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Natural Gas and Net Zero: Mutually Exclusive Pathways for the Southeast

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NATURAL GAS AND NET ZERO: MUTUALLY EXCLUSIVE PATHWAYS FOR THE SOUTHEAST

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ABSTRACT

Climate policy increasingly focuses on pathways to achieving net zero greenhouse gas emissions by 2050, providing a clear standard against which to evaluate energy system planning. Examining the current and projected fuel mix of the electric power sector in the southeastern United States shows that an ongoing transition to natural gas for electricity risks locking in decades of greenhouse gas emissions at levels fundamentally incompatible with net zero goals. Furthermore, southeastern regulatory proceedings are not well designed to engage with this reality, although useful regulatory models are emerging. Natural gas will remain an important part of the southeastern fuel mix for years to come, but plans need to be laid today for its timely phaseout. Going forward, southeastern regulators should incorporate net zero targets into their resource planning processes and require their regulated utilities to begin developing planning scenarios that achieve net zero.

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I. Introduction & Background

The nations of the world, the global scientific community, and, as of recently, the United States executive branch all agree: to limit the impacts of global climate change, humanity must achieve net zero worldwide greenhouse gas (GHG) emissions by 2050.[1] But net zero is only an initial step along a longer path which requires a further half-century of net negative emissions after 2050 to stabilize earth's climate by 2100.[2] Compounding these challenges is the relative ease or

1. Paris Agreement to the United Nations Framework Convention on Climate Change art. 2, ¶1(a), art. 4, ¶1, Dec. 12, 2015, T.I.A.S. No. 16-1104 (setting the internationally agreed upon goal of stabilizing climate at 1.5°C warming by 2100 and providing that UNFCCC parties agree to "achieve a balance between anthropogenic emissions by sources and removals by sinks of greenhouse gases in the second half of this century"); *Summary for Policymakers*, *in* Intergovernmental Panel on Climate Change, Global Warming of 1.5°C, at 3, 12 (Valérie Masson-Delmotte et al., eds. 2022) ("In model pathways with no or limited overshoot of 1.5°C, global net anthropogenic CO_2 emissions decline by about 45% from 2010 levels by 2030 . . . reaching net zero around 2050 . . . ."); *Fact Sheet: President Biden Sets 2030 Greenhouse Gas Pollution Reduction Target Aimed at Creating Good-Paying Union Jobs and Securing U.S. Leadership on Clean Energy Technologies*, White House (Apr. 22, 2021), https://www.whitehouse.gov/briefing-room/statements-releases/2021/04/22/fact-sheet-president-biden-sets-2030-greenhouse-gas-pollution-reduction-target-aimed-at-creating-good-paying-union-jobs-and-securing-u-s-leadership-on-clean-energy-technologies/ [https://perma.cc/AGZ3-8SRQ] (explaining that, by rejoining the Paris Agreement, President Biden "set a course for the United States to tackle the climate crisis at home and abroad, reaching net zero emissions economy-wide by no later than 2050"); *see generally* The United States of America: Nationally Determined Contribution: Reducing Greenhouse Gases in the United States: A 2030 Emissions Target (2021), https://unfccc.int/sites/default/files/NDC/2022-06/United%20States%20NDC%20April%2021%202021%20Final.pdf [https://perma.cc/P4AR-XD23] (providing a summary of U.S. commitments under the Paris Agreement). For a brief introduction to climate science and greenhouse gases, see Kerry A. Emanuel, Climate Science and Climate Risk: A Primer (2016), https://climateprimer.mit.edu/climate-primer.pdf [https://perma.cc/57DE-KLGJ]. The GHGs of primary concern in this Article are carbon dioxide (CO_2), a primary physical byproduct of hydrocarbon combustion, and methane (CH_4), which is a major component of unburned natural gas. For a discussion of the impacts that these two GHGs have on climate see *Understanding Global Warming Potentials*, U.S. Env't Prot. Agency: Greenhouse Gas Emissions, https://www.epa.gov/ghgemissions/understanding-global-warming-potentials [https://perma.cc/8NSZ-3AW5] (Apr. 18, 2023).

2. *See* Tara Shirvani & Climate Crisis Advisory Grp., *The Final Warning Bell: The Most Important Assessment of Humanity's Future on Earth to Date*, Climate Crisis Advisory Grp., https://static1.squarespace.com/static/60ccae658553d102459d11ed/t/612f491253769c13f5e52b1d/1630488861782/CCAG+Beyond+Net+Zero_V2.1.pdf [https://perma.cc/LAD5-LGN4] (noting that net zero target alone is "too little too late" because planning must also incorporate a half-century period of negative emissions); Wijnand Stoefs, *What "Negative Emissions"?*, Carbon Mkt. Watch (May 27, 2020, 3:13

difficulty of achieving both net zero emissions and climate stabilization through net negative emissions, which will be impacted by decisions we make today about the kind of energy infrastructure we build and use.[3] In short, the lives of our children and grandchildren will be deeply affected by the technological inheritance we leave to them.

This Article examines one small but important piece of the larger story: the technologies used to generate electricity in the southeastern United States, confined here to Alabama, Florida, Georgia, Mississippi, North Carolina, South Carolina, and Tennessee (the Southeast or southeastern U.S.).[4] There are many reasons for focusing on the Southeast's electric power sector, but fundamentally, this topic deserves examination because of the negative impact that current decisions about the region's long-term energy future—and, thus, its long-term climate future—will have on the country's ability to achieve

PM), https://carbonmarketwatch.org/2020/05/27/what-negative-emissions/ [https://perma.cc/4H5D-HLJT]; Kevin Anderson & Glen Peters, *The Trouble with Negative Emissions*, 354 SCIENCE 182, 183 (2016) (noting negative emissions generally assumed to begin contributing to net zero pathways in around 2030).

3. *See generally* T.J. Foxon, *Technological Lock-In*, *in* 1 ENCYCLOPEDIA OF ENERGY, NATURAL RESOURCE, AND ENVIRONMENTAL ECONOMICS 123 (2013) (discussing path dependency and advantages of incumbent technologies in the energy context and more generally).

4. There is no "official" definition of the southeastern United States, although the states included in this review are typically included. *See Southeastern United States*, WIKIPEDIA, https://en.wikipedia.org/wiki/Southeastern_United_States [https://perma.cc/Q2HW-JZPP] (May 21, 2023, 3:58 AM UTC). As this Article is focused on electricity regulation, it is worth noting that since 2019, these are the states that are entirely within the boundaries of the SERC Reliability Corporation. *See About SERC*, SERC RELIABILITY CORP., https://www.serc1.org/about-serc [https://perma.cc/UZX3-AZAS]; *ERO Enterprise: Regional Entities*, N. AM. ELECTRIC RELIABILITY CORP., https://www.nerc.com/AboutNERC/keyplayers/Pages/default.aspx [https://perma.cc/2DMS-R78C]. SERC's territory includes parts of several other southeastern states as well, but two other important interstate electricity organizational demarcations recommend analysis of the states chosen here. First, with the exception of parts of Mississippi and North Carolina, these states lack Regional Transmission Organizations and independent electric power markets. *See RTOs and ISOs*, FED. ENERGY REGUL. COMM'N, https://www.ferc.gov/power-sales-and-markets/rtos-and-isos [https://perma.cc/7DMB-EMGM] (Mar. 22, 2023); *Electric Power Markets*, FED. ENERGY REGUL. COMM'N, https://www.ferc.gov/electric-power-markets [https://perma.cc/285P-Q7U9] (May 16, 2023). These states are also notable as their state legislatures and, with the exception of North Carolina, governors' offices are held by the Republican Party, providing insight into developing "red-state" approaches to these issues. Certainly, there are many differences between these states, and many similarities between these states and their neighbors, but ultimately these seven states are those that share the most commonalities between energy markets, transmission management, and reliability coordination functions, and are all traditionally understood to be core "Southeastern" states.

net zero and effectively implement climate stabilization strategies.[5] Many lessons can be drawn from a regional analysis that are not clear at either the state or national level. But most importantly, the legal, policy, political, and technical processes underlying the analysis deserve to be clearly understood by those with the greatest stake in their impacts: the next generation of leaders in the Southeast.

As explained in detail below, stakeholders in the Southeast—particularly state governments and regulated utilities but also the federal Tennessee Valley Authority (TVA)—are in the process of replacing most of the Southeast's coal-fired power plants with natural gas-fired facilities instead of lower-carbon alternatives, a fundamentally problematic solution.[6] Unfortunately, although large-scale investments in natural gas infrastructure provide short-term benefits in terms of electric reliability, cost savings, and GHG reductions, they are inconsistent with the net zero and climate stabilization goals of tomorrow. In fact, such investments lock the Southeast into a future of more GHG emissions than it can remove, and for far longer than is sustainable. Quite simply, every gas plant built today will need to be shut down tomorrow. Perhaps the region could justify its focus on natural gas if it lacked viable alternatives, but, in fact, there are many alternatives to which the Southeast's energy policy experts should turn. The majority of the region's future capacity

5. *See* Kristi E. Swartz, *Can U.S. Phase Out Natural Gas? Lessons from the Southeast*, E&E NEWS: ENERGYWIRE (Dec. 8, 2021, 7:07 AM), https://www.eenews.net/articles/can-u-s-phase-out-natural-gas-lessons-from-the-southeast/ [https://perma.cc/KLH6-H9XX]; *cf.* Michael Copley, *The U.S. Wants to Slash Carbon Emissions from Power Plants. Natural Gas Is in the Way*, NPR (Dec. 5, 2022, 7:29 AM), https://www.npr.org/2022/12/05/1139401121/the-u-s-wants-to-slash-carbon-emissions-from-power-plants-natural-gas-is-in-the- [https://perma.cc/N6YW-S46J].

6. *See* Glenn McGrath, *Electric Power Sector CO_2 Emissions Drop as Generation Mix Shifts from Coal to Natural Gas*, U.S. ENERGY INFO. ADMIN.: TODAY IN ENERGY (June 9, 2021), https://www.eia.gov/todayinenergy/detail.php?id=48296 [https://perma.cc/B9U4-HZFA]; Josh Keefe & Anila Yoganathan, *TVA Finalizes Plan to Transition Cumberland Coal Plant to Natural Gas*, TENNESSEAN, https://www.tennessean.com/story/news/environment/2023/01/10/tennessee-valley-authority-to-replace-cumberland-coal-plant/69795832007/ [https://perma.cc/52YV-64AY] (Jan. 10, 2023, 3:08 PM); Lindsay Aramayo, *More than 100 Coal-Fired Plants Have Been Replaced or Converted to Natural Gas Since 2011*, U.S. ENERGY INFO. ADMIN.: TODAY IN ENERGY (Aug. 5, 2020), https://www.eia.gov/todayinenergy/detail.php?id=44636 [https://perma.cc/3DKD-TUVZ]; Ken Silverstein, *With Coal on the Way Out, Policymakers Have Their Eye on Natural Gas*, FORBES (Mar. 14, 2022, 8:30 AM), https://www.forbes.com/sites/kensilverstein/2022/03/14/with-coal-on-the-way-out-policymakers-have-their-eye-on-natural-gas/?sh=275aec94d506 [https://perma.cc/MQN3-D27Q].

additions should be met with solar energy, offshore wind, nuclear power, and other low-carbon energy resources integrated with energy storage. But these technologies will succeed only if Southeast decisionmakers insist on the transition, support its development, and temper the growing reliance on natural gas while they do so. This requires planning, starting now.

To explore these issues, this Article is broken into three Parts. The remainder of Part I introduces some basic concepts key to the discussion: what net zero means, how it can be achieved, and what concepts and terminology are necessary to compare different energy pathways and strategies against net zero goals. Part II explores the ongoing natural gas transition in the southeastern U.S. and its implications for climate change and then turns to the planning processes that will govern how much natural gas is used in the future for powering the Southeast's electric sector. Finally, Part III provides recommendations for improving these planning processes by incorporating net zero pathways into fuel mix planning.

A. Net Zero Pathways—More Net vs. More Zero

At the broadest scale and in simplest terms, achieving "net zero" emissions means striking an even balance between anthropogenic (human-caused) additions of GHGs *into* earth's atmosphere ($aGHG_{in}$) and anthropogenic removals of GHGs *from* earth's atmosphere ($aGHG_{out}$), such that the total sums to zero.[7] That is:

7. *For a Livable Climate: Net-Zero Commitments Must Be Backed by Credible Action*, UNITED NATIONS: CLIMATE ACTION, https://www.un.org/en/climatechange/net-zero-coalition [https://perma.cc/GN6J-MT6C] ("Put simply, net zero means cutting greenhouse gas emissions to as close to zero as possible, with any remaining emissions re-absorbed from the atmosphere, by oceans and forests for instance."); *see also* United Nations Framework Convention on Climate Change Secretariat, Nationally Determined Contributions Under the Paris Agreement, Synthesis Rep. by the Secretariat, at 1–11, U.N. Doc. FCCC/PA/CMA/2022/4 (Oct. 26, 2022), https://unfccc.int/sites/default/files/resource/cma2022_04.pdf [https://perma.cc/7YSB-CSYG] (discussing international progress toward Paris goals in context of net zero by 2050); THE HIGH-LEVEL EXPERT GROUP ON THE NET ZERO EMISSIONS COMMITMENTS OF NON-STATE ENTITIES, UNITED

$$\text{humanity's net zero: } aGHG_{in} - aGHG_{out} = 0$$

At the scale of nations, businesses, and individuals, these definitions become more complex. There is always a pressure to continue emitting and counting removals that, in reality, are more fairly attributable to somebody else, would have happened anyway, or are not, in fact, permanent removals.[8] But the idea remains the same: to balance additions and subtractions of GHGs evenly such that the sum climate impact of a nation, a business, or an individual is zero.[9] Humanity's net zero requires accurate accounting such that the collective "net zeroes" also sum to zero.[10]

Today, humanity's annual GHG emissions far exceed humanity's removals.[11] The result is increasing atmospheric concentrations of GHGs and associated global warming and climate change.[12] By definition, there are only two pathways from this point toward net zero: first, to *decrease* the rate of GHG additions *into* the atmosphere

NATIONS, INTEGRITY MATTERS: NET ZERO COMMITMENTS BY BUSINESSES, FINANCIAL INSTITUTIONS, CITIES AND REGIONS 15 (2022), https://www.un.org/sites/un2.un.org/files/high-level_expert_group_n7b.pdf [https://perma.cc/MRG7-QXJ6]. There are other issues to consider respecting the earth's natural carbon cycle and GHGs naturally removed from the atmosphere. *See* Andrew Moseman, *How Much Carbon Dioxide Does the Earth Naturally Absorb?*, MIT CLIMATE PORTAL (Jan. 4, 2022), https://climate.mit.edu/ask-mit/how-much-carbon-dioxide-does-earth-naturally-absorb [https://perma.cc/GB3Q-EBJN]. Net zero definitions are sometimes ambiguous in their treatment of natural removals (sinks), but the UN framework and Paris Agreement contemplate a balance of anthropogenic additions and removals, accounted separately from the natural carbon cycle.

8. *See* ANJA KOLLMUSS, MICHAEL LAZARUS, CARRIE LEE, MAURICE LEFRANC & CLIFFORD POLYCARP, HANDBOOK OF CARBON OFFSET PROGRAMS: TRADING SYSTEMS, FUNDS, PROTOCOLS AND STANDARDS 1 (2010) (discussing "additionality, permanence, leakage, quantification[,] and verification" issues in crediting context).

9. *See What Is Net Zero?*, NET ZERO CLIMATE, https://netzeroclimate.org/what-is-net-zero/ [https://perma.cc/Q5SX-LZUF].

10. *See id.*

11. Though there is no comprehensive data set calculating global GHG removals, a recently published report on CO_2 removal shows that only 2 billion tons of CO_2 is removed annually, which is a mere fraction of the almost 55 billion tons of annual emissions. *See* Gloria Dickie, *Global Carbon Dioxide Removal Totals 2 Billion Tonnes Per Year – Report*, REUTERS, https://www.reuters.com/business/environment/global-carbon-dioxide-removal-totals-2-billion-tonnes-per-year-report-2023-01-19/ [https://perma.cc/4FRW-E5NG] (Jan. 18, 2023, 7:25 PM); Hannah Ritchie & Max Roser, *Greenhouse Gas Emissions*, OUR WORLD IN DATA (2020), https://ourworldindata.org/greenhouse-gas-emissions [https://perma.cc/CWY6-DS44].

12. *Summary for Policymakers*, *in* INTERGOVERNMENTAL PANEL ON CLIMATE CHANGE, CLIMATE CHANGE 2021: THE PHYSICAL SCIENCE BASIS 4–5 (Valerie Masson-Delmotte et al., eds. 2021).

($-aGHG_{in}$); and second, to *increase* the rate of GHG removals *from* the atmosphere ($+aGHG_{out}$).[13] But because humanity currently lacks the technology necessary to remove GHGs from the atmosphere at anything close to the scale necessary to reach net zero, there is, in reality, only one currently feasible pathway toward achieving net zero: to decrease GHG emissions substantially. This approach is commonly called "mitigation."[14]

However, the net zero mitigation pathway represents an enormous challenge—really, a set of interconnected challenges. To start, mitigation requires a near total transformation of humanity's energy systems, including those systems related to generating electricity, fueling transportation, and providing heat.[15] The closer to zero emissions each of these systems can become, the less work will need to be done by the yet unproven "net" part of "net zero"—that is, the less reliance must be placed on new technologies being invented to balance out emissions on a large scale.[16] That is not to say that such technologies should not be investigated and developed—in fact, achieving negative emissions after 2050 will require their perfection and widespread deployment—rather, that mitigation now reduces the negative emissions burden later.[17] This is the driving force behind initiatives as seemingly disparate as electric vehicle development and efforts to reduce natural gas in home heating.[18] The primary benefit of

13. *See id.* at 27.

14. *Mitigation*, UN ENV'T PROGRAMME, https://www.unep.org/explore-topics/climate-action/what-we-do/mitigation [https://perma.cc/M6WV-YH5A] ("Climate Change Mitigation refers to efforts to reduce or prevent emission of greenhouse gases.").

15. *See* STÉPHANIE BOUCKAERT, ARACELI FERNANDEZ PALES, CHRISTOPHE MCGLADE, UWE REMME, BRENT WANNER, LASZLO VARRO, DAVIDE D'AMBROSIO, THOMAS SPENCER ET AL., INT'L ENERGY AGENCY, NET ZERO BY 2050: A ROADMAP FOR THE GLOBAL ENERGY SECTOR 20 (2021), https://iea.blob.core.windows.net/assets/deebef5d-0c34-4539-9d0c-10b13d840027/NetZeroby2050-ARoadmapfortheGlobalEnergySector_CORR.pdf [https://perma.cc/7X52-HPHQ] (graphing key milestones to net zero including transformations in buildings, transport, industry, electricity and heat). For a discussion of the challenges related to achieving net zero in electricity production in particular, see generally PAUL DENHOLM, PATRICK BROWN, WESLEY COLE, TRIEU MAI, BRIAN SERGI, MAXWELL BROWN, PAIGE JADUN, JONATHAN HO ET AL., NAT'L RENEWABLE ENERGY LAB'Y, EXAMINING SUPPLY-SIDE OPTIONS TO ACHIEVE 100% CLEAN ELECTRICITY BY 2035 (2022).

16. BOUCKAERT ET AL., *supra* note 15, at 14.

17. *See id.* at 15–16, 18.

18. *Id.* at 17.

the mitigation pathway is that it is built on technologies that, after decades of research and development, are now cost-competitive and equivalently functional as their fossil fuel counterparts.[19] One might think of the mitigation pathway via widespread low-carbon electrification as a "more zero, less net" approach to net zero.[20] There may be some atmospheric carbon removal, certainly, but it is not the majority of the equation.

Today: $aGHG_{in} - aGHG_{out} > 0$
mitigation pathway to zero: decrease $aGHG_{in}$ via source reduction
CCS pathway to zero: decrease $aGHG_{in}$ via capture and sequestration
removal pathway to zero: increase $aGHG_{out}$

There are, however, competing views about whether the "net" or the "zero" part of the net zero solution should predominate.[21] The other path forward relies on hoped-for advances in carbon capture and sequestration (CCS), which allows for the continued use of fossil fuels for as long as possible by offsetting ongoing emissions and widespread application of removal technologies at some future point.[22] This might

19. *See* INT'L ENERGY AGENCY & NUCLEAR ENERGY AGENCY, PROJECTED COSTS OF GENERATING ELECTRICITY 13–14 (2020), https://iea.blob.core.windows.net/assets/ae17da3d-e8a5-4163-a3ec-2e6fb0b5677d/Projected-Costs-of-Generating-Electricity-2020.pdf [https://perma.cc/Z6ZQ-XBD3]; Press Release, International Renewable Energy Agency, Renewable Power Remains Cost-Competitive amid Fossil Fuel Crisis (July 13, 2022), https://www.irena.org/news/pressreleases/2022/Jul/Renewable-Power-Remains-Cost-Competitive-amid-Fossil-Fuel-Crisis [https://perma.cc/46V3-UFFS]; *Renewable Energy and Electricity*, WORLD NUCLEAR ASS'N, https://world-nuclear.org/information-library/energy-and-the-environment/renewable-energy-and-electricity.aspx [https://perma.cc/ZQ7J-R92L]. *But see Are Renewable Heating Options Cost-Competitive with Fossil Fuels in the Residential Sector?*, INT'L ENERGY AGENCY (Dec. 1, 2021), https://www.iea.org/articles/are-renewable-heating-options-cost-competitive-with-fossil-fuels-in-the-residential-sector [https://perma.cc/NQ9U-LCQK] (noting overall cost-competitiveness of renewable energy depends on a number of factors that vary by locale such as carbon taxes, equipment costs, and local policies).

20. *See* Tom Dowdall, *Science-Based Net-Zero Targets: 'Less Net, More Zero,'* SCI. BASED TARGETS (Oct. 7, 2021), https://sciencebasedtargets.org/blog/science-based-net-zero-targets-less-net-more-zero [https://perma.cc/F3KV-XUDQ].

21. *See, e.g.*, *id.*; Martin Reeves, David Young, Julia Dhar & Annelies O'Dea, *Will Net Zero Get Us to Net-Zero Emissions?*, BOS. CONSULTING GRP. (Apr. 6, 2022), https://www.bcg.com/publications/2022/how-to-address-net-zero-limitations-to-achieve-net-zero-emissions [https://perma.cc/ES4M-FHTQ].

22. Howard J. Herzog, *What Future for Carbon Capture and Sequestration?*, 35 ENV'T SCI. & TECH. 148A, 150A (2001).

be considered the "more net, less zero" pathway. The idea here is that fossil fuel GHG contributions are well-understood physically; moreover, it is at least theoretically possible to capture those emissions, prevent them from escaping into the atmosphere, and transport the captured emissions to a location to be permanently sequestered.[23] And, indeed, there are technologies that accomplish each of these functions—specialized filtration facilities can remove GHG emissions from fossil fuel flue gases; specialized pipelines can move captured GHGs from place to place; and particular geologic formations can hold the captured GHGs underground, theoretically forever.[24] But presently, these technologies are very expensive, have key geographic limitations, and, most importantly—even after decades of research and development—are unable to deploy at scale, unlike mitigation technologies.[25] Nonetheless, given that they will also be necessary on the mitigation pathway after 2050, there is a very strong argument for continuing to develop these technologies as quickly as possible.[26]

In addition to mitigation and CCS, there is also a third option: to achieve net zero by vastly increasing removal from the atmosphere, that is, continue to release GHGs into the atmosphere but ensure that they are removed from the atmosphere.[27] This underappreciated distinction between CCS and removal is quite important; one involves capturing emissions before they enter the atmosphere, whereas the

23. Sonil Nanda, Sivamohan N. Reddy, Sushanta K. Mitra & Janusz A. Kozinski, *The Progressive Routes for Carbon Capture and Sequestration*, 4 ENERGY SCI. & ENG'G 99, 103 (2016).

24. Herzog, *supra* note 22, at 152A; J.C.M. Pires, F.G. Martins, M.C.M. Alvim-Ferraz & M. Simões, *Recent Developments on Carbon Capture and Storage: An Overview*, 89 CHEM. ENG'G RSCH. & DESIGN 1446, 1452, 1453 (2011).

25. Pires et al., *supra* note 24, at 1446–48, 1453–54.

26. *See* BOUCKAERT ET AL, *supra* note 15, at 15.

27. *See* James Mulligan, Gretchen Ellison, Kelly Levin, Katie Lebling & Alex Rudee, *6 Ways to Remove Carbon Pollution from the Sky*, WORLD RES. INST. (Mar. 17, 2023), https://www.wri.org/insights/6-ways-remove-carbon-pollution-sky [https://perma.cc/2QM9-2W35]; Katie Lebling, Haley Leslie-Bole, Peter Psarras, Elizabeth Bridgwater, Zachary Byrum & Hélène Pilorgé, Direct Air Capture: Assessing Impacts to Enable Responsible Scaling 1 (May 4, 2022) (unpublished manuscript), https://files.wri.org/d8/s3fs-public/2022-04/direct-air-capture-assessing-impacts-to-enable-responsible-scaling.pdf?VersionId=kfurOHdWhvjKlyT7zWJHzkNdFb7Ss7Ck [https://perma.cc/6976-8T4J].

other involves pulling GHGs out of the atmosphere on the back end.[28] Removal approaches can be broken down further into "nature-based solutions," meaning biological sequestration initiatives such as growing more plants to ensure that the carbon they remove from the air is sequestered forever, and technological solutions, including "direct air capture," meaning physical treatment of air to remove GHGs, primarily carbon dioxide (CO_2), and subsequent permanent sequestration of the captured CO_2.[29] Similar to CCS technologies, carbon removal technologies will be necessary for future net zero and net negative emissions pathways but are also often presented as available alternatives to mitigation. As with CCS, their primary limitations are present cost and scalability.[30]

B. Electric Power Sector GHG Mitigation

Whether emphasizing emissions reduction, CCS, or removal, it is useful to establish a basis for comparing the climate impact of different fuels and energy pathways in relation to climate goals. This is done in units of GHGs—typically mass of CO_2 or CO_2 equivalent (CO_2e)—per unit of energy produced or consumed.[31] Challengingly, this requires two types of data: combustion emissions, meaning direct GHG emissions from burning a fuel and life-cycle emissions, meaning emissions attributable to all the resources necessary to use the fuel for something.[32] The former data allows for simple comparisons between fossil fuels, while the latter allows a fairer comparison between fossil

28. Mulligan et al., *supra* note 27.

29. Lebling et al., *supra* note 27, at 2, 4.

30. *See* Mahmoud Abouelnaga, *Limitations and Potential: Scaling Carbon Dioxide Removal*, CTR. FOR CLIMATE & ENERGY SOLS. (June 10, 2021), https://www.c2es.org/2021/06/limitations-and-potential-scaling-carbon-dioxide-removal/ [https://perma.cc/8YTF-TGGY].

31. *Frequently Asked Questions: How Much Carbon Dioxide Is Produced When Different Fuels Are Burned?*, U.S. ENERGY INFO. ADMIN., https://www.eia.gov/tools/faqs/faq.php?id=73&t=11 [https://perma.cc/EUZ8-MPKM] (May 10, 2022).

32. *See Life-Cycle GHG Accounting Versus GHG Emission Inventories*, U.S. ENV'T PROT. AGENCY, https://www.epa.gov/sites/default/files/2016-03/documents/life-cycle-ghg-accounting-versus-ghg-emission-inventories10-28-10.pdf [https://perma.cc/7W8D-W96M].

and non-fossil fuels.[33] But both are discussed in terms of GHGs per unit of energy.[34] This Section explains the basis for statements about GHG implications of various energy system climate pathways.

With respect to direct emissions, the U.S. Energy Information Administration (EIA) reports fuel-associated GHG emissions in kilograms CO_2 per million British thermal units (Btu) heat energy released in combustion.[35] These units are directly equivalent to more common and useful units: million metric tons (MMT) CO_2 per quadrillion Btu (quad) heat energy released in combustion. Per the EIA, coal combustion releases about 96 MMT CO_2 per quad burned, while natural gas releases about 53 MMT CO_2 per quad burned.[36] Looking exclusively at combustion, fossil natural gas is "low-emission" and "clean" as compared to coal but still releases huge quantities of CO_2 into the atmosphere when burned.[37]

For comparison to all other fuels (including non-combustion energy sources such as nuclear, wind, and solar power) and for better comparisons between fossil fuels including coal and natural gas, it is necessary to consider life-cycle emissions—emissions calculations that account not only for combustion emissions but also for the energy inputs associated with manufacturing the equipment (e.g., the electricity used to manufacture solar cells)—and differences in

33. *See Greenhouse Gas Emissions from Energy Data Explorer*, INT'L ENERGY AGENCY, https://www.iea.org/data-and-statistics/data-tools/greenhouse-gas-emissions-from-energy-data-explorer [https://perma.cc/J38W-YSK5] (Nov. 10, 2021); *Comparative Life-Cycle Greenhouse Gas Emissions of a Mid-Size BEV and ICE Vehicle*, INT'L ENERGY AGENCY, https://www.iea.org/data-and-statistics/charts/comparative-life-cycle-greenhouse-gas-emissions-of-a-mid-size-bev-and-ice-vehicle [https://perma.cc/2YBC-W6CX] (Oct. 26, 2022).

34. *See* Shrey Verma, Gaurav Dwivedi & Puneet Verma, *Life Cycle Assessment of Electric Vehicles in Comparison to Combustion Engine Vehicles: A Review*, 49 MATERIALS TODAY: PROC. 217, 221 (2022); INT'L ENERGY AGENCY, GREENHOUSE GAS EMISSIONS FROM ENERGY 2022, at 69, 74 (2022), https://iea.blob.core.windows.net/assets/f535fcce-abe8-49ff-9cc9-5c1d9d6eec07/WORLD_GHG_Documentation.pdf [https://perma.cc/YY9W-59LZ].

35. *See Carbon Dioxide Emissions Coefficients*, U.S. ENERGY INFO. ADMIN.: ENV'T (Oct. 5, 2022), https://www.eia.gov/environment/emissions/co2_vol_mass.php [https://perma.cc/ZU73-9YZX]; *Units and Calculators Explained: British Thermal Units (Btu)*, U.S. ENERGY INFO. ADMIN., https://www.eia.gov/energyexplained/units-and-calculators/british-thermal-units.php [https://perma.cc/HNC3-3RUW] (June 30, 2022).

36. *Carbon Dioxide Emissions Coefficients*, *supra* note 35.

37. *See Natural Gas*, CTR. FOR CLIMATE & ENERGY SOLS., https://www.c2es.org/content/natural-gas/ [https://perma.cc/ESA6-PFUD].

efficiency between different fuels, all in comparison to a standard output.[38] For electricity, that standard output is the kilowatt hour (kWh). Life-cycle analysis attempts to provide standard metrics for comparison of different things, accounting for the complete range of factors that are necessary to "count" when considering any fuel source. The Intergovernmental Panel on Climate Change (IPCC), evaluating peer-reviewed assessments of such data, summarized the current knowledge of fuel carbon in terms of median life-cycle emissions by fuel type for electricity generation in terms of grams CO_2e per kWh of electricity produced (kWh_e).[39] Again, these units are directly equivalent to more useful, larger units—in this case, MMT CO_2e per petawatt hour of electricity produced (PWh_e). According to this analysis, on a life-cycle basis for electricity produced, coal-fired electricity is estimated to emit about 740 and 910 (median 820) MMT CO_2e per PWh_e, while fossil natural gas-generated electricity (combined cycle) is estimated to emit between 410 to 650 (median 490) MMT CO_2e per PWh_e.[40] Low-carbon fuels, including solar, wind, geothermal, and nuclear-generated electricity, are generally estimated to contribute below 50 MMT CO_2e per PWh_e.[41] Thus, to repeat: under the best available international review of current sciences, natural gas is a high-carbon fuel—a little more than half the carbon intensity of coal, true, but some ten times more carbon intensive (or much more) than all low-carbon fuels.

38. *See* NAT'L RENEWABLE ENERGY LAB'Y, LIFE CYCLE GREENHOUSE GAS EMISSIONS FROM ELECTRICITY GENERATION: UPDATE 1–2 (2021), https://www.nrel.gov/docs/fy21osti/80580.pdf [https://perma.cc/CTA9-3325].

39. UNITED NATIONS ECON. COMM'N FOR EUR., LIFE CYCLE ASSESSMENT OF ELECTRICITY GENERATION OPTIONS 20 (2021) [hereinafter UN ELECTRICITY GENERATION ASSESSMENT], https://unece.org/sites/default/files/2021-10/LCA-2.pdf [https://perma.cc/5X7M-8RQQ]; *see also* Thomas Bruckner, Lew Fulton, Edgar Hertwich, Alan McKinnon, Daniel Perczyk, Joyashree Roy, Roberto Schaeffer, Steffen Schlömer et al., *Annex III: Technology-Specific Cost and Performance Parameters*, *in* CLIMATE CHANGE 2014: MITIGATION OF CLIMATE CHANGE 1329, 1335 tbl.A.III.2 (Ottmar Edenhofer et al. eds., 2014), https://www.ipcc.ch/site/assets/uploads/2018/02/ipcc_wg3_ar5_annex-iii.pdf [https://perma.cc/82PH-8VPV].

40. UN ELECTRICITY GENERATION ASSESSMENT, *supra* note 39, at 72 fig.55; Bruckner et al., *supra* note 39.

41. UN ELECTRICITY GENERATION ASSESSMENT, *supra* note 39, at 72 fig.55; Bruckner et al., *supra* note 39.

Furthermore, these figures almost certainly understate the climate impact of fossil gas because natural gas is mostly methane, itself a powerful GHG, and the production, transport, and use of natural gas all involve releasing large quantities of methane directly into the atmosphere.[42] The IPCC assessment figures cited above factor in leakage from both coal and natural gas systems, but recent studies uniformly indicate that fugitive emissions from both natural gas and coal have been significantly underreported to date.[43] Although there is some debate about whether the climate impacts of natural gas are worse than those of fossil gas, this is not yet widely accepted in the scientific community, in part because coal production itself involves yet unquantified methane emissions, and in part because fugitive methane from natural gas is shorter-lived in the atmosphere than CO_2 from coal combustion.[44] For the purpose of this analysis, what matters most is that an accurate accounting of methane leakage from natural gas systems will almost certainly require upward revision of the

42. *Importance of Methane*, U.S. ENV'T PROT. AGENCY, https://www.epa.gov/gmi/importance-methane [https://perma.cc/2SEM-STLJ] (May 22, 2023).

43. Claudia Kemfert, Fabian Präger, Isabell Braunger, Franziska M. Hoffart & Hanna Brauers, *The Expansion of Natural Gas Infrastructure Puts Energy Transitions at Risk*, 7 NATURE ENERGY 582, 582 (2022) ("The latest research on methane emissions related to natural gas production and transport has found that the actual methane leakage rates far exceed previous estimates. . . . [R]egional studies on upstream methane emissions related to the oil and gas sector in Canada and the United States show that previous studies underestimated methane emissions by 50–60%." (footnote omitted)); *see supra* notes 40–41 and accompanying text.

44. *See* Leon Clarke, Yi-Ming Wei, Angel De La Vega Navarro, Amit Garg, Andrea N. Hahmann, Smail Khennas, Inês Margarida Lima de Azevedo et al., *Energy Systems*, *in* CLIMATE CHANGE 2022: MITIGATION OF CLIMATE CHANGE 613, 647 (Priyadarshi R. Shukla et al. eds., 2022), https://www.ipcc.ch/report/ar6/wg3/downloads/report/IPCC_AR6_WGIII_FullReport.pdf [https://perma.cc/5CFX-Q34J] ("While the rate of methane leakage from unconventional gas systems is uncertain, their overall GHG impact is less than coal. The stated rate of leakage in such systems ranges from 1–8%, and reconciling different estimates requires a combination of top-down and bottom-up approaches. Similarly, for coal mining, fugitive methane emissions have grown, despite some regulations on the degree to which emission controls must be deployed. Recent IPCC inventory guidance also notes considerable CO_2 emissions resulting from spontaneous combustion of the coal surface, and accounting for these emissions will likely increase the overall lifecycle emissions by 1–5%." (citations omitted)); *see also* Katsumasa Tanaka, Otávio Cavalett, William J. Collins & Franesco Cherubini, *Asserting the Climate Benefits of the Coal-to-Gas Shift Across Temporal and Spatial Scales*, 9 NATURE CLIMATE CHANGE 389, 394 (2019) (reviewing debate and finding coal-to-gas transition consistent with climate mitigation pathways); Thomas A. Deetjen & Inês L. Azevedo, *Climate and Health Benefits of Rapid Coal-to-Gas Fuel Switching in the U.S. Power Sector Offset Methane Leakage and Production Cost Increases*, 54 ENV'T SCI. & TECH. 11494, 11499 (2020) (finding very large health benefits as well).

emissions figures for natural gas, and, as coal is retired and natural gas is built at a rapid rate, long-term reliance on natural gas to produce electricity is increasingly understood to be undermining international climate goals.[45]

II. THE SOUTHEAST NATURAL GAS TRANSITION

This Part investigates the Southeast's ongoing transition from coal to natural gas for electricity production and describes how the Southeast has achieved significant reductions in regional GHG emissions since 2005 through this fuel switching—even while exposing the region to serious lock-in risks as recently built gas infrastructure will contribute significantly to climate change for decades. It then turns to the southeastern states' electricity planning processes for future electricity generating resources and shows that electric utilities in the Southeast are generally planning to expand their natural gas fleets even further over the next several decades, pushing climate goals further out of reach, all without plans in place for the necessary transition away. In addition to describing the situation, this analysis introduces a wide variety of materials and data that are relevant to the legal and administrative processes that influence energy systems.

A. The Southeast's Significant GHG Reductions Since 2005

As shown in Table 1, in 1990, the Southeast's annual inventoried GHG emissions were roughly 910 MMT CO_2e, increasing to about 1,200 MMT/y by 2005 and trending downward thereafter.[46] By 2019, the region had reduced its aggregate emissions to about 980 MMT CO_2e—that is, by about 220 MMT (-18%) below 2005 levels, but about 70 MMT (+8%) above 1990 levels.[47]

45. *See* CLIMATE ACTION TRACKER, WARMING PROJECTIONS GLOBAL UPDATE i, 15 (2022), https://climateactiontracker.org/documents/1094/CAT_2022-11-10_GlobalUpdate_COP27.pdf [https://perma.cc/CK3T-LHT5].

46. *See infra* Table 1.

47. *Id.*

Georgia State University Law Review, Vol. 39, Iss. 4 [2023], Art. 11

Table 1: GHGs by Sector in Southeast States (MMT CO_2e)[48]

	Totals			1990-2005		2005-2019		1990-2019	
	1990	2005	2019	Δ	Δ%	Δ	Δ%	Δ	Δ%
Transport	269	376	365	+107	+40%	-11	-3%	+96	+36%
Electricity	341	502	319	+161	+47%	-183	-36%	-22	-7%
Industry	145	143	116	-3	-2%	-27	-19%	-29	-20%
Commercial	50	56	75	+6	+13%	+19	+34%	+25	+51%
Residential	24	29	34	+5	+21%	+5	+18%	+10	+42%
Agriculture	53	57	53	+3	+6%	-4	-6%	0	+0%
Total	909	1189	981	+280	+31%	-208	-18%	+72	+8%

These trends—both the emissions increases through 2005 and the decreases since then—derive from changes in the Southeast's transportation and electricity sectors, although unequally. Between 1990 and 2005, emissions in both transport and electricity in the Southeast increased by over 40% each (+107 MMT and +161 MMT, respectively).[49] Between 2005 and 2019, on the other hand, the region's transport emissions remained high, decreasing by only 11

48. The data in this table derives from the EPA's *Inventory and U.S. Greenhouse Gas Emissions and Sinks* and the *Inventory of U.S. Greenhouse Gas Emissions and Sinks by State*. *See Greenhouse Gas Inventory Data Explorer*, U.S. ENV'T PROT. AGENCY, https://cfpub.epa.gov/ghgdata/inventoryexplorer/#allsectors/allsectors/allgas/econsect/all [https://perma.cc/HD4F-4H9T] (May 16, 2023). Consistent with national inventory protocols, these data reports direct emissions within these states and do not include life cycle or consumption-based emissions attributions.

49. *See supra* Table 1.

MMT (-3%), while its electric sector emissions fell much more substantially, by 183 MMT (-36%).[50] These trends have dominated much smaller shifts in the region's industrial, agricultural, and building-related emissions, meaning that the post-2005 reductions are almost entirely attributable to changes in the electric power sector.

As shown in Table 2, these trends have also begun to decouple from the region's economic growth. The Southeast's GDP has grown (in 2012-adjusted dollars) from $1.3 trillion in 1990, to $2.4 trillion in 2005, to $2.9 trillion in 2019.[51] Between 1990 and 2005, this economic expansion occurred at a faster pace than carbon emissions increases, and from 2005 to 2019, the economy continued to expand even as GHG emissions decreased.[52] In other words, the region has steadily decreased its economy's "carbon intensity" ($GDP/ton GHG) by approximately -2.3% per year since 1990.[53]

To illustrate the relative importance of these trends, Table 2 compares these regional figures to U.S. national averages. It is notable that the Southeast's transport sector emissions increases are more extreme and persistent than in the rest of the country and that the U.S. as a whole reflects somewhat more progress on electricity decarbonization than the Southeast.[54] Meanwhile, the overall relationship between these figures and GDP is, perhaps, surprising: Southeast and U.S. carbon intensities have decreased at almost exactly the same rate.[55]

Table 2 also makes these comparisons between the Southeast and California, which has almost exactly the same GDP as the combined southeastern states but a very different GHG profile. California has invested billions in GHG reductions and by 2019 had achieved a reduction of at least 2% below its 1990 baseline with plans (and

50. *Id.*
51. *See infra* Table 2.
52. *Id.*
53. *Id.*
54. *Id.*
55. *Id.*

preparations) for much greater reductions.[56] California has built this success mostly on a one-quarter reduction in electricity sector emissions and by keeping its transport sector GHG growth in check to a much greater degree than U.S. averages.[57] California has, however, seen somewhat slower economic growth over the same period (although its per-capita GDP is much higher than the Southeast or U.S. averages).[58] Perhaps surprisingly, California's annual rate of economic decarbonization is also only slightly higher than the U.S. and Southeast figures.[59] What these comparisons hide, however, is that California's *absolute* emissions have been much lower than the Southeast's throughout the entire period, meaning that its GHG reductions are up against a very different baseline.[60] It is fair to say, in fact, that the Southeast (and the U.S. as a whole) is today where California was in 1990: producing about $2,900 of GDP per ton of CO_2e emitted. Meanwhile, California today achieves almost $6,500 GDP per ton CO_2e emitted, while incurring many of the costs associated with developing an entirely new energy economy.[61]

56. *See* Press Release, California Air Resource Board, California Climate Investments Program Implements $10.5 Billion in Greenhouse Gas-Reducing Projects, Expected to Reduce 76 Million Metric Tons of Emissions (Apr. 11, 2022), https://ww2.arb.ca.gov/news/california-climate-investments-program-implements-105-billion-greenhouse-gas-reducing-projects [https://perma.cc/SA7G-3BH3].

57. *See infra* Table 2.

58. *Id.*

59. *Id.*

60. *See* CAL. AIR RES. BD., CALIFORNIA GREENHOUSE GAS INVENTORY (MILLIONS OF METRIC TONNES OF CO2 EQUIVALENT) – BY IPCC CATEGORY 22 (2007), https://ww2.arb.ca.gov/sites/default/files/classic/cc/ghg_inventory_ipcc_all_90-04_AR4.pdf [https://perma.cc/AVL4-YPHD]. In 1990, the total GHG output for California was 437.41. *Id.* By comparison, the output for the Southeast in 1990 was 909. *See supra* Table 1.

61. *See infra* Table 2.

Table 2: GHG trends in Southeast, U.S., and California

1990-2019	Southeast	U.S.	California
Δ% GHG (total)[62]	+8%	+2%	-2%
Δ% GHG (transport)	+36%	+23%	+7%
Δ% GHG (electric)	-7%	-12%	-25%
Δ% GDP (US$2012)[63]	+113%	+111%	+101%
Δ% GDP/GHG[64]	-2.3%/y	-2.3%/y	-2.7%/y
GDP/tonCO_2$e 1990	$1,500	$1,500	$2,900
GDP/tonCO_2e 2019	$2,900	$2,900	$6,500

In summary, although the Southeast is not known for its progressive climate policies, its progress on economic decarbonization has been consistent with U.S. averages, and its steady decarbonization can be taken as an indication that the region, although lagging, is on the same trajectory as other parts of the country. Such conclusions, however, are

62. For the Southeast GHG data, see *supra* Table 1. For U.S. GHG data, see *Greenhouse Gas Inventory Data Explorer*, *supra* note 48. The figures for California are sourced from the national inventory; however, California also maintains separate GHG inventory data. *See GHG 1990 Emissions Level & 2020 Limit*, CAL. AIR RES. BD., https://ww2.arb.ca.gov/ghg-2020-limit [https://perma.cc/U76X-QBJK]; *GHG 1990–2004 Inventory & Documentation*, CAL. AIR RES. BD., https://ww2.arb.ca.gov/ghg-1990-to-2004 [https://perma.cc/7J7J-Z9YV]. Although state inventory data is typically more accurate than national data, which is an estimated disaggregation, both the California and national inventories use the global warming potential metrics from AR4; neither continue to use the SAR metric. However, there are a couple of differences in the way the two inventories handle transportation emissions—especially aviation—that create slight changes in three cells within the table. Data from the California state inventory reflects the following differences from the table above: Δ% GHG (total): -3%; Δ% GHG (transport): +11%; Δ% GHG (electric): -35%. Interestingly, the GDP numbers work out to essentially the same because the total GHG amounts are very similar.

63. The GDP data derives from the U.S. Bureau of Economic Analysis and the U.S. Regulatory Economic Analysis Project. *See Regional GDP & Personal Income*, BUREAU ECON. ANALYSIS, https://www.bea.gov/itable/regional-gdp-and-personal-income [https://perma.cc/P9QV-DL2W] (Mar. 15, 2023); U.S. REG'L ECON. ANALYSIS PROJECT, https://united-states.reaproject.org/ [https://perma.cc/UP67-BL9Y]. BEA reports real GDP prior to 1997 in 1997-adjusted dollars, and after 1996 in 2012-adjusted dollars, so the 1990 data used here has been adjusted to 2012 dollars.

64. These totals are based off calculations from the data above, calculated as annualized change in U.S. 2012 $GDP per ton CO_2e between 1990 and 2019. *See supra* notes 62, 63; *see supra* Table 1. For Southeast: [(909 MMT / $1.3T 1990) * x^{29} = (981 MMT/$2.9T 2019); x = 0.9768]; for U.S: [(6453 MMT/$9.5T 1990) * x^{29} = (6571 MMT/$14.9T 2019); x = 0.9769]; for California: [(433 MMT/$1.3T 1990)* x^{29} = (424 MMT/$2.8 T); x = 0.9732].

not entirely true because the calculations in Table 2 do not consider the future pathways made more likely by developments to date.

B. *Switching to Gas for Electricity Drives the Region's Progress*

Although reductions from the region's power sector drive the Southeast's post-2005 GHG reductions, this progress is primarily attributable to shifting away from coal-fired electricity generation and toward natural gas rather than transitioning to low-carbon energy.[65]

Table 3 presents energy data maintained by the Lawrence Livermore National Laboratory, which charts information on primary energies (energy in raw fuels) attributable to fossil fuels consumed in each U.S. state as well as primary energy-equivalents for non-fossil fuels used to produce electricity in those states, enabling comparative and aggregate analysis of state-level energy systems from year to year. Comparing the 2010 data, the earliest available, with the 2019 data, the latest available prior to temporary disruptions from the COVID-19 pandemic, reveals the relative magnitude of shifts away from coal and toward natural gas and low-carbon fuels.[66]

65. *See Natural Gas*, *supra* note 37.
66. *See infra* Table 3.

Table 3: Primary Energy for Electricity Production in the Southeast (quads)[67]

State	2010 coal	2019 coal	2010 gas	2019 gas	2010 low-C[68]	2019 low-C
AL	0.650	0.268	0.290	0.431	0.485	0.562
FL	0.620	0.223	1.000	1.351	0.311	0.384
GA	0.740	0.265	0.180	0.438	0.382	0.408
MS	0.150	0.050	0.240	0.372	0.100	0.119
NC	0.720	0.307	0.074	0.313	0.477	0.563
SC	0.380	0.156	0.090	0.188	0.563	0.623
TN	0.440	0.185	0.023	0.119	0.369	0.466
Total:	**3.700**	**1.454**	**1.897**	**3.212**	**2.687**	**3.125**

Per Table 3, between 2010 and 2019, coal consumption in the Southeast's electricity sector fell from 3.70 quads (133 MMT) to 1.45 quads (52 MMT).[69] During the same period, natural gas consumption for electricity production increased from 1.9 quads (1.9 trillion cubic feet) to 3.2 quads (3.2 trillion cubic feet), while low-carbon energy sources (nuclear, hydroelectric, and renewable resources) increased to a much lesser degree, from 2.7 quad-equivalents to 3.1 quad-equivalents.[70] Said succinctly, the Southeast's shift towards natural gas and, to a much lesser degree, new low-carbon sources accounts primarily for its move away from coal.

Another way to observe this transition is to track the changes in electric power stations operating in the Southeast since 2010.[71] The

67. The data in Table 3 derives from data accumulated by the Lawrence Livermore National Laboratory. *See Energy Flow Charts*, LAWRENCE LIVERMORE NAT'L LAB'Y, https://flowcharts.llnl.gov/commodities/energy [https://perma.cc/Q5LY-NXAE]. The charts created from the relevant data sources note that "EIA reports flows for non-thermal resources (i.e., hydro, wind and solar) in BTU-equivalent values by assuming a typical fossil fuel plant 'heat rate.'" *See, e.g.*, *Estimated Nebraska Energy Use in 2008*, LAWRENCE LIVERMORE NAT'L LAB'Y, https://neo.ne.gov/programs/stats/img/216_Energy_2008.pdf [https://perma.cc/HB29-N6VX].

68. Low-C refers to "low carbon," meaning solar, wind, nuclear, and hydroelectric power.

69. *See supra* Table 3.

70. *Id.*

71. *See infra* Table 4.

shift is clear: gone are coal-fired power plants, replaced by natural gas plants and low-carbon resources, increasing much more slowly.[72] The fossil plant trends often appear in the Global Energy Monitor's Global Coal Plant Tracker and Global Gas Plant Tracker maps, as well as their detailed plant-by-plant Wiki pages.[73] As shown in Table 4, dozens of coal plants throughout the Southeast have been retired since 2010.

Table 4: Coal Plants Retired / Switched to Gas or Biomass in the Southeast, 2010-2021[74]

State	Plant Name	Unit(s)	MW	Built	Retired	Switched?	Owner
AL	Mobile	1-2	78	1985	2012		DTE
AL	Widows Crk	1-6	844	1952-54	2014		TVA
AL	Gaston	1-4	1060	1960-62	2015	gas	Southern Co.
AL	Gaston	1-2	138	1949	2015	gas	Southern Co.
AL	Gorgas	6-7	250	1951-52	2015		Southern Co.
AL	Widows Crk	7-8	1125	1961-65	2015		TVA
AL	Colbert	1-5	1350	1955-65	2016		TVA
AL	Greene Cty	1-2	568	1965-66	2016	gas	Southern Co.
AL	Gorgas	8-10	1166	1956-72	2019		Southern Co.
AL	Lowman	1-3	538	1969-80	2020		Cooperative
AL	Barry	1-3	578	1954-59	2015	gas (1, 2)	Southern Co.
FL	C. P. & Lime	1	125	1988	2012	biomass	Chase/Duke
FL	Scholz	1-2	98	1952	2015		Gulf
FL	Cedar Bay	1	292	1994	2016		NextEra

72. *See* McGrath, *supra* note 6.

73. *See Global Coal Plant Tracker*, GLOB. ENERGY MONITOR, https://globalenergymonitor.org/projects/global-coal-plant-tracker/ [https://perma.cc/QM9G-A37U]; *Global Gas Plant Tracker*, GLOB. ENERGY MONITOR, https://globalenergymonitor.org/projects/global-gas-plant-tracker/ [https://perma.cc/N4H7-S563]; *Main Page*, GLOB. ENERGY MONITOR WIKI, https://www.gem.wiki/Main_Page [https://perma.cc/M9PZ-8T98] (May 17, 2023, 16:41).

74. The data presented in Table 4 is derived from Global Energy Monitor. *See Global Coal Plant Tracker*, *supra* note 73 (follow "Launch Tracker Map" hyperlink to the interactive map; then sort the field to include only retired coal plants); *see also Main Page*, *supra* note 73. For more information on an individual plant, click on the identified location on the map and select the wiki link. *Global Coal Plant Tracker*, *supra* note 71.

State	Plant Name	Unit(s)	MW	Built	Retired	Switched?	Owner
FL	Lansing Smith	1-2	340	1965-67	2016		Gulf
FL	Fernandina Beach	5-6	118	1982-88	2017	biomass	WestRock
FL	Crystal Riv	1-2	963	1966-69	2018		Duke
FL	St. Johns Riv	1-2	1358	1987-88	2018		Muni/NextEra
FL	Indianatown	1	395	1994	2020		NextEra
FL	Big Bend	2	445	1973	2021		Muni
FL	McIntosh	3	365	1982	2021		Muni
FL	Crist	4-7	1135	1959-73	2020	gas	Gulf/Duke
GA	McDonough	1-2	598	1963-64	2012	gas	Southern Co.
GA	Harllee Branch	2	359	1967	2013		Southern Co.
GA	Harllee Branch	1, 3-4	1387	1965-69	2015		Southern Co.
GA	Kraft	1-3	208	1958-65	2015		Southern Co.
GA	Yates	1-7	1487	1950-74	2015	gas (6, 7)	Southern Co.
GA	Mitchell	3	163	1964	2016		Southern Co.
GA	Hammond	1-4	953	1954-70	2019		Southern Co.
GA	McIntosh	1	177	1979	2019		Southern Co.
GA	Scherer	4	891	1987	2021		SoCo/Muni/Co-ops
MS	Jack Watson	1-2	877	1968-73	2015	gas	Southern Co.
MS	Morrow	1-2	400	1978	2018	gas	Cooperative
NC	Buck	3-4	120	1941-42	2011	gas	Duke
NC	Cliffside	1-4	205	1940-72	2011		Duke
NC	Weatherspoon	1-3	166	1949-52	2011		Duke
NC	Cape Fear	1-2	329	1956-58	2012		Duke
NC	Dan River	1-3	290	1949-55	2012		Duke
NC	Riverbend	4-7	466	1952-54	2012		Duke
NC	Buck	5-6	250	1953	2013	gas	Duke
NC	Lee	1-3	402	1951-62	2013	gas	Duke
NC	Sutton	1-3	672	1954-72	2013		Duke
NC	Roanoke Valley	1-2	240	1994-95	2017		Westmoreland Coal

State	Plant Name	Unit(s)	MW	Built	Retired	Switched?	Owner
NC	Edgecombe	1-2	115	1990	2019		Ares Holdings
NC	Asheville	1-2	414	1964-71	2020	gas	Duke
NC	G.G. Allen	2-4	713	1957-60	2021		Duke
SC	Grainger	1-2	163	1966	2012		Santee Cooper
SC	H.B. Robinson	1	207	1960	2012		Duke
SC	Jefferies	1-2	346	1970	2012		Santee Cooper
SC	Canadys	1-3	420	1962-67	2013		SCANA
SC	Urquhart	1-3	250	1953-55	2013	gas	SCANA
SC	W.S. Lee	1-3	355	1951-58	2015	gas	Duke
SC	McMeekin	1-2	294	1958	2016	gas	SCANA
SC	Florence	3	76	1987	2018		WestRock
SC	Kapstone	1	99	1999	2018	biomass	WestRock
TN	Watts Barr	1-4	240	1942-45	2011		TVA
TN	Sevier	1-2	400	1955	2012	gas	TVA
TN	Sevier	3-4	400	1956-57	2014		TVA
TN	Johnsonville	5-10	985	1951-59	2015		TVA
TN	Johnsonville	1-4	500	1951-52	2017		TVA
TN	Allen	1-3	990	1959	2018	gas	TVA

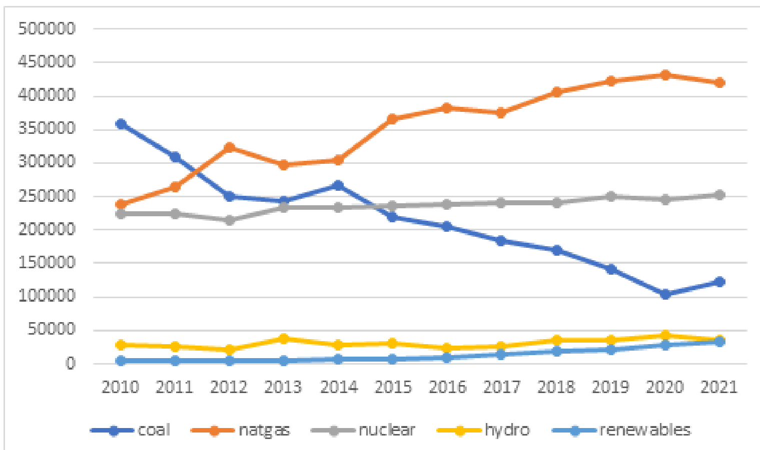
Table 4 shows that since 2010, utilities in the Southeast have retired approximately 31,000 MW (31 gigawatts (GW)) of coal-fired electric power-generating capacity, most of which was built in the 1950s, 1960s, and 1970s.[75] These include over 10,000 MW of coal capacity retired by utilities now held by the Southern Company, almost 7,000 MW shuttered by the TVA, and over 5,000 MW closed by Duke Energy and its affiliates. By state, Alabama reports the largest coal capacity retirements, followed by Georgia.

The Southeast, of course, is not consuming less electricity. Rather, these 31 GW of coal power have been replaced. As indicated in Table 4, some of these coal replacements subsume former and converted coal power plants, which are now home to natural gas power stations;

75. *See supra* Table 4.

rarely, and at small scale, replacements occur at biomass-burning facilities.[76] There are also new natural gas facilities across the Southeast, and existing gas plants are used more frequently as coal plants phase out. The result is the data presented in Figure 1, showing the amount of electricity generated in the Southeast from coal plants, natural gas facilities, nuclear power stations, hydroelectric dams, and renewables—primarily solar power—since 2010.

Figure 1: Southeast Electricity Generation by Fuel, 2010-2021 (GWh)[77]



Setting aside pandemic disruptions in 2020 and 2021, the patterns are very clear: coal is declining rapidly, natural gas is expanding at almost the same pace, nuclear output is increasing only very marginally, hydroelectric is steady, and renewables are beginning to

76. *See id.*

77. The data underlying Figure 1 derives from the EIA. *See Electricity Data Browser*, U.S. ENERGY INFO. ADMIN., https://www.eia.gov/electricity/data/browser/#/topic/0?agg=2,0,1&fuel=pfg&geo=0000001mb&sec=008&linechart=~ELEC.GEN.COW-FL-98.A~~~~ELEC.GEN.COW-GA-98.A~ELEC.GEN.NG-GA-98.A~ELEC.GEN.NUC-GA-98.A&columnchart=ELEC.GEN.ALL-FL-98.A&map=ELEC.GEN.ALL-FL-98.A&freq=A&start=2010&end=2021&ctype=linechart&ltype=pin&rtype=s&maptype=0&rse=0&pin https://www.eia.gov/electricity/data/browser/ [https://perma.cc/YB8Q-N87D].

grow.[78] Assuming about 53 MMT CO_2 per quad natural gas burned versus 96 MMT CO_2 per quad coal burned,[79] in 2010, coal and natural gas burned for electricity in the Southeast contributed about 450 MMT CO_2 into the atmosphere, while in 2019 the same activities contributed only about 310 MMT.[80] That is, fuel shifting from coal to natural gas for electricity production accounted for nearly all of the electricity sector GHG reductions in the Southeast.[81] Renewables and increased nuclear output made up the rest of the GHG reductions, covering increasing demand due to population growth.[82]

C. Switching Reductions Will Plateau as Remaining Coal Disappears

The consequences of the above analysis are quite simple: the Southeast can continue to demonstrate substantial GHG emissions reductions for the next decade or more by shutting down the region's remaining coal-fired power plants. As shown in Table 5, as of the end of 2022, there were approximately seventy-five coal-burning electric generating units operating in the Southeast, totaling over 43 GW capacity.

78. *See supra* Figure 1.
79. *See supra* note 36 and accompanying text
80. *See supra* Table 3.
81. *See supra* Table 1.
82. *See id.*; *see supra* Figure 1; *Carbon Dioxide Emissions Coefficients*, *supra* note 35; *Historical Population Change Data (1910-2020)*, U.S. CENSUS BUREAU (Apr. 26, 2021), https://www.census.gov/data/tables/time-series/dec/popchange-data-text.html [https://perma.cc/F42W-ZRT9].

Table 5: Remaining Coal Plants and Scheduled & Estimated Retirements[83]

State	Name	Unit (s)	MW	Built	Retirement	Owner
AL	Barry	4-5	1192	1969-71	2023, 2028	Southern Co.
AL	Gaston	5	952	1974	2028	Southern Co.
AL	Miller	1-4	2822	1978-91	n/a	Southern Co.
FL	Deerhaven	2	251	1981	n/a	Muni
FL	Northside	1-2	595	1966-72	n/a	Muni
FL	Seminole	1-2	1471	1984-85	2023 (1)	Co-op
FL	Crystal River	4-5	1479	1982-84	n/a	Duke
FL	Stanton	1-2	929		2027	Muni
FL	Big Bend	1, 3, 4	1377	1970-85	2023 (3)	Muni
FL	Polk	1	192	1996	n/a	Muni
GA	Bowen	1-4	3498	1971-75	2028-2035	Southern Co.
GA	Wansley	1-2	1904	1976-78	2028	Southern Co./Co-ops
GA	Scherer	1-3	3564	1982-189	2028 (3)	Southern Co./Co-ops/FPL
GA	Intl. Paper	1-2	85	1965	n/a	Intl. Paper
MS	Red Hills	1	513	2001	2031	PurEnergy
MS	Daniel	1-2	1097	1977-81	2024, 2027	Southern Co./FPL
NC	Cliffside	5-6	1530	1972, 2012	2049	Duke

83. Data for Table 5 is compiled from *Global Coal Plant Tracker*, *supra* note 71; *Global Gas Plant Tracker*, *supra* note 71. For general information on how to use these sources, see GLOB. ENERGY MONITOR WIKI, *supra* note 73. The best way to view these sources is to follow the links and use the interactive features to locate the individual data points. Units are counted if they still burn coal, even if they are capable of burning gas as well. It is understood that this data is not always perfect but is still useful for identifying trends. The best way to view these sources is by following the links.

NC	Marshall	1-4	2119	1965-70	2035	Duke
NC	G.G. Allen	1, 5	435	1957-61	2023	Duke
NC	Belews Creek	1-2	2160	1974-75	2039	Duke
NC	Roxboro	1-4	2500	1966-80	2029	Duke
NC	Mayo	1	736	1983	2029	Duke
SC	Cope	1	417	1996	2030	Dominion
SC	Wateree	1, 2	772	1970-71	2028	Dominion
SC	Cross	1-4	2390	1995-2008	n/a	Santee Cooper
SC	Williams	1	660	1973	2028	Dominion
SC	Winyah	1-4	1260	1975-81	2023-28	Santee Cooper
TN	Cumberland	1-2	2600	1973	2035	TVA
TN	Gallatin	1-4	1255	1956-59	2035	TVA
TN	Kingston	1-9	1700	1954-55	2035	TVA
TN	Bull Run	1	950	1967	2023	TVA

Between 2010 and 2019, the Southeast's coal consumption for electricity dropped by about 9 MMT/y on average.[84] If coal plant retirements in the Southeast continue at the same rate, coal would be eliminated from the fuel mix in another six years, by about 2025. However, as shown in Table 5, existing plants are currently scheduled to be closed more slowly going forward.[85] Thus, average reductions will be slower: a median estimate could be something like -5 MMT/y, resulting in zero coal in the Southeast by about 2030.[86] With many plants scheduled to operate well into the 2030s, zero coal by 2040 seems like a more likely outcome.

Whatever the pace of coal closure, replacing coal plants is crucial for the purposes of achieving net zero GHG emissions by 2050. As described above, a great many of the previously closed coal plants in the Southeast have already been converted to or replaced with natural

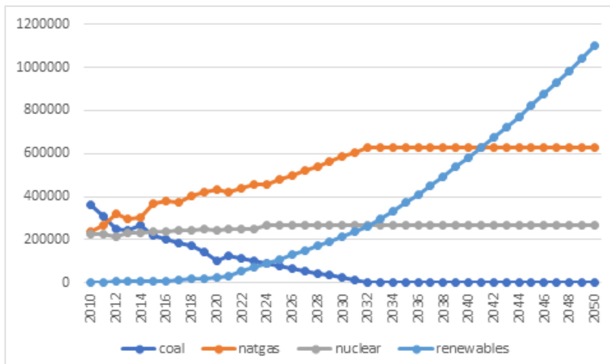
84. *See supra* Table 3; *Coal Data Browser*, U.S. ENERGY INFO. ADMIN.: COAL, https://www.eia.gov/coal/data/browser/#/topic/20?agg=1,0&geo=0000001mb&sec=g&freq=A&start=2010&end=2019&ctype=map&ltype=pin&rtype=s&maptype=0&rse=0&pin= [https://perma.cc/JJ5N-9NBN].

85. *See supra* Table 5.

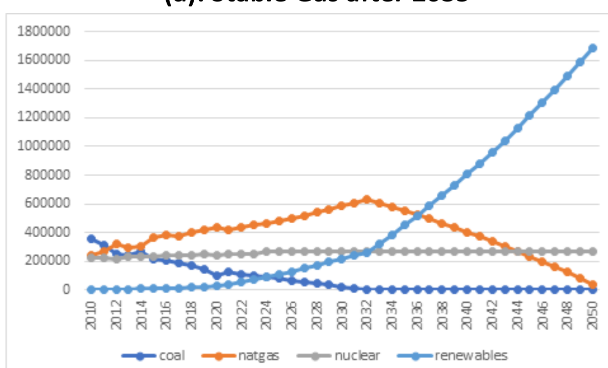
86. *See Global Gas Plant Tracker*, *supra* note 73.

gas-fired power plants. If that pattern holds—if the remaining coal fleet is replaced primarily with natural gas rather than renewables—then the region's electric-sector GHG emissions reductions will plateau when the coal is gone. In other words, assuming a forty to sixty-year operating life for natural gas units brought online to replace coal plants, they will still be operating in 2050.

Figure 2: Future Gas and Scenarios (GWh by energy source)



(a): Stable Gas after 2035



(b): Zero Gas by 2050

Figure 2 shows the same data as Figure 1 but extends beyond 2021, depicting two future scenarios for coal closure and natural gas use.[87]

87. *See supra* Figure 1. Consistent with national inventory protocols, these data report direct emissions within these states and do not include life cycle or consumption-based emissions attributions.

Figure 2(a) represents the following scenario: assuming 3% average annual load growth (attributable to population growth and new electric vehicles), coal is phased out completely by 2035 and Plant Vogtle Units 3 and 4 come online to provide additional nuclear power in 2024.[88] Equal amounts of natural gas and renewables replace coal reductions, and no new natural gas comes online, meaning more renewables to meet all new load growth (hydro is included as stable but not shown on the graph for clarity).[89] The result: the Southeast is producing about 600,000 GWh of electricity with natural gas every year after 2035.[90] These results do not decrease even when no new natural gas is built after the coal is closed because the existing natural gas plants are still being used.

Figure 2(b) shows what must happen for the southeast power sector to achieve zero emissions by 2050 under the same general assumptions: after 2035, the region must start shutting down its natural gas facilities and replacing them, in this case with renewable generating resources, at a staggering pace.[91] To the extent that renewables do not or cannot make up the difference, the shortfall would have to be made up by widespread expansion of nuclear power, widespread demand reduction, or widespread application of CCS technologies to the natural gas fleet. That is, the only alternatives to the regionwide shutdown of natural gas plants in the Southeast would be behavioral changes in consumption unprecedented in modern times or one of two extraordinary technological breakthroughs: widespread expansion of new or existing nuclear energy technologies or the perfection of carbon capture technologies and construction of related transport and sequestration infrastructure at a scale sufficient to replicate such shutdowns.

But both Figure 2(a) and Figure 2(b) assume no new natural gas after coal is shut down. In one, the region maintains its reliance on gas

88. *See Electricity Data Browser*, *supra* note 77; INT'L ENERGY AGENCY, ELECTRICITY MARKET REPORT 2023, at 3, 6, 13 (2023).

89. *See Electricity Data Browser*, *supra* note 77; INT'L ENERGY AGENCY, *supra* note 88.

90. *See supra* Figure 2(a).

91. *See supra* Figure 2(b). For other projections under similar side cases, see U.S. ENERGY INFO. ADMIN., ANNUAL ENERGY OUTLOOK 2022, at 50 (2022); BOUCKAERT ET AL, *supra* note 15, at 46 fig.1.14.

and emissions plateau; in the other, the region eliminates gas and GHGs are reduced to zero. The reality is that the Southeast is planning to expand its natural gas fleet much further than either of these scenarios suggest.

D. Southeast Electric Sector Plans Include Major Natural Gas Expansions

As explained above, the Southeast's ongoing shift to natural gas for electricity is locking in regional GHG emissions past 2050, and future reliance on natural gas would lock them in still further. How, then, is the Southeast addressing this reality? Answering this question requires examining the Southeast's fuel mix planning processes, meaning processes for assessing and selecting the types and relative quantities of fuels that will be used to produce the electricity that residents will consume in the years to come. As discussed below, most of the states in the Southeast provide broad, but not complete, discretion to their electric utilities to make fuel mix decisions, and those utilities' public plans largely indicate one thing: an increasing reliance on natural gas for the foreseeable future, unless and until external carbon pricing policies force a change. Indeed, closer examination reveals that many state regulators are influencing their utilities' selection of natural gas as a future solution.

1. Fuel Mix Planning Regulatory Basics in the Southeast

To place fuel mix planning processes in their proper context, it is necessary first to review a bit of background on electric utility regulation and how it has—and has not—evolved across the U.S. In the traditional electric utility regulatory model, electric utilities won monopoly service territories and, in return, submitted their financial decisions and prices for oversight and approval by state regulatory authorities, typically called public utilities commissions (PUCs) or public service commissions (PSCs).[92] These state regulators ensured that the utilities under their jurisdiction provided universal, non-discriminatory access within their defined service territories, and regulators ensured that service providers were not price-gouging their captive customers.[93] Traditionally, state oversight extended to electric utility fuel choice only indirectly, as regulators were required to ensure that utilities chose least-cost resource options sufficient to meet projected electricity demand.[94] In this traditional model, electrical utilities epitomized vertical integration, as a single business would make decisions about each of the major components of the electric power system under its control: where and how to generate electricity, where and how to build high-voltage transmission lines, and how to distribute electricity from the transmission system to retail customers.[95]

In the second half of the twentieth century, some states and the federal government challenged this traditional model and began taking a more active role in electric power sector decisions, particularly to promote larger-scale economic efficiency.[96] They did so through regulatory initiatives often referred to as "restructuring" (changing which entities own what parts of the system) and "deregulation" (moving from a PUC price-control regulatory model to structured markets to set electricity prices).[97] Restructuring and deregulation often involved "unbundling" the generation, transmission, and distribution functions of vertically integrated utilities, meaning encouraging or requiring regulated utilities to transfer their

92. For a history of the traditional utility regulatory model, see RICHARD F. HIRSH, POWER LOSS: THE ORIGINS OF DEREGULATION AND RESTRUCTURING IN THE AMERICAN ELECTRIC UTILITY SYSTEM 11, 26–27, 30 (1999); JAMES C. BONBRIGHT, ALBERT L. DANIELSEN & DAVID R. KAMERSCHEN, PRINCIPLES OF PUBLIC UTILITY RATES 551–52 (2d ed. 1988).

93. For a thorough introduction to the common principles of economic regulation of public utilities, see BONBRIGHT ET AL., *supra* note 92, at 515.

94. *Id.*; *see also* Herman K. Trabish, *Should the Regulatory Two-Step Give Way to a New, Performance-Based Dance?*, UTILITY DIVE (June 18, 2018), https://www.utilitydive.com/news/should-the-regulatory-two-step-give-way-to-a-new-performance-based-dance/524428/ [https://perma.cc/S7PX-Y4FE].

95. HIRSH, *supra* note 92, at 29–30.

96. *Id.* at 239–40.

97. *Id.*

transmission assets to a nonprofit coordinator—now called a regional transmission organization (RTO) or independent system operator (ISO)—that would manage transmission siting and interconnection at a regional scale.[98] It also sometimes involved encouraging or requiring vertically integrated utilities to divest themselves of their power plants while tasking RTOs/ISOs with operating electricity markets, allowing any company to produce electricity and bid to sell it into the electric power system, limiting utilities to procuring electricity through that market, and thus limiting the need for certain cost controls by state PUCs.[99] A few jurisdictions even went so far as to permit retail competition, meaning that utilities lost their exclusive service territories, and consumers could choose from their electricity retail service provider.[100] In tandem with these restructuring initiatives, many states also began to develop regulatory mechanisms to promote other public policies, including those related to fuel mix, such as fuel diversification, renewable energy integration, and energy efficiency programs.[101]

The Southeast, however, typically opts out of these reforms.[102] The region stands out as one of the "more traditional" U.S. electric utility regulatory territories. The Southeast's investor-owned utilities (IOUs) (which operate for profit and are regulated by PUCs/PSCs) are, in general, still vertically integrated monopolies.[103] There is also a great

98. *See RTOs and ISOs*, *supra* note 4; *Electric Power Markets*, *supra* note 4; *see, e.g.*, Peter R. Hartley, Kenneth B. Medlock III & Olivera Jankovska, *Electricity Reform and Retail Pricing in Texas*, 80 ENERGY ECON. 1, 1 (2019).

99. *See Electric Power Markets*, *supra* note 4.

100. *See, e.g.*, Hartley et al., *supra* note 98 (providing Texas as an example).

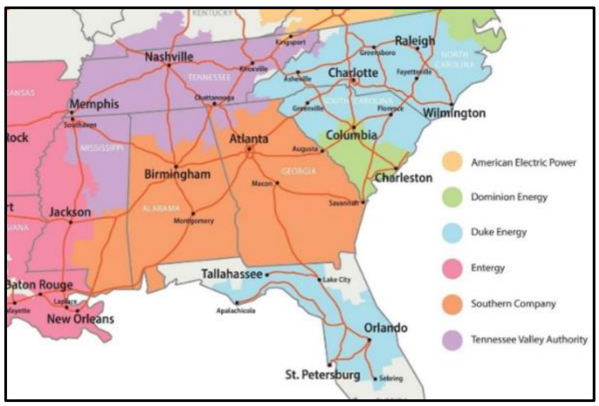
101. *See* ALL. COMM'N ON NAT'L ENERGY EFFICIENCY POL'Y, THE HISTORY OF ENERGY EFFICIENCY 10, 13 (2013), https://www.ase.org/sites/ase.org/files/resources/Media%20browser/ee_commission_history_report_2-1-13.pdf [https://perma.cc/DQF7-FD3Z].

102. *See id.* at 13.

103. *Power Sector Competition in the Southeast*, NICHOLAS INST. FOR ENERGY, ENV'T & SUSTAINABILITY, https://nicholasinstitute.duke.edu/project/power-sector-competition-southeast [https://perma.cc/9AHY-ZHH3]; *see* DAVID P. TUTTLE, GÜRCAN GÜLEN, ROBERT HEBNER, CAREY W. KING, DAVID B. SPENCE, JUAN ANDRADE, JASON A. WIBLE, ROSS BALDICK ET AL., UNIV. TEX. AUSTIN ENERGY INST., THE HISTORY AND EVOLUTION OF THE U.S. ELECTRICITY INDUSTRY 2–3, 11 (2016), https://energy.utexas.edu/sites/default/files/UTAustin_FCe_History_2016.pdf [https://perma.cc/L6P2-UXPB].

deal of economic concentration in the Southeast's electric sector—although many utilities continue to do business under their original names, most customers in the Southeast today utilize utilities owned by one of only five companies: Dominion Energy, Duke Energy, Entergy, Southern Company, and FPL (see Figure 3).[104] The federal TVA services the remainder of consumers, which is similar in that it is a vertically integrated organization and the primary provider of electricity over a vast territory.[105] Thus, subject to state regulatory oversight and one federal agency, a relatively few private authorities control a majority of the Southeast's fuel mix decisions.

Figure 3: Major SE Electric Utility Service Territories (approx.)



104. *See supra* Figure 3. This figure is adapted from a map of the National Electric Highway Coalition. *See* Press Release, Tennessee Valley Authority, Electric Highway Coalition More than Doubles, Growing to 14 Members (July 26, 2021) [hereinafter TVA Press Release], https://www.tva.com/newsroom/press-releases/electric-highway-coalition-more-than-doubles-growing-to-14-members#:~:text=Electric%20Highway%20Coalition%20More%20than%20Doubles%2C%20Growing%20to%2014%20Members,-Jul%2026%2C%202021&text=KNOXVILLE%2C%20Tenn.,to%20connect%20major%20highway%20systems [https://perma.cc/USP9-5ZCW]. It simplifies service territories and excludes rural electric cooperatives and municipal electric utilities but is useful for showing consolidated service territories.

105. *See TVA at a Glance,* TENN. VALLEY AUTH., https://tva-azr-eastus-cdn-ep-tvawcm-prd.azureedge.net/cdn-tvawcma/docs/default-source/about-tva/information-about-tva/tva-at-a-glance-1537387324.pdf?sfvrsn=c875f75b_2 [https://perma.cc/P9LM-BTH9]; TENN. VALLEY AUTH., INTEGRATED RESOURCE PLAN: TVA'S ENVIRONMENTAL & ENERGY FUTURE 24–25 (2011), https://www.nrc.gov/docs/ML1217/ML12171A189.pdf [https://perma.cc/MR9U-DEKB].

Consistent with the region's regulatory conservatism, the electric power system oversight in the Southeast is much more deferential to utility interests than in many other parts of the country and tends to focus on consumer cost minimization more than any other policy priority. This is not to say that there is no oversight at all but rather that when given chances to regulate, the states in the Southeast largely have chosen more limited approaches.

2. *Fuel Mix Planning Authorities and Processes in the Southeast*

Although each state (and the federal TVA) maintains its own standards, in general, their fuel mix planning processes each answer the same fundamental questions.[106] Some of these are more system-level planning questions: what will electricity demand look like in the future, what laws and policies will constrain power plant operations, what range of technological options will be available to reduce or meet future demand, and what will they cost? Other questions are more facility-level: is a given proposed power plant necessary to meet future demand, is it the least-cost option to meet that demand, and will it be allowed to be built at a proposed location? Questions about future cost and future policy constraints are especially important to fuel mix planning. For example, minimum requirements for renewables—often called renewable portfolio standards (RPS)—impose constraints on what must be built, where, and when. Other policy choices may implicate cost—for example, a future tax on carbon emissions would increase costs for natural gas—or may be treated wholly separate from

106. *See, e.g.*, SOUTHERN COMPANY, PLANNING FOR A LOW-CARBON FUTURE 5 (2018), https://www.southerncompany.com/content/dam/southern-company/pdf/corpresponsibility/Planning-for-a-low-carbon-future.pdf [https://perma.cc/KPU4-ZX6Q] (noting that the "planning process [must] allow[] for updates to a number of assumptions, inputs, and alternatives, including potential CO_2 prices, fuel and other commodity prices, as well as economic or other policy indicators"); *2015 Integrated Resource Plan*, TENN. VALLEY AUTH., https://www.tva.com/environment/environmental-stewardship/integrated-resource-plan/2019-integrated-resource-plan/2015-integrated-resource-plan [https://perma.cc/BL6G-PK9F] (noting importance of economic considerations in planning process).

cost, for example, a total carbon emissions reduction target that must be planned for.[107]

These questions are most often answered in one of two types of regulatory proceedings, generally authorized by state law and implemented via PUC/PSC regulation.[108] First, state regulators are typically granted authority to grant certificates of public convenience and necessity (CPCNs) for electric power system facilities, meaning permits to construct infrastructure, including power plants, under prevailing approval standards.[109] Second, regulators are empowered to require, receive, and review various types of Integrated Resource Plans (IRPs), meaning future-looking planning documents that analyze future electricity demand and the various options the utility has considered for serving it.[110] These processes, although distinct, may influence each other, particularly as consistency with IRPs may be taken as supporting evidence in facility-level proceedings and company expansion plans may influence what they examine in their IRPs.[111] Finally, it is necessary to keep in mind the degree to which public stakeholders are able to participate in and influence plan or proposal development, comment on submitted plans, and influence outcomes of regulatory proceedings. Each state has different CPCN

107. *See, e.g.*, America Wins Act, H.R. 3311, 117th Cong. § 4691 (2021) (proposing tax on natural gas, coal, petroleum, and petroleum products); *Target Setting*, U.S. ENV'T PROT. AGENCY, https://www.epa.gov/climateleadership/target-setting [https://perma.cc/V7Y4-XKZD] (Sept. 30, 2022) (introducing resources for reduction target planning); U.S. ENV'T PROT. AGENCY, AN OVERVIEW OF PUCS FOR STATE ENVIRONMENT AND ENERGY OFFICIALS 2 (2010) [hereinafter OVERVIEW OF PUCS], https://www.epa.gov/sites/default/files/2016-03/documents/background_paper.pdf [https://perma.cc/Q53V-MN54].

108. *See* OVERVIEW OF PUCS, *supra* note 107, at 2, 4–6; U.S. ENV'T PROT. AGENCY, STATE ENERGY AND ENVIRONMENT GUIDE TO ACTION: ELECTRICITY RESOURCE PLANNING AND PROCUREMENT 6 (2022) [hereinafter GUIDE TO ACTION], https://www.epa.gov/system/files/documents/2022-08/Electricity%20Resource%20Planning%20and%20Procurement_508.pdf [https://perma.cc/U932-ZMAX].

109. GUIDE TO ACTION, *supra* note 108, at 10. *See, e.g.*, GA. CODE ANN. § 46-2-20 (2023) (establishing the Georgia Public Service Commission); GA. COMP. R. & REGS. 515-7-1-.03 (2023) (stating requirements for submitting CPCNs to Georgia's PSC).

110. The Energy Policy Act of 1992 revised the Public Utilities Regulatory Policy Act (PURPA) to add national IRP standards, but PURPA allows states to adopt their own policies. 16 U.S.C. §§ 2602(19), 2621(d)(7); *see also* Energy Policy Act of 2005, Pub. L. No. 109-58 § 1251, 119 Stat. 594, 962–63 (2005) (adding fuel source standards and discussing re-diversification of fuel sources).

111. *See* 16 U.S.C. § 2621; GUIDE TO ACTION, *supra* note 108, at 1.

and IRP standards that, together, create a balance of power between large electric utilities, state regulators, and other interested parties.[112] A review of the Southeast reveals a broad range of approaches, with a great deal of regulatory development ongoing.

Alabama.[113] Today, Alabama stands out as the most traditionally conservative electric utility regulatory jurisdiction remaining in the Southeast. Since 2019, it is the only southeastern state that does not require its regulated utilities to file an IRP, and although regulated, IOU Alabama Power prepares a voluntary IRP every three years[114] that is not subject to public comment or state approval of any kind.[115] The IRP itself, furthermore, is very traditional, focusing primarily on identifying resources for least-cost electric service and considering environmental policy only in terms of compliance cost.[116] The state does provide its PSC with CPCN authority over power plant proposals and provides for public participation in those proceedings.[117] The PSC, however, maintains broad authority to craft approval standards for its CPCNs, and, although the PSC does consider conformity with the IRP in its CPCN reviews, the commission primarily considers the demand for electricity and whether any proposed power plant is the least-cost

112. It should be noted that these requirements apply only to the Southeast's IOUs that, with the exception of Tennessee, serve the majority of each state's customers. Most of the states in the Southeast are also served by groups of rural electric co-operatives and municipal power companies, which work independently on some power plant decisions and together with each other and the IOUs on other matters. GUIDE TO ACTION, *supra* note 108, at 1, 9.

113. *See generally Alabama Public Service Commission*, ALA. PUB. SERV. COMM'N, https://psc.alabama.gov/ [https://perma.cc/SAS2-GMBV] (the state's regulator); *About Us*, ALA. POWER, https://www.alabamapower.com/company/about-us.html/ [https://perma.cc/U4V9-S5UZ] (the state's IOU); *About AMEA*, ALA. MUN. ELEC. AUTH., https://www.amea.com/about/ [https://perma.cc/V5WC-GJA9] (the state's cooperative); *Who We Are*, ALA. RURAL ELEC. ASS'N COOPS., https://areapower.coop/who-we-are/ [https://perma.cc/2964-PTDM] (the state's public power). Northern Alabama is also served by the TVA. TVA Press Release, *supra* note 104.

114. *How We Operate*, ALA. POWER, https://www.alabamapower.com/company/about-us/how-we-operate.html [https://perma.cc/24A3-3ZRN].

115. ENERGY ALA., POLICY BRIEF: OPEN AND TRANSPARENT INTEGRATED RESOURCE PLANNING 3 (2021).

116. *See* ALA. POWER, 2022 INTEGRATED RESOURCE PLAN SUMMARY REPORT 13 (2022) [hereinafter 2022 ALABAMA IRP REPORT].

117. ALA. CODE § 37-4-28 (2023).

means of meeting the demand, which may be established under a fairly lenient standard of review.[118]

North Carolina.[119] On the other end of the spectrum, North Carolina is transitioning toward a much more directed fuel mix planning environment. Uniquely among the southeastern states, in 2021, North Carolina began requiring its largest regulated utilities to file "carbon plans" to identify the fuel mix they would use to achieve 70% CO_2 reductions by 2030 and carbon neutrality by 2050.[120] North Carolina is also the only southeastern state with a statutory RPS currently set at 12.5%.[121] The RPS and, going forward, carbon plans must be incorporated into utility IRPs, developed with a goal of identifying "the least cost combination (on a long-term basis) of reliable resource options for meeting the anticipated needs of its system."[122] Simultaneously, the RPS must consider "the potential benefits of reasonably available alternative supply-side energy resource options," including renewables and state policies.[123] The same authorities grant

118. *E.g.*, Ala. Power Co., No. 32953, at 27, 40–41 (Ala. Pub. Serv. Comm'n Aug. 14, 2020) (final order for a CPCN); *see infra* notes 175–79 and accompanying text.

119. *See generally About the NC Utilities Commission*, N.C. UTILS. COMM'N, https://www.ncuc.gov/Aboutncuc.html [https://perma.cc/5B5V-BY9J] (state regulator); *About Duke Energy*, DUKE ENERGY, https://www.duke-energy.com/our-company/about-us [https://perma.cc/7F7H-8XNA] (state IOU); *Our Company*, DOMINION ENERGY, https://www.dominionenergy.com/our-company [https://perma.cc/JU7S-B29D] (state IOU); *About Us*, N.C. ELEC. COOPS., https://www.ncelectriccooperatives.com/who-we-are/ [https://perma.cc/ZTS3-TPUZ] (state's cooperatives); *Public Power in North Carolina*, AM. PUB. POWER ASSOC., https://www.publicpower.org/public-power-north-carolina [https://perma.cc/JR69-ANJH] (state's public power).

120. *See Carbon Plan*, N.C. UTILS. COMM'N, https://www.ncuc.gov/Consumer/carbonplan.html [https://perma.cc/JE5H-9KQ4]; Press Release, North Carolina Governor Roy Cooper, Governor Cooper Signs Energy Bill Including Carbon Reduction Goals Into Law (Oct. 13, 2021), https://governor.nc.gov/news/press-releases/2021/10/13/governor-cooper-signs-energy-bill-including-carbon-reduction-goals-law [https://perma.cc/7C8D-WCH7] (mandating 2030 and 2050 electric sector GHG reduction goals toward "carbon neutrality by 2050" (quoting Governor Roy Cooper)); *see also Clean Energy Plan*, N.C. DEP'T ENV'T QUALITY, https://deq.nc.gov/energy-climate/climate-change/nc-climate-change-interagency-council/climate-change-clean-energy-plans-and-progress/clean-energy-plan [https://perma.cc/R2B9-5F73] (proposing same). For criticism of early carbon plan development, see Maggie Shober & Forest Bradley-Wright, *NC Carbon Plan Update: We Cannot Get Off Track Before We Even Begin*, S. ALL. FOR CLEAN ENERGY (Mar. 1, 2022), https://cleanenergy.org/blog/nc-carbon-plan-update-we-cannot-get-off-track-before-we-even-begin/ [https://perma.cc/T6C5-VDGL].

121. *See* N.C. GEN. STAT. § 62-133.8(b) (2023).

122. 4 N.C. ADMIN. CODE 11R8-60(g) (2023).

123. 4 N.C. ADMIN. CODE 11R8-60(e) (2023).

the North Carolina Utilities Commission (NCUC) power to issue CPCNs.[124] In other words, North Carolina has developed an integrated planning process for its regulated utilities that, at least in theory, will allow for transparent analysis of electric sector fuel mix decarbonization and renewables integration.

Mississippi.[125] Other states in the Southeast fall somewhere on a spectrum between Alabama and North Carolina. Although most similar to Alabama, Mississippi is interesting because its PSC very recently began requiring its regulated utilities to file relatively intensive IRPs, creating new processes for stakeholder input into utility planning.[126] The new IRP rules require consideration of "potentially viable supply-side resource alternatives, including renewable and non-renewable options and energy storage" on an equal footing with other resources, permit consideration of environmental impacts in planning, and direct utilities, after considering multiple portfolios and modeling sensitivities, to identify a preferred "action plan" for informational purposes, although there is no clear mandate to consider GHG emissions reductions as anything other than an external future cost.[127] The state's PSC also has very broad authority to review power plant proposals and issue CPCNs.[128] Although this regime does not directly promote renewables integration or climate planning, it at least provides opportunities for public input on planning

124. *See* N.C. GEN. STAT. § 62-110.1(a) (2023); 4 N.C. ADMIN. CODE 11R8-61 (2023).

125. *See generally Mississippi Public Service Commission*, MISS. PUB. SERV. COMM'N, https://www.psc.ms.gov/ [https://perma.cc/96H7-MHUK] (state regulator); *Our History*, MISS. POWER, https://www.mississippipower.com/company/about-us/our-history.html [https://perma.cc/2MYY-48HZ] (state IOU); *About Us*, ENTERGY, https://www.entergy-mississippi.com/about/ [https://perma.cc/RVC8-V5GK] (state IOU); *Who We Are*, ELEC. COOPS. OF MISS., https://ecm.coop/about_us/who_we_are [https://perma.cc/C5JE-94EV] (state cooperatives); *Public Power in Mississippi*, AM. PUB. POWER ASS'N, https://www.publicpower.org/public-power-mississippi [https://perma.cc/Y63U-BGYJ] (state public power). Northern Mississippi is served by the TVA. *See Mississippi Region*, TENN. VALLEY AUTH., https://www.tva.com/economic-development/our-team/mississippi-region [https://perma.cc/AJQ3-RT55].

126. Integrated Res. Plan. & Ann. Energy Delivery Reporting Requirements, No. 2018-AD-64, at 14–16 (Miss. Pub. Serv. Comm'n Nov. 22, 2019) (final order amending Rule 29 and establishing IRP and annual energy delivery reporting requirements).

127. PUBLIC UTILITIES RULES OF PRACTICE AND PROCEDURE, MISS. PUB. SERV. COMM'N RULE 29 (2019).

128. *See* MISS. CODE ANN. §§ 77-3-11(2), -13(3) (2023); PUBLIC UTILITIES RULES OF PRACTICE AND PROCEDURE, MISS. PUB. SERV. COMM'N RULE 7 (2019).

to regulators and a fairly clear indication of utility intentions for the next twenty years.

South Carolina.[129] Prior to 2019, South Carolina had a "filing only" IRP process similar to the Alabama process. In 2019, however, the state extensively modified its IRP statute, increasing public participation and state oversight over electric utility resource planning. The statute now requires utility IRPs to consider "several resource portfolios developed with the purpose of fairly evaluating the range of demand-side, supply-side, storage, and other technologies and services," including renewable energy resources.[130] The state's PSC also now requires modeling sensitivities for multiple carbon prices, eventually determining that consideration of a low, medium, and high CO_2 price, at $0, $12, and $35/ton, respectively, with annual growth rates, was necessary for sensitivity analysis.[131] In addition, the new statute requires South Carolina's state electric utility to develop an IRP that includes at least one scenario designed to achieve net zero goals by 2050.[132] The state PSC is required to determine whether the IRPs it receives "represent[] the most reasonable and prudent means of meeting . . . energy and capacity needs as of the time the plan is reviewed," considering multiple cost, reliability, and regulatory factors,[133] and the PSC has broad discretion to issue CPCNs

129. *See generally Welcome to the Public Service Commission*, PUB. SERV. COMM'N S.C., https://www.psc.sc.gov/ [https://perma.cc/A9GC-W22K] (state regulator); *About Duke Energy*, *supra* note 119 (IOU); *Our Company*, supra note 119 (IOU); *Created to Serve*, ELEC. COOPS. OF S.C., https://www.ecsc.org/created-serve [https://perma.cc/5VKV-HPG7] (cooperatives); *Santee Cooper Powers South Carolina*, SANTEE COOPER, https://www.santeecooper.com/About/ [https://perma.cc/JWV5-E62V] (public power); *see Public Power in South Carolina*, AM. PUB. POWER ASS'N, https://www.publicpower.org/public-power-south-carolina [https://perma.cc/9ET9-S93D] (others).

130. S.C. CODE ANN. § 58-37-40(B)(1)(e) (West 2023); *see also* Order Rejecting Dominion's Integrated Resource Plan, No. 2019-226-E, at 9, 11 (S.C. Pub. Serv. Comm'n Dec. 23, 2020) (Order No. 2020-832) (rejecting Dominion's IRP and requiring Dominion to modify its 2020 IRP); Order Accepting Modified Integrated Resource Plan, No. 2019-226-E, at 6–7 (S.C. Pub. Serv. Comm'n June 18, 2021) (Order No. 2021-429) (accepting modified IRP and providing additional instructions for future IRPs and updates); *Reports & Publications*, S.C. ENERGY OFF., https://energy.sc.gov/irp [https://perma.cc/76KW-M4CQ].

131. Order Accepting Modified Integrated Resource Plan, No. 2019-226-E, at 10 (S.C. Pub. Serv. Comm'n July 18, 2021) (Order No. 2021-429).

132. § 58-37-40(A)(4)(c).

133. § 58-37-40(C)(2).

accordingly.[134] As such, South Carolina's planning process indicates an awareness of climate-relevant planning inputs, even if, consistent with state law, it does not directly promote renewables integration or decarbonization. As discussed in the next Section, South Carolina's process also demonstrates that accounting for climate-relevant modeling inputs is not the same thing as mandating the selection of a climate friendly fuel mix.

Georgia.[135] Georgia has required its regulated electric utilities to develop and file IRPs since 1991.[136] The law requires IRPs to analyze "practical alternatives to the fuel type and method of generation of the proposed electric generating facilities and set forth in detail the reasons for selecting the fuel type and method of generation"[137] and requires the state PSC to review whether the plan "adequately demonstrates the economic, environmental, and other benefits to the state and to customers of the utility, associated with the . . . possible measures and sources of supply . . . [including f]acilities which operate on alternative sources of energy."[138] Georgia also empowers its PSC to issue CPCNs, which it must do

> upon a finding that there is or will be a need for the proposed capacity resource at the time that the proposed resource is proposed to be utilized to assure an economical and reliable supply of electric power and energy for the Georgia retail customers of a utility, that the certificate is required by the public convenience and necessity, and that the certificate complies with the

134. *See* § 58-27-1230.

135. *See generally FAQs*, GA. PUB. SERV. COMM'N, https://psc.ga.gov/faqs/ [https://perma.cc/6S3U-TEYA] (regulator); *About Us*, GA. POWER, https://www.georgiapower.com/company/about-us.html [https://perma.cc/E3MR-HMQ7] (IOU); *Who We Are*, GA. ELEC. MEMBERSHIP CORP., https://georgiaemc.com/page/About [https://perma.cc/7GXS-4VQ2] (cooperatives); *About MEAG Power*, MUN. ELEC. AUTH. GA., https://www.meagpower.org/about/overview/ [https://perma.cc/PJA6-BU64] (public power). A small part of northern Georgia is also served by the TVA. TVA Press Release, *supra* note 104.

136. 1991 Ga. Laws 1696, § 1 (codified as amended at GA. CODE ANN. §§ 46-3A-1 to -11 (1991)); GA. COMP. R. & REGS. 515-3-4.01 (2023) (implementing regulations).

137. GA. CODE ANN. § 46-3A-1(7)(B) (2023).

138. § 46-3A-2(b)(3).

> provisions of this chapter and the rules of the commission.[139]

The state is unique in the Southeast in the degree to which its IRP proceedings have been intertwined with CPCN proceedings. As discussed below, most recently, in a combined IRP and CPCN review, the PSC preferred to allow stakeholders to reach a negotiated settlement that disposed of most of the relevant issues related to sweeping changes to the future of the state's power sector. None of these authorities or processes, however, involve robust planning for achieving long-term decarbonization goals.

Florida.[140] Florida is the most complex regulatory environment in the Southeast, with the most people, most regulated utilities, and most hands-off approach to fuel mix planning in the region. Since 1973, the state has required all of its electric utilities to file documents called Ten Year Site Plans (TYSPs), which are informational, non-binding filings about the utilities' plans for power plants over the next decade (as opposed to the twenty-year planning horizon typical in IRPs, and the thirty- to sixty-year planning timeframe most useful for decarbonization planning).[141] The Florida PSC solicits public and agency comments on TYSPs and then reviews them for

139. § 46-3A-4(a); *see also* GA. COMP. R. & REGS. 515-3-4.01 (2023) (standards for applications and approval).

140. *See generally About the PSC*, FLA. PUB. SERV. COMM'N, https://www.floridapsc.com/about [https://perma.cc/B3LL-7ALM] (regulator); *About Duke Energy*, *supra* note 119 (IOU); *Company Profile*, FLA. POWER & LIGHT CO., https://www.fpl.com/about/company-profile.html [https://perma.cc/U27R-4FNA] (IOU); *About Us*, TAMPA ELEC.: EMERA, https://www.tampaelectric.com/company/about/ [https://perma.cc/D28E-A62W] (IOU); *FPU Companies & Affiliates*, FLA. PUB. UTILS., https://www.fpuc.com/about/ [https://perma.cc/6STP-A6Q3] (IOU); *Florida's Electric Cooperatives*, FLA. ELEC. COOPS. ASS'N, https://feca.com/ [https://perma.cc/6WAC-BQWU] (cooperatives); *About Us*, FLA. MUN. ELEC. ASS'N, https://assets.noviams.com/novi-file-uploads/fmea/pdf/General_Docs/FactSheet_November2022.pdf [https://perma.cc/8N8D-GSAM] (public power). As of 2022, Gulf Power was wholly integrated into the Florida Power & Light Company (FPL). *See* Press Release, Florida Power & Light Company, FPL Completes Integration of Gulf Power; Expands America's Best Energy Value to Northwest Florida (Jan. 1, 2022), https://newsroom.fpl.com/2022-01-01-FPL-completes-integration-of-Gulf-Power-expands-Americas-best-energy-value-to-Northwest-Florida [https://perma.cc/A5Z8-L23V].

141. FLA. STAT. ANN. § 186.801 (West 2023); *see also* Tampa Elec. Co. v. Garcia, 767 So. 2d 428, 434–35 (Fla. 2000) (describing history of Florida Electrical Power Plant Siting Act).

"suitab[ility],"[142] consolidating its findings into an annual report that imposes no binding requirements on the utilities.[143] The PSC also has CPCN authority,[144] which allows for more robust public stakeholder participation. Florida's CPCN standards highlight cost minimization but also require the PSC to determine, among other things, "whether renewable energy sources and technologies, as well as conservation measures, are utilized to the extent reasonably available."[145] Florida's electric power system, therefore, is characterized by short-term planning horizons and relatively lax oversight.

Tennessee and the TVA.[146] Finally, Tennessee is unique among the southeastern states as almost all of its territory is served by electricity procured from the TVA, a federal agency that makes its own fuel mix decisions (the state then regulates the entities that purchase the TVA's electricity). Thus, the most relevant planning processes are not state programs but federal ones. With respect to the TVA, the Energy Policy Act of 1992 required it to undertake a "least-cost planning program" very similar to IRP processes,[147] and the TVA today publishes IRPs under that authority.[148] The TVA's mandate is to undertake "a planning and selection process for new energy resources which evaluates the full range of existing and incremental resources (including new power supplies, energy conservation and efficiency, and renewable energy resources) . . . to provide adequate and reliable service" to TVA customers at the lowest cost.[149] Recently, the TVA has begun attempting to reconcile a fossil fuel-heavy history and least-

142. FLA. ADMIN. CODE ANN. r. 25-22.071 (2023) ("Plans that have been previously classified by the Commission as unsuitable may be classified suitable based on additional data.").

143. For a collection of the annual reports, see *PSC Annual Reports*, FLA. PUB. SERV. COMM'N, https://www.psc.state.fl.us/psc-annual-reports [https://perma.cc/UZ9N-T24U].

144. *See* FLA. STAT. ANN. §§ 403.501, .510, .511 (West 2023).

145. § 403.519(3).

146. Tennessee has two regulators. *See History and Leadership*, TENN. PUB. UTIL. COMM'N, https://www.tn.gov/tpuc/agency/tra-history-and-leadership.html [https://perma.cc/U3CN-WY4V]; *About TVA*, TENN. VALLEY AUTH., https://www.tva.com/about-tva [https://perma.cc/JZA8-AP95].

147. Energy Policy Act of 1992, Pub. L. No. 102-486, § 113, 106 Stat. 2776, 2798 (1992) (codified as amended at 16 U.S.C. § 831m-1).

148. *E.g.*, Integrated Resource Plan, 84 Fed. Reg. 48987, 48987 (Sept. 17, 2019) ("Consistent with Section 113 of the Energy Policy Act of 1992, . . . TVA employs a least-cost system planning process in developing its IRPs.").

149. § 831m-l.

cost planning mandate with more aggressive federal climate goals and commitments, resulting in its publication of a number of reports on environmental, social, and governance issues.[150] As relevant to fuel mix, in 2021, the TVA published its first "carbon report,"[151] which, although largely backward-looking, began to develop TVA's ideas for decarbonization pathways going forward.[152]

3. Current Fuel Mix Plans and Projections in the Southeast

It is possible to review the recent IRP and CPCN documents submitted under the authorities discussed above to get a sense for the future of the southeastern fuel mix. As discussed here, natural gas dominates those plans and projections, and the primary distinguishing factor between jurisdictions is the extent to which they project solar and other renewables development in tandem with natural gas expansions.

Florida. Beginning with the largest territory by electricity consumption, Florida is going all-in on natural gas—or, perhaps more accurately, has already gone all-in on natural gas and plans to continue doing so. According to the Florida PSC, its utilities' 2022 TYSPs project maintaining over 65% of the state's electricity generated by natural gas through 2031, with solar additions doing very little to reduce this dependence as demand grows as well.[153] This interpretation is bolstered by Florida's most recent reviews of CPCN petitions for natural gas plants, where the statutory requirement to determine

150. *See Environmental, Social, & Governance Information for Investors*, TENN. VALLEY AUTH., https://tva.q4ir.com/esg/ [https://perma.cc/9SX6-DWTS].

151. TENN. VALLEY AUTH., LEADERSHIP & INNOVATION ON A PATH TO NET-ZERO: TVA AND THE ENERGY SYSTEM OF THE FUTURE (2021), https://tva-azr-eastus-cdn-ep-tvawcm-prd.azureedge.net/cdn-tvawcma/docs/default-source/environment/carbon-report.pdf?sfvrsn=4971bcca_2 [https://perma.cc/GK63-RVVN].

152. *Id.* at 27–29.

153. *See* FLA. PUB. SERV. COMM'N, REVIEW OF THE 2022 TEN-YEAR SITE PLANS OF FLORIDA'S ELECTRIC UTILITIES 4 (2022) [hereinafter FLORIDA 2022 TEN-YEAR SITE PLANS REVIEW], https://www.floridapsc.com/pscfiles/website-files/pdf/Utilities/Electricgas/TenYearSitePlans/2022/Review.pdf [https://perma.cc/6YT8-VDPB]; *see also supra* Figure 2.

whether renewable energy resources are "reasonably available" to meet need have proved easy for utilities to overcome.[154]

TVA. The next largest system by customers served is the TVA, which is also looking at a very high-gas future, although it is doing much more to plan solar capacity than any other southeastern jurisdiction.[155] The TVA's most recent IRP contemplates meeting coal retirements and load growth with additions in natural gas and solar at about a 2:3 ratio, subject to many uncertainties.[156] By 2038, TVA proposes adding up to about 10,000 MW of gas capacity and about 14,000 MW of solar.[157]

Georgia. Georgia, similarly, appears to be headed toward an increasingly gas-dominated electric power sector, although it is also adding a great deal of utility-scale solar to its mix. Georgia Power's 2022 IRP was combined with a CPCN petition involving coal retirements and replacements, primarily with natural gas.[158] Georgia's process, however, also resulted in multiple other capacity requirements, including Georgia Power's commitment to procuring 2,100 MW of utility-scale and 200 MW of distributed solar by 2029.[159] The issue here is one of relative scale: the approved natural gas agreements totaled about 2,100 MW as well, leading to an increasingly gas-heavy mix.

North Carolina. As described above, North Carolina is undergoing rapid changes in its planning process as it incorporates new carbon plan mandates into its IRPs. Thus, North Carolina's most recent IRP review discussed fuel mix projections but put off major natural gas

154. *See, e.g.*, Seminole Elec. Coop., Inc., No. 20170267-EC, at 13–14 (Fla. Pub. Serv. Comm'n May 25, 2018) (final order) (determining need for natural gas-fired power plant).

155. TENN. VALLEY AUTH., 1 2019 INTEGRATED RESOURCE PLAN: FINAL RESOURCE PLAN, at ES-2 (2019), https://tva-azr-eastus-cdn-ep-tvawcm-prd.azureedge.net/cdn-tvawcma/docs/default-source/default-document-library/site-content/environment/environmental-stewardship/irp/2019-documents/tva-2019-integrated-resource-plan-volume-i-final-resource-plan.pdf?sfvrsn=44251e0a_4 [https://perma.cc/A9T2-B86Y].

156. *Id.* at 9-2 to 9-4.

157. *Id.* at 9-4.

158. Order Adopting Stipulation, No. 44160, No. 44161, at 4, para. 8 at 17 (Ga. Pub. Serv. Comm'n July 29, 2022).

159. *Id.* at paras. 19, 21–22, 24.

conclusions pending carbon plan development.[160] The NCUC has completed hearings and briefing on its utilities' carbon plan filings but, as of this writing, has not issued a decision.[161] Duke Energy Carolinas and Duke Energy Progress (the two utilities subject to carbon plan requirements) developed four pathways toward 70% GHG reductions by 2035, combining coal retirement, new natural gas, and very significant renewables expansions, while leaving post-2035 carbon neutrality pathways relatively undeveloped—but disclosing in the fine print that all new natural gas would need to be phased out by 2050.[162] Exactly how any of this will play out in practice will depend on how the NCUC reacts to the plans and the degree to which these plans actually influence IRP and CPCN proceedings going forward.

South Carolina. South Carolina has recently demonstrated that, notwithstanding well-informed modeling processes, it is still state law and policy that govern regulatory decisions. This is playing out currently in the state PSC's ongoing IRP dockets, where the utilities modeled and selected portfolios moving toward a roughly equal mix of natural gas and renewables going forward.[163] In a complex series of orders, the PSC rejected its regulated utilities' initial IRP filings and

160. 2020 Biennial Integrated Res. Plans, No. E-100, Sub 165, at 10, 14–17 (N.C. Utils. Comm'n Nov. 19, 2021) (order accepting IRPs, REPS and CPRE Program Plans). *See generally Integrated Resource Plan*, N.C. UTILS. COMM'N, https://publicstaff.nc.gov/public-staff-divisions/economic-research-division/integrated-resource-plan [https://perma.cc/RQ88-CED6] (providing a database of all IRP proceedings).

161. *See generally* Duke Energy, No. E-100, Sub 179 (N.C. Utils. Comm'n May 16, 2022).

162. *See* DUKE ENERGY, 2022 CAROLINAS CARBON PLAN, ch. 3, 4 (2022), https://p-cd.duke-energy.com/-/media/pdfs/our-company/carolinas-carbon-plan/supplemental/chapter-03.pdf?rev=6c1febc8247f410fa0a930065899bf3e&_gl=1*svfy67*_ga*MTQzODUxNTkzLjE2ODExNTY4ODg.*_ga_HB58MJRNTY*MTY4MjYyMjk4Ni40LjEuMTY4MjYyMzU5MC4wLjAuMA..&_ga=2.245251340.841899260.1682622987-143851593.1681156888 [https://perma.cc/45ET-WAP3] (showing gas resources eliminated between 2035 and 2050 in all planning scenarios in Figure 3-3).

163. *E.g.*, Duke Energy Carolinas Integrated Resource Plan: 2020 Modified, No. 2019-224-E, at 13–16, (S.C. Pub. Serv. Comm'n Aug. 27, 2021) (selecting portfolio C1, heavy in renewables); Dominion Energy Modified 2020 Integrated Resource Plan, No. 2019-226-E, at 89, 159 (S.C. Pub. Serv. Comm'n May 24, 2021) (selecting RP8, which contemplates replacing coal with a mix of natural gas and renewable resources).

developed more rigorous standards for GHG reporting.[164] But most recently, the PSC rejected Duke Energy's submitted renewables-heavy plan and mandated the selection of a more gas-heavy alternative with little explanation. In a subsequent denial of petition for rehearing, the PSC finally made its thinking clear: "In its Modified IRP, Duke designated Portfolio Cl as its Preferred Portfolio. This portfolio fails to incorporate the Commission-required input assumptions as dictated by Order No. 2021-447 and *reflects an aggressive carbon management strategy that is unsupported by South Carolina law*."[165] In other words, South Carolina's planning mandates are treated as distinct from the state's resource selection mandates, which do not mandate selection of resources identified in decarbonization scenarios.

Alabama. Alabama Power contemplates building new natural gas plants and running them as long as they can. The utility's 2022 IRP predicts exclusively natural gas additions through 2040, with solar capacity additions planned only after 2040, assuming new mandates for carbon capture for new natural gas plants.[166] In other words, Alabama Power's planning documents would lock all emissions from natural gas plants built through 2040 for their useful lifetimes. This approach is also consistent with Alabama Power's 2019 CPCN petition, which sought authority for 2,400 MW of natural gas capacity additions through 2028.[167] This is in contrast to Alabama Power's separate renewables CPCN, issued in 2015, allowing a maximum of 500 MW solar, which has not yet been fully procured.[168]

164. Order Rejecting Dominion's Integrated Resource Plan, No. 2019-226-E, at 21 (S.C. Pub. Serv. Comm'n Dec. 23, 2020) (Order No. 2020-832); Order Accepting Modified Integrated Resource Plan, No. 2019-226-E, at 17 (S.C. Pub. Serv. Comm'n June 18, 2021) (Order No. 2021-429); Order Requiring Modification to Integrated Resource Plans, No. 2019-224-E, No. 2019-225-E, at 85 (S.C. Pub. Serv. Comm'n June 28, 2021) (Order No. 2021-447); Order Approving Modified Integrated Resource Plans with Changes, No. 2019-224-E, No. 2019-225-E, at 12 (S.C. Pub. Serv. Comm'n May 5, 2022) (Order No. 2022-332).

165. Order Denying Petitions for Rehearing, No. 2019-224-E, No. 2019-225-E, at 7 (S.C. Pub. Serv. Comm'n Sept. 21, 2022) (Order No. 2022-643) (emphasis added).

166. 2022 ALABAMA IRP REPORT, *supra* note 116, at 27–29.

167. Petition for a Certificate of Convenience and Necessity, No. 32953, at 14 (Ala. Pub. Serv. Comm'n Sept. 6, 2019); Ala. Power Co., No. 32953, at 14–15 (Ala. Pub. Serv. Comm'n Aug. 14, 2020) (final order) (approving gas only, deferring solar/storage pilots to separate renewables docket).

168. Ala. Power Co., No. 32382, at 2, 4, 10 (Ala. Pub. Serv. Comm'n Sept. 16, 2015) (final order); *see also* ALA. PUB. SERV. COMM'N, 2021 ANNUAL REPORT 29 (2022).

Mississippi. Notwithstanding its new IRP rules, Mississippi seeks to remain highly reliant on natural gas. Mississippi Power filed its first IRP under Mississippi's new law in 2021.[169] The headline of that filing was that the utility submitted plans to retire much of its coal fleet and some of its most inefficient natural gas-fired stations.[170] This, however, left almost all of the company's energy generated by natural gas. Models of future years assumed natural gas would predominate until carbon pricing forced a switch to carbon capture, renewables and storage, or both.[171] Entergy Mississippi also filed an IRP,[172] in which even its most aggressive renewables scenario proposes the addition of 1,900 MW of new natural gas capacity.[173]

In summary, therefore, most of the states in the Southeast (and the TVA) are planning, in one way or another, to invest heavily in natural gas infrastructure, and with the possible exception of North Carolina, none of them are doing enough to clarify the role that natural gas will play in a net zero 2050 future. To varying degrees, however, emerging expanded IRP processes are permitting public input and advocacy that is focused on these issues, and it is this advocacy that poses the best chance for increasing public understanding of the natural gas issue, and hopefully, regulatory change.

III. CONCLUSION: TOWARD NET ZERO PLANNING FOR THE SOUTHEASTERN ELECTRIC POWER SECTOR

The statutory and commission-created standards of review for utility proposals for future fuel mix discussed above constrain and limit advocacy to some degree. It is difficult to argue about the net zero implications of the natural gas expansion when review standards focus

169. Mississippi Power 2021 IRP Filing, No. 2019-UA-231 (Miss. Pub. Serv. Comm'n Apr. 15, 2021).

170. Iulia Gheorghiu, *Mississippi Power to Retire 976 MW of Fossil Fuels by 2027*, UTIL. DIVE (Apr. 20, 2021), https://www.utilitydive.com/news/mississippi-power-to-retire-976-mw-of-fossil-fuels-by-2027/598691/ [https://perma.cc/3P2G-MXTE].

171. Mississippi Power 2021 IRP Filing, No. 2019-UA-231 (Miss. Pub. Serv. Comm'n Apr. 15, 2021).

172. *See generally* Submittal of Entergy Mississippi, LLC's 2021 Integrated Resource Plan, No. 2019-UA-232 (Miss. Pub. Serv. Comm'n June 15, 2021).

173. Entergy Mississippi, LLC 2021 Integrated Resource Plan, No. 2019-UA-232, at 79 (Miss. Pub. Serv. Comm'n June 15, 2021).

solely on least-cost planning and require GHGs to be considered, if at all, only in terms of uncertain future compliance costs. Nonetheless, advocates across the Southeast have begun to engage decision makers more aggressively on the natural gas question.[174] A small selection of this growing advocacy reveals the current "lay of the land," and suggests paths toward net zero planning that accounts for the climate impacts of natural gas.

Alabama provides an example of what happens when a state PSC is openly hostile to climate policy and net zero goals. In 2019, advocates began opposing Alabama Power's 2019 proposal—based on its 2019 IRP and pursued via a CPCN petition—to add about 2,400 MW of natural gas capacity to its system.[175] Consistent with the state's cost-focused review standards, these challenges were confined to technical disagreements over demand modeling and, particularly, resource cost, framing the natural gas problem as one of uncertain fuel cost and stranded asset risk.[176] The Alabama PSC largely dismissed these criticisms and based its approval of the natural gas expansion on the conclusion that a fossil-heavy fuel mix had allowed Alabama Power to serve its customers reliably and cheaply for decades, and—entirely discounting climate regulatory risks—that "[t]here is no logical reason for [the commission] to conclude that resources of this type, with such a long and consistent operational history, will suddenly cease to be

174. Press Release, Southern Environmental Law Center, Atlantic Coast Pipeline Problems Persist Despite Supreme Court Decision (June 15, 2020), https://www.southernenvironment.org/press-release/atlantic-coast-pipeline-problems-persist-despite-supreme-court-decision/ [https://perma.cc/9THF-PN5Q].

175. Petition for a Certificate of Convenience and Necessity, No. 32953, at 14 (Ala. Pub. Serv. Comm'n Sept. 6, 2019).

176. Proposed Order Filed by Intervenor Sierra Club, No. 32953, at 2 (Ala. Pub. Serv. Comm'n May 1, 2020) (noting "their proposal would lock APC's customers into bearing the financial risk associated with gas-fired units for multiple decades at a time of great change in the utility industry, as renewable energy and storage costs plummet"); Response to the Petition for a Certificate of Convenience and Necessity by Alabama Power Company, No. 32953, at 3 (Ala. Pub. Serv. Comm'n May 1, 2020) ("As natural gas combined-cycle generating facilities, like the proposed Barry Unit 8, are built to last for decades, such investments may become stranded or the costs may become uneconomic due to new emission standards or technological change."); Post-Hearing Brief of Alabama Solar Industry Association, No. 32953, at 9–12 (Ala. Pub. Serv. Comm'n May 1, 2020) (discussing financial risks of gas facilities).

reliable sources of electricity."[177] In a revealing passage, the PSC went on:

> Nor do we find intervenors' concerns regarding the potential effects of future environmental regulations on the operating costs of the gas resources to undercut the evidentiary basis for the proposed portfolio. We previously have dismissed reliance on unsupported "what ifs" as not providing any reasonable basis upon which to predicate a decision. Here, the anxieties are equally speculative—that elected officials might broaden already restrictive environmental regulations and foreclose the ability of energy producers and suppliers to access an abundant and low cost natural resource beneath the nation's very feet [i.e., natural gas], with no regard for the economic consequences. Considering the evidence adduced at hearing, we fail to see why it is not equally (if not more) probable that foreign nations might seek to leverage their control over the materials required to develop renewable resources, thereby limiting availability and driving up costs. As well, it would seem that technological advancements [presumably, CCS], comparable to those touted by intervenors with regard to renewables, could likewise provide solutions to concerns over greenhouse gas emissions, facilitating energy producers and suppliers' continued use of the abundant domestic natural resources available to them.[178]

This quote reveals, more than dry technical assessments, where the state's regulators are coming from—and is indicative, furthermore, of widespread opinion about electric grid decarbonization in the Southeast. Supply chain challenges for renewables are real but in no way equal the natural gas risk—but there is no forum in Alabama for

177. Ala. Power Co., No. 32953, at 37 (Ala. Pub. Serv. Comm'n Aug. 14, 2020) (final order) (noting a robust defense of reliance on natural gas).

178. *Id.* at 39–40 (footnotes omitted).

discussing those risks clearly. Advocates may appeal the PSC's decision, but they face an uphill battle.[179]

Georgia provides an interesting middle ground example, as most of the advocacy so far adheres to economic analysis but has still resulted in expansions to renewable portfolios. In the recent IRP/CPCN proceedings, environmental advocates did not emphasize carbon risks or the problem of natural gas lock-in in the context of national net zero targets but rather stuck to an economic analysis based on traditional frameworks.[180] Nonetheless, Georgia's PSC concluded that "a continuation of measured procurement of competitively bid renewable energy projects benefit Georgia Power customers and provide fuel diversity to the Company's generation mix"—while also approving significant natural gas expansions.[181] This openness to renewables development has led Georgia to higher levels of solar power than most other U.S. states, but the state is still not creating sufficient frameworks for tackling the coming challenges of natural gas.

Perhaps the most forward-looking critique of natural gas planning in the Southeast so far has come from Our Children's Trust, the group behind the *Juliana v. United States* litigation and other climate advocacy focused on U.S. youth.[182] In their comments on the Florida PSC's recent TYSP report, the organization developed arguments on the constitutionality of fuel mix planning that locked in climate change; the failure to plan for city and district commitments to low-carbon electricity; the need to incorporate better planning for renewable resources consistent with Florida energy policy; and the

179. *See* Notice of Appeal, Energy Ala. v. Ala. Pub. Serv. Comm'n, No. 03-CV-2021-900028.00 (Montgomery Cnty. Cir. Ct. Jan. 7, 2021); *see also* Casey v. Beeker, 321 So. 3d 662, 663 (Ala. 2020) (involving litigation over recording of related hearings).

180. Post-Hearing Brief and Proposed Order by Georgia Interfaith Power & Light and the Partnership for Southern Equity, No. 44160, No. 44161, at 2 (Ga. Pub. Serv. Comm'n July 7, 2022); Post-Hearing Brief of the Sierra Club, No. 44160, No. 44161, at 1–2, 17–19 (Ga. Pub. Serv. Comm'n July 7, 2022); Post-Hearing Brief of Southern Alliance for Clean Energy and Southface Energy Institute, No. 44160, No. 44161, at 16–19 (Ga. Pub. Serv. Comm'n July 7, 2022); Brief and Orders of the Southern Renewable Energy Association, No. 44160, No. 41161, at 16–17 (Ga. Pub. Serv. Comm'n July 7, 2022).

181. *See* Order Adopting Stipulation, No. 44160, No. 44161, at para. 21 at 24 (Ga. Pub. Serv. Comm'n July 29, 2022).

182. *See Legal Actions*, OUR CHILDREN'S TRUST, https://www.ourchildrenstrust.org/juliana-v-us [https://perma.cc/J8EN-SQHA].

distance between utility public statements on decarbonization goals and planning commitments—apparently in preparation for future litigation under state law, in a state that is more threatened than most by climate change.[183] To date, however, such legal arguments have not prevailed and it is not yet clear what traction they will find under Florida's laws.

Argument specifics aside, advocacy around natural gas in the Southeast's electric power sector is fragmented and constrained at a structural level by IRP and CPCN standards that frame GHG considerations primarily in terms of cost minimization and regulatory risk and operate in timeframes of ten to twenty years rather than the thirty to seventy years relevant for climate change analysis. It is not so much that advocacy is impossible but that advocates talk past regulators, while regulators marginalize advocates and business as usual prevails.

The overarching conclusion of the above analysis is that the climate implications of the Southeast's ongoing natural gas transition are not being fully incorporated into fuel mix decision processes. It is neither wise nor necessary to shut down all the natural gas resources immediately; political reality makes state-by-state RPSs unlikely in the region; and the decision makers in the Southeast are unlikely to push their regulated utilities toward net zero resource pathways without governing mandates—each state, and to some degree each PSC, has its own climate policies that are sure to dictate outcomes. What this Article proposes, rather, is that the Southeast's decisions about the climate implications of its electricity system must be made transparent, and advocates must have the ability to engage with energy regulators on the climate implications of their decisions. It should not require academic study to draw together the climate implications of ongoing resource planning processes.

In other words: there should be net zero planning standards that require utilities to explain what they would do to achieve net zero emissions by 2050, if that becomes state or national policy. As

183. *See* FLORIDA 2022 TEN-YEAR SITE PLANS REVIEW, *supra* note 153, at 89–104.

demonstrated by North Carolina, these could be incorporated into existing IRP programs; and as demonstrated by South Carolina, doing so is not the same as dictating that net zero pathways be chosen—for example, it may well be that utilities report that they plan to achieve net zero through CCS primarily and that regulators endorse this approach. The important next step is to bring these positions to light, make them public, and submit them to public scrutiny and review. Utilities should be required to examine stranded asset risks in a net zero scenario, as well as consistency of current and future preferred resource plans with plans with interim targets necessary to achieve net zero. Florida, in particular, would do well to extend its planning processes beyond the ten-year horizon that currently prevails, while Alabama should join the rest of the Southeast in initiating a robust IRP process with public input. States with existing IRP programs, including Mississippi and Georgia, should review them to determine how best to incorporate net zero planning into existing frameworks in a manner that is consistent with state law and climate policy. Each should provide stakeholders with the procedural tools necessary to engage productively on climate policy.

The Southeast is abundant in renewable energy resources, a growing leader in new energy sector technology manufacturing, and uniquely vulnerable to the worst impacts of climate change. We have the capacity to lead on climate and innovate strategies that build today's society but also protect its future—and so we should. Regulatory planning, while seemingly removed from such lofty goals, will, in fact, play an outsized role in whether we succeed.