

Attachment E-1

Benefits Analysis by Guidehouse Inc. and CRA International



Southeast EEM Benefits and Non-Centralized Costs

Southeast EEM Benefits and Non-Centralized Costs

Prepared for:

Participants in Southeast Energy Exchange Market

Submitted by:

Guidehouse, Inc.

1200 19th Street NW

Suite 700

Washington, DC 20036

Charles River Associates Inc.

200 Clarendon Street

Boston, MA 02116-5092

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Southeast EEM Benefits and Non-Centralized Costs

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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>.



Southeast EEM Benefits and Non-Centralized Costs

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 Benefits and Non-Centralized Costs

Southeast EEM Overview

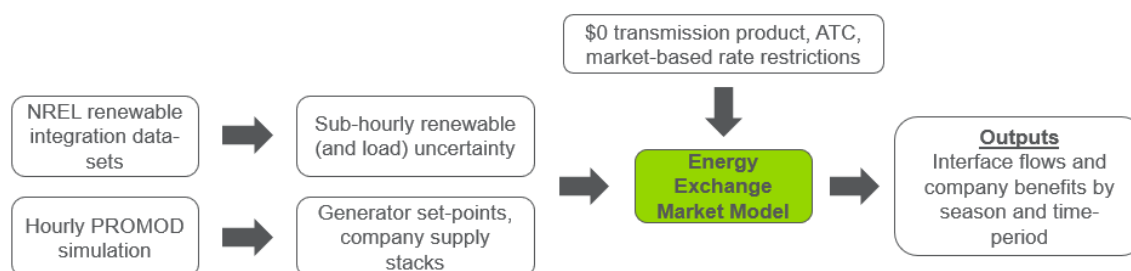
Under the proposed Southeast EEM, there will be 15-minute intra-hour trading across Southeast EEM participant interfaces, making use of any remaining non-firm ATC, with bids and offers matched through a platform to be developed by a third-party vendor with access provided to each of the Southeast EEM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

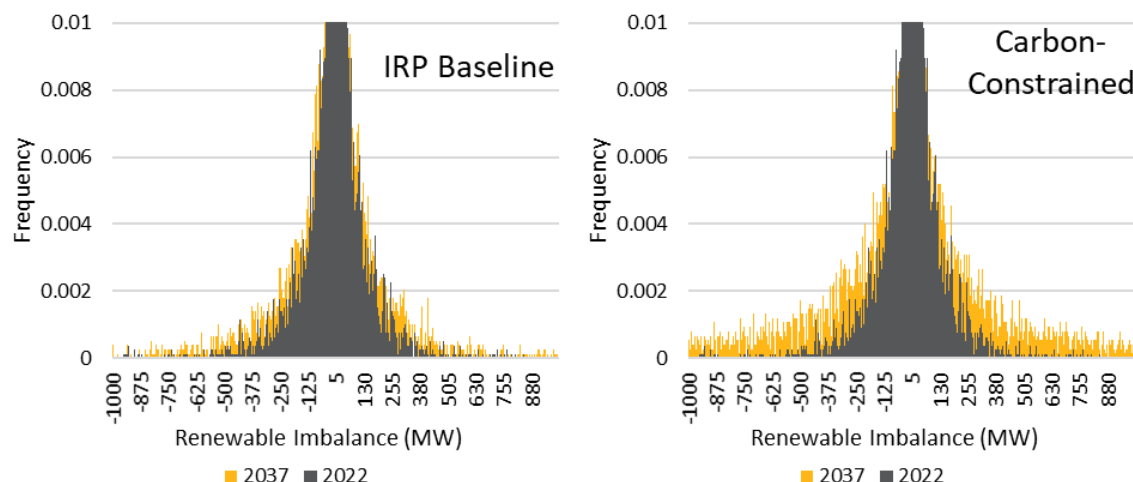
³ PROMOD is a detailed energy production cost model used to simulate hourly chronological operation of generation and transmission resources on a nodal basis.

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.

Southeast EEM Benefits and Non-Centralized Costs

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

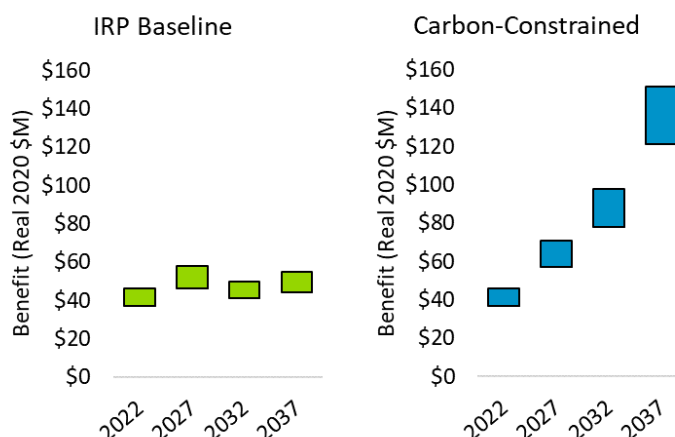
As shown in Figure 3, Southeast EEM benefits (prior to netting any Southeast EEM start-up or operating costs) average \$47M per year (2020\$) in the *IRP Baseline Outlook*. Benefits increase slightly in the mid-term largely as a result of higher renewable penetration, before stabilizing for the remainder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



Southeast EEM Benefits and Non-Centralized Costs

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\$).



Southeast EEM Benefits and Non-Centralized Costs

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.

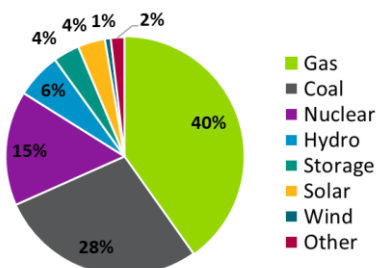
Guidehouse/CRA estimated Southeast EEM benefits against a status quo case of no intra-hour interface trading, with two market outlooks evaluated: an *IRP Baseline Outlook* and a *Carbon-Constrained Outlook*. For purposes of the benefits analysis, Southeast EEM operations are assumed to begin in 2021,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



Southeast EEM Benefits and Non-Centralized Costs

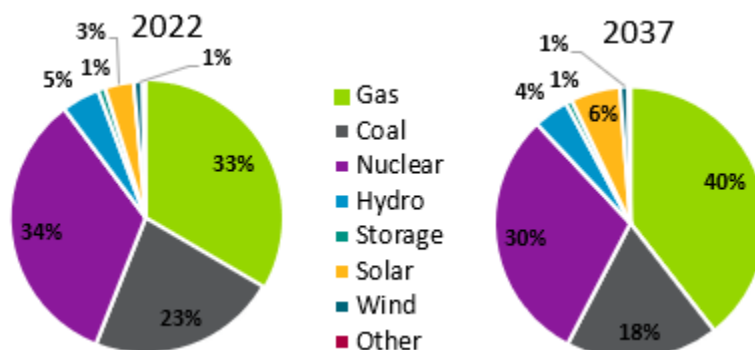
The two market outlooks considered in the study represent two plausible futures of how the Southeast power system could evolve over the next two decades and give insight into how benefits may change as the resource mix evolves.

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

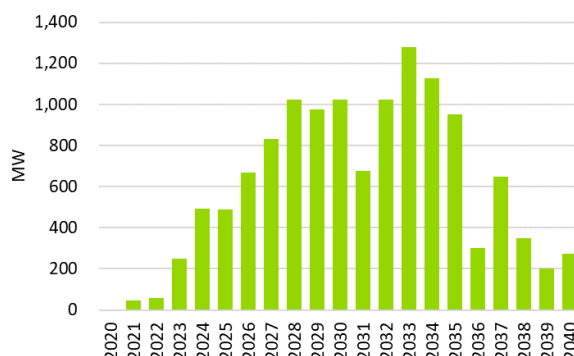


1.2.2 Carbon-Constrained Outlook

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.

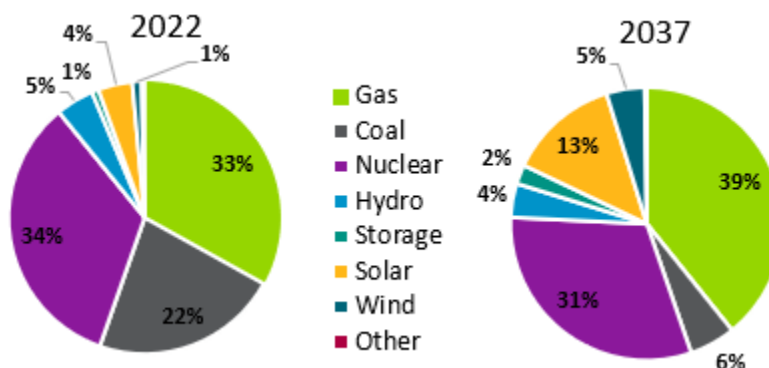
Southeast EEM Benefits and Non-Centralized Costs

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 Benefits and Non-Centralized Costs

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. PROMOD simulates a security-constrained unit-commitment and dispatch for the entire Eastern Interconnect, including each BA within the Southeast EEM footprint. Throughout the study, the unit-commitment and dispatch provide schedules for energy and sufficient operating reserves and other ancillary services, based on requirements specified by the participants. Once the commitment schedule is set and units are dispatched to satisfy BA load, PROMOD next simulates bilateral trading among BAs, including BAs outside of the Southeast EEM footprint. The simulation of bilateral trading employs interface constraints and hurdle rates to represent transmission costs and other factors limiting inter-BA trading. The reasonableness of the resulting physical bilateral trades was verified by comparing to trading levels taking place today.

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 PROMOD⁹ are also eliminated in the sub-hourly modeling to reflect the Southeast EEM centralized bid matching. Due to the complexity of the required modeling, only four years within the study period were explicitly modeled (2022, 2027, 2032, and 2037). This was sufficient to assess the potential value of the Southeast EEM. The modeling process is illustrated in Figure 8.

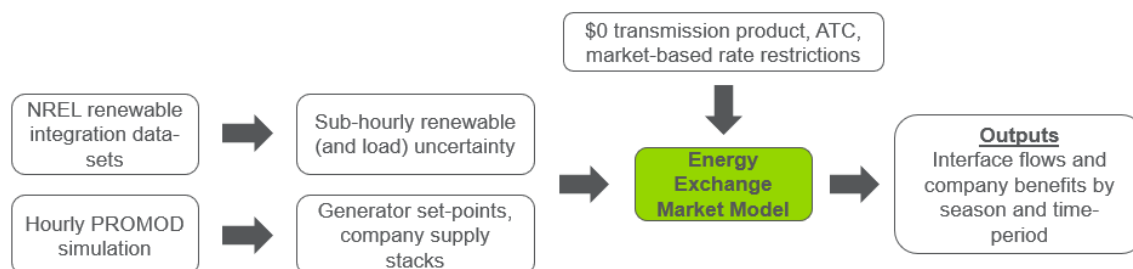
⁷ Detailed production cost modeling assumptions used in this study, including capacity additions and retirements, natural gas price forecasts, emissions price forecasts and load growth, are provided in Appendix A.

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.

Southeast EEM Benefits and Non-Centralized Costs

Figure 8. Southeast EEM Modeling Flow Diagram



1.3.3 Load and Renewable Uncertainty

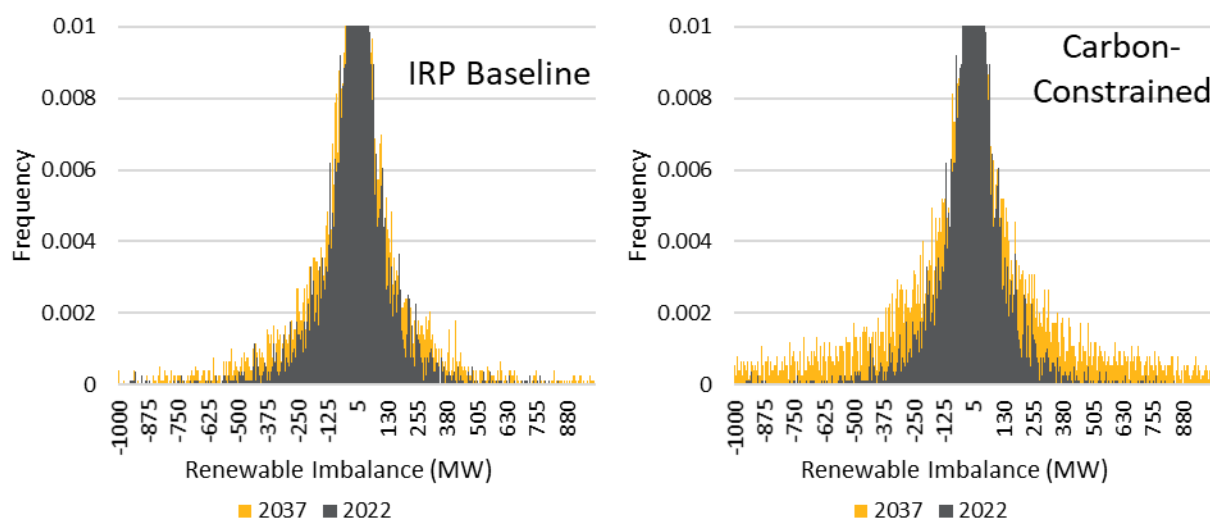
To estimate sub-hourly renewable imbalances, Guidehouse relied on NREL's geospatial Solar and Wind Integration Data Sets to simulate random days of renewable operations. These random days simulate historical operation of renewable resources including impacts of regional weather and geographic diversity. 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 ($ACE \sim Output - Schedule$). 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.

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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 days¹⁰ 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

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.



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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.

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



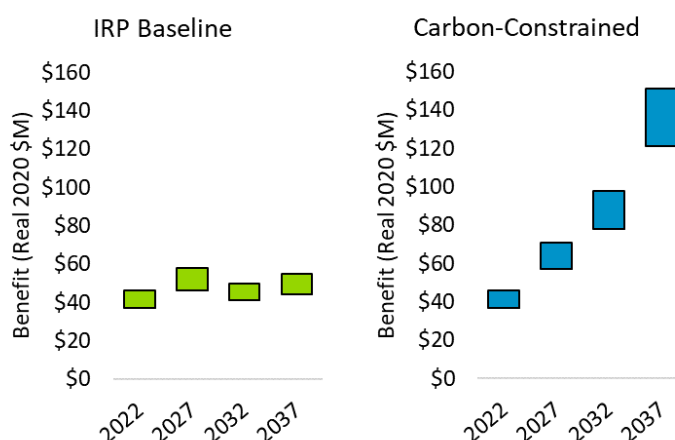
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2. SOUTHEAST EEM BENEFITS

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.

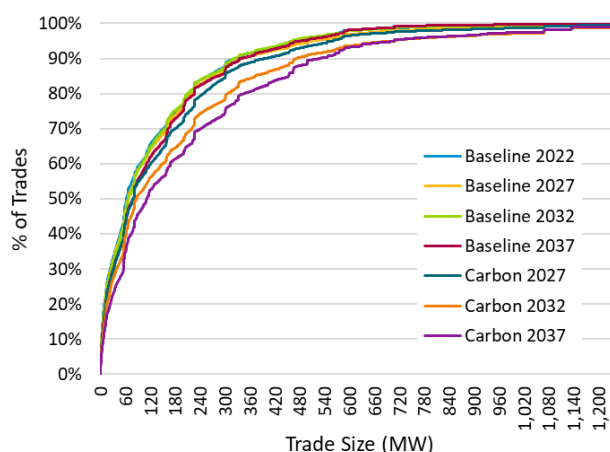
Southeast EEM Benefits and Non-Centralized Costs

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 Several factors explain the relatively large average size of the bilateral trades estimated by the Southeast EEM model. In the Southeast EEM model, intra-hour bilateral trades occur that become economic due to the elimination of hurdle rates applicable to daily and hourly schedules. Additionally, intra-hour trades are scheduled in the model even if their margin is low, until no further trades are possible due to ATC limits. Sensitivity analysis discussed further in Section 2.3 shows that even if many of these large trades simulated by the Southeast EEM model did not occur in practice, the benefits estimated in this study would not be significantly impacted.

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

Southeast EEM Benefits and Non-Centralized Costs

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

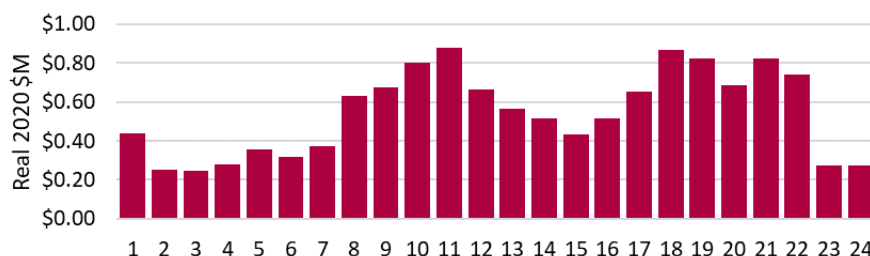


Figure 13. Average Winter Season Benefits Aggregated by Time of Day – IRP Baseline

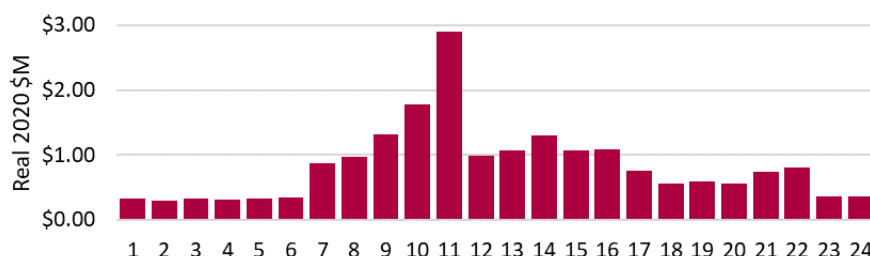
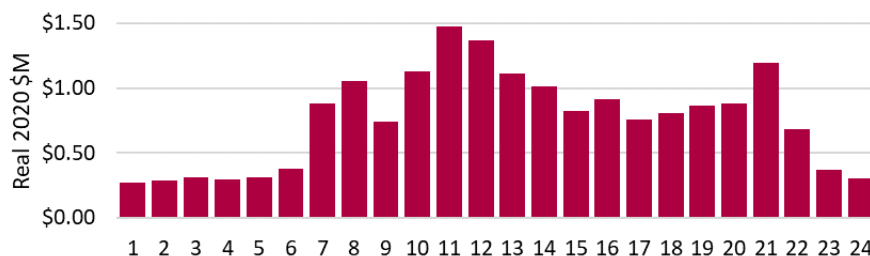


Figure 14. Average Shoulder Season Benefits Aggregated by Time of Day – IRP Baseline





Southeast EEM Benefits and Non-Centralized Costs

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. This suggests that the majority of the benefits estimated in the study occurred for trades using ATC up to 200 MW with additional trades, utilizing available ATC, showing diminishing marginal benefits. 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.



Southeast EEM Benefits and Non-Centralized Costs

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 training 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
<ul style="list-style-type: none"> • Legal and Regulatory Costs • Meetings, Travel, and Training • Hardware and Software Costs 	<ul style="list-style-type: none"> • Labor (addition of full-time employees) <ul style="list-style-type: none"> ○ Rates and Regulatory ○ Traders ○ Schedulers ○ IT ○ Other • Non-labor <ul style="list-style-type: none"> ○ 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.



Southeast EEM Benefits and Non-Centralized Costs

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.

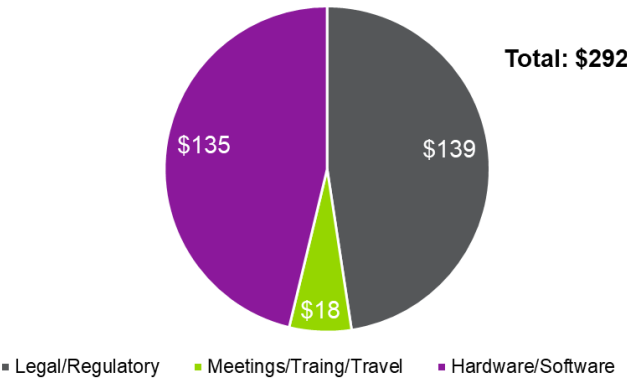
3.2 Start-up Costs

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.

Southeast EEM Benefits and Non-Centralized Costs

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)

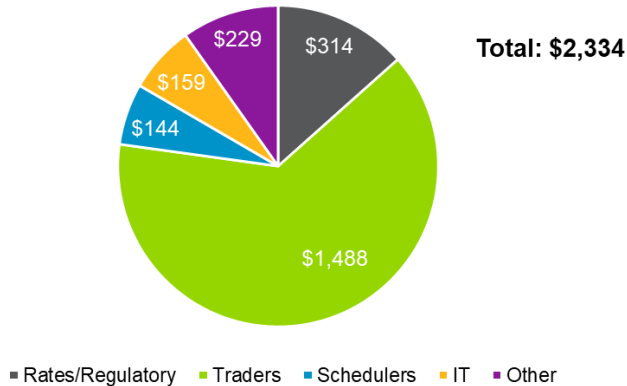
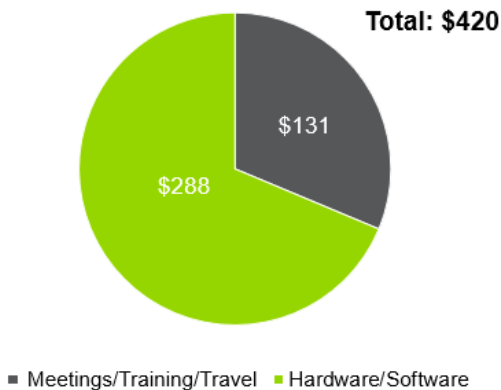


Figure 17. Real 2020\$ Levelized Annual Non-Labor Costs (\$000)





Southeast EEM Benefits and Non-Centralized Costs

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.



Southeast EEM Benefits and Non-Centralized 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

Southeast EEM Benefits and Non-Centralized Costs

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



Southeast EEM Benefits and Non-Centralized Costs

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



Southeast EEM Benefits and Non-Centralized Costs

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



Southeast EEM Benefits and Non-Centralized Costs

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



Southeast EEM Benefits and Non-Centralized Costs

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

Southeast EEM Benefits and Non-Centralized Costs

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%



Southeast EEM Benefits and Non-Centralized Costs

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 17 th , 2020	April 20 th , 2020	April 21 st , 2020	April 22 nd , 2020	April 23 rd , 2020	April 24 th , 2020	April 27 th , 2020
Dominion Energy South Carolina Duke Energy Progress and Carolinas	PowerSouth	GTC, GSOC, OPC	ElectricCities 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

Figure 18. Cost Template

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