks for the major coal basins in greater detail.

## Environmental Regulations

CRA includes a range of environmental regulations covering greenhouse gases and other airborne pollutants, renewable energy standards, treatment and disposal of coal ash, scrubber wastewater, and water used for power plant cooling in the Budget 2019 scenarios. These policies require fossil-fired generating units to install control technologies based on their location, size, and generation type. A detailed discussion of CRA’s outlook on environmental policies is included below in Section 6.

CRA believes the greatest uncertainty surrounds the regulation of GHGs, and includes varying degrees of CO2 pressure as a scenario variable in Budget 2019. GHG and other environmental regulations have several impacts on the expected operations of electric generators and the model’s selection of what type of new generating capacity will be built to meet energy and load requirements, as many of these regulations place a significantly higher burden on existing coal-fired generators compared to other forms of generation. Subsequently, these units face greater risks of retirement or lower dispatch. Coal retirements and/or lower dispatch have implications for the demand and pricing of coal and natural gas, the latter of which can substitute for coal in the electric sector, especially in the near term.

The CO2 scenarios considered in this year’s forecasts include “cost” scenarios based on CO2 prices ranging from $0 to $20 per metric ton of CO2 (in **REDACTED** dollars) starting in 2026, and then rising at **REDACTED**% annually plus inflation. The analysis does not include explicit cases which conform to a specific carbon rule but use a price on carbon as a proxy for any potential future regulation. By analyzing a wide range of CO2 prices, including a view with no additional price on CO2, and other types of environmental requirements on the power sector, the Budget 2019 analysis considers the principal impacts of various levels of GHG policy stringency on the electric sector, fuel prices, and the overall economy.

The Budget 2019 analysis has considered three different carbon views that span a wide range of possible future GHG policies:

* The $0 CO2 view is the least stringent of the Budget 2019 scenarios, and assumes that there will be no new price-base regulations on GHG emissions.
* The $10 CO2 view adds an economy-wide price on CO2 emissions that begins at $10 per metric ton (**REDACTED**$) in 2026 and rises at **REDACTED**% above inflation; and
* The $20 CO2 view has an economy-wide price on CO2 emissions that begins at $20 per metric ton (**REDACTED**$) in 2026 and rises at **REDACTED**% above inflation.

With regards to new source performance standards on CO2 emissions, all Budget 2019 scenarios prohibit new coal not already under construction without CCS. In addition, both the $10 and $20 CO2 price views are coupled with the assumption that new natural gas combined-cycle power generators will be required to have full (90% capture) CCS beginning in 2035 in the $20 case, and 2045 in the $10 case. CRA believes that the combination of these CO2 NSPS provisions and the $20 CO2 price path represents a reasonable high bound, and that a higher price is not necessary to model.

## Limitations on Electric Generation Baseload Capacity Additions

While there are many different generating technologies available to the electric sector, political and economic realities suggest that there are limitations on the quantity and timing of certain new generating capacity additions. To reflect these realities, limits on several new build types have been applied uniformly across all scenarios:

* New coal units without CCS are limited to those projects that are currently under construction. CRA did not assume any under construction coal units come online for the Budget 2019 analysis.
* New pulverized coal, IGCC, nuclear and NGCC units equipped with CCS are assumed unavailable until **REDACTED**.[[1]](#footnote-2) Nuclear limits are discussed in greater detail in Section 2.3.1. Budget 2019 sets no limits on CCS-equipped technologies and allows the model to build as much CCS-equipped capacity as is economic. The highest annual build rate across the Budget 2019 scenarios was roughly 1.4 GW per year (from 2053 through 2058) of Coal with CCS in the High Gas, $20 CO2 scenario.
* Total new NGCC builds (with and without CCS) face the same limits assumed in the Budget 2018 analysis and were developed as follows. At the height of the NGCC boom in the early 2000s, there were up to 45 GW of NGCCs built nationally per year. Since then, the NGCC build rate has slowed to the point where annual NGCC new builds averaged roughly 15 GW from 2000 through 2012. In light of history, and to allow adequate replacement of coal forced to retire by various environmental regulations, NGCCs are limited to 20 GW per year in the first model year for Budget 2019. This limit then moves with the GDP growth rate to reflect the fact that a larger economy could accommodate a higher build rate.
* New additions of intermittent resources, such as wind and solar are limited to 20% of total demand to ensure a reliable electric system.[[2]](#footnote-3) Other renewables, such as biomass, landfill gas, and geothermal, have regional limits based on available resources such as feedstocks and geologic suitability.

### Treatment of Existing and New Nuclear Capacity

On a levelized cost basis, nuclear capacity can be an attractive baseload generating technology to replace retiring coal capacity and to meet growing demand requirements, particularly under CO2 pricing scenarios. This is especially true as new low-cost renewable capacity like solar PV and onshore wind reach regional intermittency limits.[[3]](#footnote-4) In reality, nuclear capacity is limited by several factors not necessarily accounted for in a levelized cost calculation, including manufacturing capacity shortages, the ability to finance, and delays or objections to operating or obtaining environmental permits due to public perceptions regarding nuclear technology. Further, observed cost decreases for new NGCC generation technologies coupled with lower expected gas prices can put pressure on economics of new nuclear.

The overall maximum U.S. nuclear capacity levels assumed in Budget 2019 are derived from the following three assumptions: (1) power uprates and planned capacity additions, (2) the timing and extent of license extensions granted to existing nuclear units as current licenses expire, and (3) new greenfield nuclear capacity limits over time.

In terms of nuclear expansion activity in the near term, Budget 2019 incorporates 537 MW of nuclear uprates completed in 2017, the same as in Budget 2018. This figure includes 44MW of uprates at the Peach Bottom plant as published by the Nuclear Regulatory Commission (NRC) that were not reflected in the Energy Velocity dataset.[[4]](#footnote-5) Budget 2019 also incorporates new nuclear capacity additions for those facilities that have already received advanced regulatory approvals and begun construction.[[5]](#footnote-6)

Assumptions around operating license extensions and retirement date for the nearly 99 GW of existing U.S. nuclear capacity can significantly sway natural gas and coal demand forecasts. In Budget 2019, as in Budget 2018, CRA allowed approximately 11.6 GW of existing nuclear to receive a Subsequent License Renewal (SLR), extending the lifetime of these plants to 80 years. The units that can receive this second extension meet a number of criteria: (1) they came online after 1980, (2) they would reach their 60th birthday before the end of the modeling horizon, (3) they are multi-reactor facilities, and (4) they are not located in “competitive-unlikely” regions.

CRA has classified certain markets as “competitive-unlikely” regions. These are regions that are (1) “competitive”, in other words are not characterized by a vertically integrated utility construct, whereby investors have greater assurances that nuclear construction costs can be passed through to customers, and (2) were “unlikely” to support new nuclear power in the future, given treatment of proposed nuclear capacity and retired nuclear plants in their regions. These competitive-unlikely regions include ISO-NE, NYISO, California, Eastern PJM (New Jersey, Delaware, Maryland’s Eastern Shore, and Eastern Pennsylvania), and Northern Illinois (Commonwealth Edison’s service territory), and encompass over 31 GW of nuclear capacity built between 1969 and 1990.

In addition, CRA has identified seven nuclear units in Southern Illinois, Texas, Ohio, Pennsylvania, and Michigan, whose unfavorable economic and regulatory conditions warrant reassignment to the “Competitive-Unlikely” category.

In Budget 2019 CRA assumed that these 50 GW of capacity in the “competitive-unlikely” regions could be replaced by new brownfield capacity in all cases (i.e. in the $0 scenarios as well as the $10 CO2 and $20 CO2 views). In other words, CRA assumed that these regions’ regulatory bodies would allow new nuclear, such that all existing capacity could be immediately replaced upon retirement in the event nuclear generation was the most cost effective resource due to high natural gas or CO2 prices. Figure 2 charts the new nuclear replacement allowances by year (solid + dashed) in the $0, $10, and $20 CO2 price views.

Figure 2: Allowances for New Brownfield Nuclear Capacity to Replace Retiring Plants

As described above, CRA does not allow new greenfield additions until **REDACTED** due to regulatory aversion and long lead times in construction. From **REDACTED**, 2.2 GW (the equivalent of two standard-sized nuclear units) of new greenfield nuclear capacity are allowed per year, in addition to the replacement brownfield capacity.

In Figure 3 below, the solid lines represent the Budget 2019 views, while Budget 2018 is represented by dashed lines. The Budget 2019 maximum potential nuclear capacity is slightly lower than Budget 2018 after 2020 due to the cancellation of the VC Summer units, recently announced accelerated retirements, and later availability of greenfield capacity.

Figure 3: North American Maximum Available Nuclear Capacity Summary

**REMAINDER OF REPORT IS REDACTED IN ITS ENTIRETY**

1. An exception is made for Georgia Power’s Vogtle Units 3 and 4. [↑](#footnote-ref-2)
2. This figure is based on CRA’s “SPP WITF Wind Integration Study” performed on behalf of Southwest Power Pool in 2010. See <http://www.uwig.org/CRA_SPP_WITF_Wind_Integration_Study_Final_Report.pdf> for the full report. Where needed to meet RPS requirements, CRA allows greater penetration of intermittent technologies. [↑](#footnote-ref-3)
3. CRA assumes a 20% limit on intermittent generation in most regions of the US, states with more aggressive RPS programs, such as CA and NY, have this constraint relaxed. [↑](#footnote-ref-4)
4. Pending power uprates: <http://www.nrc.gov/reactors/operating/licensing/power-uprates/status-power-apps/pending-applications.html> and Expected power uprates: <http://www.nrc.gov/reactors/operating/licensing/power-uprates/status-power-apps/expected-applications.html> as of April 2, 2018. [↑](#footnote-ref-5)
5. This includes Georgia Power’s Vogtle Units 3 & 4. [↑](#footnote-ref-6)