NC SUSTAINABLE
ENERGY ASSOCIATION

December 18, 2020

Ms. Kim Campbell
Chief Clerk
North Carolina Utilities Commission
430 North Salisbury Street
Raleigh, NC 27603

Re: Docket No. E-100, Sub 171
Petition for Investigation and Rulemaking to Implement N.C. Gen. Stat. § 62-154
Petition of the North Carolina Sustainable Energy Association, Sierra Club, and the Southern Alliance for Clean Energy for Investigation and Rulemaking to Implement N.C. Gen. Stat. § 62-154

Dear Ms. Campbell,

Please find enclosed for filing the Petition of the North Carolina Sustainable Energy Association, Sierra Club, and the Southern Alliance for Clean Energy for Investigation and Rulemaking to Implement N.C. Gen. Stat. § 62-154 in the above-captioned docket. Please let me know if you have any questions or if there are any issues with this filing.

Respectfully yours,

/s/ Peter H. Ledford

4800 Six Forks Rd., Suite 300 | Raleigh, NC 27609 | 919-832-7601 | energync.org

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-100, SUB 171

In the Matter of:	)	**PETITION OF THE NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION, SIERRA CLUB, AND THE SOUTHERN ALLIANCE FOR CLEAN ENERGY FOR INVESTIGATION AND RULEMAKING TO IMPLEMENT N.C. GEN. STAT. § 62-154**
Petition for Investigation and Rulemaking to Implement N.C. Gen. Stat. § 62-154	)	

PURSUANT TO N.C. Gen. Stat. § 62-31, the North Carolina Sustainable Energy Association ("NCSEA"), the Sierra Club, and the Southern Alliance for Clean Energy ("SACE") (NCSEA, the Sierra Club, and SACE, together, "Petitioners") petition the North Carolina Utilities Commission ("Commission") to investigate surplus energy sales as authorized by N.C. Gen. Stat. §§ 62-154 and 62-30, and adopt rules and rates as necessary for such sales.

I. PETITIONERS

1. NCSEA is a non-profit corporation formed under the laws of North Carolina, with individual, business, and government members located across the State. NCSEA' s mission is to promote a sustainable future through the use of renewable energy and energy efficiency programs. NCSEA's members include customers of both Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP") (DEC and DEP, collectively, "Duke"), as well as sellers and purchasers of electricity at the wholesale level. NCSEA's address is 4800 Six Forks Road, Suite 300, Raleigh, NC 27609.

2. The attorneys for NCSEA to whom all correspondence and filings related to this proceeding should be addressed to are:

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3. SACE is a nonprofit organization whose mission is to promote responsible energy choices that create global warming solutions and ensure clean, safe and healthy communities throughout the Southeast. The principal address of SACE is P.O. Box 1842, Knoxville, TN 37901. SACE also has offices in North Carolina and Georgia, and field offices across the region. SACE's members include customers of both DEC and DEP.

4. The Sierra Club is a national environmental organization whose mission is to explore, enjoy, and protect the wild places of the earth; to practice and promote the responsible use of the earth's ecosystems and resources; to educate and enlist humanity to protect and restore the quality of the natural and human environment; and to use all lawful means to carry out these objectives. In furtherance of this mission, the Sierra Club works to accelerate the transition from fossil fuels like coal and gas to clean energy solutions like solar, wind, and energy efficiency, and advocates for state and federal policies and industry action to achieve this transition. The Sierra Club has a long history of working to reduce pollution from fossil-fueled power plants and promoting clean energy resources in North Carolina. The Sierra Club's members include customers of both DEC and DEP. The address of the Sierra Club's principal office in North Carolina is 19 West Hargett Street, Suite 210, Raleigh, NC 27601.

5. The attorneys for SACE and the Sierra Club to whom all correspondence and filings in this docket should be addressed are:

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II. NCUC AUTHORITY

A. INTRODUCTION

6. Pursuant to N.C. Gen. Stat. § 62-154, "The Commission is authorized to investigate the sale of surplus electric power and the rates made for such energy, and to prescribe reasonable rules and rates for such sales." The Commission also has broad "power and authority to supervise and control the public utilities of the State[,]"[1] and the "full power and authority . . . to make and enforce reasonable and necessary rules and regulations" to enforce Chapter 62 of the General Statute.[2]

7. On December 11, 2020, Duke made an informational filing in the DEC and DEP company folders ("SEEM Filing"). The filing included the proposed Southeast Energy Exchange Market ("SEEM") platform agreement ("Market Agreement").

8. According to the SEEM Filing, the SEEM "establishes a region-wide, automated, intra-hour platform to match buyers and sellers with the goal of more efficient

[1] N.C. Gen. Stat. § 62-30.
[2] N.C. Gen. Stat. § 62-31.

bilateral trading and assumes utilization of unused transmission capacity to achieve cost savings for customers in the Southeast[.]"[3]

9. The SEEM Filing further explains that "SEEM will increase efficiencies by using an electronic algorithm-based wholesale energy trading platform to match willing buyers and sellers in the Southeast region[.]"[4]

B. COMMISSION JURISDICTION

10. While the Federal Energy Regulatory Commission maintains *jurisdiction over markets* for wholesale power sales, under N.C. Gen. Stat. § 62-154, the Commission also maintains *jurisdiction over Duke's participation in a market* for wholesale power sales of surplus electric power. As such, it is within the Commission's authority to adopt rules governing Duke's participation in a market for the exchange of excess energy, such as SEEM or an energy imbalance market ("EIM").

11. Duke has made clear that SEEM is designed, among other things, for "better integration of diverse generation resources, including rapidly growing renewables and fewer solar curtailments."[5] Curtailment only occurs when there is surplus electric power. As such, issues related to the sale of electricity that would otherwise be curtailed falls squarely within the Commission's purview under N.C. Gen. Stat. § 62-154.

12. This jurisdiction is also evident in Duke's Regulatory Conditions, specifically Regulatory Condition 3.9(b).[6] Specifically, Regulatory Condition 3.9(b) states that "No agreement shall be entered into by or on behalf of DEC or DEP, that (i)

[3] SEEM Filing, Cover Letter, p. 1.
[4] *Id.*
[5] **Exhibit A**, p. 1.
[6] *See*, *Order Granting Motion to Amend Regulatory Conditions*, Docket Nos. E-2, Sub 1095A, E-7, Sub 1100A, and G-9, Sub 682A (August 24, 2018).

commits DEC or DEP to, or involves either of them in, joint planning, coordination, dispatch or operation of generation, transmission, or distribution facilities with each other or with one or more other Affiliates . . . absent explicit approval of the Commission." SEEM, an EIM, an independent system operator ("ISO"), and a regional transmission organization ("RTO") all involve Duke in coordination, dispatch, or operation of generation and transmission.

13. Furthermore, Regulatory Condition 3.9(d) states that "Any contract or filing regarding DEC's or DEP's membership in or withdrawal from an RTO or *comparable entity* must be contingent upon state regulatory approval." (emphasis added). While SEEM and an EIM are not RTOs, they are comparable in that they both create markets for the exchange of electricity between utilities by utilizing excess transmission capacity.

III. SEEM'S DEFICIENCIES

A. SEEM'S BENEFITS ARE MINIMAL RELATIVE TO OTHER WHOLESALE MARKET OPTIONS

14. SEEM is only one option available for Duke to address surplus electric power. Surplus electric power can also be addressed through retail rates that encourage consumption during periods of surplus electric power; through an EIM; through utilization of an ISO; or through participation in a RTO. In fact, North Carolina's Clean Energy Plan recommended "a study on the potential costs and benefits of different options to increase competition in the electricity generation, including but not limited to

joining an existing wholesale market and allowing retail energy choice."[7] Given the multitude of options for addressing surplus electric power, the Petitioners believe that the Commission should thoroughly investigate the possibilities.

15. As set forth in **Exhibit B**, it is estimated that SEEM will provide $40 million in annual benefits *across the SEEM footprint*.[8] From 2020 to 2040, this would equate to $800 *million* in benefits. In comparison, as shown in **Exhibit C**, a RTO would provide $384 *billion* in savings during this same time period.[9] Similarly, **Exhibit D** shows that the Western EIM has saved participants $1 billion in just 5.5 years – more savings than SEEM in approximately 1/4 of the time.[10] Finally, **Exhibit E** shows that a potential southeastern EIM would create $100 to $600 million in *annual* savings just for Duke's customers.[11]

16. Before the Commission approves Duke's participation in SEEM, it should thoroughly investigate other available options for the sale of surplus electric power that may be more beneficial to North Carolina and Duke's ratepayers.

B. SEEM LACKS TRANSPARENCY AND ACCOUNTABILITY

17. The SEEM Filing raises several significant issues related to accountability and oversight. For example, the Market Agreement indicates that the SEEM entity will be governed exclusively by representatives from the investor-owned utilities participating in

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[7] *North Carolina Clean Energy Plan: Transitioning to a 21st Century Electricity System*, Recommendation B-4, *available at* https://files.nc.gov/ncdeq/climate-change/clean-energy-plan/NC_Clean_Energy_Plan_OCT_2019_.pdf.
[8] Exhibit B, p. iv.
[9] Exhibit C, p. 1.
[10] Exhibit D, p. 5.
[11] Exhibit E, pp. i-ii.

the Market.[12] This proposed governance structure does not include any opportunity for oversight by state regulators or any other objective parties.[13] The SEEM also lacks an independent evaluator or market monitor. Independent oversight is critical to ensuring competition in wholesale electricity markets. This lack of accountability and oversight means there is no guarantee that the SEEM will be operated in a nondiscriminatory manner.

18. The Market Agreement also lacks sufficient transparency provisions. While the Market Agreement provides for regular reports of high-level information,[14] it does not require Members and Participant to provide regulators or the public with any information about the matches made and the generation source of energy being purchased. In fact, with limited exceptions, "the identity of all Bidders, Offerors, Sellers and Buyers shall be kept confidential from all third-party entities other than the FERC, the Market Auditor, and the Southeast EEM."[15] Wholesale markets in other regions regularly provide this kind of data to state regulators and the public.[16]

C. SEEM MAY EXCLUDE INDEPENDENT POWER PRODUCERS

19. While independent power producers—mostly solar facilities in North Carolina—are not explicitly prohibited from participating in the SEEM, the structure of the proposed Market functionally prohibits them from participating. In order to participate in SEEM, entities must have entered into an Enabling Agreement with at least

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[12] Market Agreement, Arts. 4, 5.
[13] *See, e.g.*, *id.*, Art. 6 (allowing utilities to appoint the SEEM agent with no restrictions); *id.*, App. A, Sec. VI (allowing utilities to appoint SEEM administrator with no restrictions).
[14] *Id.*, App. B at 11-12.
[15] *Id.,* Art. 10.1.2.
[16] *See, e.g.*, California ISO Market price maps, http://www.caiso.com/PriceMap/Pages/default.aspx.

three or more other SEEM participants.[17] An Enabling Agreement is a "bilateral agreement for the purchase and sale of Energy[.]"[18] As independent power producers are not *purchasing* energy, but only selling energy, they would be prohibited from participating in SEEM.

20. Further, while independent power producers may theoretically become Participants, they cannot become SEEM Members.[19] Participants, unlike Members, have no representation on the SEEM's Membership Board or Operating Committee.[20] With SEEM governance dominated by investor-owned utilities, there will be no safeguards to prevent discrimination by SEEM members against independent power producers.

D. SEEM'S POTENTIAL IMPACTS ON AVOIDED COSTS REMAIN UNEXAMINED

21. The SEEM Filing fails to consider the impact of the SEEM on Public Utilities Regulatory Policies Act ("PURPA") avoided cost rates in North Carolina. The avoided cost rate is a critical component not only of PURPA solar contracts, but also various renewable energy procurement and energy efficiency programs in the state.

22. The Georgia Public Service Commission Public Interest Advocacy Staff—the state's equivalent of the North Carolina Public Staff—recently filed testimony on this issue in the Georgia Avoided Cost proceeding. The Public Interest Advocacy Staff testified that the impacts of SEEM on avoided costs are unknown and recommending that the Georgia Public Service Commission require Georgia Power to file a report explaining

[17] Market Agreement, App. B, Sec. III.
[18] *Id.*, Art. I.
[19] *Id.*, Sec. 3.2.
[20] *Id.*, Arts. 4, 5.

how SEEM would affect calculation of avoided costs in Georgia.[21] In light of SEEM's unknown impact on this important component of state renewable energy policy, further investigation is critical.

E. SEEM MAY EXACERBATE UNECONOMIC COAL DISPATCH AND SUPPRESS CLEAN ENERGY UPTAKE IN THE SOUTHEAST

23. Recent assessments have shown that utility-owned coal-burning generators in wholesale markets disproportionately operate at a loss due to their ability to pass fuel and operational costs through to ratepayers.[22] Coal units committed to operate out of merit distort and depress regional wholesale market prices.[23] This inefficient operation not only substantially increases ratepayer costs, but disadvantages independent power producers, qualified facilities under PURPA, new renewable energy entrants, energy efficiency programs, net metering customers. [24]

24. While the proposed SEEM Members do not currently operate in a wholesale market, the price suppressive impacts of uneconomic commitment similarly impact the marginal cost of energy, and could reasonably be expected to impact the intra-

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[21] Georgia Public Service Commission Public Interest Advocacy Staff Rebuttal Testimony of John L. Kaduk, Timothy S. Cook, and Jeffrey D. Bower, Docket Nos. 4822, 16573, and 19279, 70-71 (Ga. P.S.C. Dec. 4, 2020).

[22] Sierra Club, *Playing with Other People's Money: How Non-Economic Coal Operations Distort Energy Markets* 20 (Oct. 2019) https://www.sierraclub.org/sites/www.sierraclub.org/files/Other%20Peoples%20Money%20Non-Economic%20Dispatch%20Paper%20Oct%202019.pdf; Union of Concerned Scientists, *Used, But How Useful? How Electric Utilities Exploit Loopholes, Forcing Customers to Bail Out Uneconomic Coal-Fired Power Plants* (May 2020) https://www.ucsusa.org/resources/used-how-useful.

[23] Southwest Power Pool Market Monitoring Unit, *Self-committing in SPP markets: Overview, impacts and recommendations* (Dec 2019) https://spp.org/documents/61118/spp%20mmu%20self-commit%20whitepaper.pdf; Potomac Economics (MISO Independent Market Monitor), *A Review of the Commitment and Dispatch of Coal Generators in MISO* (Sept. 2020) https://cdn.misoenergy.org/20201008%20MSC%20Item%2004%20IMM%20Coal%20Dispatch%20Study481336.pdf.

[24] Union of Concerned Scientists, *supra* note 22 at 19.

hour trading prices under the proposed SEEM. Because the SEEM proposal neither envisions an obligation to commit units efficiently nor operate cost effectively, market participants could potentially exercise market power through the suppressive impact of uneconomic generation. Such actions could rebound negatively to the captive ratepayers of SEEM participants, and act to exclude competitive generation and demand-side market participants.

25. Some proposed SEEM Members, including Southern Company utilities, rely on substantially more coal generation than DEC and DEP. The SEEM Platform does not include any safeguards to prevent these Members from selling excess coal-generated electricity, potentially suppressing renewable energy projects in North Carolina.

26. The Governor's Executive Order 80 commits North Carolina to encourage renewable energy generation and reduce greenhouse gas emissions. In light of these commitments, the Commission should ensure that the SEEM proposal would not undermine renewable energy development in the state, lead to excessive emissions from in-state coal generators, or allow for excessive out-of-state high-emissions generation substituting for lower emissions in-state generators.

IV. RELIEF REQUESTED

27. Based on the Commission's jurisdiction under N.C. Gen. Stat. §§ 62-154 and 62-30, the Petitioners believe that the Commission should investigate the sale of surplus electric power prior to authorizing Duke's participation in SEEM. The Petitioners request that, if the results of the request investigation into methods for addressing surplus electric power dictate, the Commission proceed to adopt rules pursuant to N.C. Gen. Stat. § 62-31 to implement the provisions of N.C. Gen. Stat. § 62-154.

Respectfully submitted, this the 18th day of December 2020.

/s/ Peter H. Ledford
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CERTIFICATE OF SERVICE

I hereby certify that all persons on the docket service list have been served true and accurate copies of the foregoing filing by hand delivery, first class mail deposited in the U.S. mail, postage pre-paid, or by email transmission with the party's consent.

Respectfully submitted, this the 18th day of December 2020.

/s/ Peter H. Ledford
Peter H. Ledford
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VERIFICATION

Peter H. Ledford, first being duly sworn, deposes and says that he is the attorney for NCSEA; that he has read the foregoing Petition for Investigation and Rulemaking and that the same is true of his personal knowledge, except as to any matters and things therein stated on information and belief, and as to those, he believes them to be true; and that he is authorized to sign this verification on behalf of NCSEA.

This the 15 day of December, 2020.

Peter H. Ledford

NORTH CAROLINA
WAKE COUNTY

Sworn to and subscribed before me,

this the 15 day of December, 2020.

[AFFIX SEAL OF NOTARY]

Daniel G. Brookshire
Notary Public

Daniel G Brookshire, Notary Public
Orange County, North Carolina
My Commission Expires 7/2/2022

Daniel G. Brookshire
Printed Name of Notary Public
My Commission Expires: 7-2-2022

VERIFICATION

Gudrun Thompson, first being duly sworn, deposes and says that she is the attorney for the Sierra Club and the Southern Alliance for Clean Energy; that she has read the foregoing filing and that the same is true to her personal knowledge, except as to any matters and things therein stated on information and belief, and as to those, she believes them to be true; and that she is authorized to sign this verification on behalf of the Sierra Club and the Southern Alliance for Clean Energy.

This the 16th day of December, 2020.

Gudrun Thompson

NORTH CAROLINA
ORANGE COUNTY

Sworn to and subscribed before me,

this the 16th day of December, 2020.

[AFFIX SEAL OF NOTARY]

Notary Public

Kyle F Hoopes
Printed Name of Notary Public
My Commission Expires: JAN 27, 2023

KYLE F. HOOPES
NOTARY
PUBLIC
ORANGE COUNTY, NC

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-100, SUB 171

In the Matter of: **Petition for Investigation and Rulemaking to Implement N.C. Gen. Stat. § 62-154**	))))))))))	**PETITION OF THE NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION, SIERRA CLUB, AND THE SOUTHERN ALLIANCE FOR CLEAN ENERGY FOR INVESTIGATION AND RULEMAKING TO IMPLEMENT N.C. GEN. STAT. § 62-154**

Exhibit A

Southeastern Energy Exchange Market (SEEM)

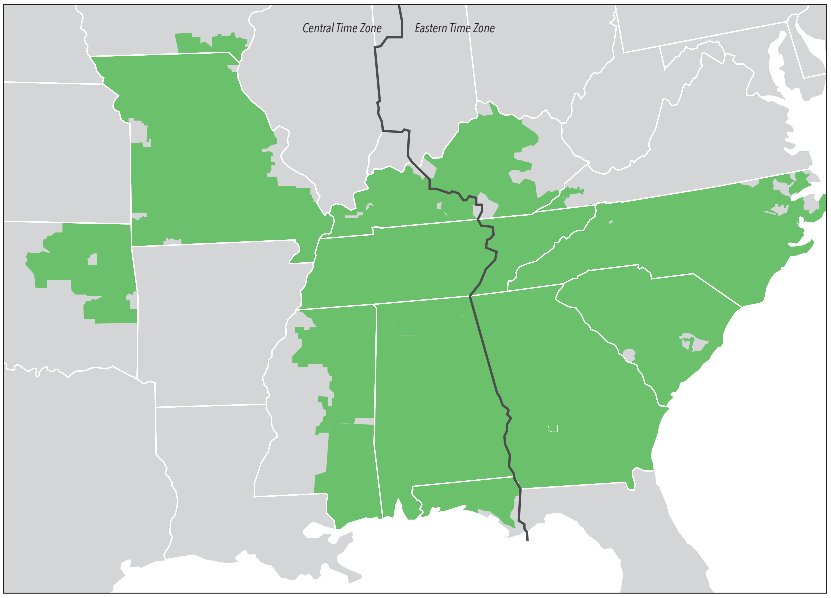
SEEM

Fact Sheet

What is SEEM?

A group of energy companies serving electricity customers across a wide geographic region in the southeastern U.S. is exploring an integrated, automated intra-hour energy exchange with goals of lowering costs to customers, optimizing renewable energy resources and helping maintain the reliable service we provide today.

> Companies exploring the energy exchange market include Associated Electric Cooperative Inc., Dalton Utilities, Dominion Energy South Carolina, Duke Energy Carolinas, Duke Energy Progress, ElectriCities of North Carolina, Inc., Georgia System Operations Corporation, Georgia Transmission Corporation, LG&E and KU Energy, MEAG Power, NCEMC, Oglethorpe Power Corp., PowerSouth, Santee Cooper, Southern Company, and TVA.



Members

- The members represent 16 entities in parts of 11 states with more than 160,000 MWs (summer capacity; winter capacity is nearly 180,000 MWs) across two time zones. These companies serve the energy needs of more than 32 million retail customers (roughly more than 50 million people).
- SEEM members would maintain existing control of generation and transmission assets, and membership is voluntary.

Benefits

- This is the first of its kind in our region and is a low-cost, low-risk way to provide immediate customer benefits through a shared market structure.
- SEEM would be a 15-minute energy exchange market that would use technology and advanced market systems to find low-cost, clean and safe energy to serve customers across a wide geographic area.
- Potential benefits include cost savings for customers and better integration of diverse generation resources, including rapidly growing renewables and fewer solar curtailments. An independent third-party consultant estimated that total benefits to grid operators and customers range from $40 million to $50 million annually in the near-term, to $100 million to $150 million annually in later years as more solar and other variable energy resources are added. (This is dependent, of course, on the number of member companies.)
- We expect customer savings to be realized through lower fuel costs as we're able to select lower-cost and more efficient generation resources to serve customer demand. As sellers identify a use for their excess energy, those profits also benefit customers.

Is SEEM an energy imbalance market?

No, while this market would share some of the same principles as an energy imbalance market (to assist with imbalances and reduce energy costs), it's less complex, less costly and less time intensive compared with setting up an EIM. It also does not rely on centralized unit dispatch.

How is SEEM similar or different from the Western Energy Imbalance Market?

	Western EIM	Southeast EEM
Resource Dispatch	5-minute nodal SCED market platform sends individual resource dispatch signals to participating resources every 5 minutes	15-minute block schedule via electronic interchange tags – BA/BA interface transactions – the Market Platform tool matches bids and offers to maximize benefit savings, while adhering to transmission capability (ATC) constraints
Complexity	Moderately complex due to establishing marketing system that also assesses security constraints	Simple due to leveraging existing bilateral trading processes
Costs	Significant startup costs	Low startup and ongoing costs
Transmission Service Charge	$0/MWh	$0/MWh
Ancillary Services	Limited	Limited
Manual/Automated	Automated	Automated
Day Ahead Market	No	No
Resource Offer into Market	Voluntary	Voluntary
Manages Imbalance	Directly	Indirectly

Regulatory approvals

FERC approval will be required to implement the SEEM. The FERC filing and approval process will provide an opportunity for the members of the SEEM to demonstrate the benefits of the proposed market design and for interested parties to provide feedback and comments for FERC to consider. State jurisdiction is limited to the affiliate component, if triggered, while FERC governs the structure and wholesale nature of the transactions.

What does this potential market mean for state utilities commissions and governing boards?

A primary objective is to maintain the same level of jurisdictional control and oversight as currently exists, where applicable, while facilitating more interchange transactions that support the cost-effective use of a diverse resource mix. FERC will have oversight authority as they do today to ensure those transactions occur with just and reasonable rates, terms and conditions.

SEEM

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to Implement N.C. Gen. Stat. § 62-154	)	
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Exhibit B

Southeast EEM Benefits and Non-Centralized Costs

Prepared for:

Participants in Southeast Energy Exchange Market

Submitted by:
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Charles River Associates Inc.
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Boston, MA 02116-5092

July 6, 2020

TABLE OF CONTENTS

DISCLAIMER

This report was prepared by Guidehouse Inc. ("Guidehouse")[1] and CRA International, Inc. ("CRA") for Project BEST. The work presented in this report represents Guidehouse and CRA's professional judgment based on the information available at the time this report was prepared. Guidehouse and CRA are not responsible for the reader's use of, or reliance upon, the report, nor any decisions based on the report. GUIDEHOUSE AND CRA MAKE NO REPRESENTATIONS OR WARRANTIES, EXPRESSED OR IMPLIED. Readers of the report are advised that they assume all liabilities incurred by them, or third parties, as a result of their reliance on the report, or the data, information, findings, and opinions contained in the report.

[1] Guidehouse LLP completed its acquisition of Navigant Consulting, Inc. and its operating subsidiaries on October 11, 2019. For more information, see: https://guidehouse.com/news/corporate-news/2019/guidehouse-completes-acquisition-of-navigant.

EXECUTIVE SUMMARY

Study Scope and Purpose

A coalition of Southeast utilities, cooperatives, and municipalities engaged Guidehouse and Charles River Associates (collectively referred to as Guidehouse/CRA) to examine the potential benefits of forming a Southeast Energy Exchange Market (Southeast EEM). The proposed Southeast EEM is a centralized automated market for trading energy between electric utilities in the Southeast U.S. on an intra-hour basis. Southeast EEM participants include Associated Electric Cooperative Inc., Central Electric Power Cooperative, Dalton Utilities, ElectriCities of North Carolina, Inc., Dominion Energy South Carolina, Duke Energy Carolinas, Duke Energy Progress, Georgia System Operations Corporation, Georgia Transmission Corporation, LG&E and KU Energy, MEAG Power, NC Electric Membership Corporation, Oglethorpe Power Corporation, Santee Cooper, Southern Company, and TVA. In aggregate, the prospective Southeast EEM participants have over 160 GW of capacity serving over 640 TWh of energy for load. As an intra-hour market, the Southeast EEM would supplement the existing day/hour-ahead bilateral market in the Southeast making use of any remaining available transfer capability (ATC) to obtain additional savings in energy costs and improved renewable integration in the region.

Guidehouse/CRA estimated Southeast EEM benefits against a status quo of no intra-hour interface trading, with two market outlooks evaluated: an *IRP Baseline Outlook* and a *Carbon-Constrained Outlook*. The *IRP Baseline Outlook* is based on the Guidehouse Reference Case outlook on North American power markets, supplemented by each Southeast EEM participant's most recent integrated resource plan (IRP). The *Carbon-Constrained Outlook* is an alternative market outlook that explores a high renewable future in the Southeast with ambitious carbon reduction goals. For purposes of the benefits analysis, Southeast EEM operations are assumed to begin in 2021 and benefits are assessed over the 20-year period from 2021 to 2040.

Based on the Guidehouse/CRA analysis, Southeast EEM benefits across the Southeast EEM footprint are projected to be over $40 million (2020$) per year in the *IRP Baseline Outlook*. In the *Carbon-Constrained Outlook*, with much higher renewable and energy storage penetration in the out-years, Southeast EEM benefits increase substantially over time to reach over $100 million (2020$) per year by 2037.

In addition to the benefits analysis, Guidehouse/CRA assisted each potential Southeast EEM participant in estimating the internal non-centralized costs, such as additional labor and software, that would be incurred for each participant to start-up and operate in the proposed Southeast EEM market. The aggregate sum of these Southeast EEM participant internal non-centralized costs are approximately $3.1 million per year (2020$) when levelized in real terms over the 2021-2040 period.[2]

[2] These internal member costs do not include the costs of operating the Southeast EEM trading platform, and the costs of other centralized Southeast EEM administrative and monitoring expenses.

Southeast EEM Overview

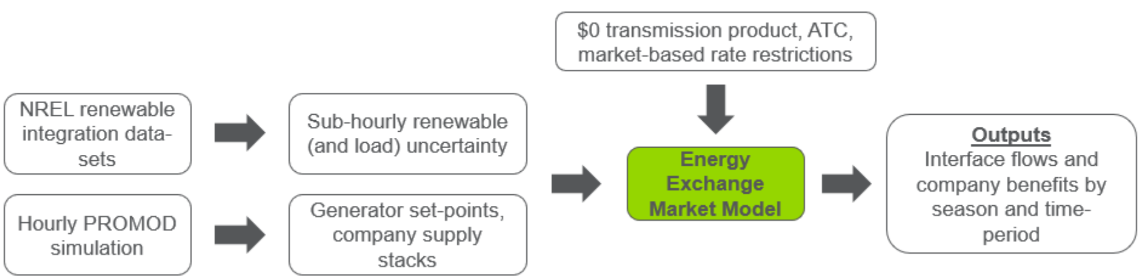
Under the proposed Southeast EEM, there will be 15-minute intra-hour trading across Southeast EEM participant interfaces, making use of any remaining non-firm ATC, with bids and offers matched through a platform to be developed by a third-party vendor with access provided to each of the Southeast EEM participants for supplying their input information.

In the Southeast EEM, there will be a new $0/MWh transmission product which can only be procured in the intra-hour market for any remaining non-firm ATC and represents the lowest level priority of non-firm transmission service. All resulting Southeast EEM transactions are between two parties, with the point of sale for each transaction at the buyer's BA interface. Southeast EEM trade prices are calculated using a bilateral "split savings" approach between the matched bid and offer. Each Balancing Authority ("BA") would be responsible for continuing to ensure adequate resource plans for meeting reserve requirements and would continue to oversee its generation and load balancing.

Modeling Approach

A combination of production cost modeling and linear programming optimization was used to estimate Southeast EEM benefits. Guidehouse uses PROMOD, a commercially available software, to develop its wholesale energy market price and plant performance forecasts.[3] In this study, PROMOD is first used to simulate regional system operations under status quo conditions, including the daily and hourly bilateral trading that takes place today. The hourly PROMOD data (e.g., output of each generating unit in the footprint) is then pulled into the Southeast EEM Model to analyze whether additional economic intra-hour trades can be made among Southeast EEM participants. This sub-hourly model incorporates load and renewable generation uncertainty, ATC, and the $0/MWh non-firm transmission product.[4] The modeling process is illustrated in Figure 1

Figure 1. Southeast EEM Modeling Flow Diagram



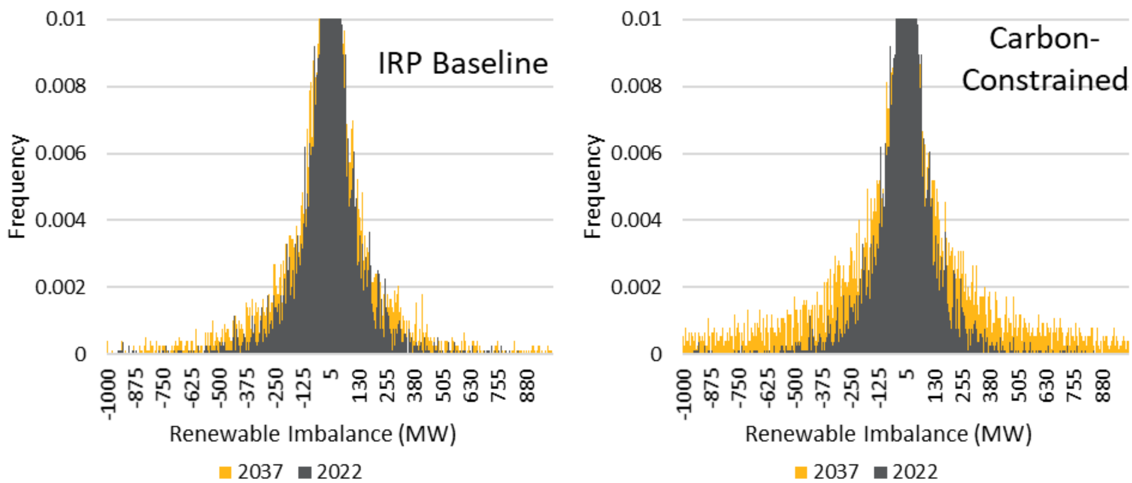
One Southeast EEM objective is to assist utilities in the Southeast with lowering energy cost for customers and renewable integration. With solar capacity representing the predominant renewable technology in the Southeast, the largest sub-hourly imbalances are observed during "solar hours" (hours ending 8:00 am to 7:00 pm). A distribution of the aggregated 15-minute renewable imbalances during solar hours for the Southeast EEM participants is shown in Figure 2 for 2022 and 2037. As shown, in approximately 16% of these 15-minute periods during solar hours, imbalances exceed +/- 130 MW for the participating BAs, with certain 15-minute periods having much larger imbalances.

[3] PROMOD is a detailed energy production cost model used to simulate hourly chronological operation of generation and transmission resources on a nodal basis.

[4] As discussed in Section 1.3.2, any market-based rate restrictions for sales within BAs that were identified in discussions with Southeast EEM participants are incorporated in the sub-hourly bilateral trade modeling. Financial transmission losses are considered in the model.

In the *Carbon-Constrained Outlook*, the significant renewable expansion by the late 2030s results in the larger imbalances becoming much more frequent. It should be noted that the Southeast EEM can help participants manage periods of excess energy and high net demand ramping created by renewable integration. However, the EEM will not be able to address minute-to-minute renewable volatility and intermittency due to the 15-minute schedule transaction update frequency.

Figure 2. Distributions of 15-Minute Renewable Imbalances During Solar Hours



Note: distribution frequency truncated at 0.01 for illustrative purposes; each bar in the histogram represents a 5 MW bin; higher imbalances attributed to Balancing Authorities with higher renewable penetration

Southeast EEM Benefits

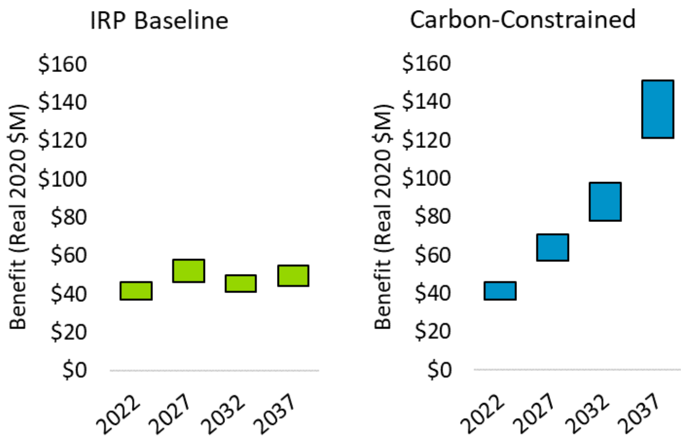
As shown in Figure 3, Southeast EEM benefits (prior to netting any Southeast EEM start-up or operating costs) average $47M per year (2020$) in the *IRP Baseline Outlook*. Benefits increase slightly in the mid-term largely as a result of higher renewable penetration, before stabilizing for the remainder of the forecast.[5]

In the *Carbon-Constrained Outlook*, benefits increase significantly in the out-years driven by increasing sub-hourly uncertainty from higher renewable penetration and increased flexibility from the expansion of battery storage. While benefits are considerably higher in the *Carbon-Constrained Outlook*, they are also more uncertain, as the resource mix and power system operation in the 2030s represents a significant change from today.

[5] The annual benefits are represented as a range in these charts to reflect the uncertainty primarily associated with market participation and ATC, and to a lesser degree, ramping capability of gas and storage assets and permissible renewable curtailment.

Southeast EEM Benefits and Non-Centralized Costs

Figure 3. Southeast EEM Benefits



The Southeast EEM benefits are derived from fuel cost savings, as the Southeast EEM gives participants access to a lower cost, more efficient pool of resources in managing subhourly load and renewable uncertainty. As shown in Table 1, annual benefits represent approximately 0.3% to 0.4% of total annual production costs in the Southeast EEM footprint in the *IRP Baseline Outlook*. Benefits as a proportion of total production costs are much higher in the *Carbon-Constrained Outlook*, reaching 1.1% by 2037.

Table 1. Southeast EEM Benefits Relative to Southeast EEM Footprint Production Costs

Year	Southeast EEM Footprint Production Costs ($2020)		Southeast EEM Gross Benefit ($2020)	
	IRP Baseline	Carbon-Constrained	IRP Baseline	Carbon-Constrained
2022	$10.8B		$37M - $46M	
2027	$12.0B	$11.4B	$46M - $58M	$57M - $71M
2032	$13.0B	$11.7B	$41M - $50M	$78M - $98M
2037	$14.1B	$12.1B	$44M - $55M	$121M - $151M

In an average hour, 15-minute sub-hourly trades represent approximately 1-2% of the total energy for load within the Southeast EEM participant footprint. In effect, the PROMOD hourly output of individual generating units in the Southeast EEM footprint is modified by plus/minus 1 to 2% on average through sub-hourly trading.

Renewable imbalance is a large driver of the Southeast EEM benefits. While it is difficult to attribute an exact proportion, Southeast EEM benefits seem to be roughly evenly split between renewable integration benefits and the benefits from taking advantage of interface price differentials with zero-cost sub-hourly transmission. A number of parameter tests were conducted to better understand the source of the benefits. Southeast EEM benefits are robust across all years, both market outlooks, and all model parameter tests.

There are several key uncertainties and risks associated with the value of the Southeast EEM:

- The study assumes a well-functioning, and relatively high-participation market. Limited participation by members is the largest risk to Southeast EEM benefits.
- The $0 transmission rate sub-hourly trading could eventually cannibalize some hourly trading yielding a reduction in non-firm transmission revenues.
- The resource mix in the *Carbon-Constrained Outlook* represents a significant change from today for the Southeast making results much more uncertain.

The Southeast EEM can also set the stage for more complex markets that could unlock even greater benefits for its members. For example, while a 5-minute market would be more complex and costly, it would likely facilitate greater renewable integration benefits and possibly a reduction in reserves held for balancing.

Non-Centralized (Internal) Costs

In forming the Southeast EEM, two separate and distinct cost streams would be incurred: shared Southeast EEM costs and internal member costs. The former costs are those incurred to facilitate the central market and settlement process and the latter are incurred at the member level to interface with the market and manage the process locally through scheduling and processing transactions. Guidehouse/CRA focused on the latter cost category (internal member costs) through an interview process with each prospective Southeast EEM participant.

Non-centralized internal costs can be segregated into two categories. The first are “start-up” costs, one-time costs related to the initial market development period. Start-up costs are primarily comprised of costs associated with meeting initial operational requirements, governance requirements, and regulatory filings, but may include other non-recurring costs as well. The second category of costs are the ongoing ones required to facilitate participation in the market. These ongoing costs are primarily labor for schedulers and traders as well as ongoing regulatory costs.

The Southeast EEM benefits modeling assumes that all economic intra-hour trades will be made; thus, members estimated internal costs robust enough to actively optimize bids every 15 minutes. For purposes of this analysis, the costs considered are incremental, meaning that only out-of-pocket expenses for software, outside legal support, additional staffing, etc. were considered. Use of existing in-house capabilities and existing staff were excluded from consideration. The collective amount of internal non-centralized costs is shown in Table 2.

Table 2. Southeast EEM Member Aggregate Non-Centralized Start-up and Operating Costs (*millions of dollars*)

Category	Total	20-year Real Levelized ($2020)
Start-up Costs	$3.8 (one time)	$0.3
Operating Costs	$2.8 (per year, growing at inflation)	$2.8
	Total:	**$3.1**

Costs are summarized in terms of a 20-year real levelized annual amount in aggregate across all Southeast EEM members. Internal non-centralized start-up costs total to $3.8 million across the members and are approximately $0.3 million per year (2020$) if recovered over 20 years. On-going internal operating costs across the members are estimated to be $2.8 million per year. In sum, total costs levelized over 20 years total to $3.1 million (2020$).

1. STUDY BACKGROUND, ASSUMPTIONS, AND METHODOLOGY

1.1 Study Scope and Purpose

A coalition of Southeast utilities, cooperatives, and municipalities engaged the Guidehouse/CRA team to examine the potential benefits of forming a Southeast Energy Exchange Market (Southeast EEM). The proposed Southeast EEM is a centralized automated market for trading energy between electric utilities in the Southeast U.S. on an intra-hour basis. As an intra-hour market, the Southeast EEM supplements the existing day/hour-ahead bilateral market in the Southeast U.S. by making use of any remaining available transfer capability (ATC) to obtain further savings in energy costs and improved renewable integration in the region.

Southeast EEM participants include Associated Electric Cooperative Inc., Central Electric Power Cooperative, Dalton Utilities, ElectriCities of North Carolina, Inc., Dominion Energy South Carolina, Duke Energy Carolinas, Duke Energy Progress, Georgia System Operations Corporation, Georgia Transmission Corporation, LG&E and KU Energy, MEAG Power, NC Electric Membership Corporation, Oglethorpe Power Corporation, Santee Cooper, Southern Company, and TVA.

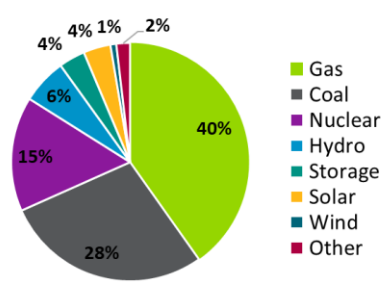
Guidehouse/CRA estimated Southeast EEM benefits against a status quo case of no intra-hour interface trading, with two market outlooks evaluated: an *IRP Baseline Outlook* and a *Carbon-Constrained Outlook*. For purposes of the benefits analysis, Southeast EEM operations are assumed to begin in 2021, and benefits are assessed over the 20-year period from 2021 to 2040.

In addition to the benefits analysis, Guidehouse/CRA assisted each potential Southeast EEM participant in estimating the internal costs, such as additional labor and software, that would be incurred for each participant to start-up and operate in the proposed Southeast EEM market. The aggregate sum of these Southeast EEM participant internal costs are presented in this report.[6]

1.2 Market Outlooks

In aggregate, the proposed Southeast EEM participants collectively have over 160 GW of capacity serving over 640 TWh of energy for load. Collectively, the current capacity mix by technology type is captured in Figure 4. Today, coal and gas-fired facilities represent 68% of Southeast EEM footprint capacity, with the remainder made up of nuclear and renewable power.

Figure 4. Southeast EEM Footprint 2020 Capacity Mix



[6] These internal member costs do not include the costs of the entity that would operate the Southeast EEM trading platform, and the costs of other centralized Southeast EEM administrative and monitoring expenses.

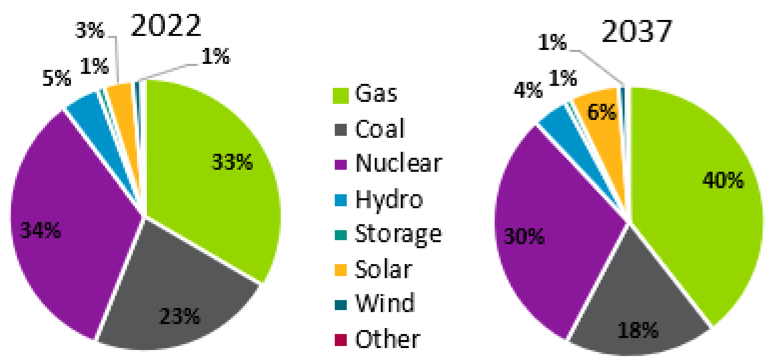
The two market outlooks considered in the study represent two plausible futures of how the Southeast power system could evolve over the next two decades and give insight into how benefits may change as the resource mix evolves.

1.2.1 IRP Baseline Outlook

The *IRP Baseline Outlook* is based on each participant's projected load and generation capacity plan. Some of these plans have been shared publicly through IRP filings and some of which have not been made public. Broader assumptions such as long-term fuel prices are based on Guidehouse's semi-annually updated Reference Case outlook on North American power markets, which is used for transaction support and is widely accepted by both financial institutions and market participants throughout the Eastern Interconnect. Guidehouse's Reference Case relies on the involvement of numerous subject matter experts with specific knowledge and understanding of such items as fuel pricing, generation development, transmission infrastructure expansion, asset operation, environmental regulations, and technology deployment.

Figure 5 shows the forecasted energy generation mix for the Southeast EEM footprint in the *IRP Baseline Outlook*. While the share of gas and solar generation increases at the expense of coal, the generation mix in 2037 is largely similar to that of today's system.

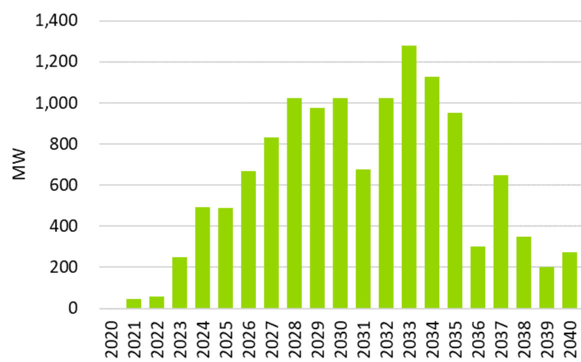
Figure 5: Southeast EEM Footprint Forecasted Generation Mix, IRP Baseline Outlook



1.2.2 Carbon-Constrained Outlook

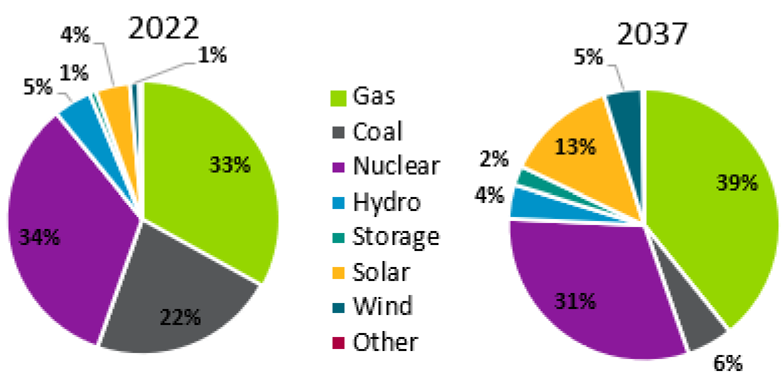
The *Carbon-Constrained Outlook* is an alternative market outlook that explores a high renewable future in the Southeast with ambitious carbon reduction goals. The future resource mix in this outlook was determined using participant's IRP carbon reduction plans if available. If not, the outlook was developed using reasonable assumptions of what a high-renewable and storage, low-carbon future may look like in the Southeast. For companies with IRP timeframes that end before the study period (ending in 2040), the remaining years of the IRP carbon plan were extrapolated to 2040 assuming no coal generation in 2040 (unless a participant provided Guidehouse/CRA with an alternate resource mix). As coal retires, energy storage, rather than natural gas, is projected to be the primary means of meeting peak reliability requirements. The expansion of battery storage throughout the Southeast EEM footprint is shown in Figure 6.

Figure 6. Southeast EEM Footprint Battery Storage Additions – Carbon-Constrained Outlook



As shown in Figure 7, the proportion of solar and wind generation in 2037 is three times that in the *IRP Baseline Outlook*, resulting in a much more variable system with greater imbalances, larger morning and evening ramping needs, reduced carbon emissions, and more zero-marginal cost hours.

Figure 7. Southeast EEM Footprint Forecasted Generation Mix, Carbon-Constrained Outlook



1.3 Study Methodology

1.3.1 Southeast EEM Overview

Under the proposed Southeast EEM, there will be 15-minute intra-hour trading across Southeast EEM participant interfaces subject to there being any remaining ATC at the interface, with bids and offers matched through a central software platform to be developed by a third-party vendor with access provided to each of the Southeast EEM participants for supplying their input information.

In the proposed Southeast EEM, there will be a new $0/MWh transmission product which can only be used in the intra-hour market and represents the lowest level of non-firm transmission using any remaining ATC. All resulting Southeast EEM transactions are between two parties, with the point of sale for each transaction at the buyer's BA interface. Each Southeast EEM bid to buy, and offer to sell, must provide the MW size, the price in terms of $/MWh, and the source for offers and the sink for bids.

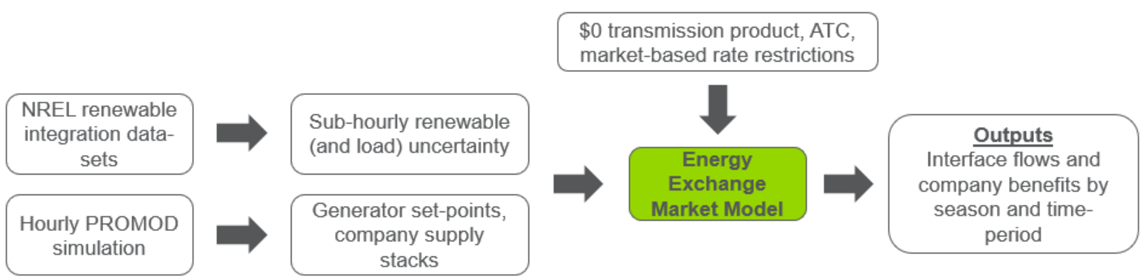
Southeast EEM trade prices are calculated using a bilateral "split savings" approach between the matched bid and offer that maximizes EEM benefits. Each Balancing Authority ("BA") would be responsible for continuing to ensure adequate resource plans for meeting reserve requirements and would continue to oversee its generation and load balancing. There is no reserve sharing and participants cannot rely on the Southeast EEM for its balancing needs. No sub-hourly bilateral trading is assumed to take place with entities outside of the Southeast EEM footprint.

1.3.2 Modeling Approach

Guidehouse used a combination of production cost modeling and linear programming optimization to estimate Southeast EEM benefits. Guidehouse uses PROMOD, a commercially available software, to develop its wholesale energy market price and plant performance forecasts. PROMOD is a detailed energy production cost model used to simulate hourly chronological operation of generation and transmission resources on a nodal basis throughout the Eastern Interconnect. Within PROMOD, production costs are calculated based upon heat rate, fuel cost, and other operating costs, expressed as a function of output.[7]

PROMOD is first used to simulate regional system operations under status quo conditions, including the daily and hourly bilateral trading that takes place today, but not including the intra-hour trading that would take place in the Southeast EEM. As an intra-hour market, the Southeast EEM cannot be fully captured in the PROMOD hourly modeling. The hourly PROMOD data (e.g., output of each generating unit in the footprint) is pulled into the Southeast EEM Model to analyze whether additional economic intra-hour trades can be made among Southeast EEM participants. This sub-hourly model takes into account load and renewable generation uncertainty, ATC, and the $0/MWh transmission product.[8] Bilateral trading friction hurdles between BAs modeled in PROMOD[9] are also eliminated in the sub-hourly modeling to reflect the Southeast EEM centralized bid matching. The modeling process is illustrated in Figure 8.

Figure 8. Southeast EEM Modeling Flow Diagram



[7] Detailed production cost modeling assumptions used in this study, including capacity additions and retirements, natural gas price forecasts, emissions price forecasts and load growth, are provided in Appendix A.

[8] Any market-based rate restrictions for sales within BAs that were identified in discussions with Southeast EEM participants are incorporated in the sub-hourly bilateral trade modeling, including the TVA "fence" (TVA, under the 1959 Bond Act, is prohibited from selling electricity outside its congressionally mandated territory, with the exception of 14 power generators on TVA`s borders with whom it already was exchanging electricity as of July 1, 1957).

[9] Energy transfers between balancing authorities are subject to economic and transactional barriers referred to as hurdle rates in production cost modelling. These hurdle rates comprise transmission fees based on Open Access Transmission Tariffs in addition to bilateral-trading friction which represent other barriers to trading such as minimum trading margins and/or administrative charges.

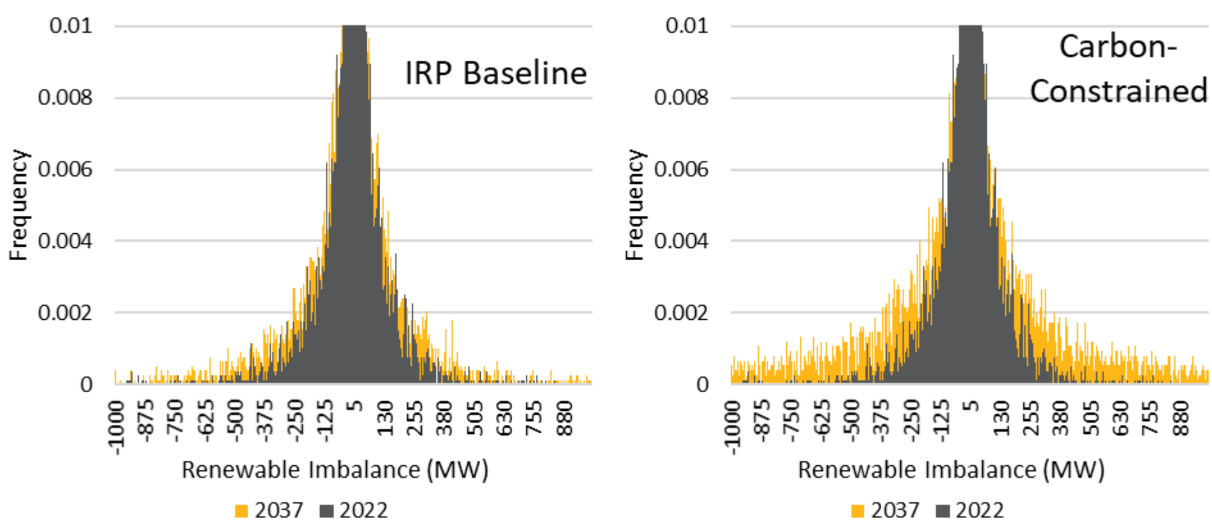
1.3.3 Load and Renewable Uncertainty

To estimate sub-hourly renewable imbalances, Guidehouse relied on NREL's geospatial Solar and Wind Integration Data Sets to simulate random days of renewable operations. These random days simulate historical operation of renewable resources including impacts of regional weather and geographic diversity. This approach ensures that the cross-correlation of the renewable generation over the entire Southeast EEM footprint is considered by randomizing the time period being drawn and pulling the operation of each resource from this period.

Each NREL solar dataset includes one year of historical simulated 5-minute data and each NREL wind dataset includes over five years of historical simulated 5-minute data. Renewable sites are selected to represent the geographic diversity of each Southeast EEM participant's current and future renewable portfolio. NREL also provides corresponding hourly schedules for each simulated solar plant, from which the area-control-error (ACE) contribution due to renewable uncertainty can be calculated (ACE ~ Output – Schedule). The ACE contributions of individual sites are scaled appropriately based on the actual capacity assumed to be at the given location, which is based on each participant's resource build-out plan.

With solar the predominant renewable technology deployed in the Southeast; the largest sub-hourly imbalances are observed during solar hours (hours ending 8:00 am to 7:00 pm). A distribution of the aggregated 15-minute renewable imbalances during solar hours for the Southeast EEM participants is shown in Figure 9 for 2022 and 2037. In the *Carbon-Constrained Outlook*, the significant renewable expansion by the late 2030s results in much higher imbalances, as shown by the much larger tails in the imbalance distributions.

Figure 9. Distributions of 15-Minute Renewable Imbalances During Solar Hours



Note: distribution frequency truncated at 0.01 for illustrative purposes; each bar in the histogram represents a 5 MW bin; higher imbalances attributed to Balancing Authorities with higher renewable penetration

In addition to renewable uncertainty, load-uncertainty is also considered and estimated using a normal distribution with a standard deviation proportional to each participant's average load.

1.3.4 Short-term Bid and Offer Curves

Typical days[10] of hourly PROMOD operation provide a set point from which hourly supply curves are created for each of the Southeast EEM members that consider what online resources are available, and able to ramp up or down to meet their 15-minute obligations. The renewable and load uncertainty discussed in Section 1.3.3 is subsequently applied to create the 15-minute net generation that must be met. At a high level, the baseline assumption is that each member will meet their 15-minute requirements with their own available resources. The Southeast EEM model analyzes the alternative case in which each participant bids in their resources and the market can make trades that reduce overall costs on the 15-minute time frame. To construct the bid and offer curves for each Southeast EEM participant, the following assumptions are made:

- Online combined-cycle plants (CCs) and simple-cycle combustion turbines (CTs) can ramp down to minimum generation limits or ramp up to their max capability
- Storage resources, including batteries and pumped-hydro, can ramp up or down at the marginal cost of energy
- Some renewable curtailment is permitted

Generally, each member holds spinning reserves or offline quick-start CTs for renewable balancing. While offline CTs are not brought online to trade in the 15-minute Southeast EEM, there are rare instances (though more prevalent in the later years of the *Carbon-Constrained Outlook*) where these offline CTs would need to ramp up to correct for large negative imbalances if the Southeast EEM market did not exist. Rather than ramping these offline units, a member can use Southeast EEM trading instead and avoid the associated costs of starting a new unit.

[10] Typical days are chosen in each month for the selected test years (2022, 2027, 2032, and 2037) in order to capture seasonal patterns to trading volumes and benefits.

1.4 Key Study Assumptions

Key study assumptions and their impacts on Southeast EEM benefits are summarized in Table 3.

Table 3. Key Study Assumptions

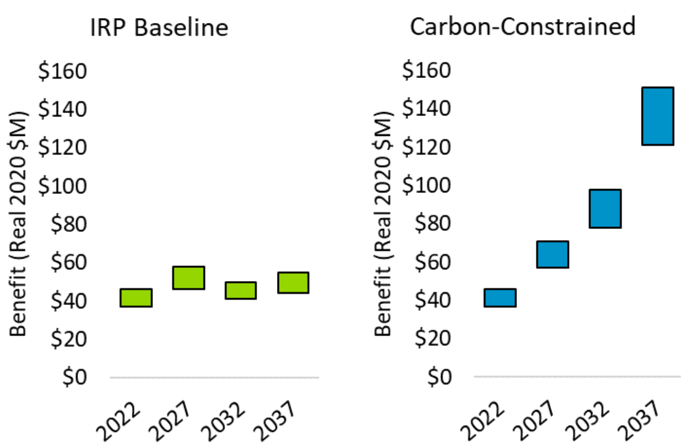
Topic	Assumption Description	Impact
Market Participation	While the study generally assumes the Southeast EEM is a high-participation, well-functioning market, modeled participation is somewhat limited to reflect that some imbalance will be handled internally as opposed to being met with the market. Sensitivity analysis on market participation was conducted to determine an appropriate range on the benefit results.	High
Transmission Representation	While the hourly PROMOD baseline operation simulates system operation nodally with a full transmission representation, potential transmission constraints are not considered in the sub-hourly trades.	Low
Transmission Losses	The study assumes 2% losses with pancaking.	Low
$0/MWh Transmission Service Cost	The study assumes zero cost intra-hour transmission service available for EEM transactions.	High
Trading Friction	Bilateral trading friction hurdles between BAs modeled in PROMOD are eliminated in the Southeast EEM. The Southeast EEM Model will execute any trade, regardless of margin, that has a global benefit to the Southeast EEM participants.	Medium
Bid/Offer Behavior	The study assumes that participants are submitting bids and offers at true costs. The impact of more complex bidding strategies was not accessed.	High
ATC	Trades are limited to 2019 average ATC, however this may be conservative if actual market operation could result in more transmission capacity being released.	Low
Fuel Prices	Guidehouse develops a fundamental gas price forecast fully integrated with the power market forecasts. In general, lower gas prices reduces benefits of the Southeast EEM.	Medium

2. SOUTHEAST EEM BENEFITS

2.1 Southeast EEM Gross Benefits

As shown in Figure 10, Southeast EEM gross benefits (prior to netting any Southeast EEM start-up or operating costs) average $47M per year (real 2020 dollars) in the *IRP Baseline Outlook*, with benefits increasing slightly in the mid-term largely as a result of higher renewable penetration, before stabilizing for the remainder of the forecast. In the *Carbon-Constrained Outlook*, there is significant upside to benefits driven by increasing sub-hourly uncertainty from higher renewable penetration and increased flexibility from the expansion of battery storage. While benefits are considerably higher in the *Carbon-Constrained Outlook*, they are also more uncertain, as the resource mix and power system operation in the 2030s represents a significant deviation from today.

Figure 10. Southeast EEM Gross Benefits



2.2 Benefits Discussion

The Southeast EEM benefits are derived from fuel cost savings as the Southeast EEM gives participant's access to a lower cost, more efficient pool of resources to manage subhourly load and renewable uncertainty.[11] As shown in Table 4, in the *IRP Baseline Outlook*, annual benefits represent approximately 0.3% to 0.4% of total production costs within the Southeast EEM participant footprint. Benefits as a proportion of total production costs are much higher in the Carbon-Constrained Outlook, reaching 1.1% by 2037.

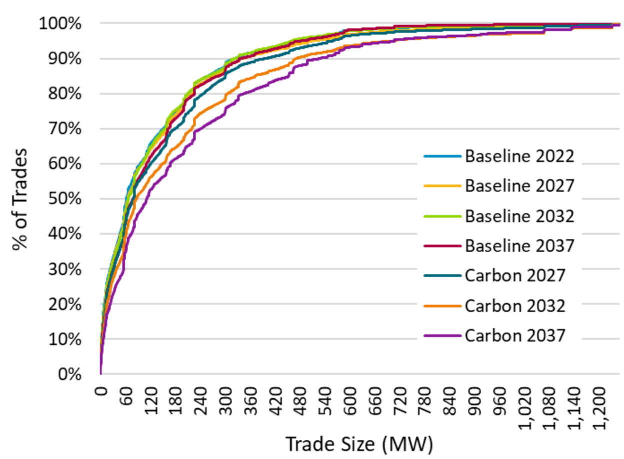
[11] As a simple example, if Company X has a negative 300 MW sub-hourly imbalance due to renewable variability; instead of ramping up its own combined-cycle unit at an incremental cost of $28/MWh, Company X will purchase energy in the Southeast EEM from Company Y which is able to ramp up at $24/MWh. The split-savings trading price of $26 provides benefits to both Company X and Y.

Table 4. Southeast EEM Benefits Relative to Southeast EEM Footprint Production Costs

Year	Southeast EEM Footprint Production Costs ($2020)		Southeast EEM Gross Benefit ($2020)	
	IRP Baseline	Carbon-Constrained	IRP Baseline	Carbon-Constrained
2022	$10.8B		$37M - $46M	
2027	$12.0B	$11.4B	$46M - $58M	$57M - $71M
2032	$13.0B	$11.7B	$41M - $50M	$78M - $98M
2037	$14.1B	$12.1B	$44M - $55M	$121M - $151M

In the *IRP Baseline Outlook*, approximately 60% of Southeast EEM trades are less than 100 MW, 90% are less than 350 MW, and 98% are less than 600 MW, yielding a weighted average of about 130 MW. With its higher underlying renewable imbalances, average trade size increases in the *Carbon-Constrained Outlook*, with approximately 60% of trades less than 150 MW, 90% less than 475 MW, and 98% less than 1,000 MW. Cumulative distributions of trading volumes are shown in Figure 11. In a typical hour there are projected to be 40 to 50 15-minute trades (or wheel-throughs) in the Southeast EEM. In 2022, the average is 41 trades (or wheel-throughs) within each hour at an average of 130 MW per trade, yielding an average hourly trade volume of 1,323 MWh.[12] As noted above, there are about $45 million (2020$) of annual Southeast EEM benefits on average in the *IRP Baseline Outlook*. If there are 41 15-minute trades within each hour on average then each trade results in approximately $2/MWh benefit for each company participating in the transaction.[13]

Figure 11. Cumulative Distribution of Southeast EEM Trading Volume



[12] 129 MW x 1/4th hour x 41 trades per hour = 1,323 MWh

[13] [$45,000,000 / (129 MW * 1/4th hour * 41 trades per hour * 8760 hours per year)] * 50% split = 1.94 $/MWh

Responding to imbalance resulting from renewables is a primary driver of benefits. While it is difficult to attribute an exact proportion, annual Southeast EEM benefits seem to be roughly evenly split between renewable integration benefits and the benefits from taking advantage of interface price differentials with zero-cost sub-hourly transmission. As shown in Figure 12 through Figure 14, during periods where renewable integration is most difficult (i.e. morning and evening ramps), Southeast EEM benefits tend to be higher as Southeast EEM participants can leverage lower cost resources elsewhere within the Southeast EEM participant footprint to correct imbalances. Overall, benefits during solar hours (hours ending 9:00 am to 7:00 pm) are nearly double those of non-solar hours.

Figure 12. Average Summer Season Benefits Aggregated by Time of Day – IRP Baseline

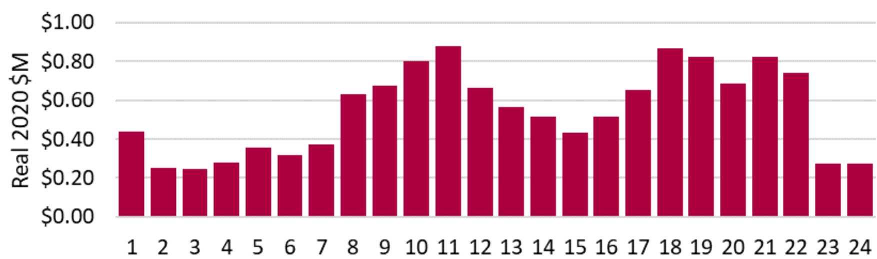


Figure 13. Average Winter Season Benefits Aggregated by Time of Day – IRP Baseline

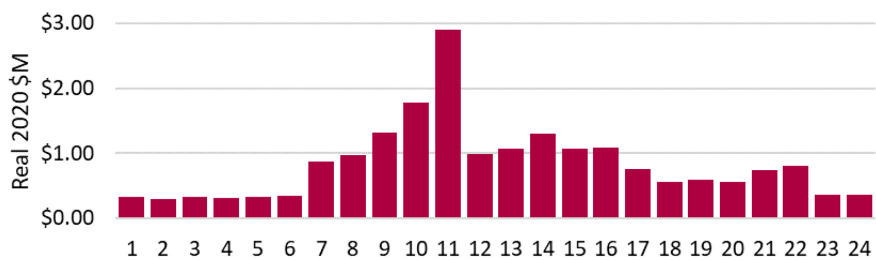
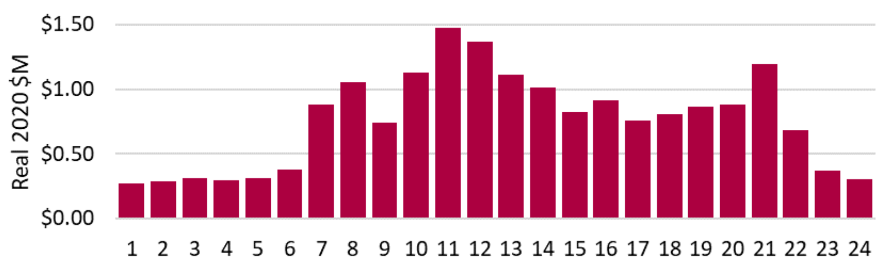


Figure 14. Average Shoulder Season Benefits Aggregated by Time of Day – IRP Baseline



2.3 Sensitivities and Parameter Testing

Several model parameters were varied to give insight into the uncertainty and robustness of the results. These parameters included market participation, ramping capability of gas and storage assets, permissible renewable curtailment, and ATC.

Without observing historical market operation, it is difficult to estimate the expected degree of market participation, making this the single largest uncertainty. Several sensitivities were run to determine the impact that would result from participants managing imbalances internally as opposed to using the Southeast EEM. It is reasonable to expect benefits to be on the lower end of the estimates in the early years of the Southeast EEM as participants become comfortable with the market. The model sensitivities show that there is considerable room for upside to benefits if participants go “all-in” with their bid/offer curves and aggressively use their storage resources as well.

For ATC, the study assumes average 2019 levels, however this may be conservative if actual market operation could result in more transmission capacity being released. To determine the impact of ATC on the results, a test was conducted where ATC was capped at 200 MW (which is significantly less than what was observed in 2019 for some pathways). Despite the large reduction in ATC, benefits only decreased by about 10% for the year. Other parameters such as ramping capability and permissible renewable curtailment were much less consequential.

2.4 Conclusions

Southeast EEM benefits are robust across all years, both market outlooks, and all model parameter tests. Southeast EEM gross benefits average $47M per year (real 2020 dollars) in the *IRP Baseline Outlook*, with forecasted annual benefits nearly triple in the *Carbon-Constrained Outlook* by the late 2030s.

There are several key uncertainties and risks associated with the benefits of the Southeast EEM:

- The study assumes a well-functioning, and relatively high-participation market. Limited participation by members is the largest risk to Southeast EEM benefits.
- The $0 transmission rate sub-hourly trading could eventually cannibalize some hourly trading yielding a reduction in non-firm transmission revenues.
- The resource mix in the *Carbon-Constrained Outlook* is unclear for the Southeast making results much more uncertain.

3. SOUTHEAST EEM NON-CENTRALIZED COSTS

3.1 Approach to Estimating Costs

3.1.1 Cost Categories

In forming the Southeast EEM, two separate and distinct cost streams would be incurred: central entity costs and internal member costs. The former costs are those incurred to facilitate the central market and settlement process and the latter are incurred at the member level to interface with the central entity and manage the process locally through scheduling and processing transactions. Guidehouse/CRA focused on the latter cost category (internal member costs) related to non-centralized costs associated with the development and operation of the market.

Non-centralized costs can be segregated into two categories. The first are “start-up” costs, one-time costs related to the initial market development period. Start-up costs are primarily comprised of regulatory and one -time software expenditures but may include other non-recurring costs as well. The second category of costs are the ongoing ones required to facilitate participation in the market. These ongoing costs are primarily labor for schedulers and traders as well as ongoing regulatory costs. Ongoing labor costs also include IT and other support activities. Ongoing, non-labor costs may include direct hardware and software costs plus raining and other recurring support costs.

It is important to note that the costs aggregated in this analysis are incremental costs – that is, costs that are not otherwise embedded in the participants existing cost structure. The Guidehouse/CRA team aggregated the cost estimates following one-on-one interviews with each prospective Southeast EEM participant. The costs estimated are categorized as shown in Table 5.

Table 5. Cost Categories Estimated

Start-up Costs	Ongoing Costs

• Legal and Regulatory Costs
• Meetings, Travel, and Training
• Hardware and Software Costs
	• Labor (addition of full-time employees)
	  ○ Rates and Regulatory
	  ○ Traders
	  ○ Schedulers
	  ○ IT
	  ○ Other
	• Non-labor
	  ○ Travel and Training
	  ○ Hardware and Software
	• Other

As noted, costs considered for the purposes of this analysis are incremental, meaning that only out-of-pocket expenses for software, outside legal support, additional staffing, etc. were considered. Use of in-house capabilities and existing staff were expressly excluded from consideration. As a result, to the extent individual market participants are able to leverage existing staff and internal resources those costs were not included in the cost benefit analysis.

3.1.2 Interview Approach

Cost assumptions were developed using a standardized spreadsheet tool and interviews with member teams (see Appendix B.1). For confidentiality purposes, the interview process was conducted in a series of individual member meetings. To the extent possible, Guidehouse/CRA provided guidance on the cost development but did not share confidential member information with other market participants. In addition, the working team did not share ranges or level of magnitude estimates of costs to any member during the interview process so as not to bias the information collected through the process.

The cost team first distributed a cost template to each individual Member. Member representatives provided start-up and on-going operation costs. Members provided their own unique estimates for each cost category described in Table 5. To accommodate for cases where there was uncertainty or dependencies related to individual costs, members were permitted to input a range of estimated cost values: “High,” “Low,” and “Median.” We used “Median” values for our final cost estimates.

One-on-one interviews were conducted with each individual Southeast EEM participant. The cost team worked with member representatives from various operations functions; roles within the membership that participated in the interview process included Managers or Directors of Transmission, Resource Operations, Bulk Power, Operations Interface, or similar. See Appendix B for further details regarding the interview process.

3.1.3 Costs Levelization and Adjustment for Inflation

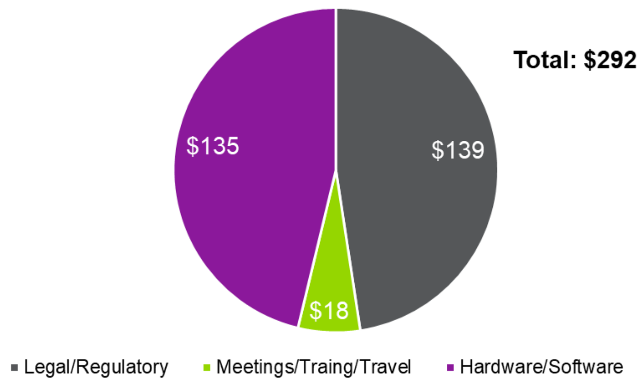
The resultant costs reflect the total, 20-year levelized annual start-up and ongoing costs across all Southeast EEM participants. Cost values are expressed in real 2020 dollars (assuming 2.0% annual inflation). All start-up and ongoing costs are presented on a levelized basis to facilitate a comparison versus the modeled market benefits. However, the lump sum start-up costs would be $3.8 million across all market participants excluding central entity costs.

3.2 Start-up Costs

Aggregate start-up costs stated on a 20-year annual levelized basis are shown in Figure 15. Individual member costs and representative ranges are not presented in this report to ensure member confidentiality.

Estimated costs are split about equally between infrastructure costs and regulatory requirements with some provision for incremental administrative costs. Some potential market participants expressed uncertainty regarding the level of software costs depending on the vendor selected for the central clearinghouse function. The driver of uncertainty was related to compatibility with existing software systems and infrastructure.

Figure 15. Breakout of Real 2020$ Levelized EIM Startup Costs by Function ($000)



3.3 On-going Costs

As with startup costs, ongoing costs are aggregated to maintain each Member's confidentiality. Results on a 20-year annual levelized basis are displayed in Figure 16 and Figure 17. The majority of the annualized costs are labor-related and of those, the costs are heavily weighted towards trading activity. Non-labor costs are largely related to hardware and software requirements.

Figure 16. Real $2020 Levelized Annual Labor Cost by Function ($000)

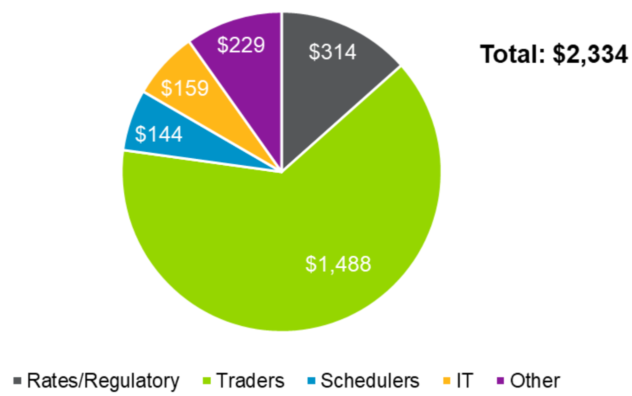
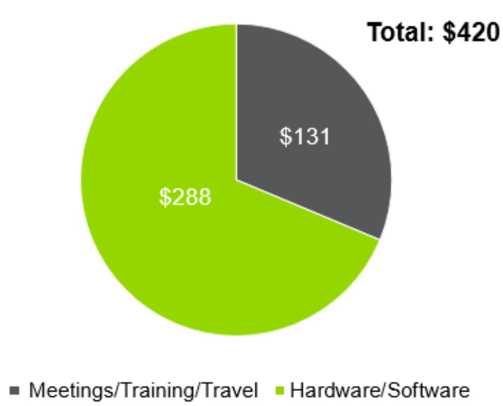


Figure 17. Real 2020$ Levelized Annual Non-Labor Costs ($000)



3.4 Insights and Conclusions

The primary uncertainty identified by potential market participants relates to the compatibility between the existing software systems in house with the software provided by the selected central entity. This uncertainty may be mitigated through coordination among market participants during vendor selection.

The anticipated ability of individual market participants to rely on tools and resources that already exist in house varies across potential market members. As a result, the cost benefit equation for individual members needs to be examined individually even though the benefits of the market in aggregate appear to significantly outweigh the aggregate market costs.

APPENDIX A. SUPPORTING DATA

A.1 Assumptions

Table A-1. Natural Gas Price Forecasts ($2020/MMBtu)

	Columbia Gas - Appalachia	Texas Eastern, M-1 (Kosi)	Transco, Zone 4	Transco, Zone 5 Delivered	Dominion South Point
2021	$2.35	$2.45	$2.55	$2.59	$2.15
2022	$2.47	$2.58	$2.68	$2.65	$2.22
2023	$2.51	$2.66	$2.75	$2.70	$2.26
2024	$2.67	$2.90	$2.99	$2.94	$2.41
2025	$2.76	$3.11	$3.20	$3.15	$2.48
2026	$2.76	$3.19	$3.29	$3.25	$2.43
2027	$2.77	$3.27	$3.40	$3.35	$2.40
2028	$2.82	$3.38	$3.50	$3.45	$2.42
2029	$2.90	$3.48	$3.60	$3.55	$2.47
2030	$2.93	$3.53	$3.66	$3.61	$2.48
2031	$2.93	$3.58	$3.71	$3.64	$2.46
2032	$3.02	$3.64	$3.77	$3.72	$2.54
2033	$3.07	$3.70	$3.83	$3.77	$2.58
2034	$3.10	$3.76	$3.90	$3.84	$2.61
2035	$3.14	$3.83	$3.95	$3.88	$2.62
2036	$3.17	$3.88	$4.00	$3.92	$2.63
2037	$3.21	$3.93	$4.06	$3.98	$2.66
2038	$3.25	$3.98	$4.10	$4.02	$2.68
2039	$3.30	$4.03	$4.16	$4.07	$2.71
2040	$3.35	$4.08	$4.20	$4.12	$2.74

Table A-2. Southeast EEM Participants Aggregated Additions (MW) – *IRP Baseline Outlook*

	CC	CT Gas	Nuclear	Pumped Hydro	Battery	Wind	Offshore Wind	Solar
2020	0	15	0	0	0	472	0	1,751
2021	0	0	1,108	65	48	159	0	2,630
2022	475	0	1,117	65	58	0	0	2,307
2023	0	100	15	65	50	0	0	762
2024	726	1,336	15	65	93	0	0	1,202
2025	1,338	0	4	0	90	0	0	305
2026	0	470	0	0	119	0	0	558
2027	1,838	0	0	0	83	0	0	768
2028	0	905	6	0	23	0	0	648
2029	600	3,055	0	0	27	0	0	654
2030	0	300	10	0	24	0	0	694
2031	0	3,040	0	0	25	0	0	731
2032	600	0	0	0	23	0	0	606
2033	0	3,432	0	0	30	0	0	810
2034	968	3,114	0	0	28	0	0	647
2035	1,324	523	0	0	0	0	0	552
2036	1,260	18	0	0	0	0	0	575
2037	1,984	934	0	0	0	0	0	224
2038	2,468	18	0	0	50	0	0	381
2039	870	18	0	0	0	0	0	287
2040	1,830	934	0	0	75	0	0	393

Table A-3. Southeast EEM Participants Aggregated Additions (MW) – *Carbon-Constrained Outlook*

	CC	CT Gas	Nuclear	Pumped Hydro	Battery	Wind	Offshore Wind	Solar
2020	0	15	0	0	0	472	0	1,751
2021	0	0	1,108	65	48	159	0	3,105
2022	475	300	1,117	65	58	100	0	4,082
2023	0	100	15	65	250	100	0	2,962
2024	726	1,336	15	65	493	150	0	3,002
2025	1,838	50	4	0	490	200	0	2,705
2026	600	1,070	0	0	669	250	200	2,658
2027	2,438	200	0	0	833	150	200	2,718
2028	1,338	1,555	6	0	1,023	525	200	2,498
2029	2,144	2,415	0	0	977	350	200	2,679
2030	500	800	10	0	1,024	250	500	2,519
2031	1,338	2,200	0	0	675	250	400	2,531
2032	840	300	0	0	1,023	325	200	2,606
2033	0	1,902	0	0	1,280	250	200	2,910
2034	968	1,434	0	0	1,128	250	200	2,697
2035	500	1,363	0	0	950	350	200	2,652
2036	0	18	0	0	300	75	400	2,025
2037	2,468	1,434	0	0	650	275	700	1,874
2038	1,500	18	0	0	350	75	0	1,931
2039	1,838	18	0	0	200	75	0	2,087
2040	1,830	934	0	0	275	75	0	1,893

Table A-4. Southeast EEM Participants Aggregated Retirements (MW) – *IRP Baseline Outlook*

	CC	CT Gas	ST / IC Gas	ST Coal	Nuclear	Other Renewable	Other
2020	0	(780)	0	(1,017)	0	0	0
2021	0	(16)	0	0	0	0	0
2022	0	(14)	0	0	0	0	0
2023	0	0	0	0	0	0	0
2024	0	0	0	(2,056)	0	0	(232)
2025	0	(97)	(254)	(300)	0	(53)	0
2026	0	0	(243)	(362)	0	0	0
2027	0	0	0	(570)	0	0	0
2028	0	0	0	(1,579)	0	0	0
2029	0	0	0	0	0	0	0
2030	0	0	(173)	0	0	0	(65)
2031	0	0	0	0	0	0	0
2032	0	0	0	(546)	0	0	0
2033	0	0	0	(1,409)	0	0	0
2034	0	0	0	(4,166)	(876)	0	0
2035	0	(494)	0	(1,162)	0	0	0
2036	0	(390)	0	(734)	(851)	0	0
2037	0	0	0	(476)	(883)	0	0
2038	0	0	0	(3,092)	0	0	0
2039	(209)	0	0	(842)	0	0	0
2040	(519)	0	0	(342)	(860)	0	0

Table A-5. Southeast EEM Participants Aggregated Retirements (MW) – *Carbon-Constrained Outlook*

	CC	CT Gas	ST / IC Gas	ST Coal	Nuclear	Other Renewable	Other
2020	0	(780)	0	(1,017)	0	0	0
2021	0	(16)	0	0	0	0	0
2022	0	(14)	0	(1,234)	0	0	0
2023	0	0	0	0	0	0	0
2024	0	0	0	(2,176)	0	0	(232)
2025	0	(97)	(254)	(2,077)	0	(53)	0
2026	0	0	(243)	(1,684)	0	0	0
2027	0	0	0	(3,047)	0	0	0
2028	0	0	0	(3,860)	0	0	0
2029	0	0	0	(3,774)	0	0	0
2030	0	0	(173)	(1,598)	0	0	(65)
2031	0	0	0	(1,022)	0	0	0
2032	0	0	0	(1,014)	0	0	0
2033	0	0	0	(4,378)	0	0	0
2034	0	0	0	(4,665)	0	0	0
2035	0	(494)	0	(1,340)	0	0	0
2036	0	(390)	0	(2,078)	0	0	0
2037	0	0	0	(2,925)	0	0	0
2038	0	0	0	(631)	0	0	0
2039	(209)	0	0	(2,431)	0	0	0
2040	(519)	0	0	(1,382)	0	0	0

A.2 Southeast EEM Results

Table A-6. Southeast EEM Gross Benefits ($2020 Millions) – IRP Baseline

Year	Summer		Winter		Shoulder		Total
	Solar	Non-Solar	Solar	Non-Solar	Solar	Non-Solar	
2022	$7M - $8.8M	$3.8M - $4.7M	$7.5M - $9.3M	$3.6M - $4.5M	$9.5M - $11.9M	$5.8M - $7.3M	**$37.1M - $46.4M**
2027	$7M - $8.8M	$3.6M - $4.5M	$13.2M - $16.5M	$4.7M - $5.9M	$12.8M - $16M	$4.9M - $6.1M	**$46.2M - $57.7M**
2032	$6.7M - $8.2M	$4.2M - $5.1M	$12.7M - $15.5M	$4.2M - $5.2M	$8.8M - $10.8M	$4.7M - $5.7M	**$41.3M - $50.5M**
2037	$5.7M - $7.1M	$5.1M - $6.4M	$14.2M - $17.7M	$6M - $7.5M	$8.4M - $10.5M	$4.9M - $6.2M	**$44.3M - $55.3M**

Table A-7. Southeast EEM Gross Benefits ($2020 Millions) – Carbon-Constrained

Year	Summer		Winter		Shoulder		Total
	Solar	Non-Solar	Solar	Non-Solar	Solar	Non-Solar	
2022	$7M - $8.8M	$3.8M - $4.7M	$7.5M - $9.3M	$3.6M - $4.5M	$9.5M - $11.9M	$5.8M - $7.3M	**$37.1M - $46.4M**
2027	$11.1M - $13.9M	$4.7M - $5.9M	$15.7M - $19.6M	$5.5M - $6.9M	$13.5M - $16.9M	$6M - $7.6M	**$56.6M - $70.8M**
2032	$18.6M - $23.3M	$5.6M - $7M	$24.7M - $30.9M	$7.6M - $9.5M	$16.2M - $20.2M	$5.5M - $6.8M	**$78.3M - $97.9M**
2037	$29.2M - $36.6M	$10.9M - $13.6M	$32.7M - $40.9M	$14.5M - $18.2M	$20.7M - $25.9M	$12.6M - $15.7M	**$120.6M - $150.8M**

Table A-8. Cumulative Distribution of Southeast EEM Trading Volumes

Transaction Size (MW)	IRP Baseline Outlook				Carbon-Constrained Outlook		
	2022	2027	2032	2037	2027	2032	2037
10	19.9%	18.2%	18.3%	16.1%	15.0%	14.1%	11.7%
25	30.2%	29.5%	29.4%	27.1%	26.7%	24.2%	20.2%
50	40.8%	39.9%	39.4%	36.3%	36.6%	32.7%	28.1%
75	54.6%	52.6%	51.9%	49.0%	48.6%	45.2%	40.1%
100	60.5%	59.7%	59.9%	57.3%	56.1%	52.2%	47.2%
200	76.4%	76.0%	77.2%	75.1%	72.0%	66.7%	62.9%
300	87.9%	86.7%	87.5%	86.2%	84.5%	78.3%	74.5%
400	92.7%	91.8%	92.9%	92.1%	90.0%	85.9%	82.3%
500	95.9%	94.9%	96.0%	95.5%	93.5%	91.1%	89.4%
750	98.9%	98.1%	99.0%	99.3%	97.8%	95.7%	95.7%
1000	99.5%	99.1%	99.4%	99.7%	98.6%	97.1%	97.4%
1250	100.0%	99.9%	100.0%	100.0%	100.0%	99.7%	99.6%

APPENDIX B. SOUTHEAST EEM PARTICIPANT COST INTERVIEW PROCESS

The purpose of each individual interview was to:

1. Familiarize ourselves with each prospective Southeast EEM member’s current capabilities and procedures for scheduling, settlement, and marketing; and,

2. Review the cost template each Southeast EEM member had completed prior to the call.

Table 6. Prospective Southeast EEM Member Interview Schedule

April 17th, 2020	April 20th, 2020	April 21st, 2020	April 22nd, 2020	April 23rd, 2020	April 24th, 2020	April 27th, 2020
Dominion Energy South Carolina Duke Energy Progress and Carolinas	PowerSouth	GTC, GSOC, OPC	ElectriCities MEAG and TEA	LG&E and KU Southern Company	AECI Tennessee Valley Authority	Santee Cooper and TEA

Sample questions posed to each prospective Southeast EEM member during their one-on-one interview included:

- What is your current procedure for power marketing, scheduling, and settlements?
    - Are settlements made on an hourly or sub-hourly level?
    - Are trades entered manually or automatically?
- What are your current software capabilities for these functions?
- Do you anticipate adding any full-time employees to interface with the new Southeast EEM?
- Will you need to file an update to your current transmission tariff?
- Will you require additional metering?

B.1 Cost Template

The cost template used to develop the non-centralized costs for each prospective Southeast EEM member is shown in Figure 18.

Figure 18. Cost Template

PRIVILEGED AND CONFIDENTIAL
Prospective Member: BLANK

Internal Staffing and Equipment Costs in Joining Interface EIM for Individual Members (K$)
Assumed Market Start Date: January 2021

Sheet does not include costs incurred for central EIM start-up and operations (e.g., bidding system operator, market monitor, etc.)

Inflation	2.0%
PV Factor	6.5%

Single value estimate
Low value estimate
High value estimate

		2020 K$/FTE EST.	2020 K$/FTE LOW	2020 K$/FTE HIGH	2020 PV	2020	2020 LOW	2020 HIGH	2021	2021 LOW	2021 HIGH
One-Time Start-up Costs (K$)											
Legal/Regulatory	(a)				200	200					
Meetings/Training/Travel	(b)				50	50					
Hardware/Software	(c)				100	100					
Total	(d)				350	350			0		
Estimate Uncertainty	20%				70	70			0		
Total					420	420			0		
On-going Costs (K$)											
Additional (Reduced) FTE											
Rates/Regulatory	(e)	180				0			0.25		
Traders	(f)	180				0			0.5		
Schedulers	(g)	180				0			0.5		
IT	(h)	180				0			0.25		
Other	(i)	180				0			0		
Total Additional FTE						0			1.5		
K$/FTE Inflation Factor						1.000			1.020		
Total Additional FTE (K$)					3,539	0			275		
On-going Non-Labor Costs											
Travel/Training	(j)				643	0			50		
Hardware/Software	(k)				643	0			50		
Other	(l)				0	0			0		
					1,285	0			100		
Total On-Going					4,824	0			375		
Total 1-Time and On-Going					5,244	420			375		

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Rates/Regulatory	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
Traders	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Schedulers	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
IT	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Additional FTE	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
K$/FTE Inflation Factor	1.040	1.061	1.082	1.104	1.126	1.149	1.172	1.195	1.219	1.243	1.268	1.294	1.319	1.346	1.373	1.400	1.428	1.457	1.486
Total Additional FTE (K$)	281	287	292	298	304	310	316	323	329	336	342	349	356	363	371	378	386	393	401
Travel/Training	51	52	53	54	55	56	57	59	60	61	62	63	65	66	67	69	70	71	73
Hardware/Software	51	52	53	54	55	56	57	59	60	61	62	63	65	66	67	69	70	71	73
Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	102	104	106	108	110	113	115	117	120	122	124	127	129	132	135	137	140	143	146
Total On-Going	383	391	398	406	414	423	431	440	449	458	467	476	486	495	505	515	526	536	547
Total 1-Time and On-Going	383	391	398	406	414	423	431	440	449	458	467	476	486	495	505	515	526	536	547

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-100, SUB 171

In the Matter of:	)	**PETITION OF THE NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION, SIERRA CLUB, AND THE SOUTHERN ALLIANCE FOR CLEAN ENERGY FOR INVESTIGATION AND RULEMAKING TO IMPLEMENT N.C. GEN. STAT. § 62-154**
Petition for Investigation and Rulemaking to Implement N.C. Gen. Stat. § 62-154	)	
	)	
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	)	
	)	
	)	

Exhibit C

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SUMMARY REPORT: ECONOMIC AND CLEAN ENERGY BENEFITS OF ESTABLISHING A SOUTHEAST U.S. COMPETITIVE WHOLESALE ELECTRICITY MARKET

BY ERIC GIMON AND MIKE O'BOYLE[1], TAYLOR MCNAIR[2], CHRISTOPHER T M CLACK, ADITYA CHOUKULKAR, BRIANNA COTE, SARAH MCKEE[3] ● AUGUST 2020

EXECUTIVE SUMMARY

Seven Independent System Operators (ISOs) or Regional Transmission Operators (RTOs) serve close to 70 percent of all United States electricity consumers. One region of the country, the Southeast, is particularly devoid of this type of market competition. This report details the impacts of enhancing competition for wholesale electricity transactions through a theoretical organized market in the Southeast region. We use a combined production-cost and capacity-expansion model of the electric power system in seven Southeastern states (Alabama, Florida, Georgia, Mississippi, North Carolina, South Carolina, and Tennessee) out to 2040. This Summary Report details the high-level findings, while a companion technical report details the model mechanics and scenario analysis in greater detail.[i]

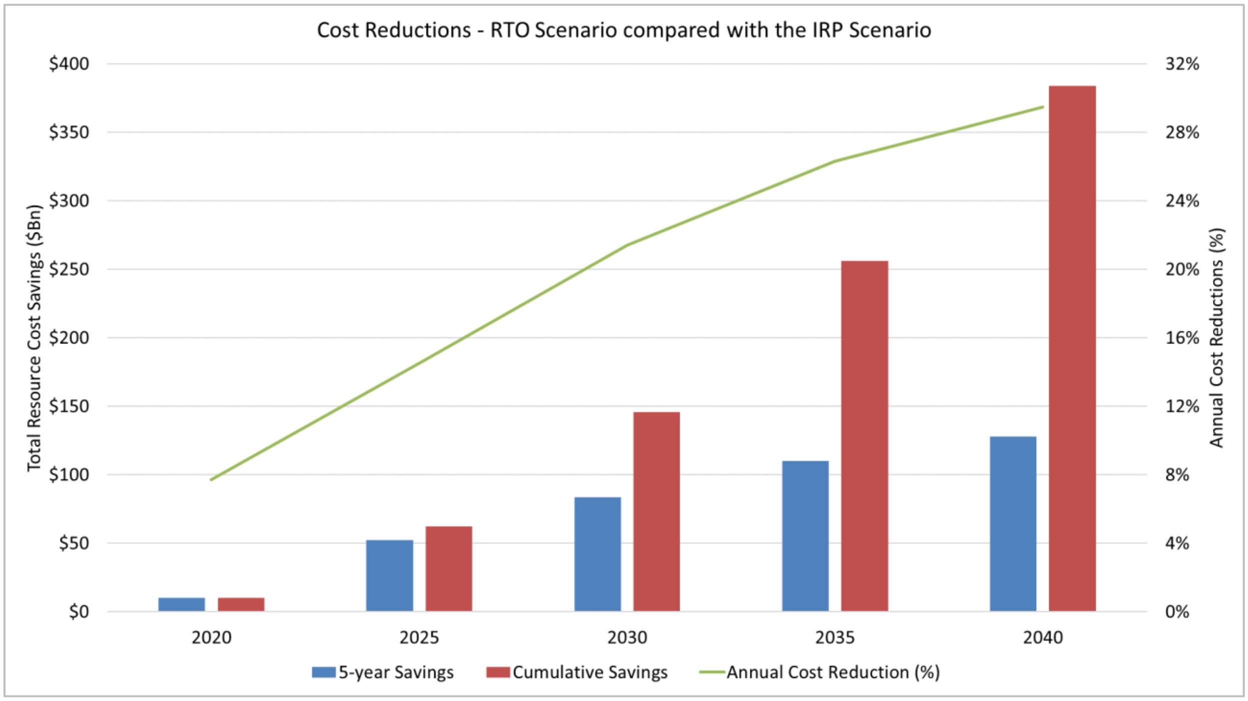
We find that a competitive Southeastern RTO creates cumulative economic savings of approximately $384 billion[ii] by 2040 compared to the business-as-usual (BAU) case. In 2040, this amounts to average savings of approximately 2.5¢ per kilowatt-hour (kWh), or 29 percent in retail costs compared to BAU. 2040 retail costs in the RTO scenario are 23 percent below today's costs. In the RTO Scenario, carbon emissions fall approximately 37 percent relative to 2018 levels, and 46 percent compared to the IRP Scenario, in which emissions increase. Other major criteria pollutants impacting human health, such as NO_X, SO_2, and $PM_{2.5}$, drop dramatically,

[1] The authors would like to thank Jennifer Chen (Duke University), Rob Gramlich (Grid Strategies), Maggie Shober (Southern Alliance for Clean Energy), Ryan Hodum (Energy Foundation), Simon Mahan (Southern Renewable Energy Association), and Sonia Aggarwal (Energy Innovation) for their helpful feedback on this report. Any remaining errors are the responsibility of the authors.

[2] GridLab https://gridlab.org/

[3] Vibrant Clean Energy https://www.vibrantcleanenergy.com/

largely as a result of eliminated coal generation. Emissions gains are driven by a vast deployment of renewable energy resources replacing coal.



Employment benefits begin accruing immediately after the RTO comes into operation, as lost jobs in coal and natural gas generation are replaced by construction jobs related to wind, solar, and battery deployment. By 2040, the RTO scenario creates 285,000 more jobs relative to the business-as-usual scenario, owing to the construction of 62 gigawatts (GW) of solar, 41 GW of onshore wind, and 46 GW of battery storage.

Our BAU case relies on the Integrated Resource Plans of the major investor-owned utilities in these states, in which utilities prescribe a coordinated set of new generating and transmission capacity necessary to meet future load projections. Vibrant Clean Energy's WIS:dom®-P model then optimizes operations for these projected resource additions and retirements based upon historical dispatch estimates, assuming no further public policy intervention. In this case, the model assumes that each utility must meet its specified load projections and planning reserve margins independently, assuming limited import/export capacity from neighboring utilities and limited transmission expansion.

We compare this scenario to a fully competitive wholesale electric market, in which an RTO-administered open market determines the most cost-effective capacity mix and resource dispatch, regardless of where that generation is located or who owns it. The RTO scenario assumes an integrated transmission planning scheme in which all seven Southeastern states share resources and expand transmission in order to meet one regional planning reserve margin at least cost. The competitive RTO Scenario modeled here grants planners and operators in the region the opportunity to co-optimize generation, distribution, and transmission benefits while planning to meet capacity in the most economically efficient way.

A companion policy report additionally details key policies to help achieve competition's benefits in the Southeast region. We focus on incremental policies that introduce competition into regional dispatch and utility resource planning and procurement. We cover principles for market design to help ensure a regional market is compatible with a cost-effective variable resource mix. We outline policies that enable regional utilities with net-zero carbon goals to meet those goals effectively while respecting and supporting the fossil-dependent communities that supported economic development in the region.

Despite the fact that new renewable energy and battery storage resources are the least-cost forms of generating electricity, the Southeast region is largely beholden to monopoly utilities that rely on existing coal fleets and new gas-fired power plants to meet consumer electricity needs. This report finds that these utilities continue to inefficiently plan the power grid at great expense to consumers. Wasted excess capacity leads to wasted consumer dollars while stifling clean energy deployment, employment gains, and public health benefits.

Policymakers considering a regional market or state-level competitive procurement should be encouraged by this analysis to keep pressing in legislative and regulatory forums. State stakeholders where utilities block competitive reforms now have new quantitative findings to challenge the assumption that the way utilities have traditionally done business is in the public's best interest.

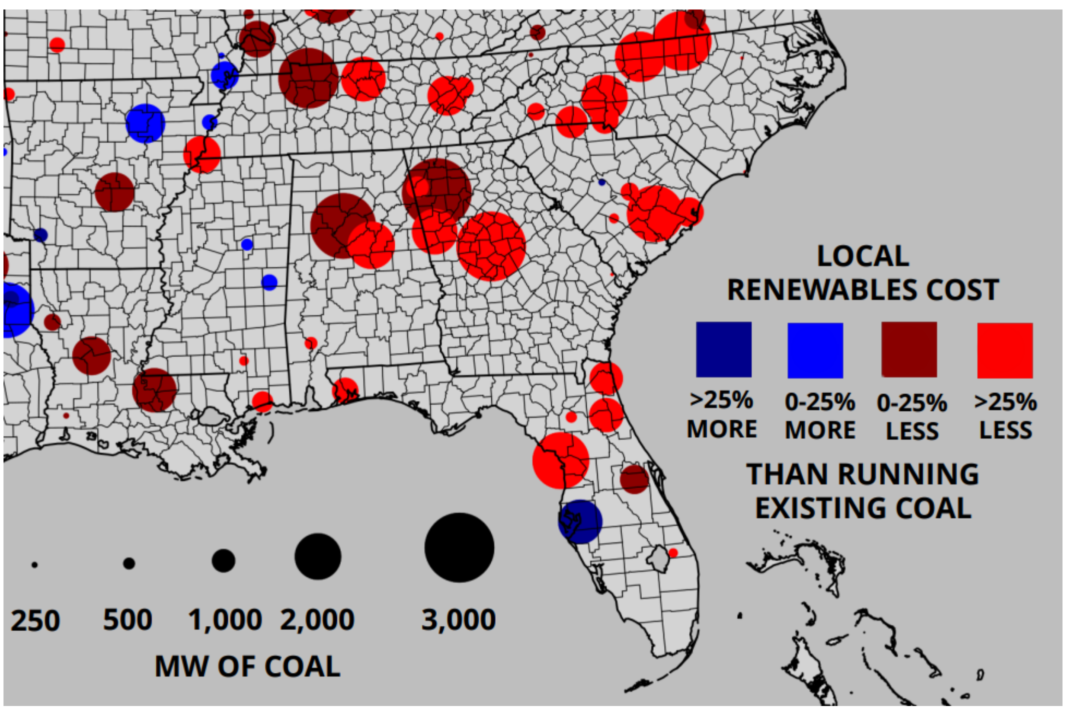
CONTENTS

INTRODUCTION

The Southeast region of the U.S. remains one of the country's only regions without organized wholesale electricity markets (along with the West). While energy restructuring and reform swept through much of the nation in the early 2000s, this reform failed to upend the traditional vertically-integrated monopoly structure dominant in the Southeast.

In effect, Southeastern utility planning is a patchwork system dominated by monopoly utilities, in which those utilities plan their electric grids independently from their neighbors (or even subsidiaries of the same holding companies). These utilities provide power within service territories to the near-complete exclusion of competition. Further limiting competition, these utilities charge any sellers importing power to their customers a "wheeling charge," which raises the cost of outside alternatives to the benefit of the utility's generation assets. Largely insulated from meaningful forms of competition, Southeastern utilities have been among the slowest to embrace clean electricity resources, even as resource costs have fallen precipitously in recent years.

In 2019, Energy Innovation and Vibrant Clean Energy partnered to compare the cost of operating each coal plant in the U.S. against the cost of building new, local wind and solar.[iii] The simple analysis revealed that about two-thirds of existing coal plants were more expensive to continue running when compared to replacement by local wind or solar. The results for the Southeast were even more pronounced: nearly every coal plant (92 percent of existing capacity) was uneconomic compared to local wind or solar in 2018.[iv] By 2025, that number grows to 100 percent.



The Coal Cost Crossover report shows nearly every Southeastern coal plant is uneconomic compared to local wind and solar resources.

While coal and renewables provide different services and value to the grid, the presence of substantial amounts of uncompetitive coal generation and low-cost renewable alternatives led us to hypothesize that competition would yield both significantly lower costs and create opportunities for clean energy resources to rapidly enter an otherwise restricted market.

Analysis of regional co-optimization and competition also bears upon ongoing conversations around introducing competition in the region. In the Carolinas, legislators from each state have called for establishment of an RTO, which would take control of power plant and transmission operations away from the incumbent monopoly utilities and optimize them for cost.[v]

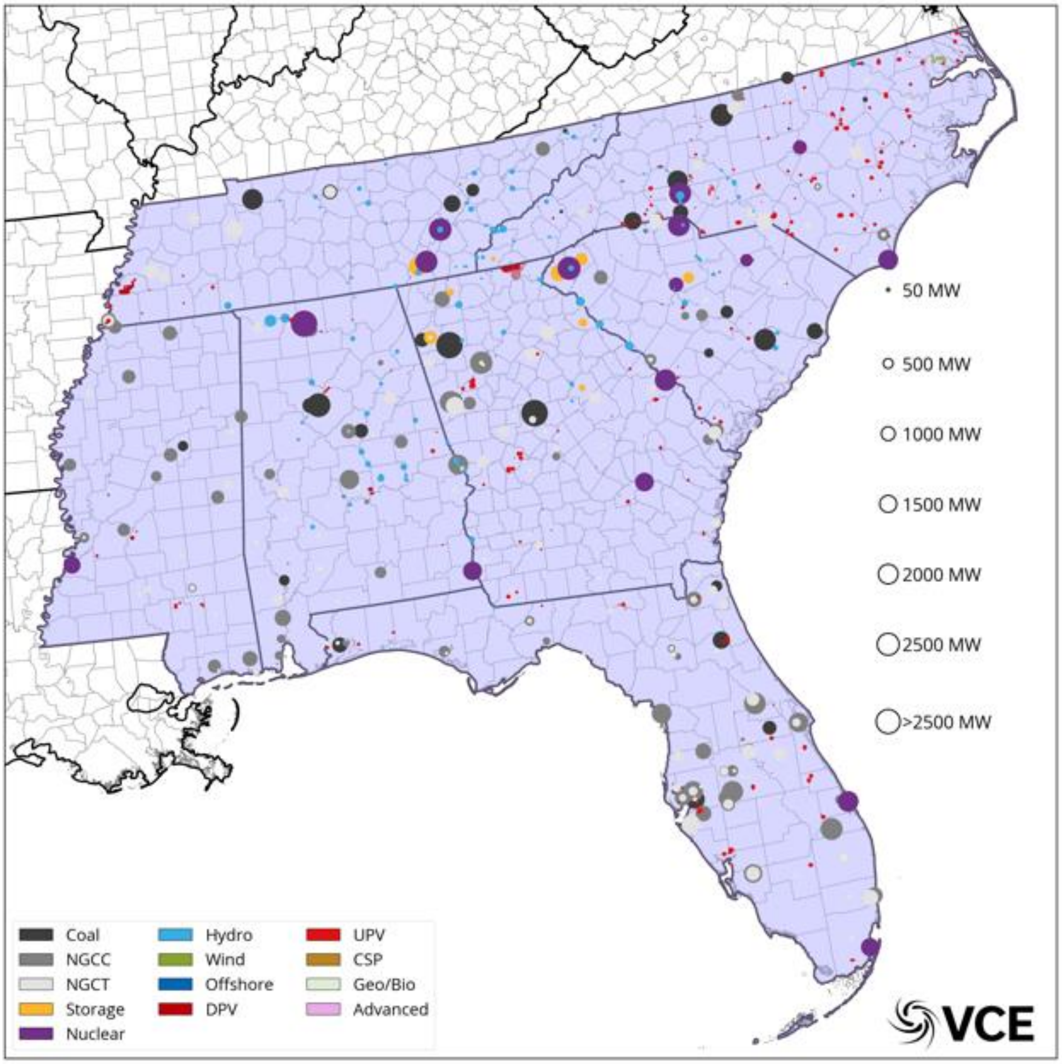
Meanwhile, the three largest utilities in the region – Duke Energy, Southern Company, and Tennessee Valley Authority (TVA), have indicated they will propose a voluntary regional energy exchange in the region to the Federal Energy Regulatory Commission (FERC).[vi] These radically different paths toward greater resource optimization and competition in the region could benefit from quantitative information to inform market design choices going forward.

THE ANALYSIS: METHODOLOGY AND SCENARIOS

To inform regionalization discussions and explore potential cost and emissions impacts of competition on the region, this study investigates the impacts of increasing competitive options for consumers using the WIS:dom®-P model (a state-of-the-art energy model developed by Vibrant Clean Energy, LLC).

It is the first commercial co-optimization model of energy grids that was built from the ground up to incorporate vast volumes of data, starting with high-resolution weather and demand data. The model relentlessly seeks the least-cost solution pathway for the electricity system, incorporating up-to-date technology performance characteristics, while conforming to reserve requirements for every region in the U.S. More information about the mechanics of WIS:dom®-P is available in section three of VCE®'s companion technical report to this summary report.[vii]

This report analyzes the impacts of a Southeast competitive wholesale electricity market, similar to how ISOs or RTOs operate elsewhere around the country. Because the WIS:dom®-P model is able to adjust to different geographic scales, VCE® configured a Southeast module, allowing the model to optimize the power system across seven Southeast states: Alabama, Florida, Georgia, Mississippi, North Carolina, South Carolina, and Tennessee.



The geographic region modeled in this analysis, including generating resources currently in operation.

VCE® modeled two core scenarios and two sensitivities. The core scenarios compare a business-as-usual approach and a fully competitive regional approach. We represent the business as usual through an Integrated Resource Plan (IRP) Scenario, whereby the model builds capacity embedded in existing Southeast utility resource plans and dispatches these resources in line with historical trends or as stated in the IRPs.

Competition is represented in the Regional Transmission Organization (RTO) Scenario, which mimics a competitive wholesale market for the entirety of the Southeast region, in which the model chooses the most economically efficient resources from an open regional market, optimizes dispatch of these resources to minimize cost, and performs co-optimized transmission and distribution planning, as well as reserve sharing across the region.

Scenario	Description	Transmission Expansion	DER Coordination	Wheeling Charges
SE IRP	The individual IRPs released by utilities in the southeast states are combined and run through optimal dispatch.	Not allowed	Off	Across state lines
SE Economic IRP	Optimal capacity expansion for the southeast states without creating an RTO	Not allowed	Off	Across state lines
SE RTO	Optimal capacity expansion with an RTO setup in 2025 over the southeast region	Allowed	On	None from 2025 onwards
SE RTO with Nuclear	Optimal capacity expansion with an RTO setup in 2025 over the southeast region. Nuclear is not retired even if uneconomic.	Allowed	On	None from 2025 onwards

In the IRP Scenario, we stitch together the IRPs of major investor-owned utilities in the region, including Alabama Power, Duke Energy (present in the Carolinas and Florida), Florida Power and Light, Georgia Power, Mississippi Power, and TVA.[viii] The IRPs represent a 10-15 year forward looking assessment of the utilities' new and retiring capacity, load projections, and other assumptions regarding utility operations in near- to medium-term. The model uses the prescribed capacity additions included in the IRPs as a key input, and then performs a production-cost analysis[ix] to determine the total system cost over the course of the study period.

The model is beholden to the energy deployments prescribed in the plans, and thus has little opportunity to take advantage of more cost-effective resource mix alternatives or economically optimal dispatch. Additionally, each utility in the region continues to operate independently within each respective service territory, with only minimal coordination of imports and exports.

Realistically, what would emerge over time with BAU in the Southeast does not exactly match the 10-15 year IRPs, which are periodically updated. Hopefully, as utilities and their regulators catch up to the reality that clean electricity is less expensive than the status quo, it is reasonable to assume the inefficiencies won't be quite as stark as the modeling implies. Nevertheless, we model the current IRPs to demonstrate how current utility plans miss out on the potential for a clean, cheap, reliable electricity system in the region and thus open up customers to financial risk from potential stranded assets.

In contrast, the RTO Scenario models a competitive wholesale electricity market across all seven states[x] in which each region procures a mix of resources to reliably meet load every hour from a modeled open market, at least cost. In this scenario, the Southeast region operates with a fully open transmission network, eliminating the inefficient "rate pancaking" that exists in this region as well as other non-RTO regions.[xi]

Similarly, the model co-optimizes the transmission and distribution network in order to ensure that resources are procured and utilized in the most-efficient and cost-effective manner. The region is planned and operated as one entity, in which resources are shared broadly across an open network to meet load and a single Planning Reserve Margin, minimizing the inefficiencies associated with meeting load on a state by state basis in the IRP Scenario. However, the new RTO does not optimize transmission and dispatch with adjacent grid operators PJM Interconnection and Midcontinent Independent System Operator (MISO).

The RTO Scenario developed by VCE® will certainly diverge from a real-world regional wholesale electricity market. Each competitive energy market in the U.S. has a different design that impacts where money flows and who bears the risks of competition. For example, some markets allow vertically integrated monopolies to continue recovering costs of generation from captive customers, while others require all generators to be independent of the poles and wires companies. RTOs today also face structural and political barriers to transmission development and fair cost allocation, distribution optimization, and clean or distributed energy resource participation, each of which are optimized seamlessly in WIS:dom®-P.

As such, the RTO Scenario represents a maximum for the benefits of competition in the region, as contrasted with the uncompetitive IRP Scenario.

We model two additional scenarios to evaluate the impact of deviations from the scenarios described above: An **Economic IRP Scenario** and an **RTO with Nuclear Scenario**. The Economic IRP Scenario allows the model to choose a cost-optimal resource mix, but does not include the co-optimized transmission and reliability planning present in the RTO Scenario. It maintains existing balancing area authorities; therefore, it represents a competitive procurement process within existing monopoly service territories, without exposing these utilities to regional competition or taking advantage of reserve sharing. The RTO with Nuclear Scenario is equivalent to the RTO Scenario, except that this scenario assumes that all existing nuclear plants licenses are extended, and the nuclear plants remain operational through the end of the study period.[xii]

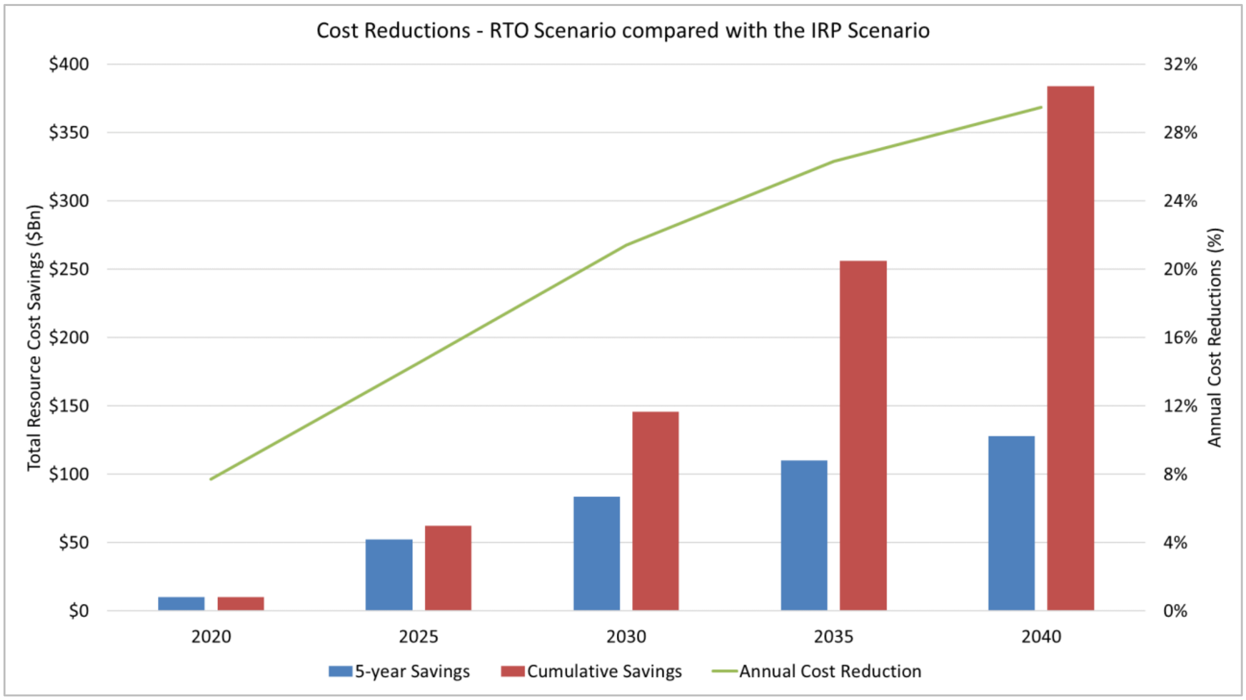
This Summary Report focuses on the core scenarios, with occasional reference to the sensitivity scenarios.

THE RESULT: COMPETITION WOULD DRAMATICALLY LOWER COSTS FOR ELECTRICITY CUSTOMERS, CREATE JOBS

COST SAVINGS

The effects of a single restructured wholesale market in the Southeast are dramatic and immediate. In 2025, the year in which the model has fully operationalized the competitive electricity market, the RTO Scenario is approximately $13 billion cheaper in operations and amortized capital costs. By 2040, the cumulative savings of the RTO Scenario is approximately $384 billion, as expensive-to-run coal and gas fired power plants are replaced with more competitive wind, solar, and battery storage.

These savings translate to 2.5¢/kWh lower rates in the RTO Scenario by 2040 compared to the IRP Scenario, a 29 percent reduction. The savings can be largely attributed to a leaner, cheaper mix of capital and fuel expenses that take advantage of more efficient system operations.[xiii]



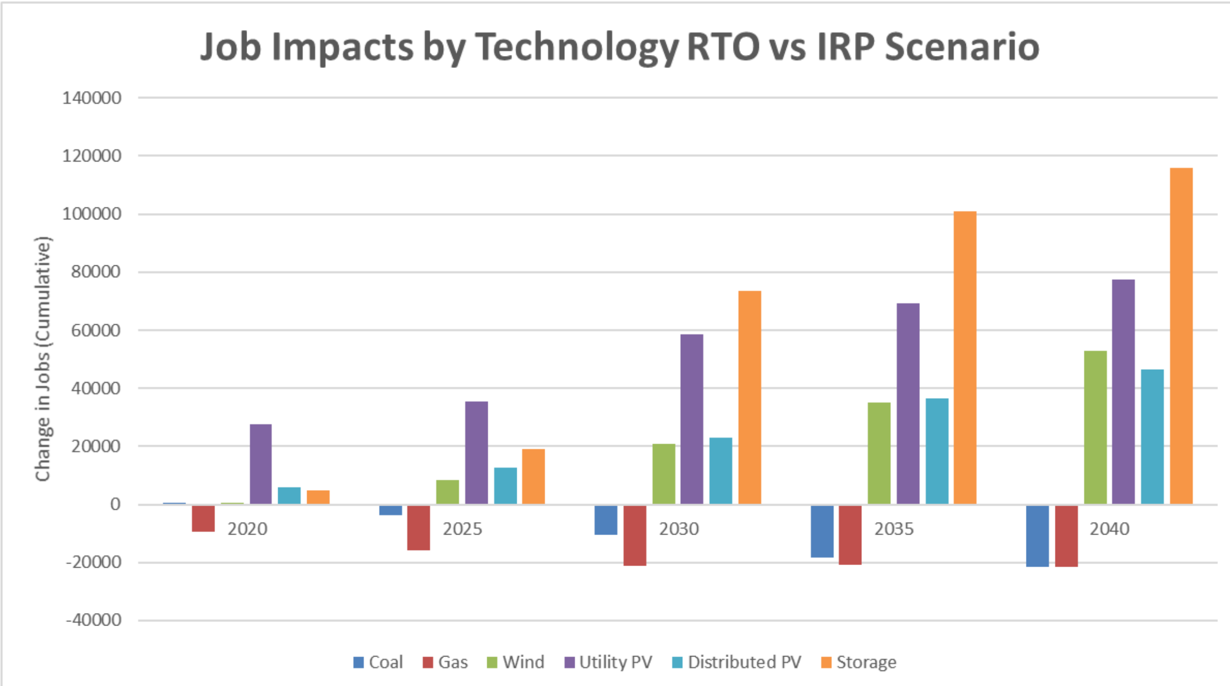
The RTO Scenario savings reflect improvements on the inefficiencies of a balkanized, uncompetitive approach to transmission planning, resource adequacy, integration of distributed energy resources, and dispatch throughout the region. Regional transmission planning through an RTO rationalizes transmission planning to reduce congestion and expose more expensive plants in load pockets to competition. It improves dispatch economics throughout the region. It allows resource sharing and efficient procurement of capacity to maintain reliability. It also accelerates displacement of uneconomic coal generation with cost-effective clean electricity resources, primarily wind, solar, and low-cost storage options, reducing system costs in each investment period.

Approximately 10 percent of cumulative savings, or $38 billion, is attributed to distribution system savings, as co-optimized distribution system planning reduces redundant investments. In the RTO Scenario, the model encourages behind-the-meter generation and storage when it reduces total system costs, including distribution infrastructure costs.

This co-optimization of bulk and small-scale resources helps reduce peak load in the RTO Scenario 11.8 percent below the IRP Scenario, creating savings from generation all the way down to distribution. Realizing these savings goes beyond reforming the market structure for the bulk power system, and likely requires regulatory incentives at the distribution level to coordinate with a central RTO, as discussed in the policy recommendation section below.

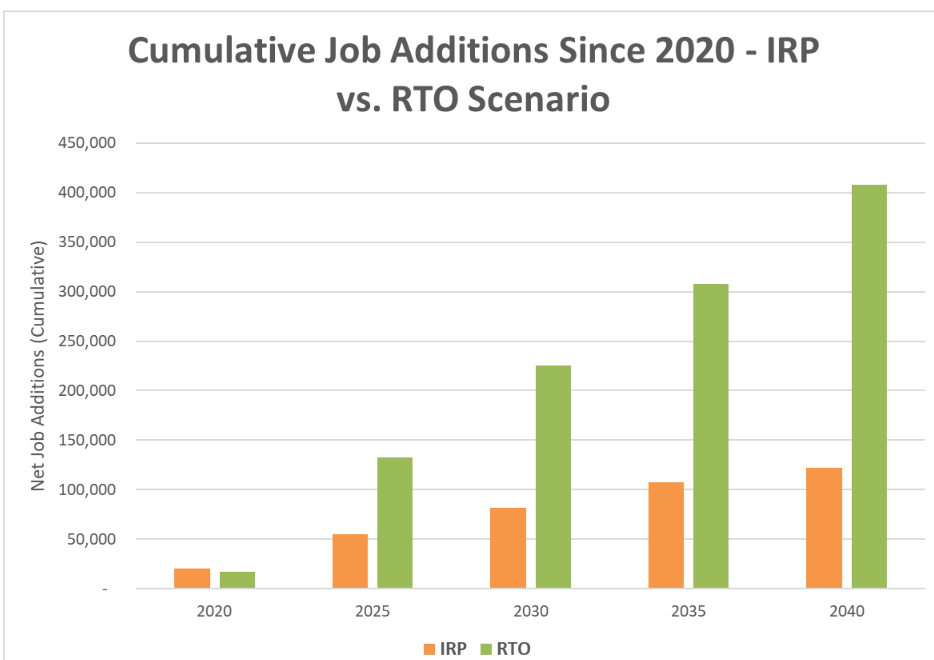
MARKET COMPETITION ACCELERATES JOB CREATION

The dramatic shift in electric power generation has significant employment impacts across the region. In both scenarios, electric sector investment leads to an increase in jobs through 2040. The RTO Scenario sees new jobs highly concentrated in cost-effective clean technologies like solar, wind, and storage.



Cumulative Change in Electric Sector Jobs by Technology Type in RTO Scenario Versus IRP Scenario 2020-2040.

The IRP Scenario also sees job growth, in part as an artifact of the inefficiency of the system. With a reserve margin over 40 percent, the IRP Scenario is significantly overbuilt, leading to more jobs in unnecessary and expensive coal and gas plants. Despite this, the IRP Scenario immediately starts lagging the RTO Scenario in job creation once the market is fully operational (2025). Overall, by 2040, the RTO Scenario leads to an additional 408,000 jobs in the sector, compared to just 122,000 new jobs in the IRP Scenario, a net of 285,000 jobs.[xiv]



Cumulative Electric Sector Jobs Added in IRP and RTO Scenarios by Investment Period, 2020-2040.

By 2040, the RTO Scenario includes 55,000 jobs in wind, 282,000 jobs in solar, and 142,000 jobs in storage, compared to just 2,700 wind, 126,000 solar, and 26,000 storage jobs in the IRP Scenario. But the build-out and associated jobs could be more significant, especially in the later years of the analysis as the industry scales. WIS:dom®-P limits the wind and solar power build out to track historical capacity expansion of these resources.[xv]

Efforts to ramp up renewable energy deployment in the immediate future may bring additional employment and cost savings benefits to the region by expanding deployment capacity, or bringing manufacturing jobs to the region. As such, the RTO Scenario represents a somewhat conservative technical analysis of renewable energy's possible contribution to both jobs and a future competitive electric system in the Southeast.[xvi]

VCE®'s jobs analysis does not consider knock-on effects of reduced electricity rates on the region's industrial competitiveness or additional consumer and business spending unlocked by the savings. Electricity rates that are 2.5¢/kWh lower by 2040 would further enhance the region's already low rates and attractiveness to industry.

An additional benefit of an organized wholesale market would be direct access to least cost renewable electricity, an attractive proposition for large corporations increasingly concerned with reducing their impact on climate change.

EMISSIONS IMPACT

The RTO Scenario dramatically reduces carbon emissions and virtually eliminates many major air pollutants (through the phase-out of coal), resulting in significant benefits to human health. Compared with the IRP Scenario, carbon dioxide (CO_2) emissions in the RTO Scenario are 46 percent lower in 2040.

Compared to 2018 levels, CO_2 emissions are 37 percent lower in 2040. In the IRP Scenario, CO_2 emissions increase due to an expansion of the electric grid, largely buoyed by additional gas investments. Major criteria air pollutants, including $PM_{2.5}$, PM_{10}, and SO_2 all drop to near-zero in 2040

Emissions Goals for Southeastern U.S. Utilities: Spotlight on Duke Energy and Southern Company

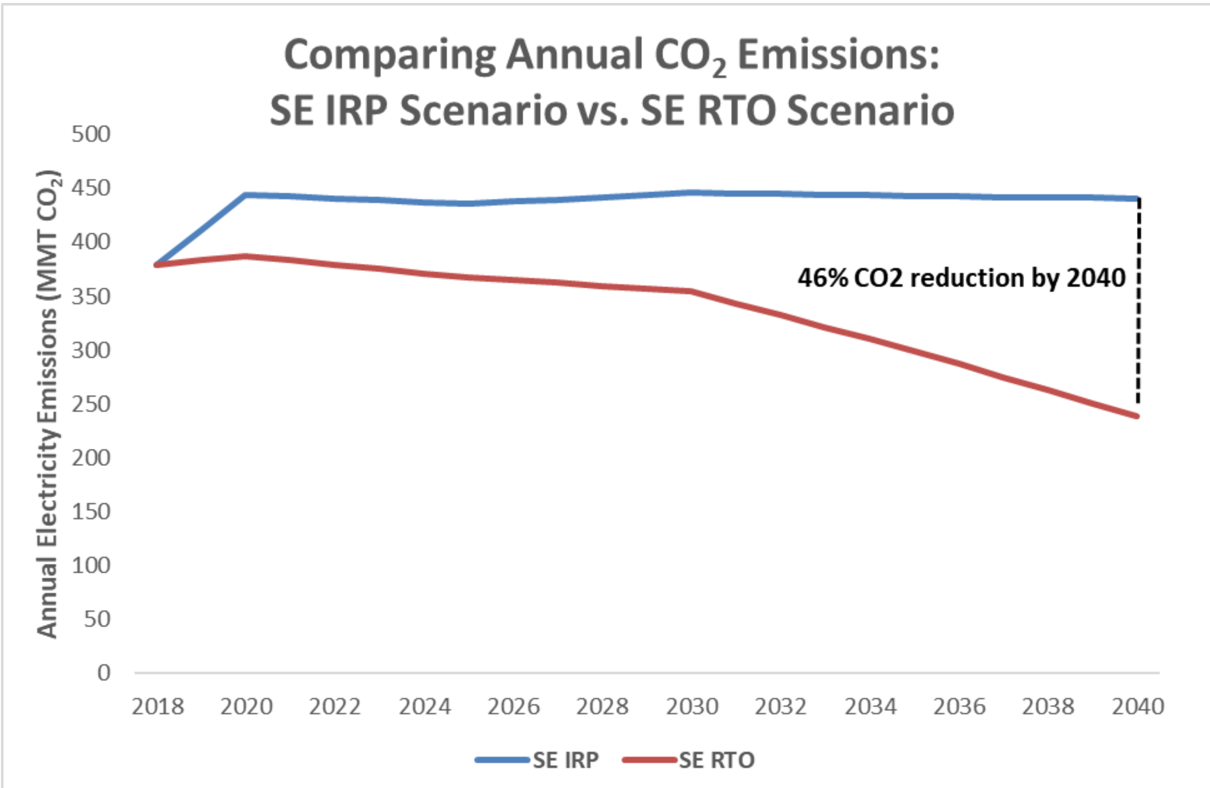
Both Duke Energy and Southern Company have pledged to achieve net-zero company emissions by 2050, an aspirational goal in line with the goals of the Paris Agreement target to keep global warming below 1.5° Celsius. Yet the modeling makes clear that Southern and Duke's IRPs are off track from what's needed to achieve these goals.

Combined, Duke Energy and Southern Company make up approximately 45 percent of total Southeast retail sales. In fact, a competitive market with no carbon policy does a better job of reducing emissions than Duke and Southern's efforts.

This reveals two dynamics: First, vertically integrated utilities' incentives to maintain and earn on existing infrastructure conflicts with both customer well-being and environmental goals. Second, regional transmission and operational approaches are more effective at integrating high shares of renewable electricity, and Duke and Southern hamper their own efforts to decarbonize at least cost by resisting regionalization efforts.

in the RTO Scenario, largely due to the retirement of all remaining coal. In the IRP Scenario, those emissions remain virtually flat. [xvii]

The emissions reductions of both carbon dioxide and other major air pollutants is significant in the RTO Scenario. The RTO with Nuclear Scenario modeled illuminates the opportunity for even greater emissions reductions with minimal cost impact, as detailed in the Technical Report, Section 2.11.



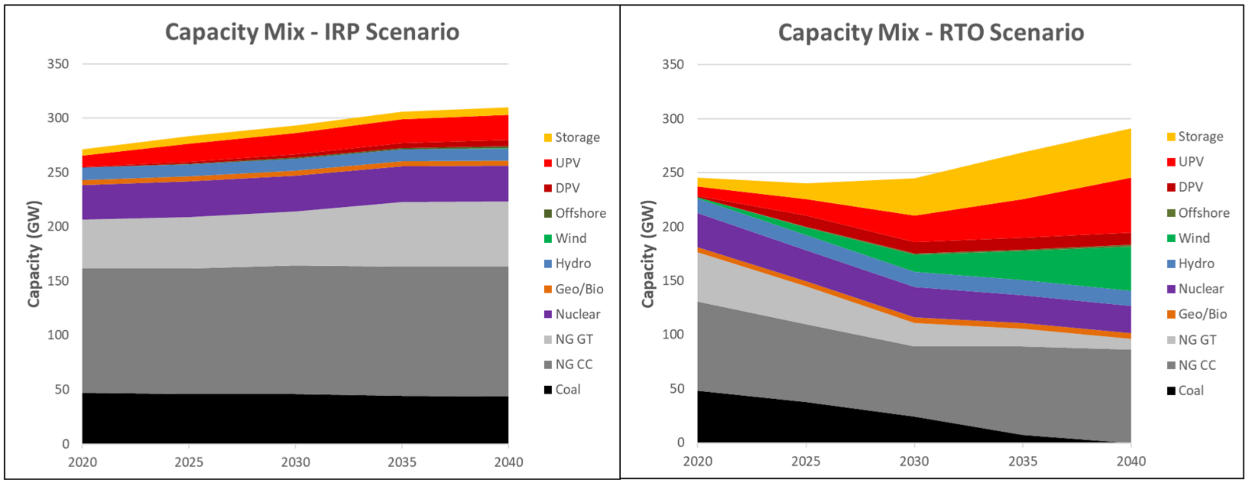
Total CO_2 Emissions from the Southeast Electric Sector in the IRP Scenario and RTO Scenarios, 2018-2040

CHANGES TO THE ELECTRICITY SYSTEM

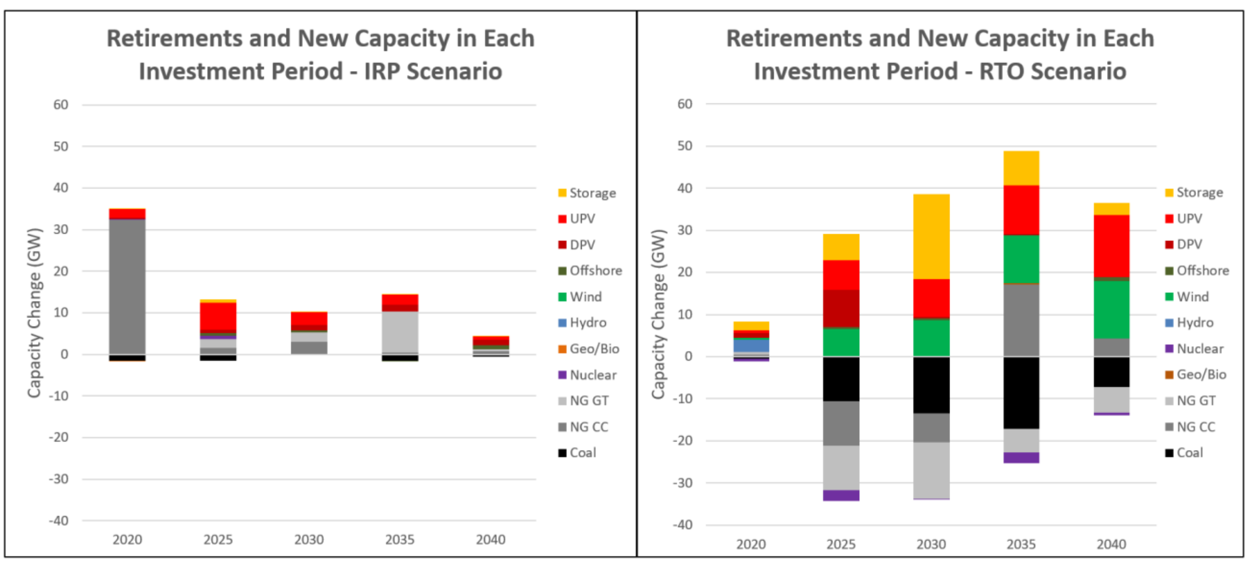
The IRP Scenario represents a particularly inefficient strategy for power systems planning. In this scenario, each utility service territory is planning to meet its peak load, plus a specified reserve margin, independently. Segmented approaches to resource planning combine with monopoly incentives to maintain existing uneconomic generation, self-build new generation, and overbuild capacity, resulting in cumulative costs exceeding those of the RTO Scenario by $384 billion by 2040.

Changing Resource Mix

Three trends become apparent by examining how the resource mix changes over time in each case. First, while the utility IRPs retain most of the existing coal fleet while adding additional fossil capacity, the RTO Scenario retires coal as it cannot compete with newer resources. Second, the IRP Scenario adds very little renewable generation, while the RTO Scenario adds significant amounts of both wind and solar PV, including significant distributed PV. Finally, the IRP Scenario relies very little on battery storage, while the RTO Scenario builds significant utility-scale and distributed battery storage as part of the cost-optimal resource mix, which also allows most of the gas peaker units to retire by 2040 as well. From this analysis it becomes clear that continuing to operate coal-fired generation and gas peakers at the expense of new clean energy resources in the region is costing customers billions.



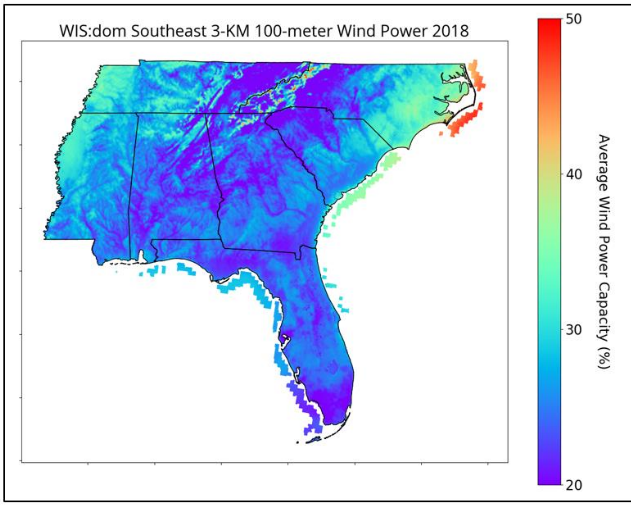
Capacity Mixes for the RTO and IRP Scenarios, 2020-2040

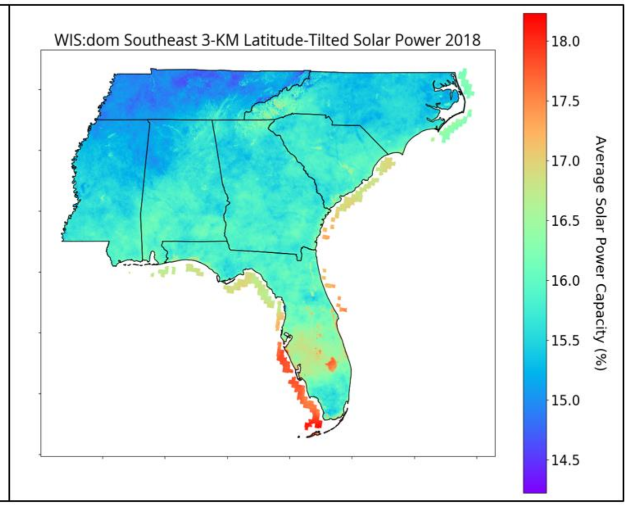


Cumulative Capacity Additions and Retirements in the Restructured Scenario, 2020-2040

Changes to the generation mix tell a similar story. By 2040, the majority of generation in the IRP Scenario consists of fossil fuels, whereas the majority of generation in the RTO Scenario is carbon-free. In the RTO Scenario, storage and gas combine to provide sufficient flexibility to integrate significant shares of variable renewable energy by 2040. In the IRP Scenario, there is almost no wind generation, and solar PV provides just 4 percent of annual generation. In contrast, wind and solar provide 22 percent of generation in the RTO Scenario; when aggregated with nuclear (20 percent), geothermal/bioenergy (5 percent) and hydropower (4 percent), 51 percent of the Southeast fleet is zero-carbon by 2040 in the RTO Scenario.

Defying the traditional notion that wind power is not a viable generating resource for the Southeast, the model builds a substantial amount of onshore wind throughout the region, owing to both the rapidly declining cost and increasing hub heights and rotor diameters of new wind turbines.





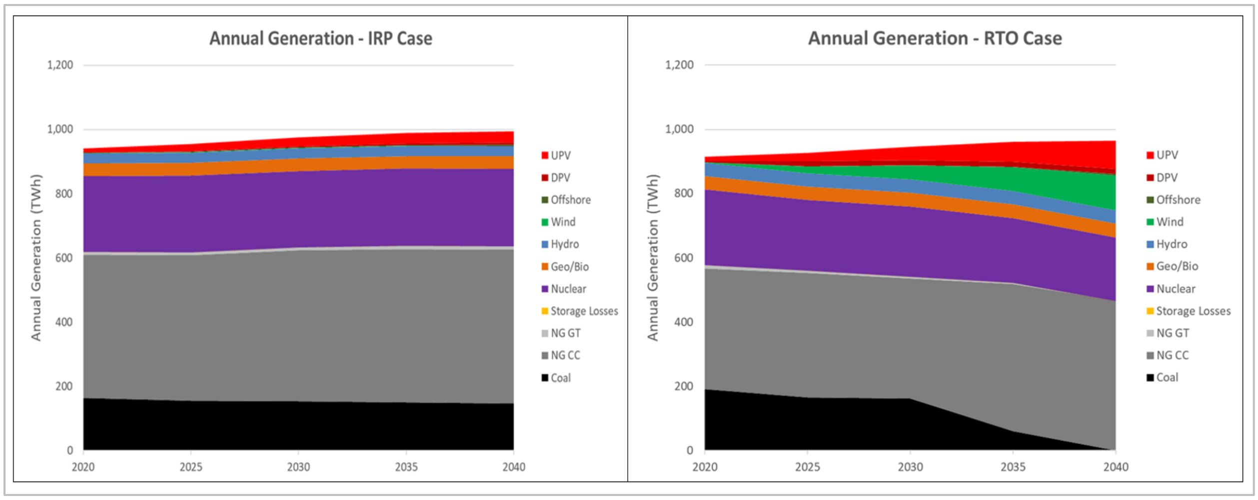
The 3-km 100-meter wind capacity resource (left) and 3-km latitude-tilted solar capacity resource (right) across the Southeast U.S. in 2018.

Additionally, wind generation in the region is particularly well-correlated with the winter peak demand, while it is anti-correlated with solar output.[xviii] Optimizing over the whole region also allows the model to take advantage of the diversity benefits of wind when it comes to meeting reliability goals.

The IRP Scenario, which relies on the capacity builds specified in each utility's respective IRP, only builds 250 megawatts (MW) of onshore wind, plus 2 GW of offshore wind hard coded in both scenarios. The RTO Scenario builds 41 GW of onshore wind, by contrast.[xix]

The availability of low-cost battery storage enables higher levels of renewable energy deployment and improves resource sharing optimization across the region in the RTO Scenario. The 46 GW of storage (a quarter of the 166 GW peak load in 2040) in the RTO Scenario provides significant load balancing and peak demand reduction, compared to just 7 GW of storage in the IRP Scenario.

This storage reduces total resource costs on the system as it not only balances variable renewables but better integrates distributed generation, adapts to inflexible nuclear generation, and reduces the need for new transmission. [xx]



Annual Generation - IRP Scenario and RTO Scenario 2018-2040

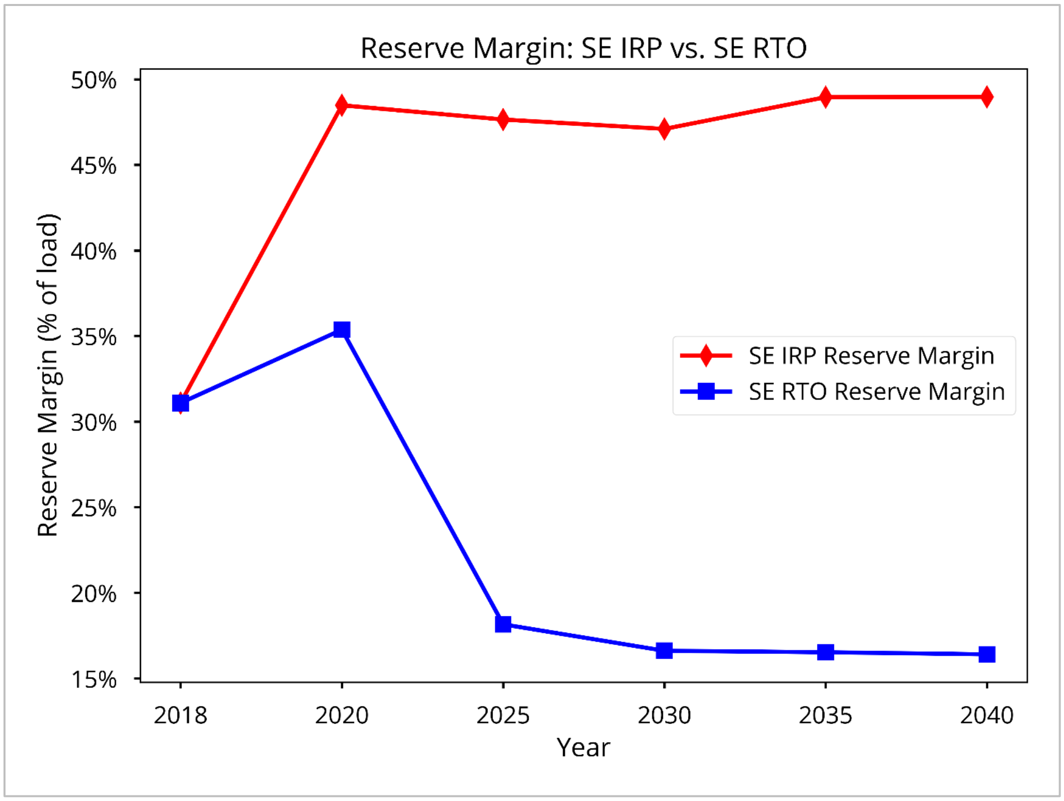
Reserve Margins

Owing to the inefficient and conservative planning regimes across utilities, the IRP Scenario results in significant overbuild. The combined planning reserve margin (PRM) of the region reaches 48 percent in 2040, which means that combined, utilities are procuring generation to meet a coincident peak demand for the region plus an additional 48 percent of reserve capacity.

This can be compared to the reference standard PRM[xxi] of 15 percent from the North American Electric Reliability Corporation, which promulgates and enforces reliability standards on the U.S. grid. It is important to note that many RTOs regularly exceed their Reference PRM targets, but few reach the level of over-procurement found in the Southeast region.[xxii]

In contrast, the RTO Scenario meets a 16 percent PRM in 2040. This contrast in reserve levels suggest the RTO system has less underutilized, and thus less wasted, capacity. Utility IRPs in aggregate are redundant and excessive on their own, but when taking a regional view where significant efficiencies could be obtained by sharing reserves, the waste becomes more apparent.

Utilities are rushing to build new gas generation that increases their earnings while planning to hold onto uneconomic coal generation for decades longer than economics would dictate. But without competition, captive customers of the monopoly utilities hold all of this risk.[xxiii]

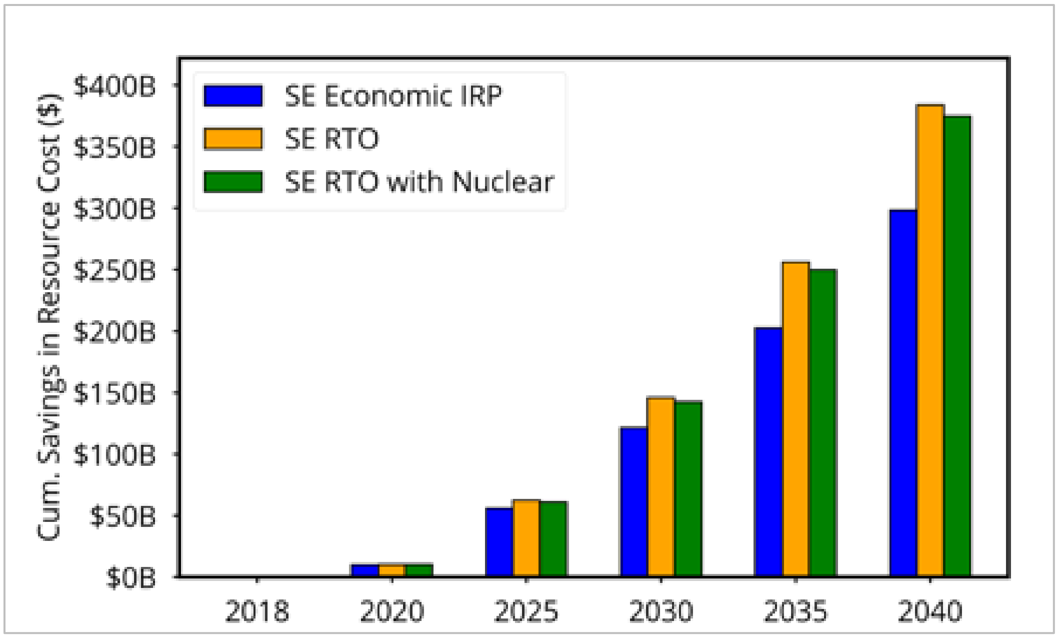


Planning Reserve Margins of the IRP and RTO Scenarios, 2018-2040

INSIGHTS FROM TWO SENSITIVITIES

We examine two modifications to the core scenarios in order to gain insight into key economic and environmental drivers in Southeast electricity market reform. In the **RTO with Nuclear Scenario**, we assume the same structure as the RTO Scenario, adding the requirement that all existing nuclear is granted license extensions through 2040 and remains online, regardless of cost-competitiveness. This scenario examines the cost and emissions tradeoffs associated with keeping existing uneconomic nuclear plants online, similar to programs recently adopted in Illinois, New Jersey, and New York.[xxiv]

In the **Economic IRP Scenario**, we allow the model to choose the appropriate cost-effective capacity mix in each sub-regional planning footprint (maintaining existing balancing area authorities), however, the model is not co-optimizing the generation, transmission, and distribution systems as it does in the RTO Scenario. This recognizes the reality that full regionalization may be politically infeasible in the near to medium term, but shows that a majority of the cost savings can still be achieved by subjecting utility procurement plans and existing generators to market competition. While more economic than the IRP Scenario, the Economic IRP Scenario still leaves significant consumer cost-savings on the table.



Cumulative Savings in Total Resource Cost of Scenarios Compared to the IRP Scenario, 2018-2040

RTO with Nuclear Scenario

Maintaining the existing nuclear fleet provides significant emissions benefits while minimally raising costs relative to the RTO Scenario. The RTO with Nuclear Scenario results in approximately $375 billion in cumulative cost savings by 2040, as compared to the $384 billion in savings under the RTO Scenario. This cost is a relatively small tradeoff for significant emissions benefits: The RTO with Nuclear Scenario leads to a 41 percent drop below 2018 levels by 2040, compared to a 37 percent drop in the RTO Scenario. Similarly, maintaining the existing nuclear fleet leads to an approximately 5 percent reduction in both NO_X and methane compared to the RTO Scenario. Maintaining the existing nuclear fleet, despite a minor 0.5 percent increase in overall system costs, leads to significant emissions and pollutant reductions.

The primary driver of these emissions reductions is the impact that additional nuclear capacity has on gas generation. The additional nuclear capacity, coupled with the flexibility that the RTO provides (to accommodate increased levels of wind and solar, extra transmission, and higher levels of storage), allows for decreased gas generation. In the RTO with Nuclear Scenario, gas capacity is approximately 5 GW lower, largely driven by the additional 7 GW of nuclear capacity that remains online.[xxv]

Economic IRP Scenario

In the Economic IRP Scenario, we allow the model to choose the appropriate, cost-effective capacity mix within each existing utility service territory, and optimize dispatch using the existing transmission network. However, the model is not co-optimizing the generation and transmission buildout between balancing authorities, nor is it co-optimizing the distribution and transmission as it does in the RTO Scenario. In effect, this scenario represents a partial step towards a fully competitive wholesale electricity market, in which the system is no longer beholden to the capacity mixes specified in each utilities' respective IRPs, but is not optimizing to gain the benefits of regionalization. One might expect a similar effect from utilities opening up capacity procurement to competition and enforcing economic dispatch of their power plants, but not participating in organized regional markets.[xxvi]

Modeling indicates some, but not all the savings, jobs, and emissions benefits of competition are attainable without regional integration exemplified by the RTO Scenario. By 2040, the Economic IRP Scenario creates approximately $298 billion in cumulative cost savings compared to the IRP Scenario – about three-quarters of the savings achieved in the RTO Scenario. Carbon emissions only drop 13 percent below 2018 levels by 2040, compared to a 37 percent decrease in the RTO Scenario. While the Economic IRP scenario expands zero-carbon resource capacity, a significant amount of coal and gas capacity remains online by 2040, leading to a smaller decrease in major air pollutants.

CONCLUSION

VCE®'s Southeast analysis makes it clear that greater competition and regional coordination could create massive cost savings, increase employment, reduce emissions, and improve market access for clean energy resources. Much of the opportunity is a function of the dysfunctional status quo. Aggregating utility integrated resource plans makes it clear they have huge opportunities for improvement. The competitiveness of the region, participation in the fast-growing clean energy economy, and market fairness depend upon making significant progress in this direction.

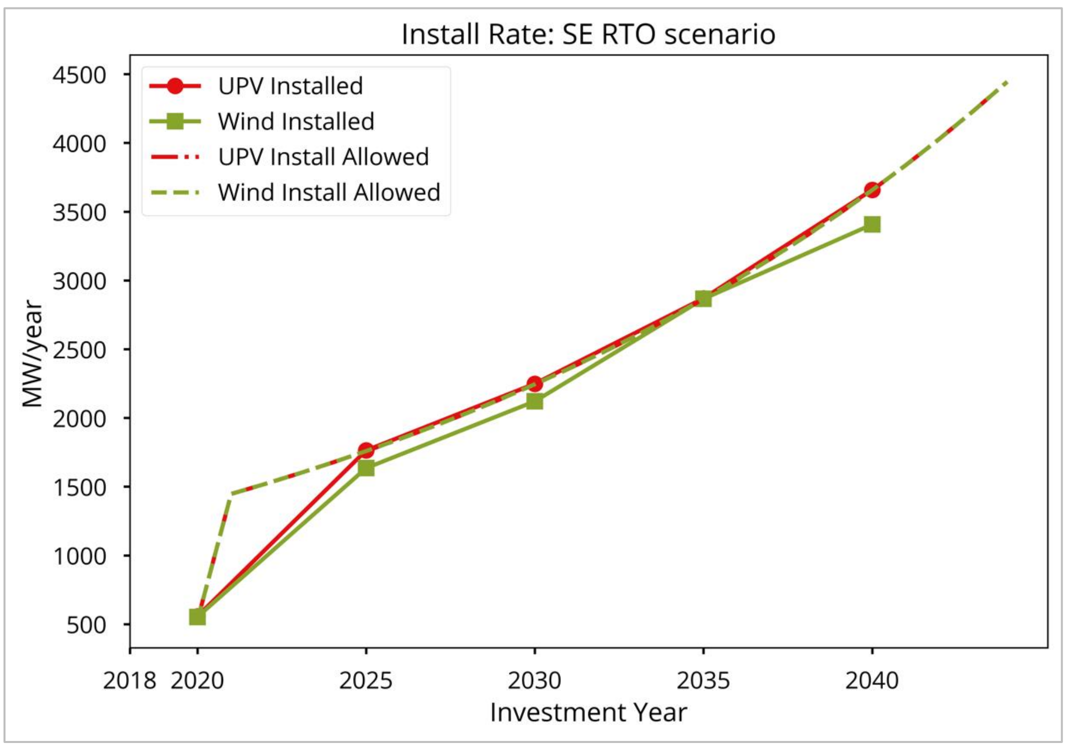
At the very least, policymakers considering going down the road to a regional market or state-level competitive procurement should be encouraged by this analysis to keep pressing in legislative and regulatory forums. It's no longer 2000 –20 years since the California Energy Crisis has proved that regional competitive electricity markets can work effectively. Incremental approaches such as an energy imbalance market, or competitive utility procurement, can yield significant benefits, and set the region on a path to continue improving the competitiveness of the electricity industry. State stakeholders where utilities block competitive reforms now have new quantitative findings to challenge the assumption that the way utilities have done business is in the public interest. We are in a period of rapid technological transition - the status quo of balkanized uncompetitive monopolies will not leverage the potential of this moment.

APPENDIX – TECHNICAL INSIGHTS

THE ROLE OF DEPLOYMENT RATES

To ensure reasonable results from capacity expansion planning, realistic constraints were imposed on the model in terms of capacity turnover and new build allowed to occur per year. The capacity turnover limits depend on several factors, such as existing supply chains that can sustain a particular buildout rate for a technology, available skilled workforce that can be called upon, disruption in host communities from retirements which leads to job losses, lost tax revenues, and other losses in the economy downstream of the power generator. In addition to the buildout limits, time lags are incorporated in installations for newer technologies.

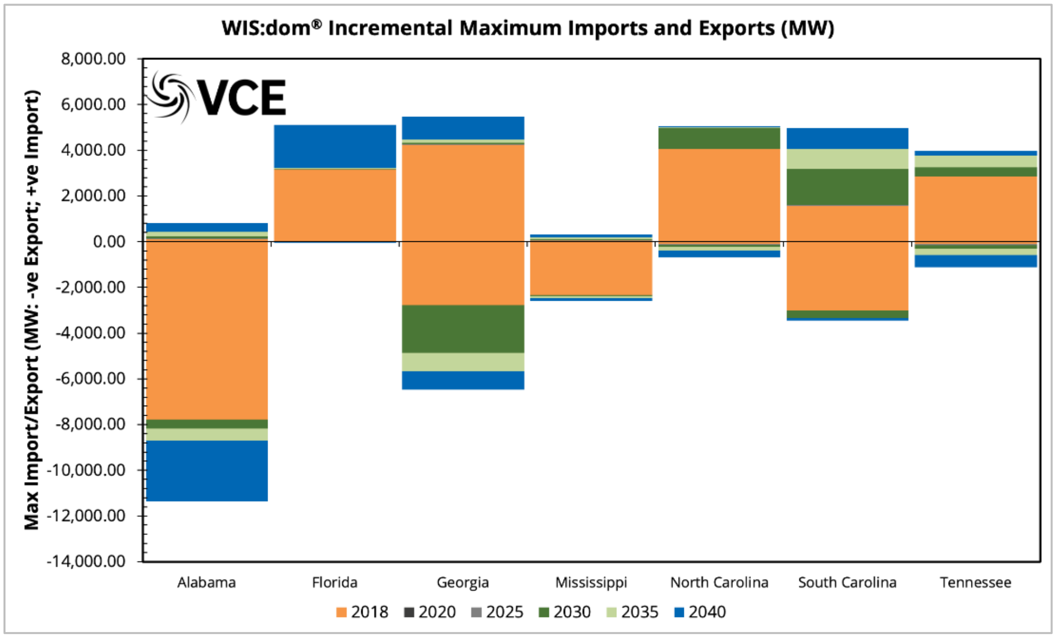
The limitation on deployment rate embedded within the WIS:dom®-P model's assumptions becomes a binding constraint on wind and solar deployment, as they are the most cost-effective resources available to the model. To reflect historical trends of patchwork policy support to overcome structural barriers, the model only allows wind and solar to grow at 1,800 MW/year annually, increasing this rate limiter by 5 percent a year in the RTO Scenario. As shown in the figure below, the RTO scenario essentially saturates these limits in all modelled years.



During model calibration, when allowed to deploy clean energy resources unconstrained, even greater total deployment of wind and solar and concomitant cost reductions were observed, along with additional transmission expansion, for further savings. Though deployment constraints must realistically exist, deployment capacity has grown faster than these limits in parts of the U.S., and much faster in parts of the world such as China. As such, the RTO Scenario represents a conservative analysis of renewable energy's possible contribution to both jobs and a future competitive electric system in the Southeast.

TRANSMISSION AND STORAGE

As clean energy deployment increases in the RTO Scenario, the transmission system plays an increasingly important role in sharing resources across the region. The import and export capacity of each state is dramatically different by 2040, as the region plans its transmission system in tandem to meet a single reserve margin. In contrast to the IRP Scenario, in which states plan their regions independently and build little to no new transmission, the RTO Scenario sees significant growth.



By 2040, the cumulative fixed costs associated with transmission are approximately $1.3 billion more in the RTO Scenario compared to the IRP Scenario. The deployment of low-cost battery storage, however, limits the need for more overall expansion of the transmission system. In effect, storage plays a similar role, serving to balance supply and demand, increase load shifting, and reduce the need for additional peaking capacity. WIS:dom®-P is able to co-optimize the deployment of storage with distribution and transmission infrastructure. Because it is modular and takes up little space, storage sited near or at renewable generation facilities limits the need to send excess power over vast distances, instead allowing local solar and wind to match local loads more effectively. This also increases the economics of lower-quality wind and solar resources, which can provide greater value paired with storage by matching load. Still, there is no replacement for some amount of transmission to access the lowest cost resources and enable efficient power system balancing across a wide geographic area. Moreover, storage and transmission serve to complement each other rather than compete.[xxvii]

ENDNOTES

[i] Technical report available at https://vibrantcleanenergy.com/wp-content/uploads/2020/08/SERTO_WISdomP_VCE-EI.pdf
[ii] All dollar values are in real 2018 dollars.
[iii] Eric Gimon et al., "The Coal Cost Crossover: Economic Viability of Existing Coal Compared to New Local Wind and Solar Resources" (Energy Innovation & Vibrant Clean Energy, March 2019), https://energyinnovation.org/wp-content/uploads/2019/04/Coal-Cost-Crossover_Energy-Innovation_VCE_FINAL2.pdf.
[iv] Data available at https://energyinnovation.org/publication/the-coal-cost-crossover/
[v] Brian Murray, "Reforming The Carolinas' Power Markets: Producing A Panacea Or A Pandora's Box?," *Forbes*, October 11, 2019, https://www.forbes.com/sites/brianmurray1/2019/10/11/reforming-the-carolinas-power-markets-producing-a-panacea-or-a-pandoras-box/#1ba674b5c5ea.
[vi] Iulia Gheorghiu, "Duke, Southern Plan Path for Southeast Energy Imbalance Market," *Utility Dive*, July 14, 2020, utilitydive.com/news/duke-southern-plan-path-for-southeast-energy-imbalance-market/581556/.
[vii] See also Christopher Clack, "The WIS:Dom® Model: Detailed Capacity Expansion & Production Cost Modeling" (Vibrant Clean Energy, n.d.), https://www.vibrantcleanenergy.com/wp-content/uploads/2019/04/VCE-WISdom-Brochure.pdf.
[viii] Refer to Section 2.1 of the technical report for details on the IRP Scenario.
[ix] WIS:dom®-P ensures that historical capacity factors continue to account for un-economic decision making.
[x] The portion of Mississippi that is already a part of MISO is matched to EIA form 860 data.

[xi] In many RTOs, grid operators determine rates for imports and exports, known as Transmission Access Charges, which are used to recover transmission revenue requirements. The rates for importing and exporting power are determined by the grid operator and spread evenly across all consumers, providing equal access and recovery for all participants in the market. In contrast, the Southeast relies on wheeling charges, in which an independent power producer pays a fee to the utility to wheel power across its lines. Different utilities may charge different wheeling prices.

[xii] Plant Vogtle is assumed to come online in all scenarios.
[xiii] Refer to Sections 2.2 and 2.3 of the technical report.

[xiv] A job is represented by one Full-Time Equivalent (FTE) employee. The jobs analysis includes only direct jobs related to the electricity sector, and does not include indirect jobs in manufacturing, mining, fuel refining, or delivery. For a detailed explanation of the jobs analysis, please refer to Section 4.3 of the technical report.

[xv] Refer to Section 3.11 of the technical report for more details.
[xvi] Refer to Section 2.1 of the technical report for the impacts on renewable energy buildout constraints.
[xvii] Sections 2.4 and 2.11 of the technical report discuss emission reductions in the SE RTO and SE RTO with Nuclear.
[xviii] Refer to Section 4.4.4 of the technical report.
[xix] Refer to Sections 4.2 and 4.3 of the technical report.
[xx] Refer to Section 2.6 of the technical report.
[xxi] "**Planning reference margins** are reserve margin targets based on each area's load, generation capacity, and transmission characteristics. In some cases, the planning reference margin level is required by states, provinces, independent system operators, or other regulatory bodies. Reliability entities in each region aim to have their anticipated reserve margins surpass their planning reference margins." "NERC Report Highlights Potential Summer Electricity Issues for Texas and California" (Energy Information Administration, June 18, 2019), https://www.eia.gov/todayinenergy/detail.php?id=39892#.
[xxii] "2020 Summer Reliability Assessment" (North American Electric Reliability Corporation, June 2020), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2020.pdf.
[xxiii] Refer to Section 2.7 of the technical report.

[xxiv] See, e.g., Patrick McGeehan, "New York State Aiding Nuclear Plants With Millions in Subsidies," *New York Times*, August 1, 2016, sec. A.

[xxv] Refer to Section 2.4 of the technical report
[xxvi] Refer to Section 2.2 of the technical report

[xxvii] Refer to Section 2.8 of the technical report.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-100, SUB 171

In the Matter of:	)	**PETITION OF THE NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION, SIERRA CLUB, AND THE SOUTHERN ALLIANCE FOR CLEAN ENERGY FOR INVESTIGATION AND RULEMAKING TO IMPLEMENT N.C. GEN. STAT. § 62-154**
Petition for Investigation and Rulemaking to Implement N.C. Gen. Stat. § 62-154	)	
	)	

Exhibit D

Free markets. Real solutions.

R STREET POLICY STUDY NO. 201
August 2020

HOW VOLUNTARY ELECTRICITY TRADING CAN HELP EFFICIENCY IN THE SOUTHEAST

By Jennifer Chen and Michael Bardee

CONTENTS

INTRODUCTION

Encouraged by cost savings, reliability benefits and emissions reductions, electric utilities across much of the United States have banded together to share resources. The Southeast, which is the last frontier for organized wholesale markets, is now contemplating how to improve efficiency through regional energy trade.

Southeastern states have adjusted the cost-of-service monopoly model to modestly accommodate demand for renewable energy, largely for corporate buyers.[1] However, energy bills in the region are high compared to consumer income, and a recent nuclear plant cancellation—which stands to leave residents in South Carolina with a tab in the billions and over 5,000 lost jobs—creates an even more precarious financial situation.[2] Dissatisfaction over such financial mismanagement and demand for more renewable energy have led lawmakers and stakeholders to question whether more fundamental departures from the current utility regulatory model make sense. For example, North Carolina's House Bill 958 could require investor-owned utilities to join or create a regional transmission entity, and both of the Carolinas' legislatures plan to study the potential benefits of such entities.[3] The primary example of a regional transmission entity—a Regional Transmission Organization (RTO)—comes with a governance structure to ensure that the transmission system is transparently operated independently of any particular utility. This helps provide open access to the transmission system, and thus the electricity markets for the organization's member generators. Southeastern utilities, however, emphasize that they want to avoid additional governance and have been discussing more incremental ideas for setting up a voluntary energy exchange.

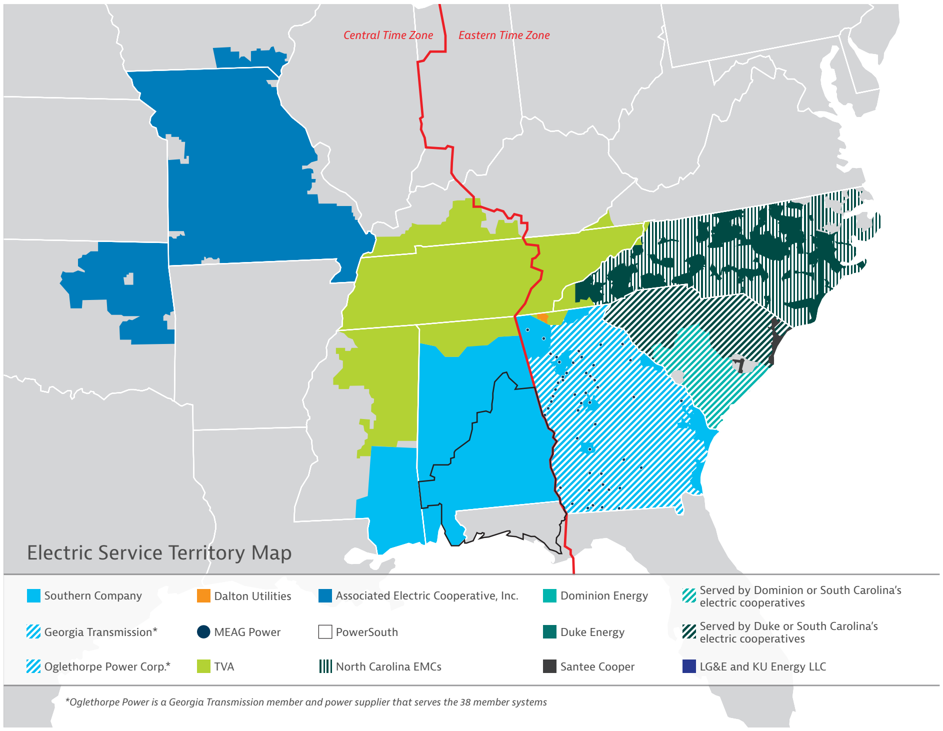
Accordingly, the present study describes various voluntary trading mechanisms, such as energy imbalance markets (EIMs) and several existing mechanisms for voluntary energy exchange in the Southeast. It then suggests that greater net benefits could be derived from a platform transparently operated by an independent entity, which may also preserve a significant degree of autonomy for utilities.

1. Jennifer Chen, "Evaluating Options for Enhancing Wholesale Competition and Implications for the Southeastern United States," Nicholas Institute for Environmental Policy Solutions, March 2020, p. 3. https://nicholasinstitute.duke.edu/publications/evaluating-options-enhancing-wholesale-competition-and-implications-southeastern.

2. Jacob Reynolds, "Former SCANA executive pleaded guilty to conspiracy over failed VC Summer nuclear project" *News19*, July 23, 2020. https://www.wltx.com/article/news/crime/former-scana-executive-pleaded-guilty-to-conspiracy-over-failed-vc-summer-nuclear-project/101-0ab3d333-da8a-4907-bb83-89dd7ced7cce.

3. See, e.g., H.B. 958, Electric Utilities/Allow and Study RTE, April 25, 2019. https://webservices.ncleg.gov/ViewBillDocument/2019/3882/0/DRH40413-RIa-25; H.B. 4940, South Carolina General Assembly 123rd Session, Feb. 12, 2020. https://www.scstatehouse.gov/sess123_2019-2020/prever/4940_20200213.htm; S.B. 998, South Carolina General Assembly 123rd Session, Jan. 14, 2020. https://www.scstatehouse.gov/sess123_2019-2020/prever/998_20200114.htm.

FIGURE I: POTENTIAL SOUTHEAST ENERGY EXCHANGE MARKET FOOTPRINT



SOURCE: Southern Company.

DISCUSSIONS OF A SOUTHEAST ENERGY EXCHANGE MARKET

A group of utilities including Duke, Dominion Energy South Carolina, Southern Company, Associated Cooperative and the Tennessee Valley Authority, have disclosed that they have been discussing a Southeast Energy Exchange Market (SEEM), which would be an automated and voluntary platform that matches buyers and sellers.[4] This exchange could cover all or parts of ten states, as shown in Figure 1 above. Florida, which has utility plans to spend big on solar, is absent from this conversation so far.[5]

The SEEM utilities emphasize that they do not want governing authorities enforcing sales or requiring that transmission capacity be reserved to ensure that sales can be delivered. The group is considering bilateral sales every 15 minutes because to support more frequent sales would require more control by a governing entity. This also makes day-ahead energy trading over SEEM unlikely.[6] In comparison, five-minute dispatch intervals were adopted in organized wholesale electricity markets because they reduce operating costs and regulation requirements. Shorter intervals can also facilitate renewable energy integration, and day-ahead scheduling has been cited as important on that issue.[7] Some stakeholders are concerned that discussions have been conducted without their knowledge and are keen to see a governance structure that is more independent of the utilities.[8]

ORGANIZED WHOLESALE ELECTRICITY MARKETS EXPLAINED

Organized wholesale electricity markets have reduced wholesale energy costs and displaced less efficient, more polluting resources with cheaper, cleaner technologies in the United States. They have also enhanced the flexibility of the power system to balance variable renewable generation and adapt to sudden disturbances.[9]

4. Iulia Gheorghiu, "Duke, Southern plan path for Southeast Energy Imbalance Market," *Utility Dive*, July 14, 2020. https://www.utilitydive.com/news/duke-southern-plan-path-for-southeast-energy-imbalance-market/581556.

5. See, e.g., Mark Watson, "Florida 100% renewables bill likely to struggle, even as Duke adds solar," *S&P Global*, Jan. 28, 2020. https://www.spglobal.com/platts/en/market-insights/latest-news/natural-gas/012820-florida-100-renewables-bill-likely-to-struggle-even-as-duke-adds-solar.

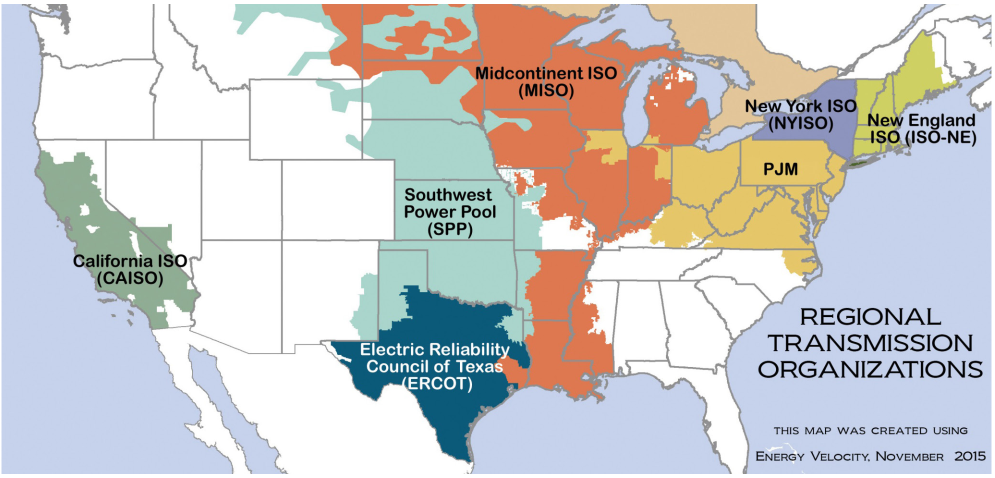
6. John Downey, "How Duke Energy could join other power giants to remake Southeast markets," *Charlotte Business Journal,* July 22, 2020. https://www.bizjournals.com/charlotte/news/2020/07/17/duke-energy-partners-local-control-for-se-market.html.

7. See, e.g., L. Bird et al., "Integrating Variable Renewable Energy: Challenges and Solutions," National Renewable Energy Laboratory, September 2013, pp. 5-6. https://www.nrel.gov/docs/fy13osti/60451.pdf; "Extending the Day-Ahead Market to EIM Entities," California Independent System Operator, Oct. 10, 2019, p. 7. http://www.caiso.com/InitiativeDocuments/IssuePaper-ExtendedDayAheadMarket.pdf.

8. Gheorghiu. https://www.utilitydive.com/news/duke-southern-plan-path-for-southeast-energy-imbalance-market/581556.

9. Chen, pp. 24-32. https://nicholasinstitute.duke.edu/publications/evaluating-options-enhancing-wholesale-competition-and-implications-southeastern.

FIGURE 2: REGIONAL TRANSMISSION ORGANIZATIONS



SOURCE: Federal Energy Regulatory Commission.

These markets are run by Regional Transmission Organizations (RTOs), which are independent, largely nonprofit organizations responsible for transmission grid reliability, planning and operation.[10] RTOs have a number of features to help ensure that generation, demand-side resources and energy storage can fairly compete, and thus promote efficiency and reduce system costs. First, RTOs independently operate the transmission system on behalf of their transmission-owning members. Second, RTO markets are independently monitored for market power abuses and manipulation. Finally, federally regulated RTOs are governed by boards that are independent of any market participants. Roughly two-thirds of the United States are currently served by RTOs, as shown in Figure 2 above.

Because RTOs operate the transmission system within their own footprints, they can optimize the entire system using sophisticated market architecture to meet customer demand with a wider array of energy resources. RTOs schedule the least-cost resources a day in advance and dispatch them over five-minute intervals. Transactions are settled on the same timeframe to ensure that prices reflect the value of energy within those intervals.[11] This incentivizes resource-owners to adjust their output over these times periods.

Overview of Energy Imbalance Markets

As shown in Figures 3 and 5 below, utilities in the non-RTO West are joining energy imbalance markets (EIMs), which leverage neighboring RTOs' existing platforms to allow limited, voluntary, real-time energy trades without becoming RTO members.

An EIM is an energy market operated by an RTO that allows utilities outside of the RTO limited, real-time trade.[12] The RTO running the EIM manages dispatch, transmission congestion, pricing and settlement associated with running a real-time energy imbalance market. All other grid operator functions are retained by the participating utilities.

EIMs do not require the participating utility to join an RTO, which would require conveying operational control of their transmission systems. Utilities that participate in an EIM are typically vertically integrated and retain control over their own systems.[13] These utilities satisfy their own customer energy needs first and then, through the EIM, transact any excess energy or meet demand at lower cost. The utilities can allow a redispatch of generation to meet their commitments, including bilateral trades. They can also ensure that certain generators are limited or not re-dispatched. Participants can offer reserved transmission service for EIM transfers in advance, and closer to real-time, unscheduled transmission capacity is made available for EIM transfers.[14]

An EIM leverages the RTO's existing architecture to optimize system-wide efficiency to reduce costs. It also leverages the RTO's status as an independent entity and its market monitoring. Thus, an EIM can be a cost-effective way for

10. Devin Hartman, "Federal Power Act and Organized Electricity Markets," *R Street Electricity 101 Series* No. 1, August 2016, p. 2. https://www.ourenergypolicy.org/wp-content/uploads/2016/12/Electricity1-5.pdf. Note: Except for the Electric Reliability Council of Tex-as (ERCOT), RTOs are regulated by the Federal Energy Regulatory Commission. This paper refers to RTOs and Independent System Operators (ISOs) as simply RTOs, as the distinction is irrelevant to the present discussion.

11. Federal Energy Regulatory Commission (FERC), *Order No. 825: Settlement Intervals and Shortage Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators*, June 16, 2016. https://www.ferc.gov/sites/default/files/2020-05/settlement825.pdf.

12. Chen, pp. 8-18. https://nicholasinstitute.duke.edu/publications/evaluating-options-enhancing-wholesale-competition-and-implications-southeastern.

13. "Western EIM FAQ," California Independent System Operator, December 2019. https://www.caiso.com/Documents/EnergyImbalanceMarketFAQs.pdf.

14. See, e.g., "Extending the Day-Ahead Market to EIM Entities," p. 3. http://www.caiso.com/InitiativeDocuments/IssuePaper-ExtendedDayAheadMarket.pdf.

a utility to achieve some of the benefits of an RTO, while retaining its autonomy. However, the downside to only trading real-time energy imbalances is their relatively small volumes. Typically, only about 5 percent of all energy transactions in RTOs are scheduled in the real-time market, and the rest are scheduled a day ahead.[15] Thus, the percentage of energy transactions met by the EIM could be even smaller.

An EIM produces transparent prices every five minutes at each node on the grid. These "locational marginal prices" can inform operational and investment decisions in generation transmission or newer, flexible resources like demand response and energy storage. Locational marginal prices reflect the incremental cost of operating the marginal resource on the transmission system—plus any additional, marginal costs caused by transmission constraints and line losses, which are location-specific and can vary widely across the system.[16] In contrast, the bilateral SEEM market does not produce a single market clearing price and would not be able to provide the same quality of information as locational marginal prices.

The shorter, five-minute dispatch intervals can produce prices that incentivize flexible generation and demand to quickly bring the system into balance. Separately, shorter lead times up to these intervals, during which generators schedule their bids, allow them to account for better information available closer to real-time and reduce the reserves needed due to uncertainty. These shorter dispatch and scheduling intervals reduce renewable integration costs.[17]

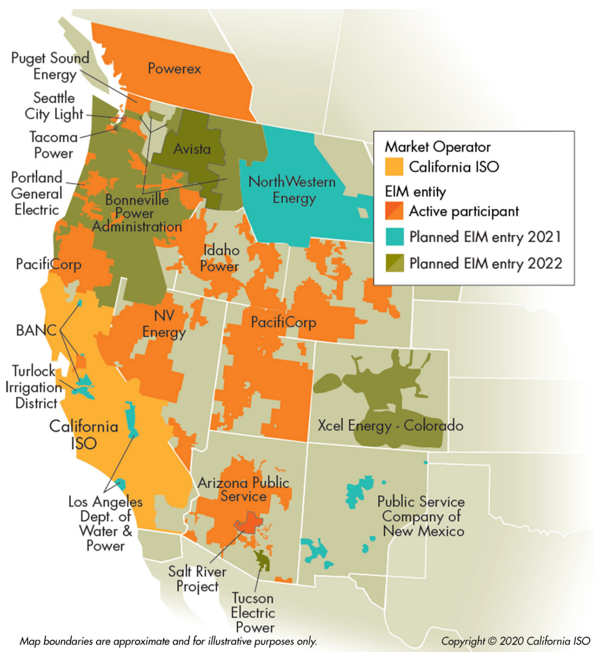
Additionally, granular pricing information by location and generator dispatch enables grid operators to identify and mitigate transmission congestion, thus helping to increase use of transmission assets. Similarly, an EIM can manage real-time changes, such as a sudden outage, by dispatching resources within five-minute cycles. The tools used to run the EIM will enable operators to have better awareness of grid conditions and improved ability to address reliability issues.[18]

The amount costs and emissions can be reduced depends on the diversity of supply and load, and the level of voluntary participation. For example, the Western EIM operated by the California Independent System Operator (CAISO) includes a resource mix of low-cost but variable wind and solar, hydro that can help store excess generation and customer demand for renewable, emissions-free resources driven by state climate policy. This diversity and broader geographic footprint help balance the system at lower cost, including lower curtailments of zero-marginal cost generation and reduced reserve requirements. Further, good governance, transparency and a system that is independently operated and monitored may provide confidence for regulators, investors and participants that the market offers a fair competitive field.

CAISO's Western EIM

The CAISO began operating its Western EIM in 2014 and includes more than 20 current and prospective utilities.[19] Collectively, these entities serve over 75 percent of the load in the Western Electricity Coordinating Council.[20]

FIGURE 3: CURRENT AND PLANNED PARTICIPANTS IN CAISO'S WESTERN EIM



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Utilities must own transmission to join because the EIM relies on its members sharing available transmission without additional transmission fees. Thus, generation-only

15. See, e.g., FERC, *Energy Primer*, U.S. Dept. of Energy, April 2020, p. 62. https://www.ferc.gov/sites/default/files/2020-06/energy-primer-2020_0.pdf; "Letter to Chair Linvill and EIM Governing Body from EIM Participants," Sept. 16, 2019, p. 1. http://www.caiso.com/Documents/PublicCommentLetter-EIMEntites-EDAM-Sep16-2019.pdf.

16. See, e.g., "FAQs: Locational Marginal Pricing," ISO New England, last accessed Aug. 10, 2020. https://www.iso-ne.com/participate/support/faq/lmp.

17. Bird et al., pp. 4-6. https://www.nrel.gov/docs/fy13osti/60451.pdf.

18. "Federal Energy Regulatory Commission staff paper: Qualitative Assessment of Potential Reliability Benefits from a Western Energy Imbalance Market," FERC, Feb. 26, 2013. http://www.caiso.com/Documents/QualitativeAssessment-PotentialReliabilityBenefits-WesternEnergyImbalanceMarket.pdf.

19. Western Energy Imbalance Market (WEIM), "About," California Independent System Operator Corp., last accessed Aug. 8, 2020. https://www.westerneim.com/Pages/About/default.aspx.

20. Western EIM, "Western EIM Benefits Report Third Quarter 2019," CAISO, Oct. 29, 2019, p. 19. https://www.westerneim.com/Documents/ISO-EIMBenefitsReportQ3-2019.pdf.

companies, such as renewables developers, would need to schedule through an EIM participant to gain access to the market. It is up to the EIM participant whether it will facilitate another company's participation.

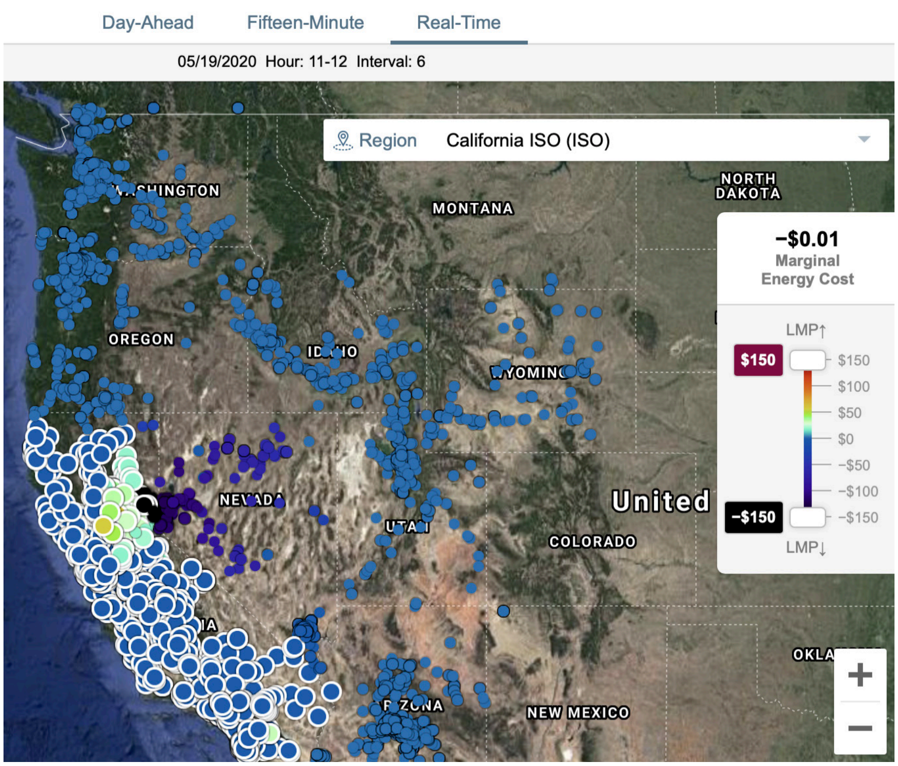
The Western EIM currently balances supply and demand over five- and 15-minute intervals while respecting bilateral contracts.[21] It may also add a day-ahead market.[22] Actual gross benefits have reached $1 billion for the Western EIM from its start in November 2014 through July 3, 2020.[23]

Avoided renewables curtailment can reduce emissions by displacing fossil-fired generation. The total avoided renewable curtailment since 2015 is estimated at 1,246,404 megawatt-hours, equivalent to 533,381 metric tons of CO_2.[24] The Western EIM saved its participants 47-54 percent of the amount of flexible ramping capacity they would have needed individually.[25]

Day-ahead scheduling across a larger footprint can improve efficiency from better coordinated unit commitment and increased diversity and renewables integration benefits. Production cost savings for the day-ahead market have been estimated at $119–$227 million per year, depending on the level of participation.[26]

Figure 4 below shows a snapshot of prices at each node on the map. The prices reflect the short-term marginal cost of energy, given system constraints. These prices are thus reasonable approximations for the short-term marginal value of energy, and utilities are starting to use them for applications like time-of-use rate design.[27]

FIGURE 4: REAL-TIME ENERGY PRICES IN WESTERN EIM



SOURCE: CAISO Market Price Maps. *Licensed with permission from the California ISO. Any statements, conclusions, summaries or other commentaries expressed herein do not reflect the opinions or endorsement of the California ISO.*

21. "About." https://www.westerneim.com/Pages/About/default.aspx.

22. "Extending the Day-Ahead Market to EIM Entities." http://www.caiso.com/InitiativeDocuments/IssuePaper-ExtendedDayAheadMarket.pdf.

23. "Benefits," Western Energy Imbalance Market (EIM), last accessed Aug. 8, 2020. https://www.westerneim; Western EIM, "Western EIM Benefits Report: Second Quarter 2020," CAI-SO, July 29, 2020, p. 18. https://www.westerneim.com/Documents/ISO-EIMBenefitsReportQ2-2020.pdf.

24. Western EIM, "Western EIM Benefits Report: Second Quarter 2020," CAISO, July 29, 2020, p. 18. https://www.westerneim.com/Documents/ISO-EIMBenefitsReportQ2-2020.pdf .

25. Ibid., p. 21.

26. "Extended Day-Ahead Market Feasibility Assessment—Update from EIM Entities," EIM Entities, Oct. 3, 2019, p. 18. https://www.caiso.com/Documents/Presentation-ExtendedDay-AheadMarketFeasibilityAssessmentUpdate-EIMEntities-Oct3-2019.pdf.

27. See, e.g., "Direct Testimony of Robert M. Meredith," The Public Service Commission of the State of Utah, Docket No. 20-035-04, May 2020, pp. 16, 34 and 50. https://www.rockymountainpower.net/content/dam/pcorp/documents/en/rockymountainpower/rates-regulation/utah/filings/docket-20-035-04/05-08-20-application/15_Meredith_Testimony_and_Exhibit.pdf.

TABLE I: ESTIMATED AND ACTUAL UTILITY SAVINGS IN JOINING CAISO WESTERN EIM

Region	Study	Projected Benefits in Millions $	Actual Cumulative Gross Benefits in Millions $
PacifiCorp	Energy and Environmental Economics, "PacifiCorp-ISO Energy Imbalance Market Benefits," March 13, 2013. https://www.westerneim.com/Documents/PacifiCorp-ISOEnergyImbalanceMarketBenefits.pdf.	2017 gross dispatch savings: $16.4-$40.8 Including flexibility reserves and renewable curtailment savings, total 2017 gross savings: $21-$129.	$251.55 (since November 2014)
NV Energy joins EIM (w/ CAISO & PacifiCorp)	Energy and Environmental Economics, "NV Energy-ISO EIM Economic Assessment," March 25, 2014. https://www.westerneim.com/Documents/NV_Energy-ISO-EnergyImbalanceMarketEconomicAssessment.pdf.	2017 savings: $7.8. Incremental 2017 benefits to other 2 utilities: $6.0.	$99.12 (since December 2015)
Arizona Public Service joins EIM (w/CAISO, PacifiCorp and NV Energy)	Energy and Environmental Economics, "APS Energy Imbalance Market Participation: Economic Benefits Assessment," April 2015. https://www.westerneim.com/Documents/ArizonaPublicService-ISO-EnergyImbalanceMarketEconomicAssessment.pdf	Dispatch efficiency savings for APS $8.9/year (2020). APS also saved $1.0-$3.2 in flexibility reserves. Dispatch savings for other 3 utilities: $1.4/year.	$157.98 (since October 2016)
Puget Sound joins EIM (w/ CAISO, PacifiCorp and NV Energy)	Energy and Environmental Economics, "Benefits Analysis of Puget Sound Energy's Participation in the ISO Energy Imbalance Market," September 2014. https://www.westerneim.com/Documents/PugetSound-ISO_EnergyImbalanceMarket-BenefitsAnalysis.pdf	2020 gross dispatch savings: $17.6. $9.1/year in balancing costs for external wind resources. $0.8/year in renewable curtailments. Incremental savings to other 3 utilities: $3.5-$4.2/year.	$46.07 (since October 2016)
Portland General joins EIM (w/CAISO, PacifiCorp, NV Energy and Puget)	Energy and Environmental Economics, "PGE EIM Comparative Study: Economic Analysis Report," Nov. 6, 2015. https://edocs.puc.state.or.us/efdocs/HAD/lc56had152028.pdf	2020 gross benefits: $2.7 from sub-hourly dispatch. $0.8 on flexibility reserves. Incremental savings to other 4 utilities: $2.7-$3.7.	$89.35 (since October 2017)

NOTE: All data in the Actual Cumulative Gross column is from "Benefits," Western Energy Imbalance Market, June 2020. https://www.westerneim.com/Pages/About/QuarterlyBenefits.aspx.

Utilities' EIM experiences have produced benefits that exceed their estimated costs of joining. For example, the Arizona Public Service (APS) cost-benefit analysis for joining the Western EIM estimated that sub-hourly dispatch savings (compared to relying on bilateral trades on an hourly basis) and savings in flexibility reserves would range from $7 to $18 million annually. In fact, APS' actual gross savings have been much higher at about $34 million in 2017, $45 million in 2018 and $54 million in 2019.[28] The APS estimated implementation to cost $13-$19 million, including metering upgrades, software for communications with the EIM and settlements, business process changes and tariff changes. The ongoing costs, estimated at $4 million annually, included software license renewal, staffing for EIM-related roles, and fees to the CAISO for running and managing the EIM.[29] Additional examples on the estimated and actual utility savings generated by joining the CAISO Western EIM are detailed in Table 1 above.

SPP's Western Energy Imbalance Service Market

The Southwest Power Pool (SPP), which became an RTO in 2004, operated an energy imbalance service in its Eastern Interconnection footprint from 2007 until 2014, when that EIM was incorporated into a full energy market.[30] The minimum qualifications for an RTO include a market mechanism for congestion management, which can be provided by running an imbalance service.[31] The EIM participants estimated their energy usage and submitted a schedule of when they were going to operate each generator. Prices were calculated every five minutes, averaged to hourly settlement prices and reflected the incremental cost of delivering energy to specific locations.[32] This EIM produced about $173 million in net benefits annually from 2007 to 2013.[33] The SPP expanded its market in 2014 to include day-ahead energy and operating reserves, and saw a total savings of $2.7 billion over the first five years.[34]

28. "Benefits." https://www.westerneim.com/Pages/About/QuarterlyBenefits.aspx.

29. Brad Albert, "Letter RE: Energy Imbalance Market: Integrated Resource Planning," Arizona Corpo-ration Commission, Docket No. E-00000V-13-0070, April 17, 2015, p. 4. https://images.edocket.azcc.gov/docketpdf/0000161758.pdf.

30. See, e.g., Nathania Sawyer and Les Dillahunty, *The Power Relationships: 75 Years of SPP South-west Power Pool* (Southwest Power Pool, 2016), p. 124. https://www.spp.org/documents/46282/spp-75th-anniversary-online.pdf; "Integrated Marketplace," SPP, last accessed Aug. 8, 2020. https://www.spp.org/markets-operations/integrated-marketplace; "Western Energy Imbalance Service Market (WEIS)," SPP, last accessed Aug. 8, 2020. https://www.spp.org/weis.

31. FERC, *Order No. 2000: Regional Transmission Organizations*, Dec. 20, 1999. https://ferc.gov/sites/default/files/2020-06/RM99-2-00K_1.pdf.

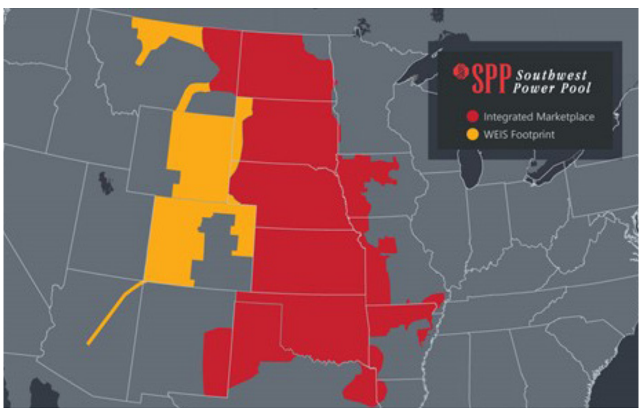
32. Sawyer and Dillahunty, p. 123. https://www.spp.org/documents/46282/spp-75th-anniversary-online.pdf.

33. "SPP Western Energy Imbalance Service Market (WEIS) Overview," SPP, Nov. 11, 2019, p. 7. https://www.wapa.gov/regions/DSW/Rates/Documents/SPP%20WAPA%20DSW%20Presentation%2011-12-19.pdf.

34. Derek Wingfield, "As it turns five, Southwest Power Pool's Integrated Marketplace is saving billions and enabling big changes in energy dispatch," Press Release, Feb. 28, 2019. https://www.spp.org/newsroom/press-releases/as-it-turns-five-southwest-power-pool-s-integrated-marketplace-is-saving-billions-and-enabling-big-changes-in-energy-dispatch.

Now, the SPP is launching the Western Energy Imbalance Service Market (WEIS) to centrally dispatch energy every five minutes for participating utilities in the Western Interconnection starting in early 2021.[35] The WEIS will leverage available transmission capacity in the market footprint at no additional charge to participants.[36] Utilities do not have to become members of the SPP RTO to participate. Each utility will be responsible for the generation needed to meet its obligation to balance their customer demand with resources in their footprints.[37] Basin Electric Power Cooperative, Tri-State Generation and Transmission Association, Wyoming Municipal Power Agency, Municipal Energy Agency of Nebraska, Western Area Power Administration (including WAPA Colorado River Storage Project, WAPA Rocky Mountain Region and WAPA Upper Great Plains Region) and Deseret Power Electric Cooperative have announced they are joining the SPP's new contract service.[38] Figure 5 below shows this combined footprint.

FIGURE 5: COMBINED FOOTPRINTS OF UTILITIES JOINING SPP'S PROPOSED EIM



SOURCE: Western Energy Imbalance Service Market (with permission to use from SPP). https://spp.org/weis.

The SPP filed its proposal with the FERC earlier this year. However, it recently rejected the proposal "without prejudice," and offered guidance on how the SPP can address its concerns about transmission usage, resource adequacy and other issues in a modified proposal.[39] The SPP plans to refile.

Regulatory Approvals and Governance

Rules that govern wholesale electricity rates are within the FERC's jurisdiction, and utilities that wish to join the EIM must seek FERC approval. Utilities that seek to recover costs from ratepayers—including costs borne to join and participate in an EIM—require state public utility commission approval.[40]

Good governance can help ensure transparency and a fair playing field, which are important to build confidence in a market platform and attract participation. Additionally, good governance can facilitate input from stakeholders and help align public utility actions with the public interest and policy goals. For example, RTO processes are evaluated based on their inclusiveness, fairness in balancing diverse interests, representation of minority positions and ongoing responsiveness.[41]

The Western EIM is governed by a five-member Governing Body with delegated authority from the CAISO Board of Governors on rules specific to EIM participation.[42] The EIM Governing Body can advise the Board of Governors on other rules involving CAISO's real-time market.[43] Members are nominated by a committee of stakeholders including transmission owners, publicly owned utilities, suppliers and marketers of generation and energy service providers, state regulators, the EIM Governing Body, the CAISO Board of Governors and public interest and consumer advocacy groups.[44] The latter three participate in committee discussions but do not vote. The committee attempts to nominate candidates with a diverse range of expertise and geographic backgrounds.

The Western EIM's Body of State Regulators is a forum on developments relevant to state responsibilities.[45] It consists of one commissioner from each state public utility commis-

35. See, e.g., "Western Energy Imbalance Service Market." https://spp.org/weis; Derek Wingfield, "SPP proposes Western Energy Imbalance Service Market to bring cost savings and grid modernization to the west," Press Release, June 17, 2019. https://spp.org/newsroom/press-releases/spp-proposes-western-energy-imbalance-service-market-to-bring-cost-savings-and-grid-modernization-to-the-west.

36. Christopher M. Nolen, "Letter RE: Southwest Power Pool, Inc., Docket Nos. ER20-1059-000 and ER20-1060-000, Submission of Western Energy Imbalance Service Market Tariff, Western Joint Dis-patch Agreements, and the Western Markets Executive Committee Charter," SPP, Feb. 21, 2020, pp. 18-19. https://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=15468364.

37. "A Proposal for the Southwest Power Pool Western Energy Imbalance Service Market," SPP, last accessed Aug. 3, 2020, pp. 5-8. https://www.spp.org/documents/60104/a%20proposal%20for%20spp's%20western%20energy%20imbalance%20service%20market.pdf.

38. "Western Energy Imbalance Service Market." https://spp.org/weis.

39. FERC, *Order on Proposed Tariff*, Docket Nos. ER20-1059, ER20-1060, July 31, 2020.

40. See, e.g., The Public Service Commission of Utah, *Report and Order: PacifiCorp dba Rocky Mountain Power 2014 General Rate Case*, Docket No. 13-035-184, Aug. 29, 2014. https://pscdocs.utah.gov/electric/13docs/13035184/26006513035184rao.pdf.

41. FERC, *Order No. 719: Wholesale Competition in Regions with Organized Electric Markets*, Oct. 17, 2008. https://ferc.gov/sites/default/files/2020-06/OrderNo.719.pdf.

42. Jennifer Rotz, "Selection Policy for the EIM Governing Body (as adopted)," CAISO, Nov. 28, 2016, p. 2. https://www.westerneim.com/Documents/SelectionPolicy_EIMGoverningBody.pdf.

43. "Charter for Energy Imbalance Market Governance," CAISO, March 27, 2019, p. 3. https://www.westerneim.com/Documents/CharterforEnergyImbalanceMarketGovernance.pdf.

44. Rotz, pp. 2-3. https://www.westerneim.com/Documents/SelectionPolicy_EIMGoverningBody.pdf.

45. Western EIM, "Body of State Regulators," CAISO, last accessed Aug. 3, 2020. https://www.westerneim.com/Pages/Governance/EIMBodyofStateRegulators.aspx.

sion in which a load-serving utility participates in the market. The Body may express a common position in the CAISO stakeholder process or to the EIM Governing Body on EIM issues. Its members are not restricted from taking any position before the FERC or any other forum concerning EIM or CAISO matters.

The Western EIM Governance Review Committee (GRC) is a temporary advisory group that will identify refinements to the EIM governance structure reflecting the evolution of the EIM, including potential governance changes if a day-ahead market is added.[46] The GRC's proposed revisions will be considered by the EIM Governing Body and the CAISO Board of Governors.

The SPP will establish a Western Markets Executive Committee (WMEC) comprised of representatives from each non-affiliated participant.[47] The WMEC will have authority to approve or reject proposed EIM tariff amendments, provide consultation to the SPP on the administrative rate charged to participants and recommend proposed amendments to the participant agreement. The SPP's independent board of directors will provide oversight of the SPP's administration of the EIM, however, they will give significant recognition to the WMEC's decision-making role. Any WMEC action or inaction may be appealed to the SPP Board of Directors for final resolution.

A Standalone EIM

Southeastern utilities could join an EIM offered by a neighboring RTO without having to join that RTO. Doing so would leverage the existing market expertise, and the hardware and software of an RTO, and thus would reduce the startup and implementation costs of a market. The RTO's market monitor can also monitor the EIM. Alternatively, Southeastern utilities could potentially form and operate an EIM, but they would have to recruit expert staff and build hardware and software, which are likely to incur more costs than leveraging the architecture and staff expertise of an existing RTO. Further, EIM participation requires utilities to share potential commercially sensitive data with the EIM operator. This has not been a concern for RTO-operated EIMs as they are independent from market participants, but could be an issue if a participating utility also operates the market. Without an independent operator, certain utilities may be in a better position to exercise market power. The FERC has emphasized independence as a bedrock principle for RTOs, ISOs and transcos.[48] While a standalone EIM is not any of these entities, it is apparent that independence—both real and perceived—is important to the FERC.

LESS-STRUCTURED WHOLESALE TRADING AGREEMENTS

The non-RTO Southeast has a number of trading arrangements between utilities, but volumes are low and virtually all physical sales are done bilaterally. Price data is therefore scarce, and the Intercontinental Exchange—a leading power brokerage platform—does not provide a financial product in the Southeast.[49] Price data can help regulators determine whether customers are indeed paying for lowest-cost generation, and whether investments other than what cost-of-service utilities are proposing are the most cost-effective.

Southern Company holds auctions for day-ahead and hour-ahead energy within the Southern Balancing Authority Area. Its website states that: "The purpose of the energy auction is to resolve perceptions that Southern Company could exercise horizontal market power through the physical or economic withholding of generation."[50] To mitigate potential market power abuse, Southern Company must offer all of its available uncommitted, thermal generation capacity into the auction after reserve requirements are met.[51] The auction is not an automated trading platform. Rather, it matches parties to facilitate bilateral transactions by sorting offers in ascending order and bids in descending order.[52] While the auction has an independent administrator, its role is largely bookkeeping, and Southern Company is the official operator.[53] In 2015, the FERC launched a section 206 investigation because auction activity had been sparse since its inception in 2009.[54] The website posts average hour-ahead purchases

46. Western EIM, "Governance Review Committee," CAISO, last accessed Aug. 3, 2020. https://www.westerneim.com/Pages/Governance/GovernanceReviewCommittee.aspx.

47. "Western Markets Executive Committee Charter," SPP, May 15, 2020, p. 4. https://spp.org/documents/61046/wmec%20charter%2020200515.pdf.

48. *Order No. 2000: Regional Transmission Organizations*, p. 193. https://ferc.gov/sites/default/files/2020-06/RM99-2-00K_1.pdf.

49. See, e.g., *Energy Primer*, p. 71. https://www.ferc.gov/sites/default/files/2020-06/energy-primer-2020_0.pdf; Chen, p. 20. https://nicholasinstitute.duke.edu/publications/evaluating-options-enhancing-wholesale-competition-and-implications-southeastern.

50. "General Auction Information," Southern Company, last accessed Aug. 3, 2020. https://www.southerncompany.com/about-us/energy-auction/general-auction-information.html.

51. *Energy Primer,* p. 71. https://www.ferc.gov/sites/default/files/2020-06/energy-primer-2020_0.pdf.

52. Alabama Power Company, "Rules of the Energy Auction," Southern Company, Feb. 2, 2017, §§ 5.4-6.5. https://www.southerncompany.com/content/dam/southern-company/pdf/energyauction/Rules-of-the-Energy-Auction-MBR-Tariff.pdf.

53. Alabama Power Company, "Rules on Southern Companies' Energy Auction Participation," Southern Company, Feb. 2, 2017, §§ 2.1A and 2.1B. https://www.southerncompany.com/content/dam/southern-compa-ny/pdf/energyauction/Participation%20Rules%20of%20the%20Energy%20Auction%20with%20Appendices%20MBR%20Tariff.pdf.

54. See, e.g., FERC, *Order on Updated Market Power Analysis, Instituting Section 206 Proceeding and Establishing Refund Effective Date*, April 27, 2015, pp. 7-8. https://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=13854842; FERC, *Order Accepting Market-Based Rate Tariff Revisions Subject to Condition*, Feb. 2, 2017, p. 18. https://elibrary.ferc.gov/IDMWS/common/opennat.asp?fileID=14482652.

and sales a day after the transactions. However, for most days of the year, the auction does not report any transactions.[55] Its market monitor performs limited functions compared to independent market monitors for RTOs who are tasked to identify ineffective market rules and recommend proposed fixes.[56] Nearly all of the data is redacted in the public version of the energy auction monitoring report.[57]

Southern Company also operates a power pool among its affiliates Georgia Power, Alabama Power and Mississippi Power.[58] The main function is to centrally dispatch excess resources—except for conventional hydro and nuclear power—beyond that needed for each utility to serve its own customers. These resources are obtained through bilateral transactions and thus energy prices and volumes are determined through contracts in advance. The centralized dispatch schedules resources according to variable costs rather than generator bids, subject to constraints and obligations across the region. Transactions are hourly—compared to every five minutes for RTOs and EIMs.[59]

Joint dispatch agreements exist between a number of utilities in non-RTO regions. Duke Energy Carolinas and Carolina Power & Light (now Duke Energy Progress) agreed to jointly dispatch some generation as a condition to the merger of Duke Energy and Progress Energy.[60] Duke Energy Carolinas dispatches the companies' generation resources to meet customer demand subject to reliability, contractual requirements and transmission constraints.[61] Payments are settled hourly.[62] The estimated cost-savings from joint dispatch of generation were $364.2 million from 2012 through 2016, and improved practices for fuel procurement and use were estimated to save $330.7 million over the same five-year period.[63]

As proposed, the SEEM is a step up from how energy is currently traded in the Southeast, but the projected net savings appear to be small compared to the net benefits utilities have reaped through EIMs. As modeled, SEEM is anticipated to save 0.35-0.40 percent of total production costs regionally in the base case. That amounts to projected savings between $37-46 million in 2022, $43-$54 million in 2027, $41-$50 million in 2032 and $44-$55 million in 2037. In a carbon-constrained scenario, the savings increase over time, beginning with $56-$70 million in 2027 and reaching $117-$146 million in 2037. These projections exceed estimated costs, which are about $5 million in startup costs and $0.750-$3 million in annual costs region-wide.[64] In comparison, a 2005 study performed by the same consultancy to weigh the costs and benefits of SPP establishing an EIM found a 2.5 percent savings in annual production costs. The SPP in 2005 was about 40 gigawatts, and the net benefits were estimated to be $373 million to the transmission owners over the ten-year study period.[65] There was no carbon-constrained scenario in the SPP study, and 2005 was before the buildout of wind took off in the SPP. With a fleet of potentially 170 gigawatts, the SEEM could be more than four times larger than the SPP in 2005.[66] The savings from the SEEM are thus diluted over a larger system. To the extent that these two systems—both consisting of vertically integrated utilities with significant fleets of baseload generation—may be compared, the projected net benefits from the 2005 study of SPP's EIM were higher on a per- gigawatt basis by a factor of three. Note that joining an existing EIM would be less costly than building a new one, as modeled in the SPP study, and thus the net benefits would be even greater.

CONCLUSION

The benefits to enhanced trading between utilities and resource sharing across broader regions can be substantial.[67] Current regulatory constructs and voluntary trading mech-

55. See, e.g., Southern Company, "Announcement," Press Release, Feb. 21, 2017. https://www.southerncompany.com/about-us/energy-auction/announcement.html; "Auction Clearing Prices," Southern Company, last accessed Aug. 3, 2020. https://www.southerncompany.com/about-us/energy-auction/auction-clearing-prices.html.

56. See, e.g., "Rules on Southern Companies' Energy Auction Participation," § 3.3. https://www.southerncompany.com/content/dam/southern-compa-ny/pdf/energy-auction/Participation%20Rules%20of%20the%20Energy%20Auction%20with%20Appendices%20MBR%20Tariff.pdf; *Order No. 719: Wholesale Competition in Regions with Organized Electric Markets*, pp. 3-4. https://ferc.gov/sites/default/files/2020-06/OrderNo.719.pdf.

57. See, e.g., The Brattle Group, "Tenth Annual Informational Report of the Independent Auction Mon-itor," Southern Company, June 28, 2019, pp. 4-5, 8, 9, Appendices B, C. https://www.southerncompany.com/content/dam/southern-company/pdf/energyauction/Informational-Report-2019-PUBLIC.pdf.

58. Charles D. Long, "Southern Company System Intercompany Interchange Contract" Southern Com-pany, May 18, 2007, p. 1. https://www.southerncompany.com/content/dam/southern-company/pdf/energyauction/Intercompany-Interchange-Contract-5-18-07.pdf.

59. Ibid., pp. 12, 23.

60. See, e.g., Duke Energy Corp. and Progress Energy, Inc., 139 FERC ¶ 61, 193 (2012); *Order denying reh'g*, 151 FERC ¶ 61, 242 (2015); *Order on remand, Orangeburg, S. Carolina v. FERC*, 862 F.3d 1071 (D.C. Cir. 2017); *Order on remand*, 166 FERC ¶ 61, 112 (2019); Duke Energy Corp. and Progress Energy, Inc., "Joint Dispatch Agreement Between Duke Energy Carolinas, LLC Carolina Power & Light Company," 2011. https://dms.psc.sc.gov/Attachments/Matter/f01eecfc-f7e6-482e-b733-d02df9f63335.

61. Duke Energy, 151 FERC ¶ 61, 242, p. 12.

62. "Joint Dispatch Agreement Between Duke Energy Carolinas, LLC Carolina Power & Light Company," pp. 7–10.

63. State of North Carolina Utilities Commission, "Order Approving Merger Subject to Regulatory Con-ditions and Code of Conduct," *In the Matter of Application of Duke Energy Corporation And Pro-gress Energy, Inc., to Engage in a Business Combination Transaction and to Address Regulatory Conditions and Codes of Conduct*, Docket Nos. E-2, SUB 998, E-7, SUB 986, pp. 17, 30. https://dms.psc.sc.gov/Attachments/Matter/0db7d38b-155d-141f-2376ec5bc8152322.

64. "Southeast EEM Benefits and Non-Centralized Costs," Guidehouse/Charles River Associates, July 6, 2020.

65. Ellen Wolfe et al., "Cost-Benefit Analysis Performed for the SPP Regional State Committee," Charles River Associates, April 23, 2005 (revised July 27, 2005), p. IX. https://www.efis.psc.mo.gov/mpsc/commoncomponents/viewdocument.asp?DocId=935666601.

66. Downey. https://www.bizjournals.com/charlotte/news/2020/07/17/duke-energy-partners-local-control-for-se-market.html.

67. Chen, pp. 24-32. https://nicholasinstitute.duke.edu/publications/evaluating-options-enhancing-wholesale-competition-and-implications-southeastern.

anisms in the Southeast have not significantly encouraged developments to enhance efficiency through trade or overcome barriers to it. Thus, trading volumes remain low, risk of generation overbuild is high and, as the resource-mix evolves to include more variable generation, utilities that attempt to balance their systems will miss the savings that a larger, more flexible grid offers.

The discussion among Southeastern utilities to implement a voluntary energy exchange is encouraging, and the regional scope of these utilities is impressive. Based on what is known about the limited centralized control and governance of the Southeast Energy Exchange Market, it could be an improvement on the status quo, but will not reap most of the benefits of an EIM or RTO. Looming questions remain about the magnitude of net benefits that can be expected. Details on costs savings, avoided renewables curtailment, emissions reductions and price transparency would help. Another big question is whether market power concerns can be sufficiently mitigated if there is no truly independent entity operating the system.

If utilities wish to trade on a voluntary basis, the EIM is a model with quantified success, and leveraging the market platform of an existing RTO could be less costly than setting up a new market or exchange. The Western EIM allows participants to set aside transmission in advance—but does not require it—and can rely on transmission that is unreserved and available in real time.

Factors for EIM success in cost and emissions reduction include a footprint with a diversity of resources and customer demand, as well as energy storage that helps avoid curtailing zero-marginal-cost energy. Leveraging existing market architecture and expertise can help contain costs. Centralized market operation can help optimize the system at the granularity of five-minute dispatch and settlement intervals, increase the flexibility of the system and enhance reliability by improving visibility, optimizing resources for dynamic conditions and coordinating dispatch. The level of market participation and transmission availability are also key.

Good governance and the ability to operate the system independently of market participants may also help inspire confidence in the platform and attract participants. The governance framework for the Western EIM has not slowed the steady stream of utilities volunteering to join. Participating utilities have done the analyses and determined that the benefits are worth accepting a governance framework to ensure that the system works for everyone.

ABOUT THE AUTHORS

Jennifer Chen is a senior fellow in the Electricity Policy division of the R Street Institute. Her work focuses on the state-federal electricity nexus, transmission policy, and the governance and expansion of organized wholesale electricity markets.

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BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-100, SUB 171

In the Matter of:	)	**PETITION OF THE NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION, SIERRA CLUB, AND THE SOUTHERN ALLIANCE FOR CLEAN ENERGY FOR INVESTIGATION AND RULEMAKING TO IMPLEMENT N.C. GEN. STAT. § 62-154**
Petition for Investigation and Rulemaking	)	
to Implement N.C. Gen. Stat. § 62-154	)	
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Exhibit E

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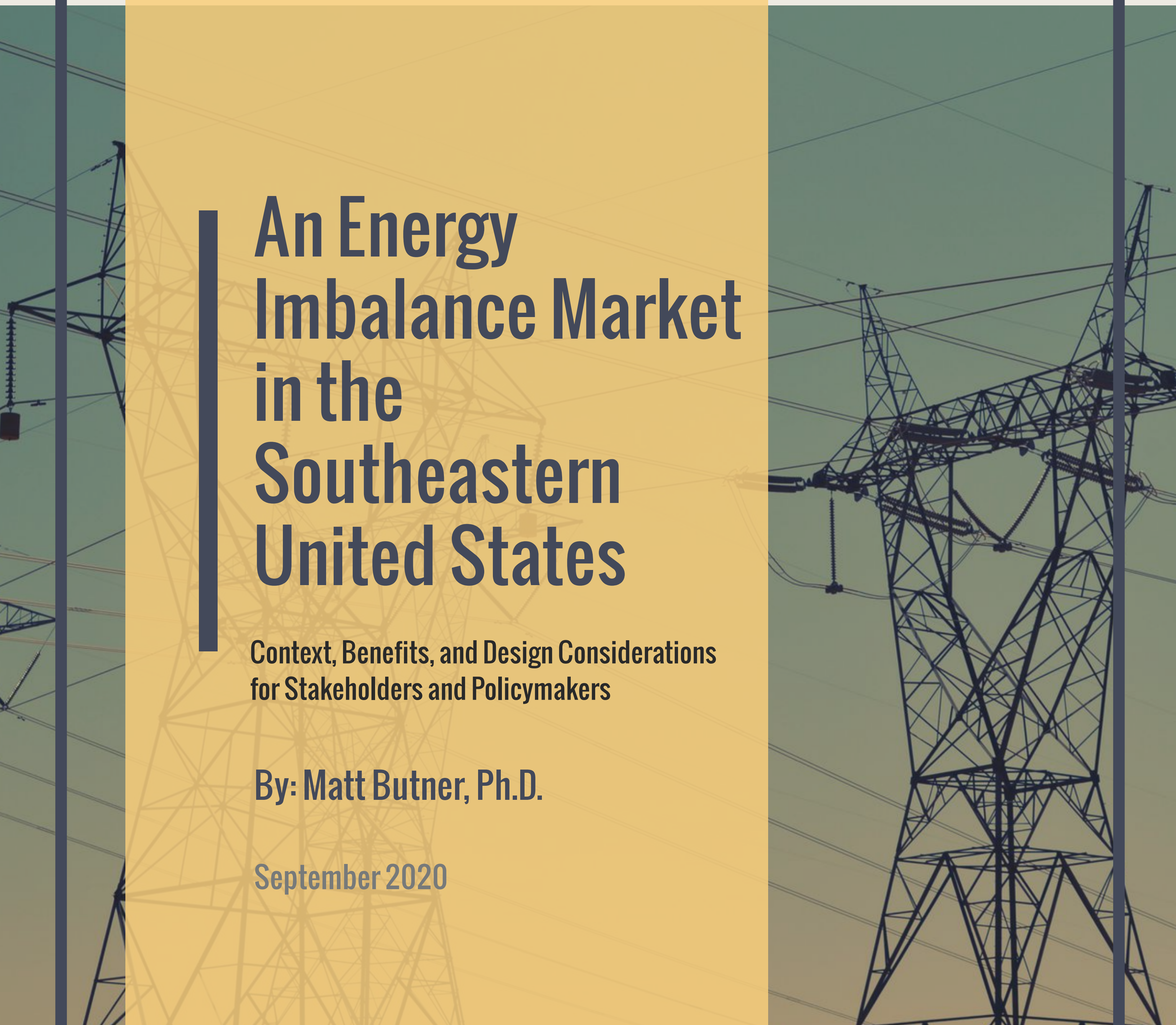

An Energy Imbalance Market in the Southeastern United States

Context, Benefits, and Design Considerations for Stakeholders and Policymakers

By: Matt Butner, Ph.D.

September 2020

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Executive Summary

Over the past twenty years, organized wholesale electricity markets have demonstrated unambiguous success in coordinating electricity production across utilities over large geographic areas in the United States. Despite the clear benefits of organized markets, however, the Southeast remains a bastion of the traditional organization of electricity production characterized by long-term contracts, bilateral trades, and a lack of competition. This organizational structure can result in inefficient and inflexible operations that are costly to customers and unyielding to the ongoing energy transition towards variable renewable energy resources.

This report establishes the case for an **Energy Imbalance Market** (**EIM**)—a voluntary wholesale electricity market operating in real-time—in the Southeastern United States. While a more comprehensive and widely implemented Regional Transmission Organization (RTO) may ultimately be optimal for the Southeast, an EIM is a straightforward, low-cost first step toward a more efficient and flexible electricity grid that can be achieved without structural reform.

Perhaps most importantly, a traditional EIM is likely to identify more cost-saving opportunities and better balance renewable generation than existing proposals for energy market reform in the Southeast—namely, the proposed **Southeast Energy Exchange Market** (**SEEM**). Specifically, the modeling conducted in this report estimates that an EIM could save $100–600 million annually to Duke Energy alone, which encompasses approximately 40 gigawatts of generating capacity. In contrast, SEEM is projected to save around $40–50 million annually across its full territory, encompassing four times the generating capacity of Duke Energy.

In summary, this report establishes the following:

- **Every region of the United States except the Southeast has some real-time energy market that dispatches electricity using a Security Constrained Economic Dispatch algorithm**. These markets, including EIMs and those carried out by RTOs, generate significant benefits by identifying the least-cost reliable way of generating electricity to balance supply and demand.

- **An EIM offers three primary benefits over the Southeast's status quo:**
    - *Economic benefits* of production cost savings realized by mutually beneficial trades of electricity in real-time amongst participating utilities.
    - *Environmental benefits* of better integration and reduced curtailment of low-cost, zero-carbon renewable energy generation.
    - *Reliability benefits* of enhanced situational awareness, automated response to energy shortfalls, and reserve shaving that reduces the costs of balancing supply and demand.

- **The economic benefits of an EIM in the Southeast can be large.** This report uses an open-source dispatch model to quantify the potential economic benefits of an EIM to Duke Energy Carolinas and Duke Energy Progress (hereafter Duke Energy). Modeling results show Duke Energy could have avoided $100 million to $600 million in production costs in 2018 if it fully participated in an EIM. A large portion of the production cost savings is realized in a small number of hours, when the cost to produce electricity in Duke's footprint is greatest.

- **The recently proposed SEEM has the potential to provide some, but not all, of the benefits of a well-designed EIM.**
  - SEEM's fundamental market design—an "exchange-based" market that automates bilateral transactions—is unlikely to realize the production cost savings of an EIM.
  - SEEM should embrace the best available practices in electricity market design, including transparent price signals, location-based pricing, 5-minute dispatch, stakeholder representation, and independent market monitoring. It remains unclear whether SEEM includes some, or any, of these practices.

- **A Southeastern EIM operated by PJM is likely the best EIM option for North Carolina.**
  - The simulations in this report show Duke Energy would have realized the largest cost savings if it had been a part of an EIM including all Carolina utilities and PJM.

- **State regulators and legislators have an important role to play in encouraging the formation of, and participation in, a well-designed EIM.**
  - Both Carolina legislatures should pass bills that explore the benefits and costs of electricity market reform. In this analysis, both an RTO and an EIM should be considered.
  - Policymakers can encourage Carolina utilities to establish a Memorandum of Understanding (MOU) with PJM to explore the costs and benefits of a Southeastern EIM, much like the PacifiCorp-CAISO MOU that established the Western EIM.

- **Recent proposed legislation in the Carolinas and discussions of SEEM indicate that the Southeast is ready for electricity market reform.** When moving forward with this process, it is important that all of the region's relevant stakeholders have the opportunity to evaluate the options available. As shown in this report, economic theory on electricity market design and demonstrated success of existing electricity markets can help inform the process.

Table of Contents

Tables and Figures

I. Introduction

"Trade makes everyone better off" and "markets are usually a good way to organize economic activity" are not just textbook concepts.[1] Applying these principles to the electric power sector in the Southeastern United States can better integrate renewable generation, improve reliability, and save ratepayers hundreds of millions of dollars per year.

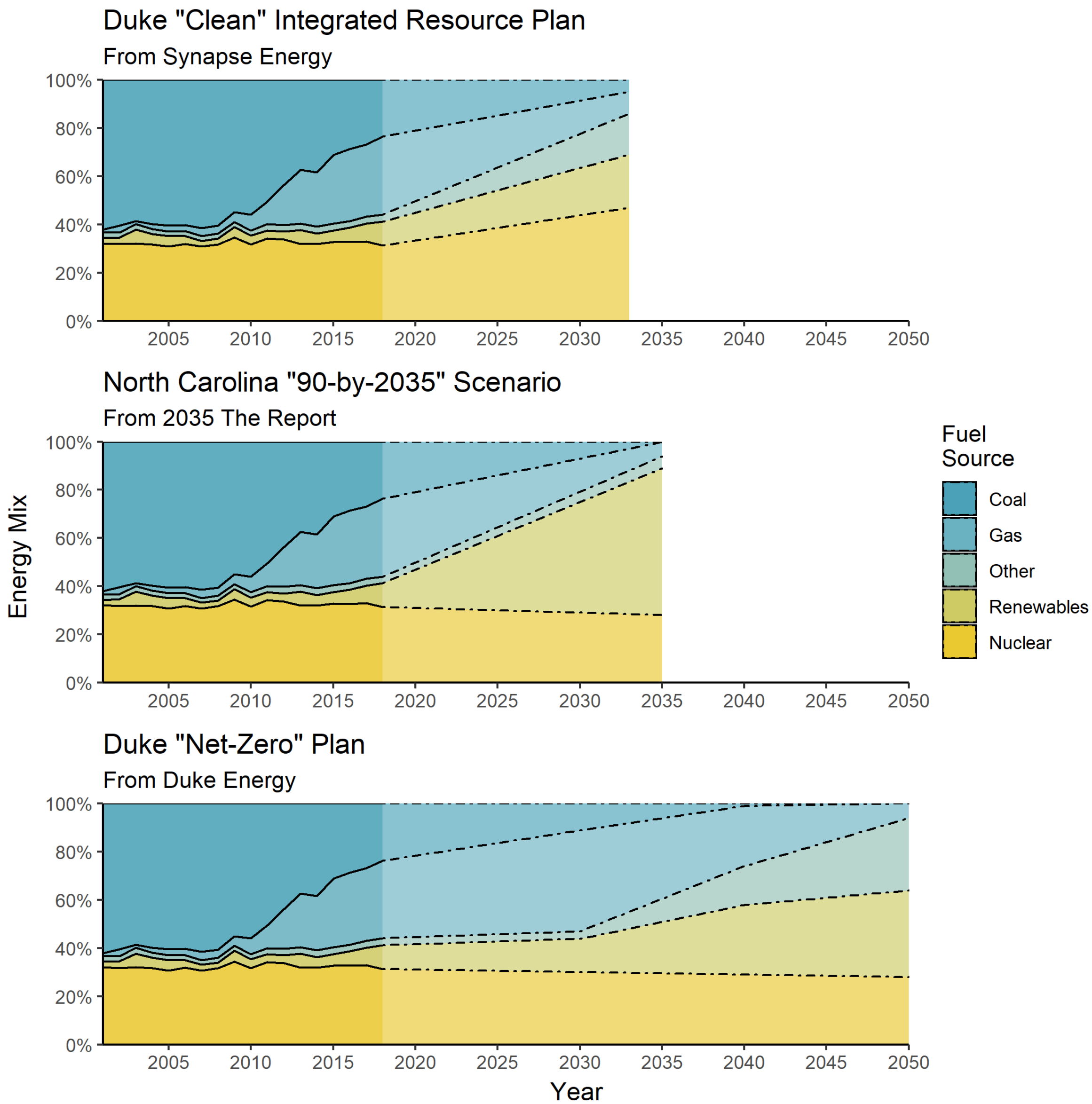
Over the past twenty years, Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs) have collectively generated billions of dollars in annual economic benefits while overseeing a majority of the electricity produced in the United States.[2] Fundamentally, these organizations operate markets that facilitate beneficial trades of electricity—especially during periods of high demand or shortfalls of supply—using well-established technologies and algorithms. Despite the evidence showing the benefits of organized wholesale electricity markets operated by RTOs, the Southeastern United States has been laggard in embracing basic economic principles.

This report makes the case for an Energy Imbalance Market (EIM) in the Southeastern United Sates as a way to increase trade between utilities, better integrate renewable generation, and enhance reliability. An EIM is not as comprehensive as the more widely implemented RTO, and is unlikely to generate benefits of similar magnitude.[3] However, an EIM can be straightforward to implement, preserves the authority of state policymakers, and maintains resource adequacy. Perhaps most importantly, a well-designed EIM can realize more cost-saving opportunities and better balance renewable generation than the recently proposed Southeast Energy Exchange Market (SEEM).

Enhanced coordination of electricity production is now more important than ever, as declining costs of solar, wind, and battery resources—and a pressing need to mitigate the harms of climate change—are prompting a technology-driven transition in the electric power sector. With more renewable generation, electricity generators must respond to more weather-based fluctuations in the imbalance between supply and demand. A wholesale electricity market over a wide geographic area can reduce the overall variability of this imbalance, and more efficiently respond to sudden fluctuations in electricity production in real-time. These features of a wholesale market reduce curtailment and the cost of integrating renewable generation. With anticipated growth of renewable generation in North Carolina's future, as show in **Figure 1**, reforms to the organization of electric power should be pursued to maximize the benefits renewables provide and reduce the cost of the transition.

This report proceeds as follows. To lend context, section II provides an abridged background on the organization of the electric power sector while highlighting some of the most common arrangements over the past century. Section III provides a comprehensive discussion of an EIM in the Southeast, including its basic operations, how it compares to existing institutions, its potential benefits, and how it compares to alternative reforms. Of particular note, this section reports the results from a simulation exercise that quantifies the benefits of increased trade that would have accrued to Duke Energy in 2018. Section IV enumerates considerations for the design of an EIM or similar energy market in the Southeast, including market scope and market design. Section V concludes.

Figure 1 – Future Fuel Mix in North Carolina (or Duke Energy).



Four future scenarios, all showing an increased share of electricity generated by renewable generaiton. The top two plots are alternatives to Duke Energy's Integrated Resource Plan with the goal of reducing greenhouse gas emissions and minimizing production costs, respectively. The third plot shows the North Carolina specific fuel mix from a modeling exercise that achieves 90% carbon-free electricity by 2035 while reducing energy costs and generating jobs. The bottom plot shows Duke Energy's plan to achieve net-zero annual greenhouse gas emissions by 2050. See, in order from top to bottom, NCSEA initial comments on NC PUC DOCKET NO. E-100, SUB 157 Attachement 1 at 6 (2019); NRDC comments on NC PUC DOCKET NO. E-100, SUB 157 Attachment 1 at 6 (2019); Amol Phadke et al., 2035 The Report Technical Appendix, at 49 (2020); Duke Energy, 2020 Climate Report, at 26, (2020).

II. The Organization of the Electric Power Industry

A. Traditional Organization of Electricity Production

In the earliest days of electric power, companies providing electricity were invariably vertically integrated—owning and operating all generation, transmission, and distribution assets. This was because the act of electricity transmission and distribution was perceived to be inseparable from electricity production. As a result of vertical integration, and improvements in larger steam engine technology, electricity benefitted from economies of scale; a single large company could produce the same electricity at a lower cost than several smaller, competing companies.

Samuel Insull of Commonwealth Edison famously identified this "natural monopoly" problem of electric power, [4] which left unchecked will lead to the classic problems of a monopolist: prices, quantities, and quality of electricity divergent from what is economically efficient.[5] As a solution, Insull championed regulation.[6] Under regulation, vertically integrated utilities would be granted monopoly rights and a guaranteed profit so long as public regulators had oversight over the utility's investment decisions and pricing practices.

Electricity prices declined over the first half of the century, as economies of scale were realized, however the vertically integrated monopoly-utility structure is not without its imperfections.[7] In particular, insular electric power companies guaranteed a profit do not have the economic incentive to seek out the gains from trade espoused in economic principles, nor do they face the forces of competition that require them to be mindful of their cost.[8] As a result, under the traditional organization of electricity production, utilities operated as balkanized entities, each separately producing electricity to achieve the complex balance between supply and demand within their own "balancing areas." Outside of Power Pool arrangements (discussed below), utilities under the traditional organization of electricity production would trade electricity only through long-run bilateral contracts or joint ownership arrangements if at all.

B. A Movement Towards Markets

The vertically integrated monopoly utility paradigm was predominant throughout most of the twentieth century. In the late 1980s, however, it became subject to scrutiny for several reasons. First, economic research began to make clear the potential inefficiencies of insular vertically integrated utilities.[9] At the same time, other industries (like rail, trucking, and air-travel) were a promising success after undergoing regulatory reform. Finally, and perhaps most importantly, lower natural gas prices, large capacity investments, and technological improvements created a divergence between the average price of electricity (paid by retail customers) and the marginal price of electricity (determined by the wholesale price of electricity). As a result, retail electricity customers felt overcharged for electric power, and called for reform so that they could benefit more directly from low marginal cost electricity.[10]

During the late 1990s and early 2000s – nearly a century after Samuel Insull advocated for the traditional organization of electric power – reform rippled across the U.S. electric power sector as State and Federal regulators imposed changes to the organization of electric power.[11] Jointly characterized as "restructuring," these reforms included (*i*) the forced divestiture of electricity generation assets owned by vertically-integrated utilities, (*ii*) the creation of competitive retail markets for consumers to choose their service provider, and (*iii*) the encouragement towards—and formation of—open-access, organized markets for the wholesale trade of electricity.[12] Of these three reforms, the formation of open-access, organized markets for wholesale electricity has stood out as being the most successful in realizing economic efficiencies to date.[13]

The basic idea justifying an organized wholesale electricity market is straightforward. The natural-monopoly character of the electric sector is confined to transmission and distribution service, which continues to be most efficiently provided by a single market participant. For at least several decades, electric generation has not had the characteristics of a natural monopoly. On the contrary, competition in the generation sector can reliably deliver large cost savings to ratepayers relative to monopoly supply. Fortunately, the economic model for generation can be readily separated from that for transmission and distribution service.[14] So, for example, a transmission system operated by an impartial third party can serve as a platform where electricity generators owned by vertically integrated utilities or independent power producers can compete to sell electricity to utilities and electricity retailers across a large geographic footprint.

C. The RTO Paradigm

Organized electricity markets can take many different forms. In the US, they have been predominately implemented as part of RTOs in compliance with FERC Order 2000. An RTO is a non-profit organization that oversees the wholesale electricity grid in its footprint, and is best described by its FERC-codified minimum characteristics and functions, listed in **Table 1**. Of particular note, an RTO is characterized by independence from market participants, appropriate geographic scope, transmission operational authority, and exclusive authority over short-term reliability.

Table 1 – Characteristic and Functions of an RTO established by FERC Order 2000.

Minimum Characteristics of an RTO:	Minimum Functions of an RTO:
1. Independence from market participants 2. Appropriate scope and regional configuration 3. Possession of operational authority for all transmission facilities under RTO control 4. Exclusive authority to maintain short-term reliability of the grid	1. Tariff administration and design 2. Congestion management 3. Management of parallel path flow 4. Provision of ancillary services 5. Development of Open Access Same-time Information System (OASIS) 6. Market monitoring 7. Planning and expansion of facilities under its control

In general, the goal of an organized electricity market is to provide "reliable electricity at least cost to consumers."[15] RTOs carry out a number of activities to achieve this goal. The core of an RTO's short-run operations is the day-ahead and real-time energy market.[16] In both markets, the market operator collects information on every electricity generator's willingness to produce electricity (offers), every load serving entity's willingness to pay for electricity (bids), and several other factors including transmission congestion and the weather. The market operator uses all of this information to solve a complex but well-established algorithm to identify the least-cost way to reliably balance the supply and demand of electricity in real-time.

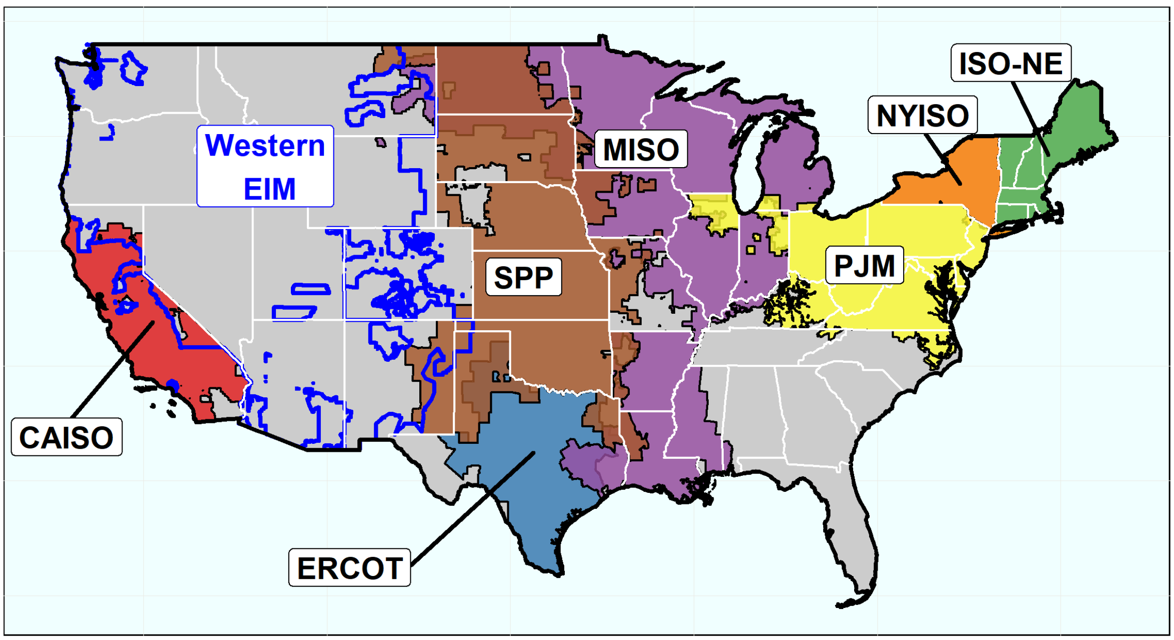
In the day-ahead market, the market operator jointly determines which electricity generators should operate (unit-commitment) and how much they should produce (dispatch) the following day. In the real-time market, the market operator resolves the dispatch problem based on the most up-to-date information including changes to electricity generators' offers and load serving entities' bids. Both markets determine dispatch by solving a Security Constrained Economic Dispatch (SCED) problem, typically every five minutes [17]

In general, SCED identifies the least-cost electricity generator by creating a "merit-order," which ranks all energy resources from low cost to high cost according to their offers.[18] The RTO dispatches the least-cost resources first, while also respecting transmission and electricity generator constraints. Every five minutes, the price for electricity is set by the last (marginal) energy resource producing electricity. Prices vary geographically by "node" according to the marginal cost of electricity, transmission congestion, and transmission losses. After the market clears, the settlement process compensates electricity generators the nodal price near them, and charges utilities the nodal price for the electricity they consume.

Other activities overseen by an RTO include ancillary services markets and congestion management in the short-run, and transmission and capacity planning in the long-run. The design of these features varies; however, they are all designed with the same goal of low-cost, reliable electricity.

Today, seven organized wholesale electricity markets have formed in the United States as RTOs, including the ISO New England (ISO-NE), New York ISO (NYISO), Southwest Power Pool (SPP), Midcontinent Independent System Operator (MISO), Electricity Reliability Council of Texas (ERCOT), PJM, and California Independent System Operator (CAISO). **Figure 2** maps the footprint of every organization that solves out the SCED problem, including the seven RTOs and the Western EIM.

Figure 2 – Map of Centralized Dispatch Energy Markets in the United States.



Map of Balancing Authority Areas of RTOs and Planned Members of the Western EIM. The extent of each Balancing Authority Area is defined by Homeland Infrastructure Foundation-level Data.

Figure 2 highlights the lack of an RTO (or EIM) in the Southeastern United States. Although several RTOs were independently proposed by utilities in the region to comply with FERC Order 2000, none of the proposals were ever implemented. [19] FERC commissioners first expressed concern over the lack of independence of the RTOs operations from major utilities in the area, and then later over limited geographic scope of the proposals.[20] Ultimately, drawn-out mediation amongst utilities, frustration by state regulators, and the coincident California electricity crisis led every proposal to a dead end.[21]

i. Demonstrated Benefits of an RTO

Over the past twenty years, RTOs have demonstrated immense benefits to their stakeholders, including electricity customers and utilities. The magnitude of the benefits provided by RTOs cannot be ignored. For example, PJM and MISO each quantified their annual benefit to exceed $3 billion.[22] While RTOs do have an administrative cost structure, the benefit they provide more than compensates.[23] This section outlines the benefits of an RTO for context, and in comparison to some of the alternative arrangements. In general, the benefits of an RTO include the following:

1. **Production Cost Savings:**
   Production cost savings from an RTO represent realized efficiencies along two channels: (1) *system efficiencies*, enhancing "the coordination and use of multiple plants," and (2) *plant-level efficiencies,* leading to "lower cost or higher availability at a particular plant."[24] A comprehensive retrospective analysis of the expansion of electricity markets across the United States estimates production cost savings average 5% of total production costs.[25] This number varies in application and is specific to the resources being integrated and the market design. Estimates generally range from 3 to 11%.[26] Overall, production cost savings represent roughly 10 to 20% of the self-identified benefits of RTOs.[27]

2. **Avoided Capacity Investments**:
   An organized electricity market, like an RTO, makes it easier for utilities to purchase wholesale electricity during periods of peak demand instead of using their own more expensive power plants built for that same purpose. This generates benefits to ratepayers through enhanced reliability and prevents redundant capital investments in generation capacity. This benefit increases with RTO size, as it pools electricity generators and combines diverse demand pattern. In addition, some RTOs organize competitive markets for generation capacity that can provide additional benefits if properly designed. This is the largest self-reported benefit of RTOs, accounting for 30 to 60% of total benefits.[28]

3. **Renewable Integration:**
   RTOs enhance the coordination of electricity generators, and so allow them to better respond to variable renewable generation and at a lower cost. In addition, the large geographic footprint of RTOs reduces variability of renewable generation in proportion to demand. Ultimately, an organized electricity market like an RTO reduces wasteful curtailment of renewable generation, and can minimize the cost of integrating variable renewable generation. In MISO, where there is a large amount of wind generation, the production cost savings from better integration of renewables provide RTO stakeholders with nearly half a billion dollars of benefits per year.[29]

4. **Grid Services:**
   Grid services maintain the stability and reliability of the transmission grid. RTOs ensure the adequate provision of grid services, including market-based mechanisms to provide ancillary services and congestion management. Although essential, especially as more renewable generation is added, grid services make up only a small share of an RTO's self-reported monetized benefits.[30]

5. **Reliability Through Transmission Planning and Management**:
   The transmission network is governed by economies of scale – it is much more efficient to build a single transmission network than many small ones providing the same level of service. This implies coordination of electricity transitions over a large geographic area, like an RTO, and can provide cost savings and identify potential efficiencies. Some RTOs serve as Transmission Planning Regions in compliance with FERC Order 1000.[31] Through a stakeholder process, RTOs plan transmission expansion in the context of their existing market for energy.[32] This transmission planning provides stakeholders with improved reliability and reduced congestion costs.[33]

D. Non-RTO Real-time Energy Arrangements

A wholesale electricity market, or market-like arrangement, need not be an RTO to provide some or all of the benefits outlined above. An RTO is simply the approach prescribed by FERC in Order 2000.[34] This section discusses other organized energy markets, or market-like arrangements, that promote mutually beneficial transactions between utilities in real-time. Although not as comprehensive as RTOs, these arrangements still provide some of the same benefits.

i. Power Pool

Soon after the traditional organization of electricity production was established, the benefits of coordinating the production of electricity among utilities became apparent. In 1927, three utilities formed what is now the PJM RTO as the first Power Pool after "realizing the benefits and efficiencies" of coordinating electricity production.[35]

A Power Pool is the most limited departure from the traditional organization of electricity markets. In this arrangement, multiple utilities come together to form an agreement on how to generate electricity and interchange power according to a pre-determined set of rules. In effect, this arrangement operates like a multilateral contract between all member utilities, similar to a cooperative. It can be thought of as a market insofar as the negotiations between member utilities that set the prices and terms by which trade occur are market-like.

A Power Pool is operated by an administrator whose goal is to ensure reliable, low-cost electricity is provided to cooperating utilities while also adhering to the Power Pool's rules. Some use centralized dispatch according to electricity generators' reported costs and availability (known as a "tight Power Pool," similar to a joint-dispatch agreement amongst all utilities). Others involve private bilateral transactions (on diverse contractual terms) between member utilities with varying terms (a "loose Power Pool").[36] The challenges accompanying a Power Pool include establishing membership and exit fees, rates for service, and participant-specific stipulations. Although a Power Pool can foster mutually beneficial trades between member utilities, there is no guarantee the operations are economically efficient.

Throughout the US, Power Pools have played a historically important role in the organization of electricity markets. Sometimes these arrangements have been steppingstones to the establishment of a more formal RTO, as in the case of PJM, SPP, ISO-NE, and NYISO, ERCOT.[37]

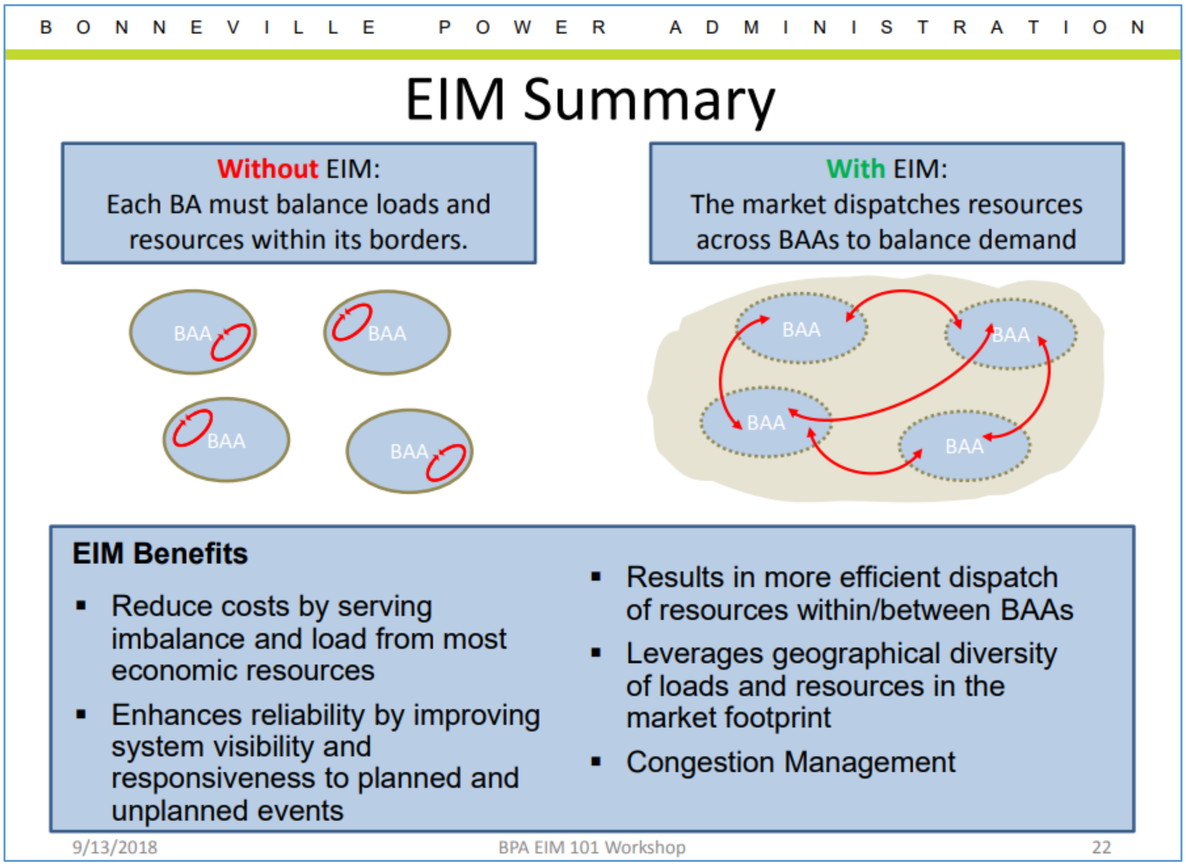
ii. Energy Imbalance Market (EIM)

An EIM is a voluntary real-time energy market that optimizes the imbalance of supply and demand of participating utilities using a centralized dispatch algorithm, typically at granular time intervals (every five minutes). In contrast to an RTO – the parameters of which were established by FERC Orders 888 and 2000 – the characterizations of an EIM in this report are based largely on past implementations. In its most basic form, an EIM consists of only the real-time energy market component of an RTO – finding the lowest cost resources to securely balance supply and demand in real-time using SCED. A summary of an EIM, and the benefits it provides, are shown in **Figure 3.** More details on this energy market are described in the next section.

Two EIMs have existed in the United States. In 2007, SPP implemented the first EIM, referred to as an Energy Imbalance Service, as an evolutionary step towards a more comprehensive RTO. More recently, SPP has reintroduced the Energy Imbalance Service as the Western Energy Imbalance Service, with the prospect of incorporating utilities to the west of its footprint.[38] Already, a number of utilities and cooperatives have signed on in anticipation of the market's launch in February 2021.[39]

The Western EIM, formed by CAISO in 2013, serves as the leading model of an EIM's potential. By enhancing the coordination of electricity generating resources over a large area, the Western EIM has generated over $1 billion in economic benefits to date.[40] Perhaps most salient is the Western EIM's ability to integrate variable generation. Since 2015 the Western EIM has prevented over 1,000 GWh of renewable energy curtailment, mitigating nearly 550,000 metric tons of climate-warming carbon dioxide.[41]

Figure 3 – Summary and Benefits of an EIM.



Source: Bonneville Power Authority supra note 53 at 22. In this figure "BA" stands in for Balancing Authority and "BAA" stands in for Balancing Authority Area.

iii. Energy Exchange Market (EEM)

An Energy Exchange Market (EEM) is an organized electricity market that automates bilateral transactions between utilities.[42] Like an RTO, the market operator collects information from participating utilities on their willingness to buy and sell electricity in real-time. The operator then uses all the information available to match buyers and sellers, facilitating gains from trade over any unscheduled transmission capacity. Unlike an RTO, an EEM does not carry out a system-wide optimization through SCED. Instead, the positions of individual energy traders are relied upon to identify production cost and savings and more efficient grid operations.

In the late 1990s, when organized electricity markets were first being designed in the US, there was a "raging" debate as to whether this exchange-based model or an "integrated" approach (using SCED) could best achieve least-cost reliable electricity.[43] In a simple economic model, both options can provide similar benefits. However, the electric power sector is complex.[44] Optimizing electricity production in real-time requires a sophisticated approach. Well-established, state-of-the-art optimization models now available to market operators suggest an integrated approach that solves

SCED has compelling advantages compared to an exchange-based one.[45] This is because the algorithms used by an integrated market can effectively identify the lowest-cost way to generate electricity while also handling the number of constraints of the electricity grid, like transmission access and congestion.[46] The integrated approach allows for dispatch to be jointly optimize with other features of the electricity grid that are important (like balancing reserves and unit commitment), is simpler for market participants, and supports competition through transparency.[47]

This exchange-based approach is more common in Europe than North America, where integrated markets have become the standard design.[48] Only one exchange-based market operates in the United States. Southern Company, the utility managing electric power in much of Georgia, Alabama, and some of Florida and Mississippi, facilitates real-time bilateral transactions through a platform called Southern Wholesale Energy.[49] Recently-proposed SEEM appears to be a similar exchange-based market.[50]

III. Overview of an Energy Imbalance Market in the Southeast

This section further details an EIM. It begins by outlining an EIM's operations and organizational structure. It then characterizes the existing institutions in the Southeast for context, before discussing the potential benefits of an EIM in depth. This includes a quantification of potential production cost savings, and a description of renewable integration and enhanced reliability. Finally, an EIM is compared to alternative reforms including a Southeastern RTO and what is known about the recent SEEM proposal.

A. Organization and Operations of an EIM

Hourly EIM operations are similar to the real-time market in an RTO. As an example, the Western EIM operated by CAISO includes a real-time market that clears every fifteen minutes and gives dispatch orders to electricity generators every five minutes. Seventy-five minutes before each 15-minute market, each utility must report to the market operator its "base schedule" and the economic bids of participating generators for that market. A utility's base schedule represents it plan to balance its own supply and demand within its balancing area; therefore, participation in an EIM does not necessarily alter a utility's approach to ensuring short-term resource adequacy.[51]

The economic bids of participating generators represent how much the parent utility is willing to increase or decrease the generator's output, and the market price the utility requires for it to do so.[52] The market operator uses the economic bids to find alternative ways to balance supply and demand relative to the base schedule. The Western EIM performs a number of "resource sufficiency tests" an hour before each 15-minute market to ensure no utility is relying too much on the EIM to balance supply and demand.[53]

Importantly, the dispatch outcome can differ from each utility's base schedule, as any participating electricity generator can be called upon to balance supply and demand in other balancing authorities – generating cost savings over other utilities' base schedule. Like an RTO's real-time market, settlement happens after the market clears. Each utility charged (or compensated) for the location-based market price and the quantity of electricity consumed (or produced) relative to their base schedule.

These real-time transactions can happen in parallel to long-run contracts, as illustrated in **Figure 4**. Suppose an electricity generator (Gen 1) has a contract to produce 100 MW power. If it participates in an EIM, and some other resource can produce the electricity more cheaply, the market operator will tell Gen 1 to reduce its output to the minimum possible amount while still remaining online. The cheaper electricity generator effectively serves the contract and is compensated the market price, while the more expensive electricity generator still receives the contract payment, but must buy electricity from the market to satisfy its contract. In this simple example, Gen 1 receives all of the benefits in the form of avoided production costs. Consumers would ultimately benefit if the production cost savings experienced by Gen 1 would reduce the retail rate for electricity.[54]

Figure 4 – Long Run Contracts in an EIM.

Production Cost and Bilateral Contracts in an EIM

Generator and Load Characteristics

Gen 1	
Production Cost	$40/MWh
Minimum Output	5 MW
Maximum Output	100 MW

Gen 1 has a long-term contract with Load A for 100 MW at $50/MWh

Gen 2	
Production Cost	$20/MWh
Minimum Output	5 MW
Maximum Output	100 MW

Load A	
Demand	100 MW
Willingness to Pay	$60/MWh

Outcomes with Bilateral Contracts

Gen 1 Contract Settlement Generates 100 MWh			
Revenue		Costs	
Contract	$5,000	100 MWh	$4,000
Profit: $1,000			

Gen 2 Contract Settlement Generates 0 MWh			
Revenue		Costs	
-	-	0 MWh	0
Profit: $0			

Load A Contract Settlement Consumes 100 MWh			
Benefit		Costs	
Contract	$6,000	100 MWh	$5,000
Net Benefits: $1,000			

Contract Net Benefits: $2,000

Outcomes with an EIM

Gen 1 EIM Settlement Generates 5 MWh			
Revenue		Costs	
Contract	$5,000	5 MWh	$200
		Market	$1,900
Profit: $2,900			

Gen 2 EIM Settlement Generates 95 MWh			
Revenue		Costs	
Market	$1900	95 MWh	$1900
Profit: $0			

Load B EIM Settlement Consumes 100 MWh			
Benefit		Costs	
Contract	$6,000	100 MWh	$5,000
Net Benefits: $1,000			

EIM Net Benefits: $3,900

A simple example showing how an EIM reduces production costs relative to bilateral contracts.

Utilities can elect to join an existing EIM or work to establish a new one.[55] The EIM itself is carried out by an independent not-for-profit organization—typically an RTO,[56] although a stand-alone EIM not connected to any RTO is feasible. In the case of the Western EIM, a utility joins the EIM after a formal process that includes cost-benefit analysis, training, and an implementation agreement.[57] The cost-benefit analysis component is crucial, as it allows utilities to consider both the potential benefits (and costs) under a number of alternative future scenarios.[58] This analysis so far has shown increasing benefits over time that outweigh the initial and ongoing costs.[59]

The market operator's actions are dictated by a "tariff" specifying the market rules.[60] In a traditional EIM, the tariff is established through a stakeholder process or by the EIM board, and ultimately approved by FERC. The standard governance structure of an EIM is based on the governance structure of an RTO, which values independence and stakeholder representation. The Western EIM governance structure, for example, consists of an EIM Governing Body of independent non-stakeholder members, an EIM Body of State Regulators to advise the EIM Governing Board, and a Regional Issues Forum for the general public to share opinions with the EIM Governing Board.[61]

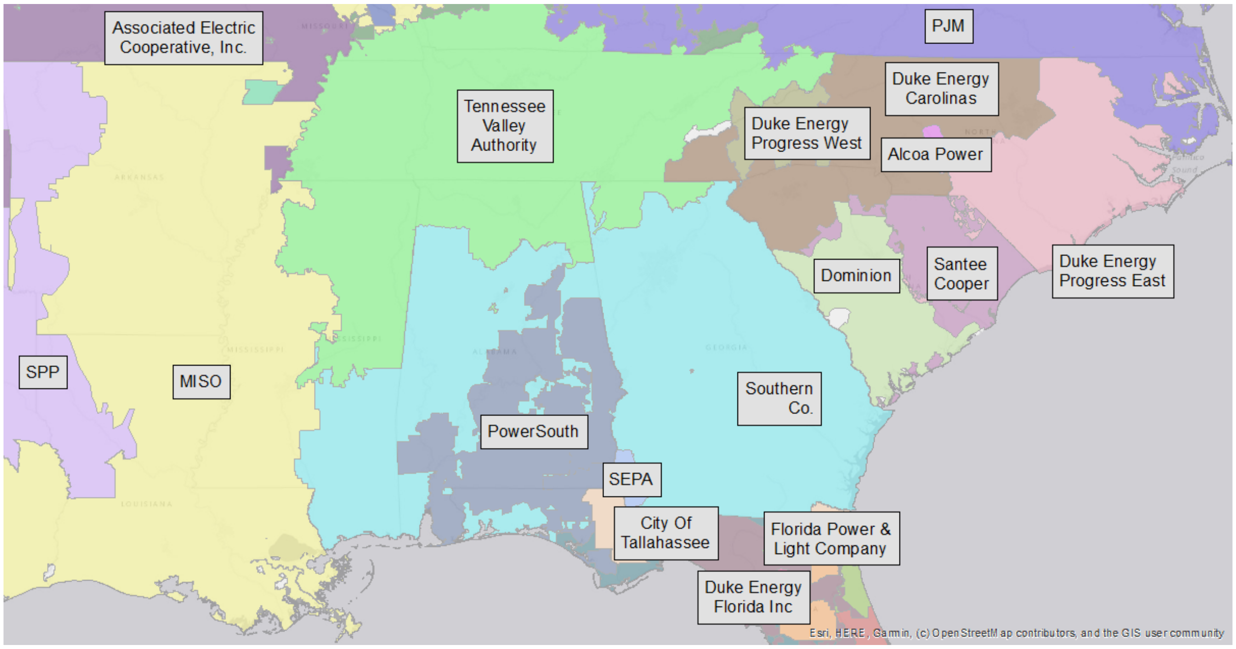
B. An EIM Compared to Existing Institutions in Southeast

The benefits of an EIM, in terms of encouraging cost-saving transactions between utilities in the Southeast, depend in part on the current level of trade. If utilities in the Southeast are already trading electricity when it is economically efficient and adequately accommodating fluctuations in renewable resource production, an EIM might not provide many incremental benefits. Aware of the benefits of trade, utilities in the Southeastern United States already exchange wholesale power. However, relative to the rest of the United States, the Southeast is characterized by less trade on average.[62]

In general, it is difficult to gauge whether or not electricity is traded efficiently because the details of bilateral transactions are often not publicly available. However, nearly all physical electricity sales in the region are done bilaterally, and so it is unlikely the production cost savings of large-scale joint-dispatch are being realized. [63] Further, of the trade that does occur, "long-term energy transactions are particularly prominent, compared to short-term transactions."[64] This suggests the short-run minute to minute balancing that is essential for the integration of variable renewable generation is not occurring at the level that is economically optimal.

Figure 5 shows a detailed map of utilities in the Southeastern United States. Although Duke Energy Carolinas (DEC) and Duke Energy Progress East/West (DEP, formerly Progress Energy Carolina) are technically separate subsidiaries of the Duke Energy, they carry out a joint dispatch agreement as a condition of their merger – effectively encouraging trade between the subsidiaries. The benefits provided by the joint dispatch are similar in nature to the production cost savings realized by an EIM. At the time of the merger, the joint dispatch agreement was anticipated to generate more than $70 million annually in consumer benefits on average.[65] This trade is especially beneficial given the extent of solar development in DEP, which can be exported and stored in pumped-hydro power plants available in DEC.

Figure 5 – Balancing Authorities in Southeastern United States.



Data comes from publicly available Homeland Infrastructure Foundation-Level Shapefiles. Author's map.

Duke Energy and PJM share a border and multiple 500 kilovolt (kV) transmission line connections, making their two territories physically interconnected at least in part. To manage activities that may influence each other, they share a Joint Operating Agreement.[66] This long-term contract provides coordination on congestion management and an agreement on the pricing imports and exports.[67] VACAR South and PJM also have a reliability coordination agreement which "provides for system and outage coordination, emergency procedures and the exchange of data."[68] These arrangements provide the fundamental basis for coordination, but in no way guarantee efficient trade.

Southern Wholesale Energy is an Energy Exchange Market that serves as a voluntary platform matching bilateral transactions at a market-set price. However, its current geographic scope, lack of independence, and market structure all suggest the benefits of Southern Wholesale Energy market are limited in comparison to a larger market that uses centralized dispatch. In particular, its exchange-based model does not effectively identify every cost-saving opportunity, taking into account transmission congestion and other system constraints. In addition, its limited participation and geographic scope suggests it does little to better integrate renewable generation than the status quo. Public data on Southern's website show there are few transactions in the market, far fewer than what is likely to be economically efficient.[69]

Relative to the existing institutions in the Southeast, an EIM has the potential to amplify the volume of trade by establishing a centralized platform that identifies the most cost-effective ways to balance supply and demand across participating resources. Compared to the existing Southern Wholesale Energy arrangement, an EIM consistent with past implementations would have market rules established through a stakeholder process, carried out by an independent board of governance, and enforced by the market monitor. What is more, an EIM with a larger geographic scope could reduce curtailment of renewable generation.

C. Potential Benefits of an EIM in the Southeast

There are three primary potential benefits of an EIM: a reduction in the cost of production, better integration of renewable energy, and improved reliability due to enhanced coordination and the pooling of reserves. This report quantifies the first of these benefits using an open-source dispatch model and publicly available data, and then characterizes the other two qualitatively.

i. Decreased Cost of Electricity

An EIM reduces the cost of producing electricity in several ways. Most significantly, through a centralized and transparent marketplace, the market operator identifies the resources with the lowest production costs and give them priority over other high-cost resources. In this way, the same quantity of electricity is produced as if there were no EIM, but the composition of resources used to generate electricity are the ones that cost the least. For example, an EIM in the Southeastern United States would allow Duke to easily buy power from other utilities or PJM when its own cost to serve additional demand is at its highest. Likewise, it could sell excess power during times in which it can produce surplus at a low cost.

The potential for cost savings is illustrated here using an open-source dispatch model of large fossil-fuel power plants.[70] In general, this model finds the lowest cost resources to generate enough electricity in a given area to match historical hourly demand. It does this using publicly available data on production costs, output, and minimum downtime. Interested readers are directed to the appendix for a more detailed description of the model and the modeling results.

To quantify the potential production cost savings, hypothetical EIM markets are defined by grouping together different balancing authority areas in the Southeast. For each hypothetical EIM scenario, the model identifies the least-cost dispatch of electricity generators across all balancing authorities in the EIM and the corresponding market price. This is done for every hour in 2018. With Duke Energy as an example, the potential cost savings are quantified as the change in the market price of electricity under the EIM scenario relative to the simulated price under Duke Energy's least-cost dispatch, multiplied by the quantity of electricity historically produced by Duke Energy.

This simulation assumes all resources of member utilities participate in the EIM, trade is frictionless within an EIM, and any resource not in the EIM cannot buy or sell electricity to an EIM member utility. For these reasons, these numbers should be considered as an upper bound of the production cost-savings achievable by an EIM.

Table 2 presents the potential cost savings relative to Duke Energy's joint dispatch in 2018. According to the model, Duke Energy's joint dispatch of large fossil-fueled plants costs $2.2 billion without trade. This number is similar to the actual reported costs for that year prior.[71] Had the dispatch been expanded to include all utilities in North and South Carolina through a transparent market, over $100 million in benefits, or 5% of production costs, would have been realized. This number grows substantially as more balancing areas are added to the dispatch. For example, an EIM with the Carolinas and PJM could have saved Duke Energy nearly $650 million in 2018.

Table 2 – Simulated Potential Production Cost Savings that Would Have Accrued to Duke Energy in 2018 Based on Alternative EIM Scopes.

Markets as Defined in **Table 4**	Potential Production Cost Savings ($ million in 2018)		Production Cost Savings as Percent of Total Cost	
	All Hours	Excluding 10% hours with largest cost	All Hours	Excluding 10% hours with largest cost
The Carolinas	$111	$80	5%	4%
North Carolina & PJM	$579	$344	26%	16%
The Carolinas & PJM	$647	$360	30%	16%
Southeastern EIM	$549	$276	25%	13%
Eastern EIM	$548	$262	25%	12%
SEEM's Footprint	$552	$277	25%	13%

Results are based on the reduced-order dispatch model and market definitions as described in the appendix.

These estimates are large relative to similar studies, but not unreasonably so in the context of North Carolina where there are a number of relatively expensive power plants. For example, recent high-level analysis of Duke Energy's North Carolina thermal generation facilities showed production cost savings of the order of 9 to 11%, larger than the typical production cost savings attributed to participation in an organized market (3 to 9%).[72] In addition, the joint dispatch agreement between Duke Energy Progress and Duke Energy Carolinas was estimated to generate over $70 million in annual benefits alone. Even larger regional coordination should provide even greater benefits, as this modeling exercise demonstrates.

Because the simulation assumes utilities do not trade at all in the baseline scenario, some may argue the numbers in **Table 2** are inflated because Duke Energy would likely buy electricity from a neighbor before using its highest cost resource. However, this alone is not likely driving the high estimates because the simulated production quantity is based on actual historical production by Duke Energy—which would be reduced had Duke Energy imported energy.

To address this concern, however, **Table 2** also quantifies the potential production cost savings while excluding the 876 hours (10% of all hours in 2018) with the highest production cost, presumably when Duke would have a found creative way to balance supply and demand. Even still, hundreds of millions of dollars in production costs savings could have accrued to Duke Energy in 2018 had it participated in an EIM.

In addition to production cost savings through better dispatch of resources, an EIM has the potential to better accommodate renewable energy and reduce curtailments as described in more detail in the next section. This generates environmental benefits, but also production cost savings as it increases the quantity of low-marginal-cost electricity produced from the same amount of installed renewable resource capacity.

These production cost savings are likely to be much larger than the cost of an EIM. For example, one-time startup costs for the Western EIM range from $2.1 million $14 million, and ongoing costs ranging from $1.3 to $3.5 million.[73]

ii. Reduced Curtailment of Renewable Generation

Renewable resources, like wind and solar farms, reduce the cost of electricity and help states meet their climate commitments by generating electricity at a low-cost and with zero carbon emissions. However, due to the inflexibility of many existing utility generators, particularly nuclear units, renewables become increasingly challenging to integrate at high penetration rates without some degree of curtailment. Without companion storage resources, renewable production is constrained by the weather, which at times can vary minute to minute. Electricity grids with high shares of renewable generation need to coordinate thermal resources to nimbly respond to changes in renewable electricity production by increasing or decreasing production. Otherwise, renewable generation must be curtailed, wasting low-cost zero-carbon electricity.

Curtailment of renewable generation is anticipated to be a serious issue in Duke Energy's future if the status quo persists. For example, recent modeling suggests up to 42% of renewable energy in Duke's footprint will be curtailed once solar penetration reaches 35%.[74] While installing flexible storage and replacing inflexible power plants can reduce the curtailment rate,[75] however, so too can better coordination between Duke Energy and the surrounding balancing authorities.

Combining the operations of balancing authorities, through an EIM or similar organized market, provides three benefits that allow for better integration of variable resources:[76]

1. Aggregating diverse renewable resources,
2. Aggregating the load, and
3. Aggregating the non-renewable balance of generation.

The first two benefits combine patterns of electricity production (supply) and load (demand), which reduces the variability in the quantity of electricity needed to balance the electricity grid. Ultimately, this reduces the quantity of reserves needed to maintain grid reliability, further reducing the cost to the grid of accommodating renewable generation.

For example, the peak demand for electricity occurs at different times in Raleigh, NC and Birmingham, AL, in part because they are in different time zones. As demand for electricity is declining after its peak in Raleigh, demand in Birmingham is likely to be on the rise. As a result, total demand for electricity across the two cities does not vary as much as if the two cities are considered on their own and independent from each other.

Likewise, aggregating diverse renewable production profiles reduces the overall variability in aggregate renewable electricity production. This is because cloud cover in Duke Energy's footprint does not necessarily mean cloud cover in Southern Company's footprint. What is more, when the sun sets in eastern North Carolina, it is still shining in Western Kentucky. By combining the output from many different renewable resources across a wide geographic area, total production from renewable energy is less volatile. This is especially apparent compared to aggregate production in Duke Energy's footprint alone.

This general concept, in the context of the Western United States, is illustrated in **Figure 6**.[77] As the renewable energy penetration level increases, so too does the variability in renewable energy production as a fraction of total electricity demand. In **Figure 6**, each colored line represents a different footprint. Smaller footprints (like western Colorado "CO-W," Wyoming "WY," and New Mexico "NM") show a strong positive relationship between renewable energy penetration and variability. In comparison, larger footprints with more diverse assets (like most of the western United States "WECC," and a larger portion of the listed states "Footprint") show a much weaker relationship between renewable energy penetration and the variability of renewable generation as a fraction of energy demand. The largest geographic area ("WECC") even shows more renewable generation *decreases* the variability of renewable generation as a fraction of total output.

Figure 6 – Renewable Penetration, Variability, and Footprint Size.

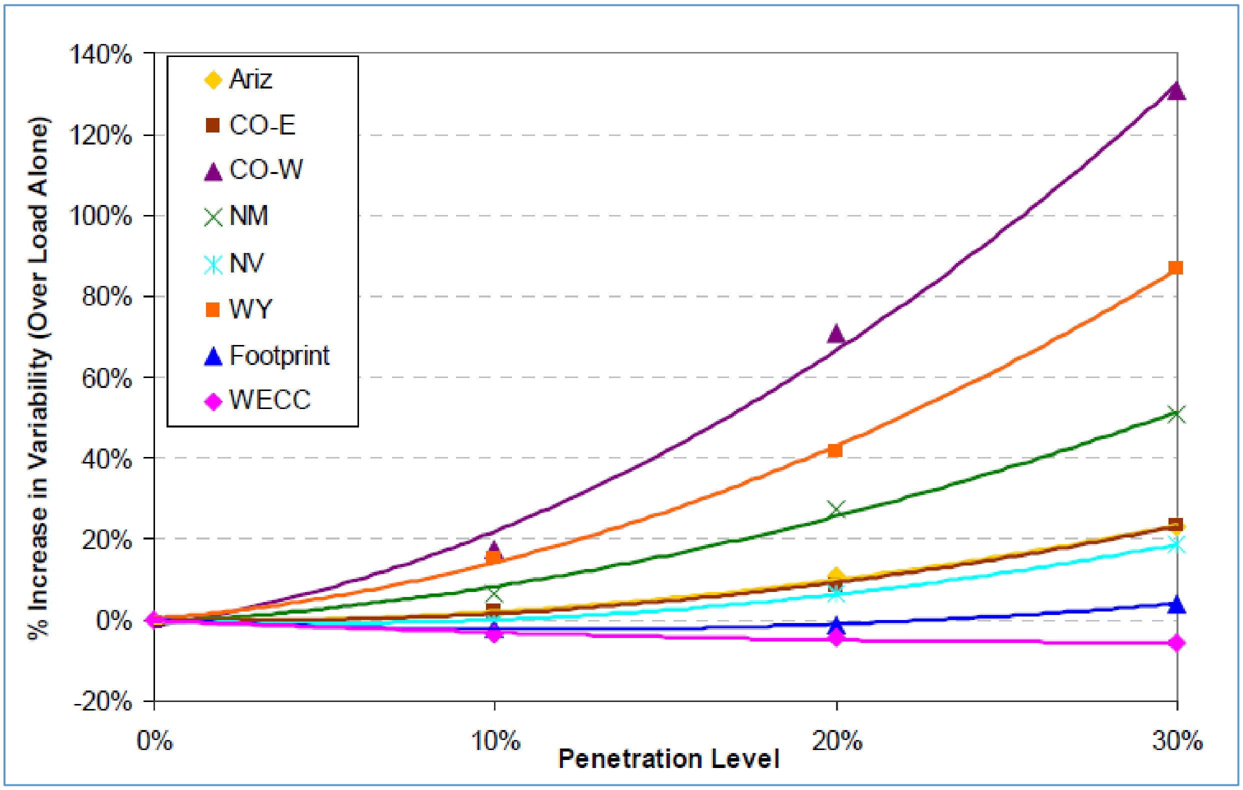


Figure showing increased renewable generation variability as a percent of demand (y-axis) with higher renewable energy penetration (x-axis) in the Western United States. Large footprints ("WECC" and "Footprint" in this setting) are associated with lower variability at higher levels of renewable energy penetration. Image Source: GE ENERGY, supra note 76 at 83.

Finally, aggregating non-renewable generation allows for the market operator to respond more easily to the remaining fluctuations in renewable supply and demand by having a larger pool of resources to potentially call on if needed. This is particularly helpful to the extent that the market pools together a larger number of fast-ramping generators. By doing so, the market operator can access the fastest-ramping least-cost units to balance renewable generation-induced fluctuations in supply. This can reduce renewable energy curtailments, and decrease the cost of balancing supply and demand.[78]

This is important in North Carolina, where both recent changes to renewable procurement and ambitious commitments to install more renewable energy suggest there can be significantly more curtailments in the future. As already mentioned, curtailment rates could reach as high as 42% without any interventions.[79] At the same time, Duke Energy now requires new solar power purchase agreements (PPAs) to provide for up to 10% uncompensated curtailment, a rate it may seek to increase in the future in the absence of an EIM or similar market.[80] This is in contrast to the diminishing number of projects being built under the Public Utility Regulatory Policies Act, which does not allow for curtailment of renewable resources except in cases of system emergency.

iii. Improved System Reliability

Reliability generally refers to the ability to meet the electricity needs of end-use customers, even when unexpected factors reduce the amount of electricity available.[81] An EIM generates reliability benefits over the traditional organization of electricity production because it aggregates all available information from market participants, and automates the response to unanticipated electricity production shortfalls.[82] This is accomplished by solving the SCED problem and short-interval (5-minute) dispatch. Ultimately, SCED allows for resources to be re-dispatched to solve electricity production shortfalls more quickly, and for it to be done in the most cost-effective way possible (considering transmission and generation constraints).

In addition, by pooling resources to balance supply and demand, an EIM allows for utilities to buy power during periods of peak demand or unexpected demand shortfalls rather than maintaining all of the resources necessary to ensure reliability. In this way, an EIM eliminates the need for many redundant balancing reserves. Instead of each utility having its own natural gas power plant on standby, for example, only a few are needed to satisfy any contingencies for the entire EIM, as reserves can more easily be imported across existing transmission lines when needed.[83]

These reliability benefits imply utilities need not invest as much in new capacity to balance supply and demand in an EIM as they would without an EIM. This is not to say an EIM is a substitute to resource adequacy investments, but that an EIM could be a substitute for investments motivated by reliability concerns. As a result, ratepayers save on capital costs and on the return they would ultimately pay the regulated utility. This is especially important given the potential of new fossil-fuel investments to eventually become stranded assets under a strict climate policy.[84]

These benefits are important for renewable integration as well. In regulated Southeast jurisdictions like Duke Energy Carolinas, Duke Energy Progress, and Dominion Energy South Carolina, variable renewable resources are now required to pay "integration charges" for every megawatt-hour of output.[85] Other Southeast utilities may impose these charges going forward, and utilities already imposing these charges may attempt to increase them over time. Utilities claim these integration charges are intended to represent the additional reserve capacity costs necessary to balance the variable output of renewable resources. Through better coordination of supply and demand with neighbors, integration charges need not be so large.

For example, by simply combining Duke Energy Carolinas and Duke Energy Progress's footprint when determining the dispatch, as an EIM would do on a much larger scale, integration costs decreased by 15% relative to treating each footprint separately.[86] These cost savings are remarkable because they are due to better coordination alone, not a costly or unproven technology. This demonstrates, on a small scale, the potential benefits of an EIM. [87]

It is likely that better coordination across the Southeastern U.S. could greatly diminish or even eliminate the capital costs required for balancing new renewable generation. For example, when the Northern States Power Company (NSP) Balancing Authority became integrated in MISO's real-time SCED dispatch in 2005, it had approximately 400 MW of wind generation and maintained approximately 80 MW of regulating reserve capacity.[88] Over the next four years, NSP tripled its wind generation capacity to 1,200 MW and maintained reliability compliance with NERC without having to adjust its regulating reserve capacity at all.[89] This experience in not uncommon. For example, the participants in the Western EIM reduced their required flexible ramping capacity by roughly 50%, compared to what they would require operating on their own.[90]

D. An EIM Compared to Alternative Reforms

An EIM is not the only option for reforming the organization of electricity production in the Southeast. This section generally compares an EIM to a Southeastern RTO, as well as public information currently available about the SEEM proposal.

i. An EIM compared to an RTO

An EIM's management of the electric power grid within its territory is not nearly as comprehensive as that of an RTO. In this sense, an EIM does not satisfy RTO fundamental characteristics #3 or #4 listed in **Table 1**, "Operational Authority" and "Short-term Reliability." As a result, many of the benefits of an RTO are not realized in an EIM. For example, coordinated capacity and transmission planning, standardized interconnection processes, more thorough market monitoring, unit-dispatch in a day-ahead market, and more complete ancillary services are all not traditionally realized in an EIM. **Table 3** characterizes traditional RTOs and EIMs, as well as other market arrangements, across a number of different measures.

An EIM and RTO both reduce production costs through SCED, facilitate the integration of renewable generation, and better coordinate operations, resulting in less capital investment and better reliability during times of peak demand. Because an EIM is voluntary, however, there might be less participation, and hence, it will likely yield benefits of smaller magnitude.

A recent report from Energy Innovation and Vibrant Clean Energy demonstrates the large potential benefits of a Southeastern RTO in comparison to the status quo.[91] In North Carolina specifically, a Southeastern RTO that includes competitive procurement new capacity, coordinated transmission planning, and centralized dispatch using SCED across the entire Southeast can generate approximately $2,400 million in economic benefits in 2025.[92] Two-thirds of these potential benefits (roughly $1,600 million) are driven by efficient capacity investment in low-cost (renewable) resources.[93] This can be achieved in an RTO or through a unbiased competitive procurement process overseen by vertically integrated utilities, but would not be part of an EIM. The remaining potential benefits (roughly $800 million) are driven by organized transmission planning, optimized use of distributed energy resources, and centralized SCED across the Southeast. The centralized dispatch benefits can be achieved under an EIM as well as an RTO.

Although an RTO can generate more benefits than an EIM, an EIM generally leaves greater authority in the hands of state regulators to administer features of the grid which they might find important. This can be consequential in states where state regulators are expected to be a major instrument of public policy – by, for example, requiring utilities to retire fossil-fuel power plants and replace them with clean alternatives. Because every interstate RTO is FERC-jurisdictional, the design of any component of an RTO will reflect FERC's perspective and theory on how that component should be implemented. This can create a conflict if an RTO requires member utilities to participate in a feature of the RTO that overlaps with state regulators' policy agenda and FERC's perspective is at odds with the goals of state regulators.

Two recent FERC decisions about capacity markets provide clear examples of how tension can arise between state and FERC policy. In December 2019, a decision regarding PJM's capacity auctions spurred Illinois, Maryland, and New Jersey to explore alternatives to participation in PJM's capacity market.[94] Similarly, a February 2020 decision regarding NYISO's capacity market led the New York Public Service Commission to commission an analysis of alternative approaches that would better align with the state's aggressive clean energy agenda.[95] Although this potential for tension might seem like a downside to RTO participation (from the perspective of state policymakers), RTOs do not inevitably operate in ways that conflict with state regulators' goals. The capacity market conflict highlighted above, for instance, has only occurred in RTOs where capacity market participation is mandatory—three out of seven—and it is possible that changes to FERC's policy in those RTOs will come to align with the goals of state regulators.

ii. An EIM compared to SEEM

What little is known about SEEM suggests that it will be an improvement over the status quo; however, it will not generate as many benefits for the Southeast as either an EIM or a Southeastern RTO.[96] Broadly, the basic market design of SEEM is an EEM (like Southern Wholesale Energy) which automates bilateral transaction between market participants based on available transmission capacity. This market design is not likely to identify the same cost-savings opportunities as an EIM that uses an "integrated" approach that solves the SCED problem. This is because the bilateral approach does not directly optimize the system considering transmission and generator constraints, nor does it directly price the cost of these constraints. Furthermore, it does not have the situational awareness to re-dispatch in response to short-run fluctuations in supply.[97]

It appears that SEEM's market will clear every fifteen minutes. This is better than existing long-run contracts and the Southern Wholesale Energy market, which clears every hour.[98] It is unclear whether or not SEEM's dispatch will be determined every five minutes, as is common in all RTOs and EIMs. Little is known about SEEM's proposed governance structure or whether there will be any market monitoring. Typical implementation of an EIM, however, includes an independent governance and market monitoring. Neither a traditional implementation of EIM or what is known of SEEM would suggest the reform would interfere with state-level resource adequacy planning like an RTO might.

Preliminary modeling suggests SEEM will generate $40 to $70 million in production cost savings over its entire footprint in the year 2027.[99] The modeled benefits are slightly larger in a "carbon-constrained" future associated with more variable renewable energy. These benefits appear small in comparison to similar potential reforms to Duke Energy and North Carolina alone. For example, this report shows an EIM could have saved Duke Energy hundreds of millions of dollars in 2018, the joint dispatch of Duke Energy Progress and Duke Energy Carolinas was supposed to generate over $70 million in annual benefits, and a Southeastern RTO has the potential to generate $2.4 billion in benefits by 2025.[100]

The estimated cost of SEEM, $5 million initially and $1 to $3 million annually, is smaller than the likely cost of an EIM (or a Southeastern RTO).[101] However, the benefits of SEEM are smaller as well. More analysis should be done to determine which arrangement can generate the most net-benefits for the Southeast, however, preliminary evidence suggests SEEM is the least net-beneficial of the potential reforms possible in the Southeast.

If a study finds benefits to an organized electricity market, state legislatures or public utility commissions can require utilities to form or join such a market. To maximize the benefits of an EIM (which allows for *voluntary* participation of power plants owned by member utilities), regulators or legislatures can require utilities to at least make a good faith effort to submit their resources to the market for consideration.

Regulators also have an important role in the rate-making process if the intent is for consumers, not utilities, to benefit from an EIM. Without properly accounting for the change in production costs, it would be possible for utilities to capture most of the benefits of an EIM, and to pass on little of the production cost savings to industrial, commercial, or residential consumers.

Table 3 – Comparing Alternative Arrangements for the Organization Electricity.

	Bilateral Contracts	*Power Pool*	*EIM*	*RTO*
Price Signals	Limited	Limited	Transparent	Transparent
Transparent Generation Data	No	No	Possible	In Aggregate
Dispatch	Utility Dispatch	Tight: Joint Dispatch Loose: Utility Dispatch	SCED of Participating Generators	SCED of All Generators
Unit Commitment	Possible	Possible	Possible	Yes
Voluntary Participation	Depends	Depends	Yes	No
Demand-Side Programs	Utility	Utility	Utility & Possible by Market	Utility & Market
Renewable Benefits	Depends	Depends	Larger Territory	Larger Territory
Ancillary Services	Depends	Depends	Some (flexible reserves)	Several (spinning, regulation)
Capacity Planning	State Regulator	State Regulator	State Regulator	RTO or State Regulator
Transmission Planning	Planning Region	Planning Region	Planning Region	RTO Planning Region, with State Engagement via Public Policy Projects
Interconnection Process	Utility	Utility	Utility	RTO
Stakeholder Process	N/A	Depends	Transparent	Transparent
Market Monitoring	No	Depends	Market Monitor	Independent Market Monitor
Governance	Utility with State Regulator Oversight	Depends	Governing Board	Governing Board

From left to right, the arrangements increase in their ability to amplify trade. SEEM is not included in this table because not enough is known at the moment. However, what little is known about SEEM would place it between a Loose Power Pool and an EIM. Of most importance, SEEM does not use SCED to determine dispatch, but instead uses automated bilateral transactions.

Currently, a number of utilities in the Southeast are separately pursuing the formation of an energy market, SEEM. This exchange-based market is not an EIM in the sense that it is not based on centralized dispatch, nor is it a more comprehensive RTO. Soon, the utilities involved are likely to file a tariff with FERC which will better outline their proposal. Duke Energy claims the formation of SEEM will not preclude the formation of an RTO at some later date, [102] and so will likely not preclude an EIM either. However, establishing SEEM only for it to be shortly upended by a better designed EIM or more comprehensive RTO would be a waste of resources for both the participating utilities and FERC. For this reason, it is important for the developers of SEEM to participate in an open dialog with all stakeholders and regulators to ensure whatever energy market is developed can generate significant benefits to the Southeast and achieve the public policy goals in the region.

Finally, incorporating utilities in the Southeast into only a component of the PJM RTO, like PJM's real-time energy market, will require discussion between PJM and the relevant utilities. Policymakers can encourage utilities to participate in this dialog and even participate in the discussion themselves. Ultimately, the dialog should be intent on establishing a Memorandum of Understanding between PJM and the participating utilities—much like the one between CAISO and PacifiCorp that led to the creation of the Western EIM.[103]

A. Market Scope Consideration

There are a number of factors to consider when determining the scope of an EIM, including the desired geographic extent, the fuel mix of potential participating utilities, the existing market constructs, and existing transmission infrastructure.

In terms of integrating renewable generation, the larger the footprint the better. With a larger footprint come more diverse load and renewable generation patterns, and subsequently less variability in required production from non-renewable resources. In addition—the more inversely correlated load and renewable generation patterns are, the better. For example, combining crepuscular wind generation from the Midwest (produced more often at dawn and dusk) with diurnal solar generation (produced more midday) results in more constant renewable generation throughout the day. Likewise, connecting regions in different time zones would reduce variability in demand for electricity and supply from solar energy.

The modeling of potential production cost savings in this report suggests that an EIM operating through PJM and including all of the Carolina utilities could generate the most benefits for Duke Energy customers. The second most beneficial scope for Duke Energy included only Duke Energy and PJM. Adding to the benefits of this arrangement, PJM has spent decades developing a comprehensive and well-functioning real-time energy market. Adding new members to the real-time market operations is not completely costless, but is likely to be much less costly than building a whole new energy market platform with from the ground up. For these reasons, an EIM extension of the PJM RTO may be one of the best options for the Southeast.

The fuel mix of utilities participating in an EIM is another important consideration. It is not always the case that adding more utilities to an EIM will decrease the average production cost within the EIM, even if doing so does generate production cost savings. For example, adding a utility with high-production cost and high demand will increase the average cost of electricity. This is not to say both regions do not experience gains from trade. Instead, the lower cost region can now export more electricity, and the higher cost region has access to lower cost electricity. Although all regions benefit from this arrangement, they do so in different ways. This highlights the importance of detailed, unit-level modeling, to quantify exactly who benefits the most from an EIM and how those benefits are realized across several market scopes.

In addition, some types of resources can better accommodate renewable generation than others. For example, pumped-hydro power plants, which are more common in the western part of the Southeastern United States, can serve as storage of potential energy during times of excessive renewable generation. An EIM could jointly optimize production from renewable resources and pumped-hydro storage. Because renewable resources are low-cost, it is more likely the pumped-hydro power plants would store energy from renewable resources than from coal-power plant. This would generate both economic savings of increased low-cost electricity production and environmental benefits of zero-carbon electricity production. For this reason, it is important to consider non-fossil resources and their production profiles when quantifying the potential benefits of a wholesale energy market.

Finally, existing transmission infrastructure is an important consideration. Currently, there are high-voltage (500 kV) transmission lines in the Southeast connecting Duke Energy to PJM through Dominion Energy and Appalachian Power Co., and to Georgia Power. This suggests that transmissions lines are an important consideration, but potentially not a limiting factor in determining which regions to include in an EIM.

B. Market Design Considerations

The design and technical details of an energy market can have significant ramifications for the benefits, costs, and outcomes realized. Generally, it is best to include both a real-time market for balancing reserves, a day-ahead market for unit-commitment, and a market for ancillary services if possible.[104] Although the last two are not essential to the design of an EIM, they should be considered as they can provide additional benefits over a real-time market for balancing reserves.

In the real-time market, an organized dispatch solving a well-considered problem like SCED is best. This integrated approach can identify all potential cost-saving opportunities while being mindful of, and directly pricing, system constraints like transmission congestion.[105] The integrated approach is also better at handling more complex problems, like co-optimized day-ahead unit commitment, should they ever be incorporated into the EIM.[106] Finally, a transparent integrated approach provides opportunities and protections for the smaller generators through an unbiased competitive structure.[107]

The more granular a time period in which the market clears, and in which dispatch instructions are given, the better. In the US, it is common to have 5-minute market periods (where generators can adjust their bids and the markets clear financially) and dispatch instructions (which are used to respond to extremely short run changes of the electricity grid).[108] This granular dispatch over time is essential for markets with large shares of renewable generation, as it increases flexibility in system operations minute to minute.[109]

Similarly, granular "nodal" prices that vary geographically are better than market-wide prices that are common in exchange-based markets. This is because location-based pricing incentivizes demand response and distributed generation where the cost (hence price) of electricity is the highest. In addition, location-based prices can help identify locations for efficient transmission and generation capacity investment, as it directly prices in the cost of transmission constraints and electricity delivery.[110]

Finally, an organized electricity market can only provide benefits to stakeholders insofar as it adheres to market principles of unbiased treatment of resources and reflects the preference of the public which it serves. For this reason, it is essential the market includes transparent and public price signals, public information on market operations, an external market monitor, and an independent governance system that includes stakeholder participation. A number of RTOs have successfully designed these features, and potential energy markets in the Southeast should look to them as an example. To date, it is unclear whether the SEEM proposal will include any of these design features.

C. *Environmental Considerations*

Finally, an EIM can provide environmental benefits by reducing curtailments from existing renewable generation while also reducing the cost to integrate renewable generation. Increasing the production from installed renewable generation capacity is a great benefit to society, as it reduces climate-warming greenhouse gas emissions and harmful local air pollutants from fossil-fuel electricity generation. In addition, reducing all barriers to renewable generation – such as integration charges – can ensure they are deployed at a scale that is compatible with state policy goals.

It is important to note, however, an EIM is far from sufficient to accomplish anything other than modest goals to reduce greenhouse gas emissions. In fact, because organized energy markets can increase the production from low-cost energy resources, it is possible the existence of an EIM can increase production from pollution intensive power plants if the pollution intensive plants can operate at a low-cost.[111] In the context of Duke Energy in the Southeast, however, the modeling in Section IV suggests the opposite. It shows an EIM reduces electricity production from Duke Energy's fossil-fueled power plants—especially older and more expensive coal-power plants. That modeling exercise doesn't identify which electricity generators are replacing Duke's fossil fuel power plants, so it is possible Duke Energy is simply importing cheaper fossil-fuel energy from another utility. However, more detailed modeling of a hypothetical Southeastern RTO, which similarly identifies the lowest-cost dispatch, shows an energy market can reduce greenhouse gas emissions significantly relative to the status quo because coal power plants are more expensive than renewable alternatives.[112]

Fundamentally, an EIM is no substitute for a well-designed climate policy. However, an organized electricity market is compatible with, and possibly even a complement to, many of the state-specific climate policy options.[113] For example, implementing a carbon price in the electric power sector or establishing a cap-and-trade program would both increase the cost of carbon-intensive electricity production (i.e. coal-fired power). Utilities subject to these types of programs have an incentive to report their pollution charges to the EIM market operator, and as a result, the EIM market operator would choose to dispatch those now higher-cost carbon-intensive power plants less often.

Ever more so, a wholesale electricity market can be designed to incorporate climate damages of electricity imported into (or exported out of) the state through border adjustments.[114] This mechanism prevents emissions leakage – whereby a policy in one region that is intended to reduce pollution is undermined by the import of pollution-generating products from outside that region. Emission leakage is a real concern in the electric power sector because of the potential of interstate electricity trade. Should a future climate policy in the southeast price carbon dioxide in some states but not others, an EIM (or RTO) can mitigate emissions leakage that would undermine the effectiveness of that policy.

IV. Conclusion

Much has changed in the electric power industry since Samuel Insull first championed the regulation of a vertically integrated monopoly utility. Now, advanced algorithms coordinating electric power production amongst utilities and across wide geographic areas can generate sizable economic, environmental, and reliability benefits. These benefits are not only supported by basic economic theory but have been demonstrated in nearly every part of the United States except for the Southeast.

This report establishes that a well-functioning electricity market can generate significant value for the Southeastern electric power sector by reducing production costs, integrating renewable generation, and improving reliability through enhanced coordination. In particular, this report advocates that a wholesale electricity market in the form of an EIM is a great first step towards a more efficient electricity grid in the Southeast. This market structure provides several of the benefits associated with more traditional RTOs, can be implemented at a relatively low cost, and guarantees state regulators retain authority over some features of electric power that they might consider to be important.

These potential benefits of an EIM can be large. For example, novel simulations show that the potential production cost savings resulting from Duke Energy participating in an EIM could have been hundreds of millions of dollars in 2018. As more renewable generation is added to the electricity grid, inter-utility coordination is more important than ever. It can reduce curtailments of renewable energy, increasing the productivity of installed renewable resources. And, better coordination through an EIM can reduce or nearly eliminate the cost of integrating more renewable generation.

Finally, this report provides several important considerations and guidelines for creating a wholesale energy market in the Southeastern United States. These considerations are important as utilities in the Southeast explore alternative arrangements to trade electricity, like the recently proposed SEEM. There are several reasons to believe an EIM extension of PJM might be the best possible option for Duke Energy at the moment, given potential cost savings and the existing, well-functioning, real-time market in PJM. Regardless, an integrated market with short-interval dispatch, location-based pricing, an independent market operator and monitor, and stakeholder engagement should be a part of whatever market is implemented in the Southeast.

At this moment, however, the most important action to take is more research. State policymakers and utilities alike should continue to pursue analysis that quantifies the costs and benefits of alternative arrangements, including an EIM. For state legislatures, this might include passing legislation to at least study the issue further. For utilities interested in reform, it is important to do analysis and modeling in a transparent way that involves a dialog with all relevant stakeholders.

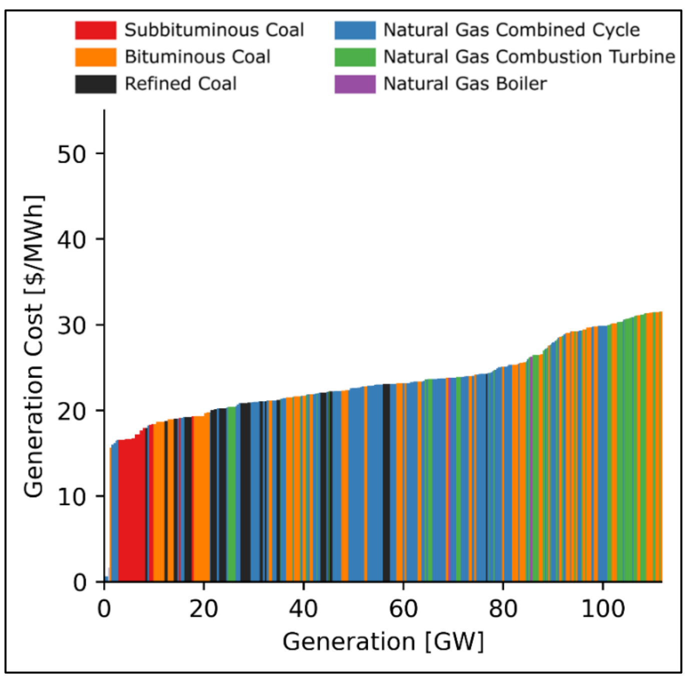
Appendix: Reduced-Order Dispatch Model

This report uses the open-source reduced-order dispatch model to quantify the potential production cost savings of better coordination amongst electricity power plants through a market construct like an EIM.[115] This model uses publicly-available data on historical fuel costs and electricity production to simulate which combination of electricity power plants can generate the same electricity as was historically produced, for every hour. It does this while minimizing production costs across all electricity generators in a geographic area and respecting historical downtime requirements of thermal generators. Interested readers are directed to Deetjan & Azevedo *supra* note 70.

The model accomplishes this by constructing a "merit-order" for every week on the sample year, which ranks large fossil-fuel electricity generators according to their cost to produce electricity.[116] An example merit-order, of large thermal electricity generators in North Carolina, South Carolina, and PJM during the first week of August is shown in **Figure 7**. This merit-order varies week-to-week according to publicly available fuel prices and observed plant-specific efficiency rates.

For every hour in the sample, the model determines which combination of resources could have produced the same quantity of electricity as historically produced by large fossil-fuel electricity generators, but at the lowest possible price, by finding where the merit-order intersects with the demand for large fossil-fuel generation. In doing this, it respects weekly limits on minimum and maximum output, as well as required down time of larger fossil-fuel power plants. Although relatively simple, this model does a good job capturing many features of the electric power system. This model is not able to model the dynamics of unit-commitment, non-fossil resources, or transmission capacity constraints.

Figure 7 – Merit-order from Reduced-Order Dispatch Model.



This merit-order reflects the cost, and maximum production output, of all large electricity generators in North Carolina, South Carolina and PJM for the first week of August in 2018

Because the merit-order represents the marginal cost to produce electricity for a corresponding quantity of fossil-fuel energy demanded, the cost of the most expensive electricity generator operating in an hour is the one that determines the market price. This price reflects only the cost of energy, not transmission losses or transmission congestion costs. As a result, this model does not capture all features of the electric power sector. Nonetheless, comparing historical electricity prices to prices simulated from the model suggests it is appropriate for broad scenario analysis.[117]

The scenarios presented in this report separately solve for the hourly dispatch of electricity generators to minimize costs using data from 2018. They do so multiple times, varying the geographic scope – defined in terms of balancing authority footprints listed in the EIA – as shown in **Table 4**.

Table 4 – Market Definitions in Dispatch Simulation Model.

Scenario	Balancing Authorities Included
Reference Case	Duke Energy Carolinas, Duke Energy Progress East, Duke Energy Progress West.
The Carolinas	**Reference Case** + South Carolina Electric & Gas, South Carolina Electric & Gas Company, South Carolina Public Service Authority, Alcoa Power Generating, Inc. (Yadkin Division).
North Carolina & PJM	**Reference Case** + PJM
The Carolinas & PJM	**The Carolinas** + PJM Interconnection, LLC
Southeastern EIM	**The Carolinas** + Southern Company Services, Inc., Southeastern Power Administration, Tennessee Valley Authority, PowerSouth Energy Cooperative
Eastern EIM	**Southeastern EIM** + **PJM**
SEEM's Footprint	**Southeastern EIM** – Southeastern Power Administration + Associated Electric Cooperative, Inc., Louisville Gas and Electric Company and Kentucky Utilities

Electricity generators within each balancing authority are identified according to EIA data.

The baseline scenario includes 74 fossil-fuel electricity generating units owned by Duke Energy, of which approximately 75% are powered by natural gas. The hourly dispatch of these electricity generators is determined assuming Duke Energy Progress and Duke Energy Carolinas are carrying out a joint dispatch that minimizes the cost of producing electricity within their footprint. Trade between Duke Energy and neighboring utilities is assumed to be equivalent to historical trade, so that the quantity produced by all of Duke Energy's large fossil-fuel resources is the same in the simulation and historical data. The result in the baseline scenario is 8760 hourly dispatches, with a single price of energy across all of Duke for every single hour simulated.

For each EIM scenario, electricity generators from neighboring balancing authorities that are now members of the EIM are added to the model and simulation procedure. The output is a single energy price for every hour in 2018 for each EIM scenario. Underlining this energy price are the assumptions that all electricity generators owned by balancing authorities in the EIM are jointly dispatched to minimize the cost of energy, there is frictionless trade between all utilities in the EIM, and trade between utilities in the EIM and outside the EIM is accurately reflected in the historical data.

For each scenario, the potential production cost savings of an EIM are calculated as the sum over all hours of the difference between the reference case energy price and the EIM scenario energy price, times the quantity historically produced by Duke Energy. This calculation assumes that Duke would have to buy from the wholesale market enough electricity to match their historical production, less the electricity they produced in each EIM scenario.

To be explicit, for each market scenario m the production cost savings are:

$$Production\ Cost\ Savings_m = \sum_t Production_t \cdot (ReferencePrice_t - ScenarioPrice_{mt}).$$

Here, $Production_t$ is the historical production of Duke Energy in hour t, and likewise $ReferencePrice_t$ is the simulated energy price of Duke Energy in hour t.

In the refence case simulation, Duke Energy produces a total of nearly 9 GWh of electricity at a price of 33 $/MWh on average. The quantity produced by Duke Energy in the baseline scenario ranges considerably from nearly 3 GWh to nearly 20 GWh, depending on the hour. This seems small relative to historical data by all electricity generators owned by Duke Energy, but that is only because the model does not simulate electricity production from nuclear or renewable electricity generators. The energy price in the reference case simulation ranges from 23$/MWh to over 100 $/MWh.

The average price of electricity in the EIM scenarios is uniformly less than 33 $/MWh. For example, in The Carolinas & PJM scenario, the simulated energy price is 26 $/MWh on average. In every alternative scenario, Duke Energy produces less electricity from both its coal and natural gas electricity generators. The reduction in coal powered electricity production is nearly always twice, if not three times, as much as the reduction in natural gas-powered electricity production across all EIM scenarios. In particular, every EIM scenario sees nearly a GWh reduction in electricity produced from the Belews Creek, Marshall, and Cliffside coal power plants on average. As currently modeled, it is unclear which electricity generators in neighboring balancing authorities are replacing these electricity generators.

The modeling results imply Duke Energy must import additional electricity across transmission lines. In reality, there are physical limits to how much electricity can be transferred along the existing transmission infrastructure. Across the alternative EIM scenarios, the simulation results suggest Duke energy must import nearly 2 to 6 GWh on average. Although this is a significant amount of electricity to import, it is not impossible (or even unlikely) for Duke Energy to import this amount of electricity. For example, the EPA Power Sector Model specifies the general Carolina region can transfer nearly 9 GWh through existing transmission lines, including a 3 GW connection with Southern Energy and nearly a 6 GW connection to PJM.[118] If anything, this highlights the importance of additional transmission capacity in generating production cost savings through better dispatch and trade.

References

[1] GREGORY MANKIW, PRINCIPLES OF MICROECONOMICS at 6-7 (4th ed. 2006). (Principles #5 & #6).

[2] Hereafter, ISOs and RTOs will be collectively referred to as RTOs. Although there are minor differences between ISOs and RTOs (for example RTOs are generally considered to be larger and have a more established role in transmission resource planning), they are effectively identical for the purpose of this report. About two-thirds of electricity demand in the United States is cleared in an organized electric market. *See*, FED. ENERGY REG. COMM'N, ENERGY PRIMER: A HANDBOOK FOR ENERGY MARKET BASICS 39 (2020).

[3] *See*, Jennifer Chen, *Evaluating Options for Enhancing Wholesale Competition and Implications for the Southeastern United States*, Nicholas Institute for Environmental Policy Solutions (2020). (Discussing EIMs and RTOs. And suggesting an RTO may have provide benefits than an EIM.); *See also,* Eric Gimon et al., *Summary Report: Economic and Clean Energy Benefits of Establishing a Southeast U.S. Competitive Wholesale Electricity Market*, Energy Innovations and VCE (2020). (Quantifying a Southeastern RTO's potential benefits.).

[4] *See* SAMUEL INSULL, CENTRAL-STATION ELECTRIC SERVICE: ITS COMMERCIAL DEVELOPMENT AND ECONOMIC SIGNIFICANCE AS SET FORTH IN THE PUBLIC ADDRESSES (1897-1914) OF SAMUEL INSULL at 199 (1915). ("I think it was some twelve years ago that I first tried to voice the idea that our business is a natural monopoly and that we must accept, with that advantage, the obligation which naturally follows, namely, regulation").

[5] *See* GREGORY MANKIW *supra* note 1 at 305; *See also, generally,* A. Michael Spence, *Monopoly, Quality, and Regulation*, 6 BELL J. ECON. 417 (1975).

[6] Samuel Insull *supra* note 4.

[7] For example, under the predominant form of regulation (cost-of-service regulation), electric power companies are fully compensated for their cost of production and thus have zero incentive to minimize their operating costs. This moral hazard can lead to wasted resources, inflated fuel and labor costs, and inefficient plant operations. *See*, Steve Cicala, *When Does Regulation Distort Costs? Lessons from Fuel Procurement in US Electricity Generation*, 105 AM. ECON. REV. 411 (2015); Kira R. Fabrizio et al., *Do Markets Reduce Costs? Assessing the Impact of Regulatory Restructuring on US Electric Generation Efficiency,* 97 AM. ECON. REV.1250 (2007). In addition, utilities typically earn profits in proportion to their capital investments. As a result, utility decision making has an inclination toward capital intensive solutions even if they are not the most efficient. *See*, *generally*, Harvey Averch & Leland L. Johnson, *Behavior of the Firm Under Regulatory Constraint,* 52 AM. ECON. REV. 1052-69 (1962).

[8] *See, generally,* Erin T. Mansur & Matthew White, *Market Organization and Efficiency in Electricity Markets*, YALE SCHOOL OF MGMT. WORKING PAPER (2009); Steve Cicala, *Imperfect Markets Versus Imperfect Regulation in US Electricity Generation,* UNIVERSITY OF CHICAGO WORKING PAPER (2019) (showing market-based dispatch reduces cost and increases trade relative to bilateral arrangements.). *See also, generally*, Cicala *supra* note 7; Fabrizio et al., *supra* note 7. (Showing how regulated utilities don't minimize costs.).

[9] *See* Severin Borenstein & James Bushnell, *The US Electricity Industry After 20 Years of Restructuring*, 7 ANN. REV. ECON. 437, 438 (2015). (Summarizing the restructuring of the electric power sector); Joskow, Paul L. "Restructuring, competition and regulatory reform in the US electricity sector." Journal of Economic Perspectives 11.3 (1997): 119-138. (Summarizing restructuring in the moment.); Paul Joskow and Richard Schmalense. MARKETS FOR POWER. 1983. (Identifying some of the benefits and costs of departing from the traditional organization of electric power.)

[10] *See* Borenstein & Bushnell *supra* note 9 at 438. ("The central premise of this article is that views of restructuring in the electricity industry over the past two decades have been driven primarily by … fluctuations in the relationship between the average cost and marginal cost of producing and delivering electricity to consumers.");

[11] The first major reform encouraging competition was the Public Utility Regulatory Policies Act of 1978 (PURPA), which encouraged competition from third parties. In the 1990s, several states legislatures and public service commissions began to directly decouple electricity generation from transmission and distribution, and encouraged, or mandated, electric utilities join or form a wholesale market. Of particular note at the Federal level, the Federal Energy Regulatory Commission promulgated Order 888 in 1996 requiring utilities to provide open access to their transmission infrastructure and Order 2000 in 1999 encouraging transmission utilities to join RTOs. Both of these Orders resulted from the Energy Policy Act of 1992. See FED. ENERGY REG. COMM'N, *supra* note 2 at 39. (Summarizing restructuring.)

[12] *See* Borenstein & Bushnell *supra* note 9 at 439-447. (Identifying these three implementations of restructuring.)

[13] *See* Borenstein & Bushnell *supra* note 9 at 439. ("There is clear evidence that competition has improved efficiency at power plants and improved the coordination of operations across a formerly balkanized power grid.") at 445 ("The creation and expansion of the RTO/ISO model may be the single most unambiguous success of the restructuring era in the United States . . . Although the early momentum for aggregating utility control areas into more regionally managed RTOs was provided by the belief that it was a necessary step toward the ultimate goal of deregulating generation and retail, the expansion of the RTO structure has come to be viewed as a valuable legacy of this period, even for states that never showed serious interest in these other aspects of restructuring.")

[14] *See* Joskow *supra* note 9 at 119-120. ("Potentially competitive segments (the generation of electricity) are being separated structurally or functionally from natural monopoly segments (the physical transmission and distribution of electricity). Prices for, entry to and exit from the competitive segments are being deregulated, and consumers are given the opportunity to choose among competing suppliers. Services provided by the natural monopoly segments are being unbundled from the supply of competitive services, nondiscriminatory access to "essential'' network facilities mandated and prices for use of these facilities determined by new regulation mechanisms that are designed to control costs better than traditional rate-of-return regulation procedures.")

[15] *See* Cramton, *Electricity Market Design*, 33 OXFORD REV. ECON. POLICY 4, 589-612, 591, (2017). ("In broadest terms, regulators seek a market design that provides reliable electricity at least cost to consumers.")

[16] *See, generally*, Jennifer Chen, *supra* note 3 at 9. (Discussing the operations of an RTO.).

[17] U.S. DEPT. OF ENERGY, *The Value of Economic Dispatch* (2005). (Defining economic dispatch, characterizing and quantifying the benefits it provides.); FED. ENERGY REG. COMM'N, *Security Constrained Economic Dispatch: Definition, Practices, Issues and Recommendations* (2006). (Summarizing SCED practices and identifying recommendations to improve SCED.); U.S. DEPT. OF ENERGY, *Economic Dispatch of Electric Generation Capacity* (2007). *See, also,* 155 FERC ¶ 61,276 ("Order 825") (requiring each RTO settle energy transactions in its real-time markets at the same time interval it dispatches energy.) Prior to Order 825, every RTO dispatched electricity generations in the real-time market every 5-minutes.

[18] *See, generally,* Cramton, *supra* note 15 at 597. (Describing a real-time energy market).

[19] *See*, Kate Konschnik, *Competition Case Study: The Southern Grids: 2000–2006*, Nicholas Institute for Environmental Policy Solutions (2019) at 2.

[20] *Id.* at 3.

[21] *Ibid.*

[22] PJM Value Proposition, https://www.pjm.com/about-pjm/~/media/about-pjm/pjm-value-proposition.ash (Accessed 08/20/2020); MISO Value Proposition Study, https://www.misoenergy.org/about/miso-strategy-and-value-proposition/miso-value-proposition/ (accessed 08/20/2020).

[23] MISO *supra* note 22 (Showing costs are roughly 10%).

[24] *See* JAMES BUSHNELL, ERIN T. MANSUR & KEVIN NOVAN, REVIEW OF THE ECONOMICS LITERATURE ON US ELECTRICITY RESTRUCTURING 24 (2017), https://arefiles.ucdavis.edu/uploads/filer_public/e0/ee/e0eefda6-9fe2-4f88-8ca6-a00f25379754/restructuring_review.pdf

[25] *See* Cicala *supra* note 8 at 1.

[26] *See* Judy Chang, Johannes Pfeifenberger, & John Tsoukalis, *Potential Benefits of a Regional Wholesale Power Market to North Carolina's Electricity Customers*, Brattle Group, (2019) at 7.

[27] PJM *supra* note 22 (Showing "Energy Production Costs" as 20% of total benefits.); MISO *supra* note 22 (Showing "Dispatch of Energy" as 10% of total benefits.).

[28] PJM *supra* note 22 (Showing "Integrating More Efficient Resources" and "Generation Investment" both as an additional 30% of total benefits.); MISO *supra* note 22 (Showing "Footprint Diversity" as over 60% of MISO's total benefits, and "Improved Reliability" as an additional 10% of the benefits.).

[29] PJM *supra* note 22 (Showing annual 10 million tons of carbon emissions avoided due to reduced curtailment.); MISO *supra* note 22 (Showing "Wind Integration" as $415 to $477 million in annual benefits.).

[30] MISO *supra* note 22 (Showing "regulation" and "spinning reserves" as 2 to 3% of total benefits.)

[31] FED. ENERGY REG. COMM'N Regional Compliance Orders, https://www.ferc.gov/industries-data/electric/overview/order-no-1000-regional-compliance-orders

[32] E.g., MISO Transmission Expansion Plan (MTEP) process. https://www.misoenergy.org/planning/planning/.

[33] PJM *supra* note 22 (Showing "Reliability" as 10% of the benefits).

[34] *See* Tony Clark, Ray Gifford and Matt Larson, Utility Dive Opinion, It's Time for Emergent Markets to Take Center Stage in Non-RTO Regions of The Country, July 27, 2020. (Discussing how RTOs are "prescribed" markets.).

[35] *See* PJM History, https://www.pjm.com/about-pjm/who-we-are/pjm-history.aspx.

[36] *See* W. M. Warwick, A Primer on Electric Utilities, Deregulation, and Restructuring of U.S. Electricity Markets, Prepared for the US DOP Federal Energy Management Program, at 5.2 (2002).

[37] *See* FED. ENERGY REG. COMM'N *supra* note 2, at 38.

[38] *See* Jennifer Chen & Michael Bardee, *How Voluntary Electricity Trading Can Help Efficiency In The Southeast*, R Street Policy Study No. 201, 6, (2020). (Describing SPP WEISS in context of voluntary electricity trading); SPP, Western Energy Imbalance Service Market, https://www.spp.org/weis.

[39] SPP *supra* note 38 (Listing utility participants.).

[40] *See* California ISO, Western EIM Benefits Report Second Quarter 2020, at 3 (2020). https://www.westerneim.com/Documents/ISO-EIMBenefitsReportQ2-2020.pdf.

[41] *Id.*, at 3, 18.

[42] *See* Robert Wilson, *Architecture of Power Markets*, 70 ECONOMETRICA 4, 1299-1340, 1303 (2002). (Identifying the difference between "integrated" and "exchange-based" (referred to as "unbundled") markets.).

[43] *See* Cramton *supra* note 15, at 608. (". . .in the late 1990s, the debate between market models was raging in the US.").

[44] In particular, there are non-convexities in the cost of electricity production due to startup costs and minimum/maximum production limits for each generator, transmission constraints, production externalities, the public good of frequency-regulation, redundant cost structures; all of which are happening nearly instantaneously in real-time.

[45] *See* Cramton *supra* note 15, at 610. ("I do believe that there are settings where the exchange model can work well . . . However, in most other settings, the integrated model has compelling advantages.")

[46] *See*, Cramton *supra* note 15 at 608. ("Today's integrated model simply does a better job of addressing and pricing the constraints via direct optimization. Efficient transmission pricing is a lead example. The exchange model operating in much of Europe is improving, but still falls short in pricing transmission congestion both within and across countries.").

[47] *See* Cramton *supra* note 15, at 608-610. (Generally discussing "Which market design is best?". For example, at 608, "The integrated model, however, better handles non-convexities and is simpler for participants.").

[48] *See* Cramton, *supra* note 15 at 590; FED. ENERGY REG. COMM'N, *Working Paper on Standardized Transmission Service and Wholesale Electric Market Design* (2002).

[49] Southern Company, Southern Wholesale Energy, https://www.southerncompany.com/about-us/our-business/southern-wholesale-energy.html (accessed 08/30/2020).

[50] John Downey, *Duke Energy, Southern Co. and others in talks to establish a Southeast energy market*, Carolina Business Journal, July 14, 2020; Maggie Shober, Potential Energy Market in the Southeast? What We Know So Far About SEEM. https://cleanenergy.org/blog/potential-energy-market-in-the-southeast-what-we-know-so-far-about-seem/.

[51] For example, if demand for electricity is expected to be 300 MW, the utility submits a base schedule showing how it can generate the 300 MW or purchase it from another utility to match forecasted demand.

[52] Economic bids are typically price-quantity pairs outlining the electricity generator's supply function. It can include other information such as the minimum and maximum it can produce economically (or in emergencies).

[53] In Western EIM, resource sufficiency tests include a balance test, a bid capacity test, a flexible ramping sufficiency test, and a feasibility test. See, Bonneville Power Administration, EIM 101 Workshop Presentation, 59, (2018). https://www.bpa.gov/Projects/Initiatives/EIM/Doc/20180913-September-13-2018-EIM-101-Workshop.pdf.

[54] If a utility under rate of return regulation does not enjoy the benefit of an EIM, because cost savings are passed on to ratepayers, they are less likely to participate in a voluntary EIM. State regulators can play an important role in requiring the utility to participate in the EIM and ensuring the production cost savings are passed on to ratepayers.

[55] *See* Chen & Bardee, *supra* note 38 at 7-8. (Discussing regulatory approval and governance, and a standalone EIM.)

[56] *See* Chen *supra* note 3 at 16 (Describing an Energy Imbalance Market or Service.)

[57] Western Energy Imbalance Market, Join EIM, https://www.westerneim.com/Pages/JoinEIM.aspx..

[58] For example, Western Energy Imbalance Market, Energy Imbalance Market – benefit assessments: https://www.westerneim.com/Pages/documentsbygroup.aspx?GroupID=7DF86332-C71D-44B7-836B-56181A694C8C. (A catalog of the benefit-cost analysis done by the Western EIM's current members prior to joining the Western EIM.)

[59] *Id. See, specifically,* Puget Sound Energy, Benefits Analysis of Puget Sound Energy's Participation in the ISO Energy Imbalance Market at 2, https://www.westerneim.com/Documents/PugetSound-ISO_EnergyImbalanceMarket-BenefitsAnalysis.pdf. ("These startup costs, … ongoing costs and annual benefits … would produce a Net Present Value (NPV) of $153.7 million to $174.4 million.")

[60] For example, the current tariff for the Western EIM is filed by CAISO. See, California Independent System Operator Corporation Fifth Replacement Electronic Tariff, Section 29, August 1, 2019: http://www.caiso.com/Documents/Section29-EnergyImbalanceMarket-asof-Aug1-2019.pdf

[61] *See*, Bonneville Power Administration, *supra* note 53 at 26.

[62] *See* FED. ENERGY REG. COMM'N *supra* note 2 at 61. ("Volumes for short-term transactions can be low, particularly under normal weather conditions. . . The Southeast has relatively low volumes of short-term trades compared to the Western regions . . [there is a] relatively small market for short-term transactions.")

[63] *See* FED. ENERGY REG. COMM'N *supra* note 2 at 61.

[64] *See* FED. ENERGY REG. COMM'N *supra* note 2 at 61.

[65] *See* State of North Carolina Utilities Commission, "Order Approving Merger Subject to Regulatory Conditions and Code of Conduct," In the Matter of Application of Duke Energy Corporation and Progress Energy, Inc., to Engage in a Business Combination Transaction and to Address Regulatory Conditions and Codes of Conduct, Docket Nos. E-2, SUB 998, E-7, SUB 986, pp. 29. https://dms.psc.sc.gov/Attachments/Matter/0db7d38b-155d-141f-2376ec5bc8152322 ("According to the Compass Lexecon Study, total system savings over five years attributable to joint dispatch, using base case assumptions, are expected to be as follows: 2012 – $38 million; 2013 – $49 million; 2014 – $64 million; 2015 – $97 million; and 2016 – $116 million.")

[66] *See* Monitoring Analytics, *Quarterly State of the Market Report for PJM: January through March*, 397, (2018). http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2018/2018q1-som-pjm-sec9.pdf

[67] *Id.*

[68] *Id.* at 403. VACAR South Includes: Duke Energy Carolinas, LLC (DUK), Duke Energy Progress (DEP), South Carolina Public Service Authority (SCPSA), Southeast Power Administration (SEPA), South Carolina Energy and Gas Company (SCE&G) and Yadkin Inc. (a part of Alcoa)

[69] Southern Company Auction Clearing Prices are available here, https://www.southerncompany.com/about-us/energy-auction/auction-clearing-prices.html.

[70] *See* Azevedo. See, Thomas A. Deetjen & Inês L. Azevedo " Reduced-Order Dispatch Model for Simulating Marginal Emissions Factors for the United States Power Sector." 53 Environmental Science & Technology 17, 10506-10513, (2019). https://doi.org/10.1021/acs.est.9b02500.

[71] *See* Chang et al., *supra* note 26 at 7. (Showing Duke Energy's operating cost of over $2 billion in 2017.)

[72] *See* Chang et al., *supra* note 26 at 7. ("Based on this high-level analysis, we estimate that production cost savings from Duke joining PJM could be as high as 9% to 11%").

[73] *See* PacifiCorp-ISO Energy Imbalance Market Benefits at 14, https://www.westerneim.com/Documents/PacifiCorp-ISOEnergyImbalanceMarketBenefits.pdf. ("For a PacifiCorp-ISO EIM, ISO estimates that PacifiCorp would incur a one-time fixed charge of approximately $2.1 million and $1.35 million per year in administrative charges"); Benefits Analysis of Puget Sound Energy's Participation in the ISO Energy Imbalance Market at 2, https://www.westerneim.com/Documents/PugetSound-ISO_EnergyImbalanceMarket-BenefitsAnalysis.pdf. ("PSE staff has estimated that PSE would incur one-time EIM startup costs of $14.2 million including contingency costs, and ongoing costs of approximately $3.5 million per year.")

[74] *See* Reiko Matsuda-Dunn, Michael Emmanuel, Erol Chartan, Bri-Mathias Hodge, and Gregory Brinkman. 2020 at *vi*. Carbon-Free Resource Integration Study. Golden, CO: National Renewable Energy Laboratory. NREL/TP-5D00-74337. https://www.nrel.gov/docs/fy20osti/74337.pdf.

[75] *Id.*

[76] *See* GE ENERGY, WESTERN WIND AND SOLAR INTEGRATION STUDY 311 (2010) (prepared for National Renewable Energy Laboratory). *See also* PAUL DENHOLM & ROBERT MARGOLIS, NAT'L RENEWABLE ENERGY LAB., ENERGY STORAGE REQUIREMENTS FOR ACHIEVING 50% SOLAR PHOTOVOLTAIC ENERGY PENETRATION IN CALIFORNIA 12 (2016), https://www.nrel.gov/docs/fy16osti/66595.pdf.

[77] *See* GE ENERGY, *supra* note 76 at 83.

[78] To the extent that the cost of balancing reserves are borne by third-party suppliers of renewable energy, as is now the case in the Carolinas, they unnecessarily penalize, and potentially inhibit, the development of renewable resources.

[79] *See* Matsuda-Dunn et al., *supra* note 74.

[80] *See* Duke Energy Carolinas, LLC and Duke Energy Progress, LLC CPRE RFP Tranche 2, at 16, Oct. 2019, https://dms.psc.sc.gov/Attachments/Matter/327ceaca-88d7-454a-8f87-801b620897f6 ("DEP/DEC has the right to curtail energy from the Facility up to 10% of the Facility's annual energy production in the DEP jurisdiction and 5% in the DEC jurisdiction, without compensation to the Facility owner.")

[81] *See* Federal Energy Regulatory Commission staff paper, *Qualitative Assessment of Potential Reliability Benefits from a Western Energy Imbalance Market*, at 1 (2013).

[82] *Id*., at 4, 8

[83] In application, an EIM might place limits on how much a Balancing Authority can "lean-on" the EIM to balance supply and demand. This is to prevent the free-riding problem inherent with public goods, which in this case includes the service of providing excess reserves. This is the case in the Western EIM. *See* Bonneville Power Authority *supra* note 53.

[84] *See* Environmental Defense Fund, Managing the Transition, Practice Solutions for Stranded Gas Asset Risk in California: https://www.edf.org/sites/default/files/documents/Managing_the_Transition_new.pdf

[85] *See, for example,* Public Service Commission of South Carolina Order NO. 2019-881, at 31.

[86] *See* Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Reply Comments, NCUC Docket No. E-100, Sub 158, at pp. 92-94.

[87] *See* Direct Testimony of R. Thomas Beach, On Behalf of NCSEA, NCUC Docket No. E-100, Sub 158, 17.

[88] *See* Federal Energy Regulatory Commission staff paper, Qualitative Assessment of Potential Reliability Benefits from a Western Energy Imbalance Market (2013), at 18.

[89] *Id.*

[90] *See* California ISO, *supra* note 40, Table 9 at 21.

[91] *See* Gimon et al., *supra* note 3

[92] *See* Gimon et al., *supra* note 3. *See also,* Energy Innovation, Southeast U.S. Wholesale Electricity Market/RTO Online Data Explorer, https://energyinnovation.org/2020/08/25/southeast-wholesale-electricity-market-rto-online-data-explorer/ (accessed 9/6/2020).

[93] *See* Energy Innovation *supra* note 92. (Displaying the total resource costs in North Carolina for 2025. IRP (status quo) scenario reports total resource costs of approximately $13.6 billion. Economic IRP (including competitive capacity procurement) scenario reports total resource costs of approximately $12 billion. RTO scenario (including competitive capacity procurement, optimized dispatch, capacity planning, and distributed resource optimization) scenario reports total resource costs of approximately $11.2 billion.)

[94] *See, e.g.*, Sonal Patel, Power Magazine, The Significance of FERC's Recent PJM MOPR Order Explained, https://www.powermag.com/the-significance-of-fercs-recent-pjm-mopr-order-explained/; *See also, e.g.*, Robert Walton, Utility Dive, New Jersey looks to exit PJM capacity market, worried MOPR will impede 100% carbon-free goals, March 31 2020.

[95] *See, e.g.,* Jeff St. John, *FERC Decisions Could Undermine Renewables and Energy Storage in New York Capacity Markets,* Greentech Media, February 21, 2020.

[96] *See* Chen & Bardee *supra* note 38 at 10.

[97] *See*, Cramton *supra* note 15 at 608. ("Today's integrated model simply does a better job of addressing and pricing the constraints via direct optimization. Efficient transmission pricing is a lead example.")

[98] Southern Company System Intercompany Interchange Contract (2007) at 23.

[99] *Supra* **Table 4** for a description of SEEM's footprint.

[100] State of North Carolina Utilities Commission *supra* note 65; Gimon et al., *supra* note 3.

[101] *See* Chen & Bardee, *supra* note 38 at 9. *See supra* note 73 for costs of an EIM.

[102] *See* John Downey, *supra* note 50. (Quoting Duke staff.).

[103] Energy Imbalance Memorandum of Understanding, https://www.westerneim.com/Documents/ISO-PacifiCorpMOU_Effective20130212.pdf

[104] *See*, Cramton *supra* note 15 at 593. (Describing a successful market design.)

[105] *See*, Cramton *supra* note 15 at 608. ("Today's integrated model simply does a better job of addressing and pricing the constraints via direct optimization. Efficient transmission pricing is a lead example. The exchange model operating in much of Europe is improving, but still falls short in pricing transmission congestion both within and across countries.")

[106] *See*, Cramton *supra* note 15 at 608. ("The integrated model, however, better handles non-convexities and is simpler for participants.")

[107] *See*, Cramton *supra* note 15 at 608. ("The integrated model provides opportunities and protections for the smaller generators that may be missing in the exchange model. . . The integrated model also supports competition through transparency")

[108] *See* FERC *supra* note 17.

[109] *See*, IRENA, Innovation Landscape Brief: Increasing Time Granularity on Electricity Markets, International Renewable Energy Agency, Abu Dhabi, (2019) at 8.

[110] *See*, IRENA, Innovation Landscape Brief: Increasing Space Granularity in Electricity Markets, International Renewable Energy Agency, Abu Dhabi, (2019) at 7.

[111] *See*, *e.g.*, Paul Brehm & Yiyuan Zhang, The Efficiency and Environmental Impacts of Market Organization: Evidence from the Texas Electricity Market, Working Paper (2019), https://www2.oberlin.edu/faculty/pbrehm/BrehmZhang_Electricity_Mkt_Structure.pdf.

[112] *See*, Eric Gimon et al., *supra* note 3 at 13. (Showing 46% reduction in carbon dioxide emissions by 2040.)

[113] *See*, COMMENTS OF THE INSTITUTE FOR POLICY INTEGRITY BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO, Proceeding No. 19M-0495E, at 12.

[114] *See*, MATT BUTNER ET AL., CARBON PRICING IN WHOLESALE ELECTRICITY MARKETS: AN ECONOMIC AND LEGAL GUIDE 14 (2020), https://policyintegrity.org/publications/detail/carbon-pricing-in-wholesale-electricity-markets.

[115] Deetjen & Azevedo *supra* note 70. The entirety of the model's code, written in python, can be found at https://github.com/tdeetjen/simple_dispatch.

[116] In this setting "large" means >25 MW capacity. The model only includes these electricity generators because only their hourly production is publicly available through EPA's Continuous Emissions Monitoring System.

[117] Figure S5 in Thomas A. Deetjen & Inês L. Azevedo. "Supporting Information: A reduced-order dispatch model for simulating marginal emissions factors for the U.S. power sector." https://pubs.acs.org/doi/suppl/10.1021/acs.est.9b02500/suppl_file/es9b02500_si_001.pdf

[118]EPA Power Sector Modeling Platform v6 using IPM , Table 3-21 Annual Transmission Capabilities of U.S, https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6-november-2018-reference-case

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